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-21148
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

MICHAEL A. TORREY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

Q. Please state your name and business address.

A. My name is Michael A. Torrey, 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 its Vice President, Rates and Regulation.

Q. Please describe your educational background.

A. I graduated from the University of Michigan-Flint in 1982 with a Bachelor of Business Administration in Accounting degree, and in 1992, I earned a Master of Business Administration degree with a finance major from Western Michigan University. I have also completed courses and seminars in utility accounting, economics, finance, and ratemaking.

Q. Please describe your professional experience.

A. In May 1983, I joined Consumers Energy's Nuclear Operations Department as a Graduate Accountant assigned to the Controllers Department at the Palisades Plant. I progressed through several levels of increasing responsibility during my Palisades Plant assignment, achieving the position of Senior Accounting Analyst in April 1993. In July 1998, I was appointed Director of Revenue Requirements, Cost Analysis and Planning in the Company's Rates Department. In December 2006, I was promoted to Executive Director-Rates. In March 2015, my responsibilities were expanded to include Regulatory Affairs. In July 2016, I was promoted to Vice President, Rates and Regulation.

Q. What are your responsibilities as Vice President, Rates and Regulation?

A. I am responsible for ratemaking and regulatory activities at Consumers Energy, including revenue requirements, cost of service, rate design, tariff administration, Consumers Energy's Michigan Public Service Commission ("MPSC" or the "Commission") compliance program, as well as regulatory affairs and policy.

Q. Are you a member of any professional organizations?

A. Yes. I am a member of the Institute of Management Accountants, a worldwide association of accountants and finance professionals. I also belong to Beta Gamma Sigma, the honor society of the business school accreditation organization the Association to Advance Collegiate Schools of Business. In addition, I am a member of School of Management's Advisory Board at the University of Michigan – Flint.

Q. Have you previously testified before the Commission?

A. Yes. I have sponsored testimony in the following Consumers Energy cases:

U-12891	Electric Restructuring Implementation Costs;
U-13000	Gas General Rate Case;
U-13380	Stranded Cost;
U-13720	Stranded Cost;
U-13715	Securitization;
U-14098	Stranded Cost;
U-14274	Power Supply Cost Recovery ("PSCR") Plan;
U-14347	Electric General Rate Case;
U-14992	Palisades Sale;
U-14981	Midland Cogeneration Venture Limited Partnership Sale;

U-15290	Balanced Energy Initiative;
U-15415	PSCR Plan;
U-15611	Big Rock Decommissioning Reconciliation;
U-16191	Electric General Rate Case;
U-16861	Department of Energy Litigation Settlement Proceeds;
U-17473	Power Plant Securitization;
U-17990	Electric General Rate Case;
U-18124	Gas General Rate Case;
U-18322	Electric General Rate Case;
U-18424	Gas General Rate Case;
U-20134	Electric General Rate Case;
U-20165	Integrated Resource Plan;
U-20322	Gas General Rate Case;
U-20650	Gas General Rate Case; and
U-20963	Electric General 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, including a summary of the key drivers. I will highlight the customer value and benefits related to the proposals presented in this proceeding. Finally, I will address from a policy perspective, certain issues detailed in the direct testimony and exhibits of several Company witnesses.[1]

[1] There are references to other witnesses' testimony and work product throughout this testimony. For the readers' convenience, a table of witness names and topics is included as Appendix 1.

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

A. No, I am not.

Q. How is your direct testimony organized?

A. My direct testimony is organized as follows:

I. <u>CUSTOMER VALUE</u>

II. <u>KEY DRIVERS</u>

III. <u>CUSTOMER IMPACTS</u>

IV. <u>ADJUSTMENT MECHANISMS AND ACCOUNTING REQUESTS</u>

V. <u>SUMMARY</u>

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 135 years. Today, the Company provides natural gas service to 1.8 million customers in Michigan's lower peninsula.

Q. Why is Consumers Energy initiating this proceeding?

A. The Company initiated this proceeding to request rate relief that will fund critical capital infrastructure investments and key financial and operational items necessary to continue to provide customers safe, reliable, affordable, and increasingly clean natural gas service. The Company's net zero methane emission goal for its natural gas business by 2030 requires continued investment as it moves forward with implementing the Natural Gas Delivery Plan ("NGDP") put forth in Exhibit A-45 (NPD-1).

I. CUSTOMER VALUE

Q. How does customer value impact the Company's decisions?

A. The Company's day-to-day focus is to enhance and improve service to customers and to care for the communities where its employees live and work. That means supplying safe, reliable, affordable energy to warm homes and power businesses. It also means acting as a good corporate citizen and committing not only financial resources, but also the time and talents of the Company's employees, to enhance the quality of life for those the Company serves by providing reliable and increasingly clean energy. Most importantly, it means ensuring a safe natural gas system for both the public and the Company's employees. Consumers Energy's core commitment to serving customers, communities, and Michigan has guided the Company's decisions for the past 135 years.

Q. What are some of the customer benefits that will be enhanced by the proposals in this proceeding?

A. Customer benefits may be considered in four categories:

1. **Safety** – First and foremost, customers expect natural gas to be delivered safely to their homes and businesses. They expect the Company to quickly detect and diagnose at-risk distribution pipe, as well as replace any damaged or aged pipe through risk-based approaches to maximize system risk reduction, and to ensure that the Company's natural gas infrastructure will continue to deliver gas safely to customers for years to come. Customers also expect that when an issue is identified, it gets addressed in a timely and efficient manner. Finally, customers expect transparency about what is being done to ensure system safety and how they can be best prepared to handle any safety related issue;

2. **Reliability** – Customers expect gas to be available for their use whenever they need it – regardless of weather conditions. They expect the Company to leverage technology advancements, make investments in pipelines, compressor stations, storage fields, demand response ("DR"), and other infrastructure necessary to ensure reliable delivery. Customers also expect the Company to keep them informed about work being done to improve all aspects of gas delivery;

3. **Customer Value** – Customers consider the price they pay, the service received, and the level of effort or ease of their transaction when assessing value. The focus is to keep residential and small business bills affordable and prices to larger businesses competitive while service is maintained or improved, where necessary. Investments that help reduce operating and maintenance ("O&M") costs and/or improve the Company's ability to access and store gas supply also help maintain affordability and price stability. Regarding service, the Company leverages customer data from the Customer Experience Index ("CXi") score developed by Forrester, J.D. Power, Customer Effort as measured by Gartner, and other sources such as on-time delivery and call center metrics, to ensure the Company's proposals provide value for customers and support ease of use. This includes investments in technology, security, metering, customer service, customer experience, reliability, safety, and communications; and

4. **Clean** – Customers expect the Company to do business in a socially and environmentally responsible manner. This means caring for Michigan's environment, encouraging economic opportunities, and enhancing the quality of life in the communities Consumers Energy serves. Consumers Energy is committed to operating sustainably and working to leave Michigan, and the world better than the Company found them. As part of this commitment to providing increasingly clean energy, the Company is proposing to build and operate a Renewable Natural Gas ("RNG") production facility. Production of RNG can potentially deliver an affordable carbon negative fuel for all customers. RNG's renewable attributes can either be monetized to reduce the overall revenue requirement and to deliver a carbon negative fuel to customers. Additionally, since the 1990s, Consumers Energy has been working to protect Michigan's environment by cleaning up sites of 23 former manufactured gas plants throughout the state. The Company's pipe replacement programs work to mitigate gas losses across the system and reduce methane emissions. Consumers Energy has goals to reduce water use, encourage recycling to reduce landfill space, and promote sustainable business practices among the companies with which it works. Additionally, Consumers Energy is working with companies to help expand their operations and attract new employers to Michigan.

Q. What steps has Consumers Energy taken to prioritize customer service?

A. The Company has several methods for listening to customers. Informal methods include feedback from customer service representatives and business customer account managers who interact with customers daily. The Company analyzes customer data from informal and formal complaints, and feedback from customers who participate in various Company product and service offerings. Additionally, Consumers Energy conducts primary customer research through methods such as focus groups and quantitative survey research.

Company witness Cullen M. Hale describes how the Company continually strives to interact with its customers in a positive way. The Customer Experience and Operations division relies on data analysis and customer feedback to ensure that Consumers Energy connects with customers through their preferred communication method to provide timely, accurate information and enhanced energy products and services. To that extent, Mr. Hale discusses the Company's investments that will help it better meet customers' needs, assess the impact of their behavior on their bills, and recommend personalized programs for better outcomes, in order to help enroll customers in programs which meet our clean energy goals and help customers meet their energy needs. And, as further explained by Company witness Karen M. Gaston, Consumers Energy continually works to cultivate a best-in-class workforce to ensure the Company meets customers' needs and expectations. This includes undertaking projects that involve real-world training experiences for field employees, and talent management technology upgrades. These actions help to improve customer service.

Q. Why is it important for a utility to offer good customer experience?

A. Consumers Energy is an active participant in helping customers achieve their energy needs. It is important for the Company to build trust with its customers and provide its customers with a world class customer experience because Michigan's energy future necessitates customer participation. An important element of the Company's ability to achieve the targets of the Consumers Energy Clean Energy Plan is customer participation in programs like the Gas DR Pilot, Energy Waste Reduction, and the Voluntary Carbon Offset program. Customers also stand to benefit from the Company's DR offerings by enabling decreased costs during peak times. To build trust with customers through a positive customer experience, the Company needs the capability to interact with customers on their channel of choice in a way that's easy for them. If customers are dissatisfied with the means through which they interface with Consumers Energy, they are unlikely to participate in programs that will provide cost savings and support their clean energy needs.

II. KEY DRIVERS

Q. Please summarize the Company's revenue request in this case.

A. Presented in the following table is a summary of the Company's requested rate relief of $278 million:

Table 1

		(In Millions)
Investment	**$**	**247**
Cost of Capital	**$**	**22**
Sales/Revenue	**$**	**13**
Operating Expenses	**$**	**(4)**
Rate Relief	**$**	**278**

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

A. The outcome of Case No. U-20650 was a Commission-approved agreement that included a deferral of this filing until no earlier than December 1, 2021. When rates from this case are implemented in October 2022, it will be two years since new gas base rates were established for Consumers Energy's retail gas business. Consumers Energy continued to invest $1 billion annually in its natural gas system and supporting infrastructure; therefore, this application includes the request to recover actual and projected costs related to two years of accumulated investment. As shown in Table 1, this request is largely driven by new investment.

Q. Please describe more significant gas investments included in the Company's rate case filling.

A. Consumers Energy has initiated this case in large part to secure spending approval for the Company's NGDP through the projected test year. Significant natural gas investments included in this case are the Enhanced Infrastructure Replacement Program ("EIRP"), other vintage materials replacements including the Vintage Service Replacement ("VSR") Program, RNG, New Business Program, Compression and Transmission Replacement Programs, Pipeline Integrity Program, Asset Relocation Program, DR, and Technology 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 respond to customer-initiated requests. The Company's investments are grouped into five main categories: (i) system reliability; (ii) compliance; (iii) gas DR; (iv) enhanced technology and security; and (v) system decarbonization.

System Reliability

The ongoing EIRP is focused primarily on the assessment and replacement of distribution pipe, such as cast iron, bare steel, and threaded and coupled mains to improve safety and increase reliability of gas delivery to customers. This program was spurred in part by growing industry and regulatory concerns with vintage gas distribution and transmission piping systems and eliminating them from the Company's system will enable portions of it to operate at higher pressures while lowering line losses and methane emissions. Reduced losses translate to lower operating expenses which will directly benefit customers, while reducing emissions makes the Company's system safer and better for the environment. This investment ensures reliability and the safety of customers and the public.

As of the end of the 2020 calendar year, through the EIRP, nearly 500 miles of high-risk pipe have been replaced, including 180.4 miles of cast iron and over 59,000 services. As discussed by Company witness Kristine A. Pascarello, through the well-planned, thoughtful execution of the EIRP, the Company can better manage high-risk distribution materials in a more cost-effective manner, as opposed to scenarios under emergent conditions. As discussed in its Plan, Consumers Energy is looking to accelerate vintage material replacement, with the potential to eliminate all the approximately 2,869 miles of high-risk pipe materials originally identified as part of the comprehensive main replacement program in Case No. U-16885 by the end of 2030.

Accelerated replacement is supported through both the EIRP and the VSR Program. Launched in 2017, the VSR Program works to replace outdated service materials not replaced under other material condition and relocation programs, thereby furthering our commitment to replace at-risk or aged distribution services for improved system safety.

The New Business Program consists of the capital cost of adding new residential, commercial, and industrial customers. The program costs include the cost of installing mains and services and the cost of meters to service new customers. These costs are partially offset by customer contributions. The Company's projections for the New Business Program includes the expansion of service to additional residential, commercial, and industrial customers. In total, the Company expects to install service to approximately 8,400 customers in 2021; 8,568 in 2022; and 8,568 for the full year in 2023.

The Compression and Transmission Replacement Programs include compressor rebuilds and other reliability-related projects, such as the Freedom Compressor Station upgrades, to ensure reliability of gas delivery to customers. In addition, the Transmission Replacement Program includes expenditures for the Transmission Enhancements for Deliverability-Integrity ("TED-I") projects. TED-I projects are focused on maintaining deliverability and integrity and improving the ability to control gas flows. Projects include replacing or retiring higher-risk transmission pipeline segments and installing remote-control valves to quickly stop the flow of gas in case of a pipeline failure. These investments will provide important enhancements to the system so that the Company can continue to ensure customer and public safety. Additionally, it will allow for increased natural gas capacity within Michigan for economic growth and access to lower-cost natural gas. Major projects included in this filing are the Saginaw Trail Pipeline Project, the Mid-Michigan Pipeline Project, and the South Oakland Macomb Network projects. Additionally, to support the system and maintain pressure to meet increased load, additional investment is needed to improve gas quality and measurement accuracy; configure pipelines to meet Pipeline Integrity Program standards, and ensure system reliability by rebuilding or making other improvements to existing city gate facilities. The Company has included additional details to provide justification surrounding these projects in the direct testimony of Company witnesses Pascarello, Michael P. Griffin, and Timothy K. Joyce.

Consumers Energy's Fleet Services ensures the Gas Operations Department can deliver reliable and uninterrupted gas service to customers through the maintenance, acquisition and disposition, and management of the Company's fleet. Fleet Services aims to provide high availability and minimize breakdowns and maintenance of vehicles to enable our frontline works to provide safe, dependable gas service to customers. Additional detail surrounding the Company's recommendation is available in the testimony of Company witnesses Adam S. Carveth and Christopher Shaffer.

Compliance

The Pipeline Integrity Program includes the necessary inspections and projects that are required to comply with federal and state pipeline safety regulations and mandates by Pipeline and Hazardous Materials Safety Administration ("PHMSA") and MPSC. The program expenditures change from year to year because of work scope variations, which are driven by risk assessments and threat evaluation. A priority-based inspection schedule and the expected remediation costs resulting from the findings of these inspections are included in this program, which complies with the federal PHMSA requirements and state MPSC requirements. Through the use of inline inspection tools, Consumers Energy is able to identify and remediate various anomalies related to corrosion, seam defects, and other defects in the pipelines, thereby reducing risk on the transmission system to ensure system safety and reliable delivery of gas to customers. Consistent with the testimony of Company witness Paul M. Wolven, the Company will continue to improve system risk inspections and update the risk ranking methodology to a probabilistic model. While the current inspection and remediation cycle already meets or exceeds regulatory standards, Consumers Energy is striving to meet best practices for safety and reliability.

The Asset Relocation Program includes gas transmission and distribution infrastructure replacement projects which are required due to civic improvement activities initiated by federal, state, or local governmental units. In addition, some relocations are from individual customers' requests and some are due to relocation of facilities initiated by the Company. Civic improvements include projects that replace or improve aging public infrastructure, such as roadways, bridges, sewer lines, water lines, and drainage ditches. If the Company's system is in the public right-of-way, and we must move it to eliminate interference, the work is done at Consumers Energy's expense in accordance with the law. The Company works with the involved governmental units to coordinate work and negotiate design criteria wherever possible to minimize expense. Due to the economic growth the state is experiencing, and the aging municipal infrastructure, public infrastructure initiatives continue to be a significant focus at the state and local political levels, and funding for these projects continues to increase as the Michigan economy remains strong.

The Company has included additional information to justify these projects in the testimony of Company witnesses Wolven, Pascarello, and Griffin.

Gas Demand Response

During the winter of 2020, the Company executed its first gas DR pilot for residential and small and medium business ("SMB") customers and plans to run the pilot again in the winter of 2021. Consumers Energy will also run a pilot for C&I customers in the winter of 2021. Both pilots align with the Company's Settlement Agreement in Case No. U-20650. The gas DR pilots incentivize residential, SMB, and C&I customers to reduce their gas consumption during times of peak system demand or abnormal system conditions. These pilots could provide a voluntary tool that can be called upon to balance the Company's available system capacity and customer load requirements, ultimately minimizing system constraints and downstream customer impacts in support of providing system reliability. The Company is requesting an expansion of the residential and SMB pilots for two additional years to continue to expand the Company's learnings in the space of reliability, clean energy, financial impacts, and geo-targeting. The details pertaining to these proposals are supported in the testimony of Company witness Steven Q. McLean.

Enhanced Technology and Security

Continually improving on customer service and internal operations will require significant Information Technology ("IT") upgrades as outlined in the Digital Three-Year Plan ("Digital Plan") included in this case, developed with input from the MPSC Staff ("Staff"). The Company's investments and O&M spending presented in the Digital Plan address the new digital capabilities and foundational technology required to realize the outcomes of the NGDP, 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 eliminate reactive events on our system. Additionally, ensuring that our technology systems are secure for our customers and employees requires investment in security technologies to minimize risks presented through evolving cyber threats and vulnerabilities. For more detail, Company witness D. Duncan Paterson sponsors the Company's Digital Plan and Company witness Audra L. Cumberworth addresses Security.

System Decarbonization

Consumers Energy has committed to reduce fugitive methane emissions from the delivery system, while also better understanding the emissions from the natural gas upstream suppliers and end-use customers. The system methane reductions and net-zero methane emissions goals will occur by 2030 and provide the initial basis and learnings for greater gas system decarbonization. In Case No. U-21141, the Company requested approval of a voluntary carbon offset program which will provide customers an economical solution to offset their individual carbon footprint. Additionally, the Company is making significant investments in its infrastructure to reduce emissions, such as replacing vintage pipe through EIRP and VSR programs to reduce leaks and reducing blowdown emissions. Consumers Energy is also proposing the development of an RNG production facility to explore this resource as a cost-effective alternative fuel for customers. Production of RNG can potentially deliver an affordable carbon negative fuel for Michigan's gas supply. Further support for this proposal can be found in the testimony of Company witness Neal P. Dreisig.

Q. Why is Consumers Energy making significant gas investments?

A. Consumers Energy has built and maintained a complex natural gas system comprised of approximately 30,000 miles of distribution and transmission pipelines. The Company operates 15 storage fields and eight compressor stations, and all 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 1.8 natural gas customers who rely on it every day.

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

A. Consumers Energy's investment represents its commitment to modernizing the Company's natural gas pipeline and continued improvements in energy efficiency. The EIRP continues to replace significant portions of our 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 our damage prevention program and third-party coordination to mitigate and reduce third party caused leaks on the system. Solutions like the Voluntary Carbon Offset Program described above aim to empower customers to help reduce emissions, and RNG is a promising method for delivery of a carbon negative fuel. 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. What is the Company's proposal to maintain its credit metrics and credit quality during the period of investment?

A. The Company is requesting a return on equity ("ROE") of 10.5%, with an equity ratio of 52%. Company witness Marc R. Bleckman shows that equity ratio and ROE have a direct impact on the Company's credit metrics and credit quality. Mr. Bleckman's analysis shows that an ROE below 10.50% and an equity ratio below 52.00% would lead to a key credit metric, Funds from Operations to Debt ratio, that would not be supportive of maintaining the Company's current credit ratings. Moody's Investors Service ("Moody's"), a credit rating agency, recently downgraded their credit rating for Consumers Energy, citing the

ROE and equity ratio authorized in the Company's most recent electric rate case. Consumers Energy needs to continue to attract capital and maintain robust financial health as the Company undertakes the large capital expenditures required to continue to serve its customers safely, reliably, and affordably. A healthy equity ratio and strong credit quality will be key in raising the necessary capital at the lowest overall cost to customers over the long-term. Mr. Bleckman provides a framework for fulfilling the Commission's desire for the Company's capital structure to be balanced, and to achieve this by 2023, in a manner that will not materially harm the Company's credit metrics.

Q. What progress has been made on the recovery of the rate plan and insurance claims associated with the Ray Compressor Station Incident?

A. Consumers Energy has submitted a claim with the insurer for losses associated with the Ray Compressor Station incident. The Company's claim includes capital, O&M, as well as incremental fuel costs associated with the Ray fire and subsequent repair of the Ray facility. The claim is currently pending with the insurer. The Company has recognized an estimated receivable from the insurer net of the insurance deductible. The receivable estimate was allocated between the capital, O&M, and fuel cost components based on probability of recovery and on their relative value to the claim. The capital component of the estimated receivable is $4.3 million. The final insurance settlement is unknown currently. However, capital associated with the Ray facility repair in this case is recorded net of the estimated insurance recovery. If a final settlement occurs during this case that impacts the capital recovery of the Ray facility repairs the Company will provide an update to this case. Further details can be found in the testimony of Company witnesses Steven J. Herrygers and Joyce.

Q. Is the insurance reimbursement of O&M costs associated with the Ray Compressor Station Incident relevant to this case?

A. No. Consumers Energy customers have never paid for O&M costs associated with the Ray Compressor Station Incident, and the Company is not requesting recovery of these costs in recovery in this case.

Q. What steps has Consumers Energy taken to reduce operating expenses and mitigate cost increases?

A. The Company proactively seeks out opportunities to minimize the increase in O&M expense through productivity improvements, first-time quality, and reducing employee safety incidents. Overall, the Company's corporate services O&M expense levels are reasonable. As detailed by Company witness Gaston, S&P Global Market Intelligence ranked Consumers Energy's 2020 gas Administrative and General costs, excluding pension and benefits, the fourth lowest out of the 31 top companies ranked on a cost per customer basis for gas utility companies with more than 500,000 customers. This reflects the Company's diligence in managing O&M costs to help keep rates affordable for customers.

Additionally, efforts undertaken by the Company's IT Department to streamline operations have realized substantial savings for customers. By reducing software and hardware maintenance agreements, improving processes for labor efficiency, and reducing managed services contract costs, the IT Department was able to optimize the total operational cost, as discussed by Company witness Paterson.

Consumers Energy has also identified a "grid approach" method – explained in greater detail by Company witness Pascarello – to vintage main pipe replacement that offers many benefits to its cost per mile performance. This approach was piloted in 2020 for significantly larger project sizes, producing better economies of scale that increase productivity, reduce cost, improve long-term coordination with local governments on their planned project work, and reduce customer impact over time. Specifically, this approach will result in fewer project locations, meaning less travel time, fewer equipment storage locations, more cost-effective use of heavy equipment, reduced return trips to the same area, and lower project mobilization and demobilization cost each year where it can be utilized.

The Company also continues to undertake measures that reduce rework and process improvement initiates that improve efficiency across several operating areas. As discussed by Company witness R. Michael Stuart, the Company's focus on employee safety has reduced incidents by 80% since 2006. The resulting reduction in lost workdays and medical expenses is approximately $4.8 million annually, again accruing to the benefit of the Company's customers.

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-time 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 expenditures 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?

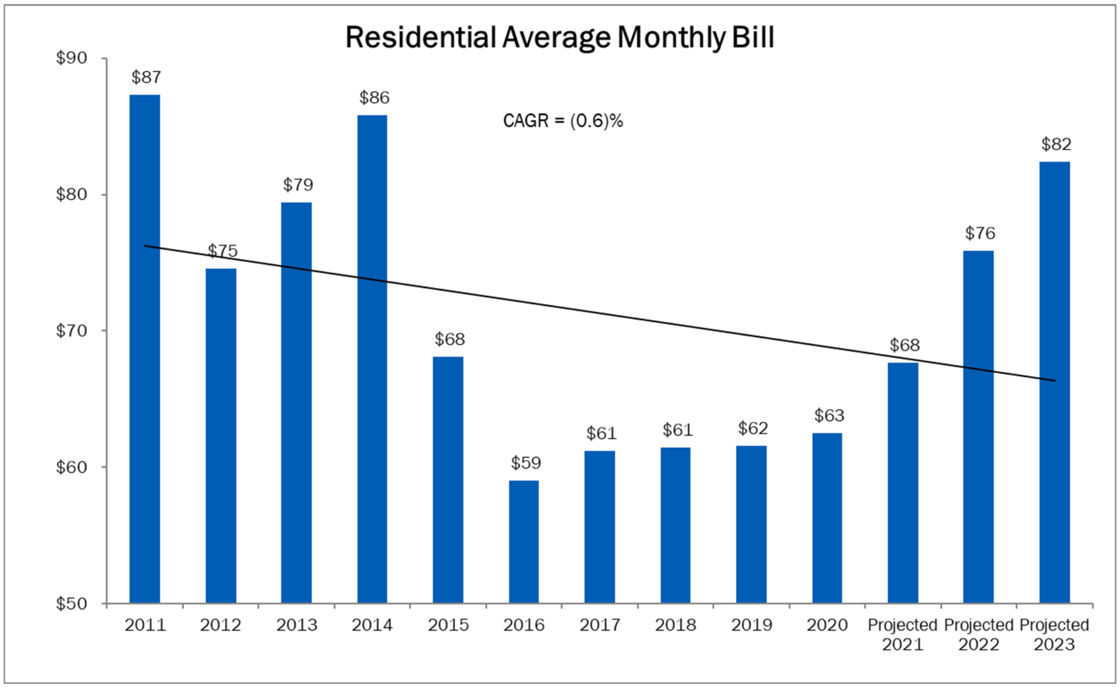
A. Yes. The Company's plans provide its best estimate of the total cost it expects to spend on each program. However, when actual dollars are spent in the test year, unforeseen circumstances (such as new business, extreme weather, or unanticipated civic improvement projects undertaken by state or local 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 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. Due to this circumstance, the Company would then need to adjust spending in another program to compensate for this additional spending. It is not possible for the Company to anticipate every event or circumstance which will arise multiple years from now. Therefore, the need to have flexible spending between programs is prudent and in the best interest of the customer.

III. CUSTOMER IMPACTS

Q. How does this request account for customer affordability?

A. The Company anticipates that the average monthly residential bill for the 12 months ending September 2023 will increase by 12.5% over current rate levels. Even with this increase, however, the compounded decrease of the monthly bill is expected to be about 0.6% compared to 2011. The trend in the monthly bill is shown in Figure 1 below, which illustrates the average weather-normalized bill from 2011 to 2020 and forecasts the periods 2021, 2022, and 2023. Consumers Energy expects that the average residential gas customer will pay approximately $2.79 per day for the natural gas service that provides an affordable fuel for heating, cooking, and hot water.

FIGURE 1.



The Company is aware that this increase will challenge some customers more than others. The Company offers assistance programs to customers who may continue to be more impacted. Examples of this assistance include Consumers Affordable Resource for Energy Program, the Residential Income Assistance Provision, and the Low-Income Assistance Credit. These programs are designed to assist customer with the management of their energy use and bills. As part of the Case No. U-20650 Settlement Agreement, the Company requested approval Percentage of Income Pilot ("PIP") for low-income customers. 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 local community service organizations. The Company strives to keep its requested increase to the lowest level it believes is reasonable, while balancing the need for improved safety, reliability, and customer service.

Q. What lessons learned has the Company taken away from the customer impacts during the COVID-19 pandemic?

A. Consumers Energy is conscious of the significant impact the COVID-19 pandemic has had on its customers. In recognition of the challenge's customers faced, the Company supported a voluntary moratorium on customer shutoffs, funded direct payment assistance programs, donated millions of dollars to COVID-19 relief efforts, and more. While working to help customers through the worst of the pandemic, the Company continued service to its customers in a caring manner throughout. The constantly evolving nature of the pandemic generated valuable learnings and experience for the Company. Like our customers, Consumers Energy remained resilient through the pandemic to ensure safe, reliable, and affordable gas was delivered to our customers and will continue to do so as different challenges arise in the future.

Q. What does the Company think about its journey with Diversity, Equity, and Inclusion ("DE&I") in relation to the plans presented in this case?

A. Consumers Energy has committed to a renewed emphasis on DE&I. Race, sexual orientation, gender identity, socioeconomic status, ability, or otherwise, affect the Company's customers, employees, and the communities we serve. The Company has taken a stand to consider DE&I in every aspect of the business. The Company's focus on DE&I in our hiring, training, employee retention, and promotions will continue to evolve and retain a diverse talent pipeline. Diverse perspectives at the Company will continue to benefit our business and inform the Company's work on investment planning and customer programs, as well as investment in communities, charitable giving, and addressing the cost burden placed on low-income and disadvantaged communities. The Company is currently participating in the Energy Affordability & Accessibility Collaborative ("EAAC"), ordered by the Commission in Case No. U-20757, where the Company is working with a diverse group of stakeholders to review customer programs and related policies, consider a long-term data strategy, and work with the Commission's internal DE&I initiative in order to provide insight on equity and energy burden. This work will likely continue into 2023. Report recommendations from this workgroup should provide guidance on the next steps in the Company's DE&I journey. By placing DE&I at the forefront of decision making, Consumers Energy is a corporate leader in eliminating bias, correcting, and preventing injustices, and ensuring all feel welcome and valued both inside the Company and across the state of Michigan. This commitment to DE&I enables the Company to create a more diverse, equitable, and inclusive future.

IV. ADJUSTMENT MECHANISMS AND ACCOUNTING REQUESTS

Q. Has the Company proposed any adjustment mechanisms in this case?

A. Yes, the Company is proposing a Gas Revenue Decoupling Mechanism ("RDM") in this case. The RDM allows the Company to recover the level of revenue (excluding gas cost recovery and customer charges) authorized and necessary to cover what are, for the most part, fixed costs related to investment and expenses approved by the Commission. This is the same mechanism currently in place. More details on this proposed mechanism are given by Company witness Alex M. Gast.

Q. Is the Company proposing any major cost of service study or rate design changes as part of this filing?

A. Yes, the Company is proposing a Demand Charge for all Transportation Rate Schedules. The demand charge will collect a portion of costs identified as demand related in the cost of service study through a demand-based charge. This rate design change results in a better reflection of cost causation and is discussed further by Company witness Gast.

V. <u>SUMMARY</u>

Q. Please summarize your direct testimony.

A. Consumers Energy respectfully submits this request for $278 million in annual rate relief. Consistent with Consumers Energy's deeply-held 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, the Three Year Digital Plan, as well as other programs that will enhance the customer experience. The Company is also minimizing the increase in O&M expense through productivity improvements, first time quality, and reducing employee safety incidents. Consumers Energy is committed to 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.

Appendix 1: Company Witnesses and Testimony Topics

Bleckman, Marc R. – *Capital Structure*

Bowers, Sarah Hollis – *ECAP and Risk Based Assessments, Remote Inspection, Sewer Locate, and Advanced Methane Detection*

Carveth, Adam S. – *Fleet*

Christopher, Lora B. – *Employee Benefits*

Conrad, Amy M. – *Incentive Compensation*

Cumberworth, Audra L. – *Security*

Dreisig, Neal P. – *Natural Gas Delivery Plan, Renewable Natural Gas*

Fultz, Christopher T. – *Gas Operations O&M*

Gast, Alex M. – *Cost of Service, Rate Design*

Gaston, Karen M. – *Corporate Departments*

Griffin, Michael P. – *Transmission & Certain Distribution Capital and O&M*

Guinn, Quentin A. – *Facilities*

Hale, Cullen M. – *Customer Experience*

Herrygers, Steven J. – *Ray Fire Resolution*

Hurd, Shawn C. – *Tariffs*

Joyce, Timothy K. – *Compression and Storage Projects, Cost of Gas, and LAUF and Company Use Gas*

Keaton, Eric J. – *Sales Forecast*

McLean, Steven Q. – *Demand Response*

Pascarello, Kristine A. – *Distribution Capital, Gas Engineering and O&M Supply*

Paterson, D. Duncan – *Information Technology*

Patton, Hannah L. – *Accounting for RNG*

Prentice, Heather M. – *Manufactured Gas Plant Remediation Program*

Rayl, Heather L. – *Revenue Requirement*

Shaffer, Christopher – *Fleet Lifecycle Report*

Stuart, R. Michael – *Employee Incentive Compensation Program*

Torrey, Michael A. – *Overall Policy*

VanBlarcum, Brian J. – *Tax*

Watkins, Kevin J. – *Depreciation Rate for RNG*

Watson, Stephanie V. – *Gas Safety Management System*

Wehner, Todd A. – *Return on Equity*

Wolven, Paul M. – *Pipeline Integrity*

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-21148
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

MARC R. BLECKMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

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 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 Motor Company 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-16581, the Company's 2011 Application for biennial review of the RE Plan;
- Case No. U-16543, the Company's 2011 Application to Amend 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-20722, the Company's RE Plan reconciliation proceeding for 2019;
- Case No. U-20697, the Company's 2020 Electric Rate Case;
- Case No. U-20963, the Company's 2021 Electric Rate Case; and
- Case No. U-20984, the Company's RE Plan amendment proceeding for 2021.

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's gas business.

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-24 (MRB-8)		Current and Historical Credit Ratings;
Exhibit A-25 (MRB-9)		Recent Utility Corporate Bond Issuances;
Exhibit A-26 (MRB-10)		Peer Company Equity Ratios;
Exhibit A-27 (MRB-11)		Moody's Investors Service May 10, 2021 Credit Opinion; and
Exhibit A-28 (MRB-12)		State Regulatory Evaluations.

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, 2020, 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 September 30, 2023. 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 52.00%. The equity ratio as a percentage of total capital is 42.71%.

Q. What Return on Equity ("ROE") are you assuming to determine the overall cost of capital for Consumers Energy's gas business?

A. I am assuming an ROE for Consumers Energy's gas business of 10.50%. This ROE is recommended by Company witness Todd A. Wehner and explained in further detail in his 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 5.96% 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 mainly 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. Short-term debt included in the Company's capital structure also includes the balance from the Company's renewable liability.

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, 2020, 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 September 30, 2023, in column (g) that I am recommending be used in this case.

Q. Please explain the common equity adjustment of $1.978 billion.

A. I have projected that the 13-month common equity balance for the test year will be $1.978 billion higher than the December 31, 2020 balance. The common equity adjustment of $1.978 billion consists of two components. The first is an adjustment to reflect $353 million in projected retained earnings on a weighted average basis from January 2021 through September 2023. The second is an adjustment of $1.625 billion to reflect the projected equity infusions on a weighted average basis from January 2021 through September 2023.

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 $353 million.

A. Since I started with the December 31, 2020 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 September 30, 2023.

Q. Please explain how you calculated the change in Consumers Energy's retained earnings from January 2021 to December 2021.

A. For the period of January 2021 through August 2021, I relied on actual changes in retained earnings, as reported by the Company's Rate Department in its monthly cost of capital study. For the period of September 2021 through December 2021, I assumed the change in retained earnings would be equal to the change in retained earnings for the same months in 2020.

Q. Please explain how you projected the change in Consumers Energy's retained earnings from January 2022 through the test period ending September 2023.

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 $13.57 million per month, or $162.8 million per year from January 2022 through September 2023. Failure to reflect retained earnings would understate the common equity balance for the test year.

Q. Please explain how you arrived at Consumers Energy's retained earnings rate of $162.8 million per year.

A. Based on Consumers Energy's Securities and Exchange Commission ("SEC") Form 10-K for 2020, I determined that Consumers Energy's net income for the 12-month period ended December 31, 2020, was $814 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 $162.8 million [$814 * (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 September 30, 2023.

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 $1.625 billion adjustment for the new equity infusions in your recommended capital structure?

A. This is the amount needed to hold a 52.00% equity ratio for the test period in this case. In 2021, CMS Energy made three equity infusions into Consumers Energy totalling $575 million. The amounts of each of these 2021 infusions are consistent with the Company's filing in Case No. U-20963. In addition, CMS Energy plans to make an equity infusion into Consumers Energy of $450 million by January 2022, $415 million by June 2022, and $300 million by February 2023. 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 September 30, 2023 is $1.625 billion. When the 13-month average for the equity infusions of $1.625 billion is combined with the 13-month average $353 million retained earnings adjustment, the increase to equity capital is the $1.978 billion shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 1.

Q. How did the Company arrive at this level of equity infusions for 2022 and 2023?

A. The Company reviews a number of factors in determining the level of required equity infusions, including the level of cash flows, capital expenditures, and the resulting credit metrics. The Company also considers the current mix of debt and equity (equity ratio) and how to strike the optimal balance for customers. Given these considerations, the Company is committed to keeping its equity ratio relatively flat, from 51.94% at year-end 2020 to 52.00% for the test year of this case.

Q. How did you determine that 52.00% was the appropriate level for the Company and customers and why is it important to approve the proposed equity ratio?

A. In recent orders, the Commission has stated its desire for the Company to follow a path to "rebalance" its capital structure and to "arrive at an optimized capital structure that is both supportive of planned infrastructure investments, yet is not unnecessarily burdensome on ratepayers." While the Company believes that a 50% equity ratio would be unsupportive of its current credit quality, the Company has taken the Commission's orders into account in arriving at the 52.00% projected equity ratio in this case. As I will show later in my testimony, this places the Company on a path to a "balanced" capital structure on an adjusted basis which the Company believes satisfies the Commission's stated objectives. My testimony describing the key factors and providing evidence that supports the proposed equity ratio of 52.00% is organized as follows:

i. Equity Ratio / ROE Impact on Credit Quality
ii. Credit Risks and Recent Rating Agency Actions
iii. Projected Equity Ratio 50.7% on an Adjusted Basis
iv. Peer Equity Ratios are Higher
v. Ability to Fund Significant Capital Expenditures at Optimal Rates
vi. Rating Agency Adjustments Lower the Equity Ratio
vii. Summary

i. 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"). As described in Company witness Wehner's testimony, 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 drop and cause significant credit deterioration. An equity ratio of 52.00% and an ROE of 10.50%, 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 a 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 income (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.

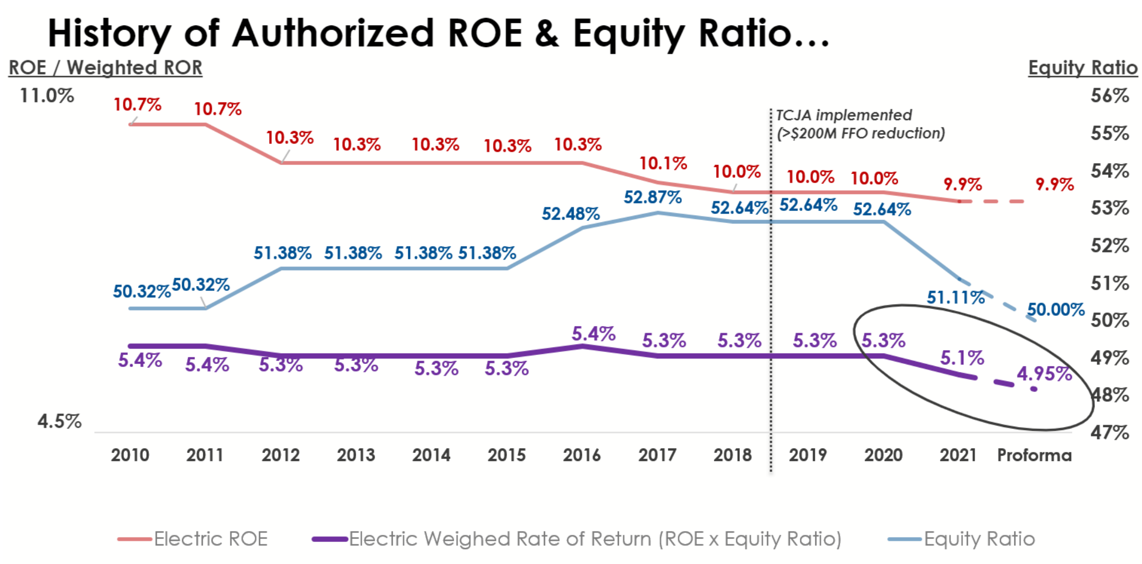
A. As discussed earlier in my testimony, ROE and equity ratio are two inputs in determining the Company's ratio of FFO to Debt, and FFO-to-Debt ratios are used by credit agencies to determine the Company's financial health. Consequently, it is important to recognize that the Company's ROE and equity ratio cannot be evaluated in isolation, but should, instead, be viewed as interconnected components that determine the Company's overall financial health. This relationship is illustrated in Company witness Wehner's Exhibit A-145 (TAW-3) which provides a mathematical development of how ROE and equity ratio determine a company's FFO-to-Debt ratio over the long term, assuming steady state conditions. An ROE of 10.50%, when taken <u>together</u> with an equity ratio of 52.00% 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. The relationship between the equity ratio, ROE, and rating agency credit metrics is discussed in more detail in Company witness Wehner's direct testimony.

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 52.00% from column (c) is multiplied by the ROE of 10.50% from column (e) to produce a weighted cost of 5.46%, 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 52.00% equity ratio and 10.50% ROE is a combination that the Company believes is acceptable in the current case and is responsive to recent Commission orders.

Q. What is the weighted cost of the equity ratio and ROE combination from the December 17, 2020 Order in Case No. U-20697, the Company's most recent electric rate case?

A. Multiplying the equity ratio of 51.11% by the ROE of 9.90% from the Order in Case No. U-20697 results in a weighted cost of 5.06%. If a 50.0% equity ratio were used with a 9.90% ROE, the resulting weighted rate of return would be even lower at 4.95%. This is illustrated in the following chart which also includes a history of electric authorized ROE, equity ratio, and resulting weighted rate of return. Note that the order in the most recent electric rate case results in a sharp decline in rate of return following a long period of stability.



It should be noted that DTE Energy Company, whose subsidiary DTE Gas Company ("DTE Gas") was downgraded by Moody's Investors Service ("Moody's") in July 2019, had a weighted cost of 5.12% (equity ratio of 51.16% times ROE of 10.0%) which is higher than the weighted cost from the Company's December 17, 2020 Order in Case No. U20697. Maintaining an authorized ROE of 9.90% without raising the approved equity ratio would result in cash flow and credit metric deterioration.

Q. What would the impact to the rating agencies' FFO-to-Debt ratios be assuming the Company realized an equity ratio of lower than 52.00% and an ROE lower than 10.50%?

A. Lowering the equity ratio and the ROE would reduce the Company's overall cost of capital and rate of return. This, in turn, lowers the Company's cash flow and FFO-to-Debt ratio. The Company would also have to increase its long-term debt to achieve a lower equity ratio. This increase in debt would also weaken the Company's FFO-to-Debt ratio. The negative impacts could cause the Company's FFO-to-Debt ratio to drop below the established rating agency thresholds, placing the Company's credit quality and credit ratings at risk.

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. As shown in Exhibit A-28 (MRB-12), SNL Energy classifies Consumers Energy as operating in an above average

"Tier 3 A" jurisdiction. While the Company is currently considered above average, this rating is frequently evaluated. 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. A continuation, or even worse a further degradation, of the authorized equity ratio and ROE puts the Company at risk of dropping in its regulatory environment ranking which could negatively impact the Company's credit quality and credit rating.

ii. <u>Credit Risks and Rating Agency Actions</u>

Q. What are the risks if the Company's key financial metrics and credit quality weaken?

A. Rating agencies have stated that the Company's credit rating could be lowered if core financial measures underperform. This risk was realized by the Company in May 2021 when Moody's downgraded the Company's credit rating. See Exhibit A-27 (MRB-11) for this credit opinion. On page 1 of this credit opinion, Moody's clearly states:

> On 3 May 2021, we downgraded the ratings of Consumers Energy due to its weakened credit metrics. Although the regulatory environment in Michigan remains relatively credit supportive, the outcome of recent rate cases has put pressure on its credit metric ratios and we do not expect the ratios to recover back to historical levels.

The credit opinion goes on to cite the Company's last electric rate case in which the Commission authorized a 9.9% ROE and a 51.11% equity ratio. It is clear from Moody's credit opinion that the recent ROE and equity ratio authorizations and the negative impacts on the Company's credit metrics was central to their decision to downgrade the Company.

As these comments from Moody's demonstrate, the Company's ROE and equity ratio are integral components of the Company's financial credit metrics and are a key factor in combating the negative impacts of the TCJA. Further, both of these measures have already been decreased from the levels in July 2020 as a result of the December 17, 2020

Order in Case No. U-20697. Therefore, the equity ratio and ROE awarded in this case will be critical to the future credit profile of the Company.

Q. Have any other rating agencies commented recently on the Company's ROE and equity ratio as it relates to the Company's credit metrics and credit quality?

A. Yes. In January 2021, Standard and Poors ("S&P") issued a credit opinion on Consumers Energy in which they commented on the outcome of the Company's most recent electric rate case in December 2020 (Case No. U-20697). When referring to the equity ratio of 51.11% and ROE of 9.90% authorized in that case, S&P concluded that if these "lower ROEs and a lower equity ratio persist, credit quality could weaken." In addition, S&P noted that "…we expect some modest weakening in financial metrics as a result of the recent electric rate case order…" It is clear from S&P's report that the equity ratio of 51.11% and ROE of 9.90% is not considered supportive of the Company's credit quality and continuation at these levels could negatively impact the Company's credit metrics.

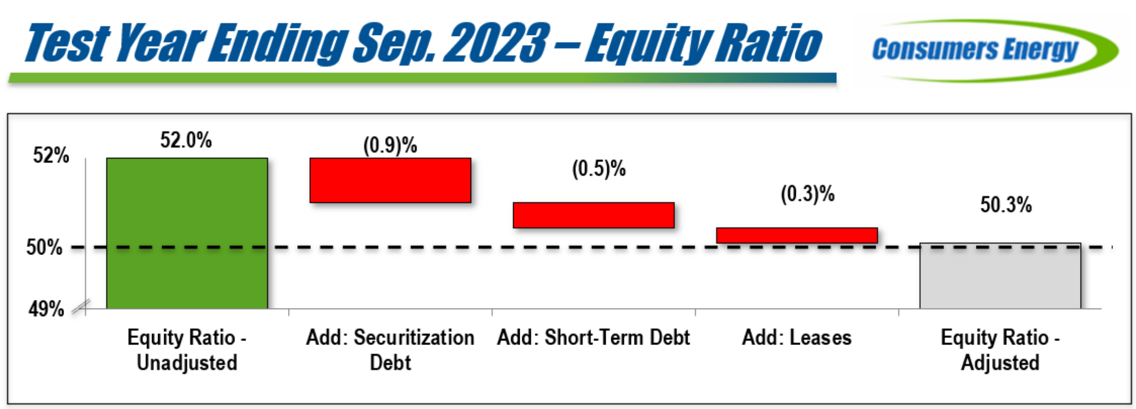
iii. <u>Projected Equity Ratio 50.3% on an Adjusted Basis</u>

Q. Are there differences in how components of the capital structure are classified on a ratemaking basis and on a financial basis?

A. Yes. See Exhibit A-14 (MRB-3), Schedule D-1b, for a list of examples of the differences in component classifications. For example, capitalized leases and the effect of mark-to-market accounting would be included in determining capital structure on a financial basis. They are excluded, however, in determining a capital structure on a ratemaking basis. Also, on a ratemaking basis deferred ITC, deferred income taxes, and deferred Job Development ITC would be included.

Q. When calculating the equity ratio for the test year in this case, are there additional items that should be taken into account?

A. Yes. The 52.00% equity ratio reflected on Exhibit A-14 (MRB-1), Schedule D-1, page 1, excludes items such as securitization debt, short-term borrowings, and leases. These are debt liabilities that are reflected in the Company's financial statements and are also considered as debt by rating agencies and many analysts and investors. By including these balances, which are reflected on the Company's balance sheet, the Company's debt is higher, and the resulting equity ratio is lower compared to a regulatory basis. These are debt items that are part of the Company's books and records. Exclusion of these items does not appropriately acknowledge all of the debt recorded on the Company's balance sheet. It is important for the Company's regulators to take into consideration these debt items, which are on the Company's balance sheet, when determining the Company's authorized equity ratio so as to avoid negative credit consequences such as a credit rating downgrade. As shown on Exhibit A-14 (MRB-1), Schedule D-1, page 2, the adjusted equity ratio for the test year in this case, taking these debt balances into account, is 50.3%. This is also illustrated on the following chart:



Q. How does the Company propose to satisfy the Commission's stated objective for the Company to achieve a "balanced" capital structure?

A. The February 28, 2018 Order in Case No. U-17990 stated the following:

> The Commission desires to arrive at an optimized capital structure that is both supportive of planned infrastructure investments, yet is not unnecessarily burdensome on ratepayers. The Commission also anticipates that a cycle of heavier-than-usual investment will present an ideal opportunity to rebalance Consumers' capital structure to reach its 50/50 goal.

The Company proposes to reach and maintain a "50/50" capital structure on an adjusted basis as just described, which best reflects the Company's full balance sheet, in 2023. As detailed in Case No. U-20889, the Company's application for a financing order approving the securitization of qualified costs, the Company intends to issue debt in mid-2023 in order to securitize D.E. Karn ("Karn") Units 1 & 2 assets. This securitization debt will bring the Company close to a 50/50 capital structure on an adjusted basis. This is shown on Exhibit A-14 (MRB-1), Schedule D-1, page 2. The Company proposes to maintain this 50/50 ratio on an adjusted basis in 2023 and going forward, thus meeting the Commission's stated desire. The regulatory equity ratio proposed for the test year in this case is critical to support the move to a balanced capital structure (preferred by the Commission) after these adjustments.

Q. Has the MPSC Staff ("Staff") commented on the reasonableness of taking securitization debt into account when calculating a balanced capital structure for the Company?

A. Yes. In Case No. U-21090, the Company's application for approval of an Integrated Resource Plan, Staff described this approach as reasonable. In his direct testimony, Staff witness Nichols stated that "If the Commission were to approve securitization of the regulatory assets related to retiring coal plants, Mr. Maddipati provides a reasonable method to preserve both the Company's credit and financial profile. Mr. Maddipati proposes 'Because securitization debt is recorded on the GAAP balance sheet of the Company, the Commission could accommodate the impact of securitization by considering the incorporation of securitization debt in determining a balanced capital structure.'"

Q. What does the Company project the <u>unadjusted</u> equity ratio will need to be in 2023 in order to achieve a 50/50 capital structure on an adjusted basis?

A. The Company projects that the unadjusted equity ratio for the 13 months ending December 2023 will be approximately 52%. This is shown on Exhibit A-14 (MRB-1), Schedule D-1, page 2, column (f), line 6. The Company also expects that, in the years subsequent to 2023 as the balance of securitization debt decreases with principal payments, the equity ratio on an unadjusted basis will also decrease.

Q. Does the Company believe that the capital structure and resulting equity ratio as filed is in line with the Commission's direction in previous orders?

A. Yes. In Case No. U-20697, the Commission indicated its desire for the Company to continue on a track to rebalance its capital structure while maintaining wide access to capital markets. As I have shown in my testimony and exhibits, the Company's equity ratio on an adjusted basis is 50.3% for the test year in this case and is anticipated to be 50.0% for the year ending 2023.

iv. <u>Peer Equity Ratios are Higher</u>

Q. Have you performed an assessment of how the 52.00% equity ratio proposed in this case compares to other utilities?

A. Yes. For each of the companies represented in Company witness Wehner's ROE proxy group, I calculated the equity ratio (as a percentage of permanent capital at the regulated subsidiary level) at year-end 2020. This is reflected on Exhibit A-26 (MRB-10). The average equity ratio for the Company's peer group was 55.8%, 380 basis points higher than the 52.00% proposed for Consumers Energy in this case. Despite this higher peer average, I am proposing a ratio of 52.00%, which balances capital investment plans, credit metrics, customer rate impacts, the guidance of this Commission, and continues to support affordable utility infrastructure financing for the state of Michigan.

Q. Why is it appropriate to consider peer company equity ratio averages and trends in determining the appropriate equity ratio for the Company in this case?

A. In Case No. U-20697, the Company's most recent electric rate case, Staff considered national averages of authorized ROEs in developing its ROE recommendation. In its Order in that case, the Commission cited Staff's average ROE analysis as one of the factors considered in determining the Company's approved ROE. While the Company argued that Staff's average ROE analysis was incomplete in that case, Staff and the Commission considered peer averages an important piece of evidence to inform the ratemaking process. To be consistent with that philosophy, it is appropriate to consider peer company equity ratio averages and trends in determining the equity ratio for the Company in this case.

v. Ability to Fund Significant Capital Expenditures at Optimal Rates

Q. What are the Company's plans for capital investments and how does the equity ratio keep the cost of capital lower?

A. As set forth in the testimony and exhibits of the Company's multiple capital witnesses, the Company is making significant capital investments over the next five years to maintain and improve infrastructure to the benefit of customers ("Capital Expenditure Program"). 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. 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. 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 Capital Expenditure Program. Strong credit ratings can also enable the Company to issue long-term debt ahead of upcoming maturities ("prefund") 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. An example of this is the $250 million refinancing that the Company executed in June 2020 and the $375 million refinancing that the Company executed in September 2020. By refinancing at a lower interest rate, the Company eliminates issuance interest rate risk, while realizing interest savings throughout the term of the called bonds. These savings and risk reductions are passed along to ratepayers in the form of a lower cost of capital.

Q. Do rating agencies consider the size of the Company's Capital Expenditure Program in evaluating its credit quality?

A. Yes. Consumers Energy's large Capital Expenditure Program is generally indicative of higher risk due to the fact that the Company will need to access capital markets with greater size and/or frequency. This exposes the Company to increased financial market and interest rate risk. In its downgrade of DTE Gas in July 2019, Moody's pointed to "the robust investment program of DTE Gas," along with the negative cash flow impact of Tax Reform as a basis of that downgrade. In its June 2019 credit opinion for Consumers Energy, Moody's noted the Company's elevated capital investment program and further noted that the investment program "will require continued regulatory support in order to maintain the company's current financial profile." It is, therefore, critical for the Company to maintain an equity ratio that is supportive of its strong credit profile, particularly during this period of significant capital investment. Failure to do so will put the Company at risk of experiencing the negative credit rating impacts faced by other utilities such as DTE Gas.

Q. With regard to the Company's projected capital expenditures, is it possible to trace equity dollars directly to those individual capital projects?

A. No. In addition to equity infusions, the Company also funds capital expenditures with long-term debt financing. Further, in determining the projected capital structure for the Company, a combined capital structure approach is utilized for both electric and gas rate cases. The combined capital structure is fungible and supports the Company's entire rate base. This is a long-standing approach that has been accepted and approved by the

Commission for many years. As a result, it is not possible to tie dollar-for-dollar the equity issuances to specific gas capital projects described in this case. This same standard applies to long-term debt financing, which also cannot be directly tied to specific capital projects. The capital expenditures in this case are identified, quantified, and supported by the Company's various capital witnesses.

vi. Rating Agency Adjustments Lower the Equity Ratio

Q. How does the Company's equity ratio on a regulatory (ratemaking) basis differ from rating agencies' views of the Company's equity ratio?

A. Certain credit rating agencies (e.g., Moody's) include benefits obligations as additional debt when calculating equity ratios. Other credit rating agencies (e.g., S&P) also include Power Purchase Agreements ("PPAs"), asset retirement obligations, and leases as additional debt when calculating equity ratios. These rating agency adjustments reflect the debt-like nature of these long-term fixed payment obligations. When credit rating agencies increase debt by including these items, the ratio of equity to debt used to evaluate the Company's credit-worthiness is thereby lowered. A 52.00% equity ratio calculated by the Company, thus, gets adjusted to a lower ratio by the credit rating agencies, which, in turn, reflects a diminished credit strength held by the Company. Incorporating the projected equity infusions in 2022 and 2023 in the common equity balance enables the Company to maintain reasonable equity ratios after the upward adjustments to debt made by credit agencies.

Q. What is the impact of rating agencies' adjustments to debt in calculating the Company's equity ratio?

A. Rating agencies' adjustments significantly reduce the Company's equity ratio. For example, in calculating financial metrics for 2019, S&P increased the Company's debt balance for the following items:

- $546 million to reflect the impact of PPAs;
- $194 million for pension obligations; and
- $374 million for Asset Retirement Obligations.

This aggregates to over $1.1 billion of additional debt reflected in their assessment of the Company's balance sheet and results in an equity ratio of 48.4% as evaluated by S&P in their credit assessment. The rating agencies' debt adjustments support the need for the Company to maintain a relatively higher unadjusted equity ratio to be on par with comparable utilities after adjustment. In addition to lowering the Company's equity ratio, rating agencies' adjustments to increase debt also reduce the Company's FFO-to-Debt ratio. As explained above, a lower FFO-to-Debt ratio negatively impacts the rating agencies' view of the Company's credit quality.

Q. Is the Company's capital structure balanced from a rating agency perspective?

A. No. In fact, as shown above, rating agency adjustments reduce the Company's equity ratio below 50%. Given these rating agency adjustments, a regulatory equity ratio of at least 52.00% is necessary to support the Commission's desire, as stated in Case No. U-20697, for Consumers Energy to maintain an evenly balanced capital structure.

Q. Does the Company expect that its capital structure will be balanced from a rating agency perspective in 2023?

A. No. The Company expects that its equity ratio will be below 50% from a rating agency perspective in 2023. Rating agencies assess the Company's debt level on a financial basis, including items such as securitization debt, short-term debt, and leases. These are the same items that the Company included in its adjusted equity ratio calculation for 2023 of 50% shown on Exhibit A-14 (MRB-1), Schedule D-1, page 2. However, in addition to these items, rating agencies also include additional debt items as mentioned earlier in my testimony, including PPAs, pension obligations, and asset retirement obligations. As a result, the Company expects that its rating agency adjusted equity ratio will fall below 50% in 2023.

vii. <u>Summary</u>

Q. In summary, why is having a 52.00% equity ratio, assuming a 10.50% ROE in this case, the right balance for customers and the Company?

A. In my testimony, I have shown that equity ratio and ROE have a direct impact on the Company's credit metrics and credit quality. I have also shown that an ROE below 10.50% and an equity ratio below 52.00% would lead to an FFO-to-Debt ratio that would not be supportive of maintaining the Company's current credit ratings. In fact, one credit rating agency (Moody's) has already downgraded the Company's credit rating, citing both the Company's capital structure and equity ratio specifically as a factor. Further, I have shown that taking into account debt-like obligations recorded in the Company's financial statements effectively reduce the projected equity ratio from 52.0% to 50.3%.

I have shown that equity ratios for the Company's peer utilities are, on average, at 55.8%. This is higher than the 52.00% recommended by the Company in this case. In addition, the Company is in the midst of a major infrastructure upgrade cycle throughout its service territory in Michigan. This will require billions of dollars in new capital funding to complete these needed upgrades for customers. A healthy equity ratio and strong credit quality will be key in raising the necessary capital at the lowest overall cost to customers over the long-term.

Finally, I have provided a framework for fulfilling the Commission's desire for the Company's capital structure to be balanced, and to achieve this by 2023, in a manner that will not materially harm the Company's credit metrics.

While lowering the Company's equity ratio below the 52.00% recommended in this case may appear to have a near-term cost savings impact, as debt financing is presently less expensive than equity, such a move would result in a deterioration of credit quality and may lead to customers paying higher financing costs over the long-term. The equity ratio of 52.00% is appropriate and reasonable under the current circumstances, made in conjunction with the 10.50% ROE proposed by Company witness Wehner. While a higher equity ratio could be supported, the Company has heard and understands the input of the Commission and intervenors in previous rate cases and is attempting to strike the right balance for customers, the state of Michigan, and credit rating agencies by holding the equity ratio at the Company's filed position of 52.00%.

Q. Please explain the long-term debt adjustment of $1.805 billion.

A. I have projected that the average debt balance for the test year ending September 30, 2023 will be $1.805 billion higher than the December 31, 2020 balance. This adjustment consists of the following components:

Long-Term Debt (in millions)			Sep 30, 2023
Month	Issuance	Retirement	Test Year Impact
Aug. 2021	$300	$0	$300
Sep. 2021	$35	$0	$35
May. 2022	$705	$0	$705
Aug. 2022	$610	$0	$610
Jun 2023	$0	($300)	($92)
May 2023	$550	$0	$211
Aug. 2023	$605	$0	$93
Aug. 2023	$0	($325)	($50)
Subtotal			$1,812
Changes in Unamortized Fees			(7)
Total			**$1,805**

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 2022, August 2022, May 2023, and August 2023.

A. The debt planned to be issued in May 2022, August 2022, May 2023, and August 2023 will be used for general corporate purposes of the Company including financing capital expenditures. The debt planned to be issued in May 2023 will also be used for the retirement of the Company's $325 million 3.375% bonds which mature in August 2023. 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 September 30, 2023?

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 September 30, 2023. The average amount outstanding on line 57, 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 September 30, 2023?

A. I have projected an average short-term debt balance for the test year of $191 million. This balance is shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1, line 10, column (b), and on Exhibit A-14 (MRB-2), Schedule D-1a, page 1, line 10, column (g).

Q. What are the components of the average short-term debt balance?

A. The average short-term debt balance is composed of two components. The first is the average short-term debt - short-term liquidity facilities balance of $146 million. The second is the average short-term debt – renewable liability balance of $45 million. These balances are shown on Exhibit A-14 (MRB-5), Schedule D-3, page 1, lines 1 and 3.

Q. What are the components of short-term liquidity facilities?

A. Revolvers, commercial paper, and intercompany borrowing are three short-term liquidity financing options available to the Company. Revolvers represent 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 London Interbank Offered Rate ("LIBOR") minus 10 basis points. The Company utilizes 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 cash surplus and effective borrowing rates must be lower than rates available under the Commercial Paper Program. Therefore, the intercompany borrowing facility is not considered part of the total liquidity capacity available to the Company.

Q. How was the short-term liquidity facilities balance of $146 million developed?

A. Exhibit A-14 (MRB-7), Schedule D-6, shows the projected balances of short-term liquidity facilities for the test year ending September 30, 2023 by month. 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. How do these projections compare with the historical trend?

A. The profile of monthly balances is consistent with the historical trend where the Company borrows on short-term facilities during fall and winter months and no short-term funding is required during summer months. The resulting 13-month average is $146 million.

Q. Are the projections for short-term debt – short-term liquidity facilities 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 pecking order in which the Company utilizes its short-term financing facilities:

		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

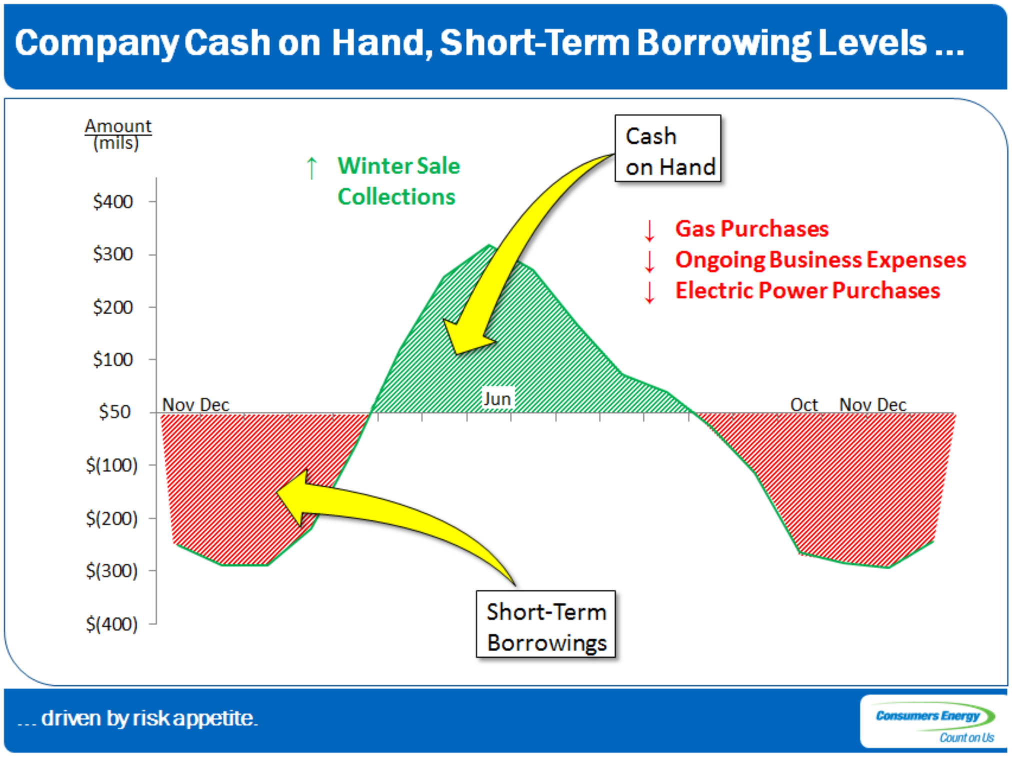
*Takes away $500 million of the JPMorgan revolver's $1.1 billion capacity (leaving $600 million available). The facility amount is currently $850 million, expected to increase to $1.1 billion prior to the test year ending September 2023.

**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 – short-term liquidity facilities 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 disappears as was witnessed during the 2008 credit crisis and again in March 2020 as a result of pandemic-related market fear. 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 equity balance would need to increase in order to achieve the appropriate 52.00% equity ratio. Doing so would result in a higher overall cost of capital. It should be noted that the Commission agreed with the Company's cash and short-term debt balances in Case No. U-20697.

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 $400 million of short-term borrowings in December 2021 and November 2022 via the Commercial Paper Program. However, access to the commercial paper market requires an equivalent amount of revolving credit capacity as a "backstop." The current maximum capacity under the Company's Commercial Paper Program is $500 million; therefore, of the Company's $1.35 billion of revolving credit facilities, $500 million is used to support commercial paper issuance. The remaining $800 million of revolver capacity is a vital backstop for capital expenditures and upcoming long-term debt maturities.

Q. What does the short-term debt–renewable liability represent?

A. This liability represents the amount of renewable surcharges that the Company has collected in excess of the required revenue requirements for the renewables portfolio standard.

Q. How was the renewable surcharge liability balance developed?

A. I have projected an average renewable surcharge liability of $45 million for this case. Exhibit A-14 (MRB-7), Schedule D-6, shows the monthly projections of this liability. The projections are consistent with Consumers Energy's RE Plan in Case No. U-20984.

Q. Please explain the deferred income tax adjustment of $298 million.

A. The Company's Tax Department has projected that the average deferred income tax balance for the test year ending September 30, 2023 will be $298 million higher than the December 31, 2020 balance. This increase is based on projecting book versus tax differences that the Company expects to record from January 2021 through September 2023. These adjustments total $298 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 September 30, 2023 will be $119 million, $4 million higher than the December 2020 balance. The balance is based on forecasted balances of both existing and anticipated new ITC credits that the Company expects to record from January 2021 through September 2023. These adjustments total $4 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 3.62% 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, 2020. I then added the new debt issuances in August 2021 and October 2021. These new debt issuances are shown on Exhibit A-14 (MRB-4), Schedule D-2, line 36 and line 45. I then added the planned new debt issuances in May 2022, August 2022, May 2023, and August 2023. These new debt issuances are shown on Exhibit A-14 (MRB-4), Schedule D-2, lines 37 through 40.

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 expense. 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 debt issuances in August 2021 and October 2021.

A. Since the debt issuances in August 2021 and October 2021 have already taken place, I used the actual interest rates specified in those bond issuances.

Q. The long-term debt issuances listed as "Floating Rate FMB" and the debt issuances listed as "PCRB - MSF LORB" in Exhibit A-14 (MRB-4), Schedule D-2, column (a), have relatively low interest rates. Is it expected that subsequent long-term debt issuances will have these same low interest rates?

A. No. The Company was able to achieve atypically low interest rates for these issuances. While the Company continuously seeks financing alternatives that maximize interest savings, these issuances are not likely to be repeatable in the near-term. The floating rate First Mortgage Bond ("FMB") issuances provided a unique security for a very limited investor pool. The debt bears interest at a rate of 3-month LIBOR minus 30 basis points with a 0% rate floor, maturing 50 years from issuance. The October 2019 and October 2021 issuances were for Pollution Control Revenue Bonds (PCRB). While the savings from these low interest rates will be passed along to customers in the form of a lower cost of capital, they represent the maximum size limit available to the Company at the time of issuance. Further, while the Company will continue to try to identify similar opportunities, there are not any currently identified, and similar offerings are not and should not be expected or anticipated on a regular basis going forward.

Q. Please explain the rationale for the December 2020 0.35% debt issuance reflected on Exhibit A-14 (MRB-4), Schedule D-2, line 35.

A. As discussed earlier in my testimony, and as detailed in Case No. U-20889, the Company intends to issue debt in mid-2023 in order to securitize Karn Units 1 & 2 assets. The 0.35% coupon FMB reflected on Exhibit A-14 (MRB-4), Schedule D-2, line 35, will mature in June 2023 and will lower customer costs in two ways. First, the aligned timing of the bond maturity allows the Company to retire debt with securitization proceeds in 2023 without having to pay an early call fee (or call premium) on a longer dated maturity. Second, customers will save as a result of the lower interest rate associated with this shorter dated debt as compared to the cost of a traditional 30-year issuance through the time of the bonds' retirement.

Q. Please explain the cost rate you assumed for the planned debt issuances in May 2022, August 2022, May 2023, and August 2023.

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 average of the projected 30-year U.S. Treasury rates of IHS Markit ("IHS") and Blue Chip Economic Indicators ("Blue Chip").

Q. What are IHS and Blue Chip and why are they reliable?

A. IHS and Blue Chip are companies that compile consensus economic forecasts and publish the results in a periodic report. These reports are widely used by companies in financial planning and analysis.

Q. What did you do next?

A. For each of these four planned debt issuances, I then added a 132 basis point credit spread. For the May 2022 and August 2022 planned debt issuances, the average of the IHS and Blue Chip 30-year U.S. Treasury rate forecasts for 2022 was 2.41%. Adding the 132 basis point spread resulted in a total coupon interest rate of 3.73% for this issuance. For the May 2023 and August 2023 planned debt issuances, the average of the IHS and Blue Chip 30-year U.S. Treasury rate forecasts for 2023 was 2.79%. Adding the 132 basis point spread resulted in a total coupon interest rate of 4.11% for these issuances. 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 extra compensation investors receive for bearing credit risk of the investment. 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 132 basis points?

A. Unlike U.S. Treasury rates, credit spreads for long-term bond issuances are not projected by financial forecasting companies such as IHS or Blue Chip. 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. Given the lack of a reliable source for projected credit spreads, I applied the calculated average from the last 12 years. From 2009 to current, the average credit spread on a 30-year debt issuance for investment grade utilities was approximately 132 basis points.

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, that have variable interest rates. The Floating Rate FMB issuances shown on line 30 and lines 33 through 34 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 LIBOR less 30 basis points. Therefore, I took the average of the projected 2023 three-month LIBOR rates from IHS and Blue Chip Forecasts (equal to 0.50%) and subtracted 30 basis points for an interest rate of 0.20%.

Q. Please explain Exhibit A-14 (MRB-4), Schedule D-2, line 51.

A. Exhibit A-14 (MRB-4), Schedule D-2, line 51, 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 51?

A. The amount shown on line 51 represents the amortization of losses on reacquired debt with refunding (including call premiums). The projected amortization expense for the 12-month period ending September 30, 2023 is $4,429,000.

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 1.36%. 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. As explained earlier, the short-term debt balance is composed of two components. The first is short-term debt – short-term liquidity facilities. I calculated the annual cost of short-term debt – short-term liquidity facilities to be $2.4 million. The second component is short-term debt – renewable liability. I calculated the annual cost of this component to be $0.2 million. This is shown on Exhibit A-14 (MRB-5), Schedule D-3, page 1, lines 1 and 3, column (b). The total average balance of short-term debt, shown on Exhibit A-14 (MRB-5), Schedule D-3, page 1, line 5, column (a), is $191.2 million. Dividing the total cost of $2.6 million by the total average short-term debt balance results in a total short-term debt cost rate of 1.36%, as shown in column (c).

Q. Please explain the cost of short-term debt – short-term liquidity facilities.

A. As indicated above, I projected a cost of short-term debt – short-term liquidity facilities of $2.4 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. **Interest on Borrowings** – Equal to the projected outstanding balance times the projected interest rate. The projected balance, all assumed to be commercial paper, is $146.2 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 LIBOR[1] rate for the test year of 0.50%. This was multiplied by the projected balance of $146.2 million. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $0.7 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 $0.1 million for Letter of Credit Fees. The Letter of Credit Fees shown on Exhibit A-14 (MRB-5), Schedule D-3, page 2, pertains 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 $1.0 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 $0.6 million for amortization of upfront revolver fees.

[1] Intercontinental Exchange London Interbank Offered Rate (LIBOR), a benchmark interest rate used in calculating short-term variable interest rates throughout the world.

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.

Q. What cost have you used for the short-term debt – renewable liability?

A. Section 21(4) of Public Act 295 of 2008 discusses the cost rate for the renewable liability, and it provides for "the creation of a regulatory liability that accrues interest at the average short-term borrowing rate available to the electric provider during the appropriate period." I have used the projected short-term borrowing rate available to the Company under its Commercial Paper Program of 0.50%. I then applied this rate to the projected average renewable liability balance for the test period of $45.0 million, shown on Exhibit A-14 (MRB-7), Schedule D-6. This results in a total cost for the test year of $0.2 million.

iii. <u>Preferred Stock Cost Rate</u>

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. Company witness Wehner recommended an ROE range of 10% to 11%. Based on my recommended equity ratio of 52.00%, I applied Company witness Wehner's cost rate of 10.50% 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 generally believes it is preferable for the ratemaking equity ratio to reflect the Company's actual capital structure (i.e., ratemaking should match reality). 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 favorable 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-24 (MRB-8).

A. Exhibit A-24 (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-24

(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-25 (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-25 (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 September 30, 2023 should be based on the 13 months ended June 30, 2021 (the working capital historical period)?

A. No. This historical period includes several months, beginning in March 2020, in which the country experienced extreme volatility, disruption, and illiquidity in the financial markets related to the COVID-19 pandemic. During this time, the Company took a proactive approach by issuing long-term debt and temporarily holding elevated cash balances. These actions limited the Company's risk of being unable to raise needed capital, strengthened the Company's liquidity, and ensured funding for the continued operations of the Company during this uncertain time. As a result of these actions, however, using the 13 months ended June 2021 results in a cash balance of $87 million, which is higher than what is normally expected and required for the Company in the test year of this case.

Q. What period do you believe that the projected cash balance for the test year ending September 30, 2023 should be based on?

A. I believe that the projected cash balance for the test year in this case should be based on the 13 months ended December 31, 2019 which results in a cash balance of $30 million. The cash levels from this period are appropriate since it is reflective of normal levels of cash balance.

V. <u>SUMMARY AND CONCLUSIONS</u>

Q. Please summarize your recommendations and conclusions.

A. Consumers Energy's capital structure should be based on the capital structure as of December 31, 2020, 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 5.96%. Also, the Company's projected cash balance for the test year in this case should be based on the 13 months ending December 31, 2019, which results in a balance of $30 million.

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-21148
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

SARAH HOLLIS BOWERS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

Q. Please state your name and business address.

A. My name is Sarah Hollis "Holly" Bowers (she/her/hers), 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 the Executive Director of the Operations Compliance and Controls division within Operations.

Q. Please describe your educational background and work experience.

A. I graduated from Michigan State University in 1998 with a Bachelor of Science Degree in Biosystems Engineering with a specialization in Environmental Studies. I received a Masters in Business Administration degree from Baker College in 2007. I presently hold the Executive Director of Operations Compliance and Controls for Consumers Energy, a position I have held since May 17, 2021. Prior to that, I was the Executive Director of Gas Asset Management since December 15, 2013. I was the Construction Manager for the Southwest zone and have held various other positions within engineering, operations, and business planning beginning in 1998.

Q. What are your responsibilities as the Executive Director of Operations Compliance and Controls at Consumers Energy?

A. I am responsible for driving improved operational performance across Consumers Energy Gas, Electric and Generation Operations units with a focus on enhancing compliance and strengthening operational controls to ensure a safe and reliable system. This includes the areas of Operations Compliance, Contractor Oversight, Gas & Electric Distribution

Contractors, Damage Prevention, Damage Claims, Operator Qualification and the Enterprise Corrective Action Program.

Q. Are you a member of any professional societies or trade associations?

A. Yes. I am a member of and represent the Company with the American Gas Association. Over the years, I have been on the Managing Committee, Engineering Committee, and supported multiple initiatives.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I previously testified in Case Nos. U-17882, U-18124, and U-20322.

Q. What is the purpose of your direct testimony?

A. My direct testimony explains the Company's plan to implement new corrective and preventative processes that will enhance the Company's capability for reducing system risk, and implementing sustainable controls, in alignment with American Petroleum Institute Recommended Practice 1173 ("API RP 1173") Gas Safety Management System ("GSMS") to improve safety and reliability to our customers and Michigan. My testimony includes descriptions of new programmatic solutions to enhance safety, controls, and compliance. These new solutions and process controls include:

I. Enterprise Corrective Action Program ("ECAP");

II. Risk Based Assessments and Field Compliance Program;

III. Remote Inspection Program;

IV. Advanced Methane Detection Program;

V. American Society of Mechanical Engineers ("ASME") B31Q technical standard for Operator Qualifications; and

VI. Sewer Locate Program.

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

A. No.

Q. Does the Natural Gas Delivery Plan ("NGDP") discuss the new initiatives that you are sponsoring?

A. Yes, it does. The enhanced controls and processes are discussed in the NGDP. These initiatives support the GSMS as described in Section 5 "Operational Capabilities" within the NGDP. This safety management system is discussed in the NGDP, and is sponsored by Company witness Neal P. Dreisig, and also discussed within Company witness Stephanie V. Watson's testimony. In general, API RP 1173 provides guidance to pipeline operators for developing and maintaining a pipeline safety management system. The elements of this recommended practice are structured to minimize non-conforming conditions regarding pipeline safety processes and procedures.

I. Enterprise Corrective Action Program ("ECAP")

Q. Please describe the ECAP initiative?

A. The ECAP was initiated at Consumers Energy in 2020 as an enterprise-wide issue management and compliance program supporting safe and excellent operations. ECAP is a program consisting of a dedicated team of individuals who operate in the Operations Compliance and Controls organization, supporting the overall ECAP process and platform that end-users at the Company will use to document corrective and preventative actions. The structured platform and methodology allows 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, will focus risk reduction efforts, inform operational business decisions, and promote the integrity and deliverability of the energy infrastructure. As part of the program's first phase, ECAP will support stakeholders in Gas Operations and Engineering to maintain adherence to GSMS standards established in API RP 1173. The Company's ECAP will address the crucial gaps by:

- Aligning and supporting the enterprise on a single repeatable Corrective and Preventive Actions ("CAPA") process.
- Streamlining the CAPA process by eliminating the use of disparate reporting systems and platforms.
- Providing transparency on action item completion and effectiveness.
- Enhancing operational excellence by fixing safety and quality/compliance problems and preventing recurrence.

Q. Can you describe the scope included in the program?

A. ECAP is a program that will ensure non-conforming conditions related to system safety and compliance are managed to ensure conditions are contained and remediated to prevent recurrence. As a reference, in 2020 Consumers Energy received 76 violations from MPSC inspections, resulting in roughly 100 corrective and preventative actions taken. The program's first phase of its rollout, will in part, support elements 3 through 7 of the GSMS. ECAP's scope includes: (1) improved issue identification and resolution within the Safety Assurance and Incident Management GSMS elements; (2) document retention, including audit trail and initialization, and oversight of corrective action plans; (3) data trending and predictive analysis providing the organization with a historical basis for measuring the effectiveness over time of issue remediation; (4) reduction in repetition and severity of nonconforming findings; and (5) improvement in employee empowerment, including self-identify and self-correct. Phase 1 of ECAP is focused on supporting GSMS as well as all of Gas Operations and Compression, Gas Engineering, Gas Regulatory Compliance and Assurance. The focus in Phase 1 deployment is to ensure these affected stakeholders are aligned to a standard process for issuing and dispositioning corrective actions related to conditions adverse to system safety, quality, and compliance. The following table describes the scope of the ECAP platform's capabilities:

Table 1. ECAP platform's capabilities scope

In-Scope	**Business Capability**	**Customer Benefits**
1. Creating an intake process to record the issue as it is identified	Creates and delivers a consistent method to facilitate the intake / collection of recording and documenting issues as they are identified enterprise-wide	Reinforces a behavior of standards adherence and eliminates repeat findings delivering repeatable and predictable compliance and process safety performance.
2. Implementing a method to do analytics	Creates and provides users a method to use a system to do analytics on corrective and preventative actions	Prescribes a method and process for proactive sharing, trending analysis and action for issues.
3. Assembling content that becomes a secure repository	Creates a standard categorization for content in an enterprise-wide secure repository	Consistency in categorization and trends through causal analysis process using risk-based approach and method.
4. Setting up a standard issue and cause taxonomy	Creates a standard issue and cause taxonomy enterprise-wide	Establishes a cadence and engagement model that ensures controls are established, tested, and mitigates future causes.
5. Assembling a repeatable risk-based remediation process	Creates a standardized and repeatable risk-based remediation process	Prescribes a risk methodology and process to proactively inform plans, programs, and operational controls to drive sustainable system performance.

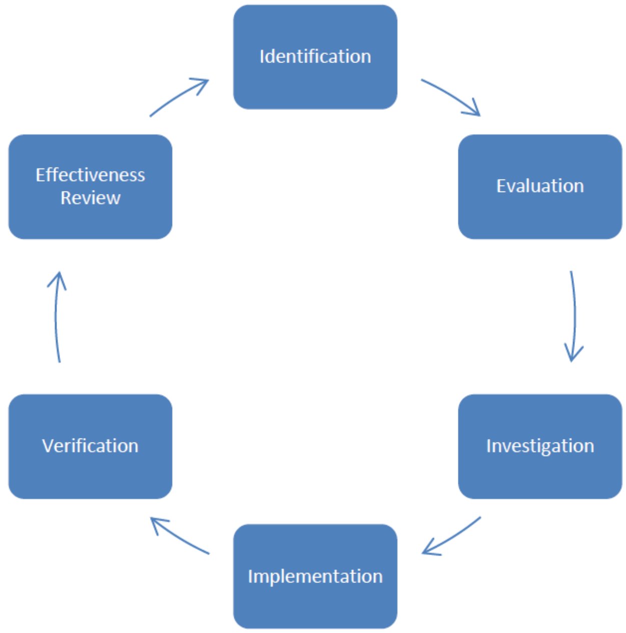
6. Producing a risk-based evaluation with quality standards	Creates and produces a risk-based evaluation process with quality standards	Establishes a prescribed cadence and engagement model which ensures controls are established, tested, and implemented to ensure.
7. Invoking statistical and cognitive trending data queries	Creates and provides users statistical and cognitive trending query capabilities real-time	Prescribes a method and process for proactive sharing, trending analysis and action for issues.
8. Creating a system of record for an audit trail	Creates a quality system of record and audit trail for all corrective actions enterprise-wide	Delivers a single source repository to the enterprise for system of record for audit purposes. Reduce and prevents Michigan Public Service Commission (MPSC) non-compliance and audit severity findings.

Q. How will the Company utilize ECAP to initiate and provide oversight of corrective action plans?

A. The ECAP standard is being deployed, starting in 2022 with Gas Operations, Gas Compression, Gas Engineering and Supply. This alignment to a standard process for initiating a CAPA will ensure a consistent and uniform flow of information, documentation of risk analysis, causal evaluation, action item development, verification of actions taken, and evidence of effectiveness. The cross-functional collaboration within this process, will be steered by a dedicated ECAP team reporting to an executive oversight committee to ensure the process and platform are meeting its intended purpose.

Q. Please discuss how ECAP will improve issue identification and resolution?

A. ECAP provides a standard approach to identify non-conforming conditions as it pertains to system safety and compliance. The closed loop process is as follows:



Q. Please describe an initiating event.

A. An initiating event is a non-conforming or adverse condition to system safety, quality and/or regulatory compliance. When an event is initiated, an issue description of an event will be documented, such that the following questions will be answered:

- What is involved? (e.g. process procedure, product, equipment)
- What is the event? (e.g. what happened, what should have happened)
- Who was involved? (e.g. company, contractor)
- Where was the event observed? (e.g. company facility, field, business unit)
- When did the event occur? (e.g. time, date)
- How did the event occur? (e.g. what failed)

Q. How does the Company plan to evaluate the event?

A. The issue owner and ECAP team will complete the following steps to evaluate the event.

- Step 1 is to assess the event based on impact and likelihood to assign a risk score. Risk scoring (1 to 25) is based upon the product of two number scales (1 through 5) measuring the likelihood of the event and the overall impact of the event. This score dictates the minimum actions and timeframes based on severity.

- Step 2 is to identify the extend of condition using a problem-solving tool to identify who, what, and where.
- Step 3 is to schedule, complete, and align on problem solving outcomes, with the applicable business partners to ensure timely and effective completion.

Q. How will the event be investigated?

A. The investigation phase of a CAPA is based upon the incoming risk calculation of the identified issue from the evaluation step. If an issue risk ranks high (15-25) or moderate (5-12) on the scale (1-25), an investigation process includes cross-functional collaboration, timeliness and quality checks by the ECAP team and issue owner leadership to ensure the root cause(s) has/have been identified adequately. The use of standard problem solving methodology as established by Consumers Energy lean operating system known as the "CE Way" will be deployed for documenting the problem definition, root cause analysis, extent of condition and containment actions. In the case of specific high risk classified events these investigations will follow a more formalized independent root cause investigation process. The ECAP platform will be the means by which these investigations will be documented and tracked as part of the corrective action process, and will be stored as a record for the required record life in accordance with information asset management protocols.

Q. Once the event is investigated, how will the actions be implemented?

A. Actions owners are responsible for completing their tasks as assigned, during this phase. Action owners will update milestones in the ECAP action tracking system to ensure timely completion of assigned actions and to make progress visible. Actions will be marked complete after uploading the required supporting evidence, and/or documenting the specifics on how the action(s) were completed. The implementation phase could take one day or multiple years and will be monitored through closure.

Q. Please describe how the Company will ensure controls and verification on the implemented actions.

A. Actions that are generated as a result of an initiated CAPA into the ECAP program, will be directly tied to a control hierarchy known as ERICPD (Eliminate, Reduce, Isolate, Control, Personal Protective Equipment ("PPE") or Direct). Eliminate is an action taken to completely eliminate the hazard or risk so that the likeliness of an event/incident is nullified. Reduce is an action taken to reduce the probability or severity of the known hazard. Isolate is a means by which exposure to an event or hazard has been limited (i.e. physical barricading). Control is an action related to an administrative or indirect means by which a "soft" barrier limits exposure to the event/hazard; this can include procedural guidance, new job aids, or similar type documents. PPE is an action taken to reduce the impact of the incident/event to personal or public safety by ensuring its used correctly and is available when a known risk is present. Direction as an action, is an effort to coach and correct frontline workers to current work practices and compliance requirements by direct report leadership. Each type of action item created in support of the overall initated CAPA will be part of the action plan that will require verification as part of the work process to ensure the intended action was taken, and that the appropriate level of control defined is in fact in use to mitigate risk in the corresponding manner. For each action that is verified an associated effectiveness measure will be communicated through the ECAP platform back to the issue owner, before the CAPA plan can be considered closed.

Q. How will the Company ensure that these implemented actions are effective and will not result in repeat findings?

A. An effectiveness review of verifiable actions that have been implemented will be documented as part of the standard work flow process in the ECAP platform for CAPA items. To close the initated CAPA item upon verification and performing the effectiveness review, the following questions will be considered:

- Has the root cause been addressed by appropriate actions that actually prevent the issue from recurring?
- Have all defined actions been completed and validated in a timely and quality manner, commensurate with the incoming risk score of the iniated CAPA?
- Are controls effective and monitoring in place to identify if a control is no longer active or in use?
- Has the solution introduced any additional risk?
- Is the supporting evidence well documented?

If a CAPA is deemed ineffective by the reviewer there will be timely communication to appropriate levels of leadership prior to the next opportunity for the same issue/event to occur. Expected output of this phase is a record providing evidence that issues are resolved with effective, long-term sustainable solutions. Tracking and trending within the ECAP platform will allow for periodic reviews of repeat findings/violations in areas of the business where the CAPA process has been implemented.

Q. Is the Company planning technology projects that support this compliance and controls initiative?

A. Yes. The Company has selected software technology from the vendor DevonWay. The expenditures for this project are contained within the testimony and exhibits sponsored by Company witness Kristine A. Pascarello, Exhibit A-124 (KAP-9), line 4. The scope of work for this project includes the following DevonWay products. Each module will be part of ECAP's Phase I deployment supporting the Gas Organization. Each module is interconnected to each other, some primarily used for intake of issues that have integration with CAPA. The six modules being implemented are as follows:

- CAPA
- Requirements & Compliance Management
- Non-Conformance Reports ("NCR")
- Audits & Assessments
- Failure Mode & Effects Analysis ("FMEA")
- First Part Acceptance ("FPA")

Q. Please describe any additional resources that will be required to support this program.

A. The ECAP program will be staffed with eight full time employees and augmented support personnel through 2023 as follows; a director, manager, system lead, two corrective action specialists, and three causal investigators. Augmented Staff includes business unit corrective action specialist, change communication consultants, information technology support and learning and development support. These expenses are within Company witness Christopher T. Fultz's testimony under the Operations Compliance and Controls program, Exhibit A-46 (CTF-1) line 3.

Q. With the implementation of this program, please explain the benefit the customers will see delivered through this initiative.

A. ECAP is in support of other important initiatives such as GSMS. By deploying an ECAP program the customers will see improved safety, reliability and service through (1) assurance that significant non-conforming conditions are resolved on the gas system, (2) customer complaints are reduced by corrective actions preventing recurrence of non-conforming conditions directly impacting the customer, (3) promotion of continuous improvement to the overall gas system and management of ECAP and (4) an aligned method for problem solving to ensure consistent/repeatable outcomes.

Q. Do other utilities or companies have a similar program?

A. Yes. Many utilities have a similar program. The following is a short list of the companies, that are currently using DevonWay Software platform to support their Quality Management Systems ("QMS"): US Department of Energy, two of the three National Security Administration Laboratories, National Laboratories, two of the top five US Engineering and Construction firms, GE Hitachi, GE Healthcare, Framatome, Pacific Gas and Electric (PG&E), DTE Energy, and over 50% of the US nuclear fleet (a regulatory requirement in 10CFR50 Appendix B, Criterion XVI).

Q. Please describe the cost for the Test Year for successful implementation of ECAP.

A. The total costs of the ECAP program are as follows in 2022 and 2023 for O&M and Capital Expenses as of 8/19/2021. Capital Expense for 21 months ending 9/30/2022 are primarily the upfront cost for five years of license fees from the Software Vendor, including but not limited to, the subscriptions to the quality management software, maintenance support and business intelligence reporting. The remaining costs are associated with project implementation initiated in 2021 and continuing into 2022. O&M expenses in the 12 months ending 12/31/2021 are the cost of internal departments supporting the project (i.e. design requirements gathering, user acceptance training, process development, etc.).

Table 2. ECAP cost elements

Capital Expenditures (Dollars in 1000s)
*Contained within **Exhibit A-124 (KAP-9), line 4***

Description	Historical 12 Mos Ending 12/31/2020	Projected Bridge Year			Projected Test Year
		12 Mos Ending 12/31/2021	9 Mos Ending 9/30/2022	21 Mos Ending 9/30/2022	12 Mos Ending 9/30/2023
ECAP platform	$0	$1,592	$102	$1,694	$34

O&M Expense Expenditures (Dollars in 1000s)
*Contained within **Exhibit A-46 (CTF-1), line 3***

Description	Historical 12 Mos Ending 12/31/2020	12 Mos Ending 12/31/2021	12 Mos Ending 12/31/2022	Projected Test Year
				12 Mos Ending 9/30/2023
ECAP platform	$1	$222	$0	$0

II. <u>Risk Based Assessments and Field Compliance Program</u>

Q. Please describe Risk Based Assessment.

A. A Risk Based Assessment ("RBA") is a programmatic evaluation of operational areas within the Company's gas operations governed by 49 CFR 191, 49 CFR 192, 49 CFR 199, and the applicable state-added rules in the Michigan Gas Safety Standards. RBAs identify and address risk associated with operations, maintenance, engineering, and construction activities and assess adherence to written procedures. RBAs represent program-level initiation and evaluation activities, as described previously in the six-phase ECAP approach. Identification of these risks is necessary to create effective risk mitigation as well as prevention and correction of non-conformances through ECAP investigation, implementation, and verification activities.

Q. Please describe the Field Compliance Program.

A. The Field Compliance Program is a team of Union and non-Union operations personnel dedicated to providing in-person field oversight of operations, maintenance, and construction ("OM&C") activities being performed by Union OM&C and contractor employees. These discipline-specific quality field observations are primarily performed by a dedicated group of experienced Union employees, whose objective it is to ensure adherence to the Company's established OM&C procedures, as well as to identify, stop, coach, correct, and document instances of procedural non-adherence. These documented field compliance findings are trended and evaluated for recurrence, and repeated findings are considered for formal problem solving and risk mitigation. The Field Compliance Program thus reduces compliance and safety risk in two primary ways: coaching and correcting (direction corrective action) individual instances of procedural non-adherence at the point of execution, and as an input for correcting and preventing recurring findings. In this manner, the Field Compliance Program follows the six-phase ECAP approach with field-identified non-conformances as the primary intake versus the program-level findings typically identified through RBAs.

Q. How do RBAs improve Consumers Energy's performance and the safety of the system?

A. RBAs holistically evaluate gas operational areas for the existence and adequacy of quality and compliance controls, including (but not limited to): governance and oversight, training and qualifications, key performance indicators ("KPIs"), presence of and adherence to standard work, and records management. The assessments are conducted under the direction and supervision of Certified Quality Auditor(s), so designated by the American Society of Quality ("ASQ"). Assessment deliverables include positive program observations, summary of assessment results, list of findings with prioritized risk, and request for associated corrective and/or preventive actions with deliverable dates.

Corrective actions are designed to eliminate the cause of issues identified by the RBA, while preventive actions are designed to eliminate the causes of potential non-conformance, defect, or other undesirable situation in order to proactively prevent occurrence. The auditor responsible for the RBA is tasked with reviewing the CAPA plan developed to address the assessment findings. The auditor reviews the CAPA plan to ensure that the underlying cause is being treated, and accordingly accepts the CAPA plan as written, or requests additional clarifying information.

Q. How does the Field Compliance Program improve Consumers Energy's performance and the safety of the system?

A. The Field Compliance Program provides daily oversight of OM&C activities across the Company's system of gas transmission, storage, distribution, and service facilities. Work activities are selected for observation both on a sampling and risk-based approach, with as many as 500 task-level field observations performed each day. These observations provide opportunities for independent identification of procedural non-adherence by a team of experienced and knowledgeable discipline-specific Union field compliance personnel, as well as non-Union field leadership. Instances of procedural non-adherence are stopped before the completion of the work, while the employee performing the work is coached and corrected on the proper procedural steps. This provides real-time risk mitigation and performance improvement, and the data gathered for purposes of trending repeat non-adherences allows for further problem solving and CAPA plan development on those field tasks with systemic performance issues. By identifying, correcting, and preventing quality and compliance deficiencies, the CAPA cycle (whether initiated by RBA or Field Compliance findings) helps ensure that gas operations and supporting activities are more measurable, repeatable, controlled, and in compliance with applicable state and federal pipeline safety rules.

Q. What are the Operational Areas that the Company has completed and plans to complete RBAs on?

A. There are 34 operational areas defined under the Company's GSMS framework. Operational areas were delineated as a means of discretely categorizing the Company's operational activities regulated within 49 CFR 191, 49 CFR 192, 49 CFR 199, and applicable state rules. The number and scope of the operational areas are subject to revision as and when new regulations are promulgated, or as the Company determines its operational activities should be categorized and delineated. Through 2021, a RBA has been completed or initiated for 11 operational areas, as listed below:

Table 3. Risk Based Assessments Completed/Initiated

Inventory Year (Year RBA commenced)	Operational Area
2019	Welding
2019	Plastic Fusion
2019	External Corrosion
2020	Compression Engineering
2020	Damage Prevention
2020	Atmospheric Corrosion
2021	Gas Odorization
2021	Emergency Plans
2021	Meter/Service Lines
2021	Incident Reporting & Investigation
2021	TIMP (Transmission Integrity Management)

For the Test Year (October 2022-September 2023), the following Operational Areas are planned.

Table 4. Planned Risk Based Assessments

Inventory Year	Operational Area
2022	DIMP (Distribution Integrity Management)
2023	Abnormal Operating Conditions
2023	Leak Repair
2023	Pressure Regulation (operation and maintenance)

The balance of the Operational Area inventory is as follows.

Table 5. Future Year Risk Based Assessments

Operational Area
SIMP (Storage Integrity Management)
Records Management
Leak Investigation
Leak Survey & Patrol (Transmission)
Pipeline Design & Material Specifications
Emergency Valves
Leak Survey (Distribution)
Internal Corrosion
Construction Practices
Class Location (monitoring and studies)
Operator Qualifications
MAOP Records
Pipeline Uprating
Overpressure Protection
Pipeline Markers
Pressure Testing
Pipeline Public Awareness
Drug & Alcohol Testing
Gas Control

Q. Please describe some of the corrective and preventative actions that this program has identified and resolved.

A. Previous RBAs have identified program nonconformances in the following categories: governance, standards and controls, data integrity and management, recordkeeping, procedural roles and responsibilities, processes, and key performance indicators. Each associated finding has been subject to formal problem solving, up to and including, root cause analysis, and CAPA plans have been developed to mitigate the risk of the parent finding. Corrective and preventative actions developed to address these findings include, but are not limited to, the following:

Table 6. Corrective and Preventative Actions Implemented

Operational Area	Finding Type	Corrective and Preventative Action	Implementation Date
Welding	Governance/Roles & Responsibilities	Develop a dedicated welding organization to provide leadership and best practices for the Welding Program and help to ensure high quality and safe welding on our system.	April 2020
	Governance/ KPIs	Establish and implement KPIs to track the progress and execution of the welding program to evaluate the progress to completion of welds on our system and measure effectiveness of implemented programs.	April 2020
	Processes Standards & Controls	Establish and implement a Quality Assurance (QA) strategy to help ensure all welding activities meet the most current policies and procedures established by the Welding Organization.	September 2021
Plastic Fusion	Processes	Develop and implement a monitoring process for fuses that fail inspection or integrity testing prior to placing in-service.	July 2021
	Processes/ Data Integrity & Management/ Recordkeeping	Develop and implement a documented review process to assess tools and equipment used in fusing, to ensure the employees have safe and reliable tools to make fuses in accordance with 49 CFR 192.273.	July 2020
External Corrosion	Governance	Develop a Corrosion Governance Council to oversee Corrosion operations and maintenance activities across the system, ensuring visibility of risks and barriers and helping to better ensure safety and compliance.	April 2021
	Governance/ KPIs	Evaluate and establish new KPIs to help drive decision-making, based on progress and outcome of operations and maintenance activities related to corrosion.	April 2021
	Processes	Implement a change management process, including enhancements to the corrosion QA/QC process, to ensure procedural adherence and complete and accurate corrosion records.	September 2021

Q. Please describe the costs included in the test year.

A. Test year costs include the following initiatives, each of which is associated with RBA, Field Compliance Program, and downstream CAPA plans and are included in Exhibit A-46 (CTF-1), line 3 of Company witness Fultz, and in Exhibit A-124 (KAP-9), line 4 of Company witness Pascarello's testimony.

Table 7. RBA and Field Compliance cost elements

Capital Expenditures (Dollars in 1000s)
Contained within Exhibit A-124 (KAP-9), line 4

Description	Historical 12 Mos Ending 12/31/2020	Projected Bridge Year			Projected Test Year
		12 Mos Ending 12/31/2021	9 Mos Ending 9/30/2022	21 Mos Ending 9/30/2022	12 Mos Ending 9/30/2023
Field Compliance Corrective Action technology solutions	$0	$0	$0	$0	$35
Management Action Plan (MAP) technology solutions	$0	$0	$343	$343	$468

O&M Expense Expenditures (Dollars in 1000s)
Contained within Exhibit A-46 (CTF-1), line 3

Description	Historical 12 Mos Ending 12/31/2020	12 Mos Ending 12/31/2021	12 Mos Ending 12/31/2022	Projected Test Year
				12 Mos Ending 9/30/2023
Compliance Assurance Auditor-Sr Business Support Specialist	$0	$0	$0	$24
Operations Compliance contract auditor-led Assessments	$0	$0	$0	$21
Field Compliance Corrective Action technology solutions	$0	$0	$0	$40
Field Compliance Contract Inspection Services	$0	$0	$0	$30
Management Action Plan (MAP) technology solutions	$0	$0	$0	$404
MAP Team Change/Training Role	$0	$0	$0	$24
MAP Data Analytics Role	$0	$0	$0	$24

Compliance Assurance Auditor Resources supplement the Company's current audit resources in order to ensure RBA inventory targets are met. Field Compliance Corrective

Action technology solutions are critical to developing sustainable and effective preventative and corrective actions to address Field Compliance findings. Problem solving initiated by Field Compliance problem solving typically results in short-cycle CAPAs requiring relatively modest funding, including:

(1) *Learning Enhancements* – Delivery of visual and audio content to end-users in the field in order to improve point-of-use procedural adherence through technology.

(2) *Data Visualization* – Create and maintain visual management.

(3) *Field Device Software Modifications* – Solutions involve the addition/modification of prompts, banners, or alerts to draw additional attention to standards and procedures that have repeatedly been followed incorrectly.

Field Compliance Contract Inspection Services supplements Company field leaders and remote inspection with third-party contract inspectors providing additional oversight and assurance of procedural adherence, quality, and compliance. Contract inspection services provide similar oversight as the aforementioned Union Gas Code Standard Representatives, but for contractor-executed OM&C activities. Management Action Plan (“MAP”) technology solutions allow audit and assessment findings to be resolved faster and more reliably, and thus reduce the overall gas system risk. Specific technology solutions are dependent on assessment finding type and outcome of formal problem solving and causal evaluation and include: Robotic Process Automation, Process/Control Prototyping, Artificial Intelligence/Machine Learning (AI/ML). MAP Change Management is necessary in order to successfully implement long term and sustainable corrective actions. This ensures that all stakeholders understand the change being undertaken and prepare them for deployment. MAP Data Analytics is key to implementation of effective and sustainable corrective and preventative actions. Most

MAPs have a data visualization/dashboarding component, and the ability to quickly build visual management tools is critical to ensure timely and reliable implementation of corrective and preventative actions. Projected test year costs for Field Compliance Corrective Action and MAP technology solutions are based on the scale of anticipated technologies previously mentioned, as well as actual and estimated costs of historical and in-process solutions.

Q. Please describe how the RBAs will impact Consumers Energy's stated goals in the NGDP and implementation of GSMS.

A. RBAs are an integral part of GSMS maturity through support of the Safety Assurance and Operational Controls elements detailed in American Petroleum Institute's ("API") Recommended Practice ("RP") 1173 for Pipeline Safety Management Systems.

> *15.7 Contributions of Safety Assurance*
> *A focus on safety assurance is a form of defense-in-depth, i.e. multiple layers of safety assurance in managing risk. Applying the multiple layers demonstrates commitment to improved performance. This elements assures the operator checks and validates the risk management processes are systematic and disciplined, This element specially speaks to the crucial nature of employee engagement, reporting a, and feedback on issues and concerns, The opportunity is here to evaluate the culture of trust and openness in the organization, which is vital to growing a more resilient organization, the quality and independence of assessment and audit process for the rigor that should result in increased organizational confidence and positive peer attitudes, which feed motivation for engaging in safety. (Pipeline Safety Management System, AIP First Edition July 2015, pg. 22)*

The achievement of safety assurance element maturity requires the use of audits to assess the operator's risk management and pipeline safety performance. Audit program considerations as defined by API RP 1173 includes but is not limited to incident investigations, operational lessons learned, abnormal operations, and personnel interviews.

RBAs serve as the Company's own internal mechanism for auditing of risk management and pipeline safety performance.

> *15.5 Contributions of Operational Controls*
>
> *Operational controls lead to greater certainty that the pipeline operator and pipeline system perform as expected. A greater sense of certainty about all aspects of operations contributes to the perception that there is an intentional commitment to safety. Employees share this sense of purpose, and it influences how they interact with each other and how they participate in owning and reinforcing this value. Employees will know that the practice of safety tasks is important. Employees will have confidence that they can stop work and identify problems for management resolution. (Pipeline Safety Management System, AIP First Edition July 2015, pg. 22)*

Operational controls element maturity is supported by the aforementioned audit activities, primarily through the scrutiny of operating procedures. Reviewing and observing the existence of, and adherence to, operating, maintenance, and construction procedures is an integral part of the audit activities conducted under the RBA and Field Compliance programs.

III. Remote Inspection Program

Q. Please describe remote inspection.

A. Remote inspection is the use of technology, and the empowerment of field crews performing work to use this technology, to capture and log information about their activities as they complete the work. This information can consist of work order information, address, dates and times, and photos of work at multiple stages of completion. The photos are then reviewed by Company personnel as a quality control point.

Q. Please describe how remote inspection works?

A. The Company utilizes a Geospatial Information System ("GIS") application that field workers can leverage from mobile devices such as smartphones, tablets, and laptops. Field workers use the mobile solution application to answer and document pre-determined questions, take photos and geolocate data points showing their completion of the work and its adherence to company standards. The application tracks date and time information, along with time stamps for pictures and when the survey was signed and submitted. After field workers submit the completed survey, Company Field Leaders are tasked with reviewing the submissions. During review, Field Leaders can review survey responses by checking answers to survey questions asked, viewing all pictures taken, and ensure the work was done according to Company guidelines. For example, a picture is required at the start of a pressure test showing the pressure gauge, and is also required at the stop of the test. Each photo is time stamped to show the test duration.

Q. Please explain how remote inspection provides greater oversight to construction and maintenance activities.

A. Construction rules (192.301-328) require each transmission line or main to be constructed in accordance with comprehensive written specifications or standards that are consistent with part 192. Company management is entrusted with performing crew visits and audits to ensure adequate adherence to operations manuals and procedures. Due to the amount of work occurring on the system daily and the vast geographic territory, it is impractible to be able to physically be at each site when the majority of work is carried out. Remote inspection supplements inspections on jobs where field leadership is unable to perform an in-person inspection. This increased ability to perform digital review of completed work helps contribute to the Company's GSMS, specifically the operational controls and safety assurance elements.

Q. On what activities has Consumers Energy implemented remote inspection?

A. Currently the Company is conducting Remote Inspections for contractor performed aggregate delivery, traffic control, hydrovac, gas contractor construction, sewer locates, property restoration, leak survey, private utility locates, and directional boring. Each Remote Inspection is described below.

- Aggregate Remote Inspection provides documentation of the services provided by aggregate contractors. Covering furnishing and delivering of aggregate materials, pick up of earthen debris from construction projects, or providing time and materials services for the Company. This inspection helps ensure proper invoicing for the services provided.

- Traffic Control Remote Inspection gathers documentation for when a job site needs to manage traffic for Company work. The submitted surveys ensure that safety guidelines are followed for each job. Pictures are taken to document that proper placement of each item used to control traffic flow is done according to the traffic plan.

- Hydrovac Remote Inspection provides detailed information on the work performed by contractors. Surveys are submitted that include excavation details of staking pictures (both pre-dig and post-dig), that the site is secured for "safe to leave" post dig, and show the boom stored for the Hydrovac equipment.

- Gas Contractor Remote Inspection provides detailed information on the work performed by gas underground contractors. Documentation ensures the contractor is following the gas construction guidelines. Each survey collects the job type, crew members, photos of the job, method of construction, type of work, bore pre-shot checklist, and documents the air testing gauges though time stamped photos. If restoration is required, details of the restoration are collected. The survey helps ensure that work performed follows Company gas construction guidelines and safety standards.

- Sewer Locates Remote Inspection documents the information gathered during the sewer locate process, pre- and post- construction, capturing the "sewer locate card" which contains all tie-down or stationing measurements and depths, along with photos of the paint and staking activities in the job scope.

- Restoration Remote Inspection survey documents information on what type of restoration is required, surfaces that were restored, before and after pictures. This inspection assists in tracking that each restoration satisfies the customer needs and follows Company standards.

- Leak Survey Remote Inspection enhances the collection process to document the leak survey detection process by gathering information related to material conditions, recording condition of the riser, placement details and other leak survey observations including pictures.

- Directional Drilling Remote Inspection covers crew information, location, Miss Dig, overall project photos, bore path, and job prints.

Q. Please explain the benefit to customers with the implementation of remote inspection.

A. Remote inspection provides a control point to increase the quality of work through vendor/worker accountability. This ensures that the work that is completed and meets the quality requirements and adheres to the operating procedures. This helps create a culture where all work is reviewed, and crews are aware that their workmanship will be monitored. This drives consistency in execution, validation of on-site and off-site times for billing, and proof of site conditions before and after work. This increase in data collection drives higher quality work, reduces complaints and damages related to customer property, and helps validate billing for contractors. By inspecting more work though the Remote Inspection platform, the Company is preventing additional costs and rework due to unseen/unidentified deviations.

Q. Are there plans to expand the use of remote inspection?

A. Yes. Remote Inspection is currently managed and configured with a single employee. This employee is tasked with scoping, designing, architecting, training and publishing these application deployments and associated dashboards. This limits the amount of active deployments and users that can successfully use the platform. The plan for expansion includes additional analysts to assist with the configuration/deployment of solutions and management of data and field support personnel that will train, coach, conduct follow-up problem solving, and build reports on the findings. This expansion will enable the application to get deployed to additional contract resources working on the Company's system to increase the amount of work that is being collected and reviewed, along with piloting and exploring additional application to non-contractor work groups.

Q. Please describe the cost for the Historical and Test Year for remote inspection.

A. The costs for remote inspection are sponsored by Company witness Fultz within A-46 (CTF-1), line 3, and of Company witness Pascarello's Exhibit A-124 (KAP-9), line 4. A summary of those expenses are shown below.

Table 8. Remote Inspection cost elements

Capital Expenditures (Dollars in 1000s)
Contained within Exhibit A-124 (KAP-9), line 4

Description	Historical 12 Mos Ending 12/31/2020	Projected Bridge Year			Projected Test Year
		12 Mos Ending 12/31/2021	9 Mos Ending 9/30/2022	21 Mos Ending 9/30/2022	12 Mos Ending 9/30/2023
Remote Inspection Expansion	$0	$0	$0	$0	$169

O&M Expense Expenditures (Dollars in 1000s)
Contained within Exhibit A-46 (CTF-1), line 3

Description	Historical 12 Mos Ending 12/31/2020	12 Mos Ending 12/31/2021	12 Mos Ending 12/31/2022	Projected Test Year 12 Mos Ending 9/30/2023
Remote Inspection	$1	$6	$7	$7
Remote Inspection Expansion	$0	$0	$646	$1,205

IV. Advanced Methane Detection Program

Q. Please describe Advanced Methane Detection.

A. Consumers Energy currently conducts leak surveys with handheld instrumentation through foot patrol of gas service lines and infrastructure. These devices read methane indications in parts per million ("PPM") and lack geospatial and verification capabilities. Advanced Methane Detection ("AMD") is the utilization of higher sensitivity instrumentation (parts per billion ("PPB")), that also captures information like breadcrumbing and geospatial locations of methane indications, through time-stamped datalogging.

Q. How will this technology improve the Company's capability to find leaks on the system?

A. This technology will enable the company to find and prioritize the higher risk leaks to improve public safety. When used with risk-based and algorithm capabilities it will deliver increased safety to the customer while also delivering higher quality, tracking, and cost management.

Q. Please explain the benefit to the customer delivered through the AMD?

A. AMD will improve data and understanding of system risk, target higher risk areas for system improvements and improve detection of methane. AMD will improve safety and reliability by aiding in a strategic and data driven approach to higher-risk leak identification and remediation. It will improve affordability by reducing leak survey costs by an estimated 30% after full implementation of Phase 2. It also supports the Company's goal of net zero methane emission by first time quantification and identification of large volume emission locations leading to prioritized remediation.

Q. What solution is the Company planning on implementing?

A. The Company is currently using the vendor Picarro for Phase 1 execution and Phase 2 proof testing. This decision was made after careful consideration of industry offerings, and peer-to-peer conversations and communications with utilities across the United States. Picarro 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. The expertise of Picarro will assist in the Company's deployment of AMD in a thoughtful and progressive way to lower risk and increase safety for our customers.

Q. Did the Company consider other industry offering and equipment for comparison and testing of outputs?

A. Yes, as part of the internal evaluation, other options were evaluated for both capabilities and investment costs. The Company evaluated an option that it ultimately eliminated due to the cost of that solution exceeding estimated cost to operate Picarro units. Another was not selected as its solution was newer to the market and had a lack of precedence in the industry or with large-scale implementation. It also deploys a differing approach to scientifically detecting methane/ethane (Middle InfraRed Analyzer "MIRA" vs Ring-Down) which is newer to the industry and overall unproven.

Q. When comparing alternatives, what did the Company consider?

A. When comparing industry offerings, the Company considered technology, software, precedence and operating modes. With these areas of consideration, Picarro was the selected vendor that was best able to satisfy all 4 areas.

- *Technology*: Ring down spectroscopy is and has been an industry recognized offering in the methane detection space. A differing technology option is MIRA, which uses a different wavelength frequency and is reported to provide differing outputs from Ring-Down methodologies.

- *Software:* In addition to the hardware/technology side of any offering is the postproduction software and analytic tools that accompany the raw data. Picarro has a cloud based, turnkey solution that digests drive data into actionable data for operators.

- *Precedence:* While technology and hardware may be cutting edge and provide increased capabilities, some are so new to the market that a full-scale implementation of untested and unvetted equipment may result in unsatisfactory results and increased defects.

- *Operating modes:* Some hardware offerings can identify methane and ethane plumes, as a raw data collection device. Picarro offers multiple operating modes such as leak survey, super emitter survey, system integrity analysis, emissions quantification, and risk-based leak survey.

Q. How is Consumers Energy planning on implementing this technology?

A. Consumers Energy plans on 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 will look 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.

Table 9. AMD Phases

Phase 1	Phase 2
DIMP/Engineering Replacement Model data collection	Compliance Leak Survey & Risk Based Leak Survey
Emissions Quantification	
Source Discrimination	
Leak metadata	
Leak Survey Testing	

Q. Please explain the aspects that are part of Phase 1.

- DIMP/Engineering Replacement Model data collection will collect and link emissions data to pipe segments, helping aide pipe identification and selection for replacement.

- Emissions Quantification is rapid driving to link raw emission data to a geographic area.

- Source discriminations work with AMD devices will assist in the pinpointing hard to locate leaks, or to rule out bio-gas methane that could produce false positives through current leak survey methodologies.

- Leak metadata will leverage AMD collection on currently actionable leaks to identify emissions rate, gas composition, etc.

- Finally, leak survey testing will be performed in parallel with current methodologies to determine differences in output and quality, while also developing standards and practices for future implementation.

Q. Please describe Phase 1.

A. Phase 1 started in 2021 and runs through 2022 and beyond. For Phase 1, the Company is using AMD to track methane emissions as an input in the Company's asset risk assessment as part of the Distribution Integrity Management Program ("DIMP") to contribute to the Company's rank risking for project selection and scoping. In addition to project scoping data collection, the AMD devices will be used to help clarify sources of existing leaks (e.g. Biogas and non-Company methane), quantify/collect holistic emissions data, and pilot leak survey trial runs and perform test cases to build standards and practices for Phase 2. The key items of interest in the trial will be the use of risk based leak survey and analytics tools to ensure that the heightened sensitivity of the Picarro devices will identify actionable leaks for remediations. The stated objectives of Phase 1 are expected to continue indefinitely and will not be affected by Phase 2 timelines and decisions.

Q. What will Phase 2 include?

A. For Phase 2, the Company will replace the current leak survey process and methodology with a planned implementation from 2023-2026. The Company will integrate/compliment new application hardware and software with current asset management, work management, and analytics platforms - including GIS, Inspection Manager, SAP, Service Suite and Distribution Risk Analysis Model ("DRAM"). As standards and practices are proposed and adopted, a staggered implementation strategy for vehicle procurement and implementation will provide the Company flexibility on decisions.

Q. Why is AMD not being applied to Compliance Based Leak Survey in Phase 1?

A. AMD equipment is 1,000 times more sensitive than current leak survey equipment. The analytical tools and risk-based leak survey capabilities of the Picarro software will be explored to help provide a Phase 2 implementation solution that both increases the safety of customers through improved/modern leak survey and ensures that the most critical leaks are identified without unactionable methane indications. This approach will provide the Company an opportunity to calibrate the technology to the Company's gas system, and to seek adoption prior to its use on a compliance activity.

Q. Please describe the difference between Emissions Quantification and leak survey when using this technology?

A. The Picarro operating mode for Emissions Quantification is different from the leak survey operating mode in a few key ways. Leak survey provides actionable outputs that indicate a probability of a leak. Conversely, methane detection does not provide leak indications for further follow up. The purpose of raw methane detection/emissions quantification is to associate an emission quantification to an area or pipe segment. This raw data is run through a different software module, and in lieu of generating probable leak locations, the data is coupled to nearby assets or geographic areas. This data then allows for analysis that will help contribute to project scoping, risk ranking of pipe health, and overall environmental impact monitoring through aggregate project wide emissions and methane scoring.

Q. What costs are associated with Phase 1 and Phase 2 rollouts?

A. Test Year costs for Picarro include the continuation of 2 vehicle costs for Phase 1, and also includes the first 2 vehicle costs for Phase 2 implementation in 2023. The costs for Phase

1 and 2 are sponsored by Company witness Fultz within Exhibit A-46 (CTF-1), line 3, and Company witness Pascarello's Exhibit A-124 (KAP-9), line 4. A summary of those expenses are shown below.

Table 10. AMD investment by year

Capital Expenditures (Dollars in 1000s)
Contained within *Exhibit A-124 (KAP-9), line 4*

Description	Historical 12 Mos Ending 12/31/2020	Projected Bridge Year			Projected Test Year
		12 Mos Ending 12/31/2021	9 Mos Ending 9/30/2022	21 Mos Ending 9/30/2022	12 Mos Ending 9/30/2023
Phase 1: Advanced Methane Detection - Picarro	$0	$6,837	$2,029	$8,866	$2,710
Phase 2: Advanced Methane Detection - Picarro	$0	$0	$0	$0	$5,488

O&M Expense Expenditures (Dollars in 1000s)
Contained within Exhibit A-46 (CTF-1), line 3

Description	Historical 12 Mos Ending 12/31/2020	12 Mos Ending 12/31/2021	12 Mos Ending 12/31/2022	Projected Test Year
				12 Mos Ending 9/30/2023
Phase 1: Advanced Methane Detection - Picarro	$0	$175	$201	$173
Phase 2: Advanced Methane Detection - Picarro	$0	$0	$364	$805

Q. What type of resources will be required to operate and manage this new technology and data?

A. This new technology and data will be managed by a dedicated team of personnel, to ensure consistent and impactful delivery of the equipment. A lead will manage the program, direction and deployment. Analysts will identify and develop drive/route plans for execution, and upon successful drives, digest and manage that data into a deliverable for peer workgroups within the Company. The driver will pilot the vehicle on differing shifts throughout the lower peninsula of Michigan.

Q. Has this initiative been reviewed by management?

A. Yes. The Company has a major project management review process where projects progress through different stage gates for management review and approval. The AMD project has successfully completed the stage gate process needed to begin the implementation of the program.

Q. Is this technology used at other utilities?

A. Yes. DTE, CenterPoint, PG&E, NiSource and multiple other gas operators across the US and world are using Picarro for methane detection. ItalGas in Italy is the largest consumer of Picarro products, and in addition to Japan and Australia, Picarro operates on multiple continents. Below are some media releases from other utilities that are using Picarro.

- NiSource Release: https://www.prnewswire.com/news-releases/nisource-reports-second-quarter-2021-results-301347757.html
- ItalGas Release: https://www.prnewswire.com/in/news-releases/italgas-now-world-s-largest-user-of-picarro-natural-gas-asset-management-solution-850942045.html
- PG&E Press Release: https://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20150126_pge_launches_next_phase_of_its_industry-leading_gas_leak_management_strategy
- CenterPoint: Keeping you safe with PICARRO Surveyor Leak Detection Technology: https://www.bing.com/videos/search?q=centerpoint+picarro&docid=608045954814909796&mid=6E5B53A6107AD46144756E5B53A6107AD4614475&view=detail&FORM=VIRE

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 (https://www.federalregister.gov/documents/2021/06/10/2021-12155/pipeline-safety-statutory-mandate-to-update-inspection-and-maintenance-plans-to-address-eliminating). 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.

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 digital capabilities 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, "11.2 – *Management shall also periodically evaluate new technology that may enhance pipeline safety*."

V. <u>ASME B31Q Standard for Operation Qualifications</u>

Q. What is the ASME B31Q standard?

A. This standard provides general and specific requirements for the qualification of pipeline personnel. The implementation of this standard is intended to minimize the impact on safety and integrity of the pipeline due to human error that may result from an individual's lack of knowledge, skills, or abilities during the performance of certain activities.

Q. Why is the Company transitioning to this standard?

A. The ASME B31Q Standard is a leading best practice in the industry and allows for portability of covered tasks when requested to perform mutual assistance to interstate and intrastate utilities. This standard supports the company's ability to provide mutual aid assistance to other utilities when there is a significant gas incident in the industry. The transition to this standard also supports the 2019 Statewide Energy Assessment and associated mutual aid working groups.

Q. What is required to transition to this standard?

A. The ASME B31Q Standard implementation plan includes:

- OQ Program comparison to ASME B31Q Standard
- Creation of a compatible task list in accordance with ASME B31Q
- Implementation of a compatible task list in accordance with ASME B31Q
- One-year ASME B31Q compatible task list implementation plan

The implementation of this standard has impacts on several work groups. Operator Qualification Evaluators will be required to have additional training and credentialing. The Operator Qualification Program will undergo streamlining of covered task summaries, span of control ratios, performance evaluations and requalification intervals. Additionally, there will be training and skilling of the Learning and Development Advisors, OM&C workers, and the internal Joint Gas Operations Certification Committee. Finally, Company representatives will need Midwest Energy Association training and operator qualifications or equivalent for contractor covered task support.

Q. When is the Company planning on making the transition to this new standard?

A. The Company's goal is to have this transition completed by the end of quarter two in 2023.

Q. What is the projected cost of this transition?

A. The costs associated with this transition are related to labor resources required to implement the transition and maintain going forward, and includes a Learning and Development Advisor and additional Operator Qualifications Evaluators. The Operator Qualification Evaluators are sponsored by Company witness Fultz within Exhibit A-46 (CTF-1), line 3.

Table 11. ASME B31Q cost elements

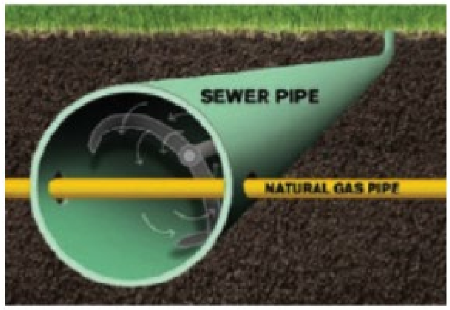
O&M Expense Expenditures (Dollars in 1000s)
Contained within Exhibit A-46 (CTF-1), line 3

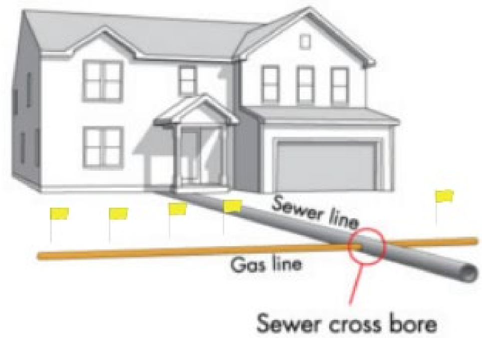
Description	Historical 12 Mos Ending 12/31/2020	12 Mos Ending 12/31/2021	12 Mos Ending 12/31/2022	Projected Test Year 12 Mos Ending 9/30/2023
B31Q Implementation	$0	$0	$0	$10

VI. Sewer Locate Program

Q. Please explain the purpose of a Sewer Locate Program.

A. Consumers Energy has become aware of the possibility that in the process of the directional boring of gas lines, since the practice began in 1976, the Company or its contractors may have inadvertently bored through sewer laterals. Over time, this can cause sewers to clog, and when the sewer lines are cleared the gas lines could be damaged. This impingement is commonly referred to as a 'cross bore' and can pose major risks to customer safety.





Q. What is the Company's program to mitigate this risk?

A. The Company believes that a successful Sewer Program consists of four major tenants:

a. Pre-project sewer locating;

b. Construction standards/operating procedures;

c. Legacy crossbore investigations; and

d. Community/Customer outreach and education.

Q. What is Pre-project sewer locating?

A. Pre-project sewer locating uses a "built in quality" philosophy to prevent errors from occurring. The Company seeks cross bore *prevention*, not just cross bore identification. Sewer contractors use technology that gives precise depth and location to locate the sanitary system, which is then staked and painted, mapped onto a sewer locate card with tie-down measurements and uploaded to the Company GIS database. Pictures of the paint and stakes are also taken to corroborate the sewer locate card.

Q. When and how often is Consumers Energy using this methodology?

A. The Company uses pre-project sewer locates on all work that could result in a crossbore. Directional bore trenchless installation must ensure 2' of separation, which can only be achieved by proper pre-identification of the sewer infrastructure. This work accompanies all replacement and install work including vintage service, enhancement infrastructure replacement, leak and material remediation, new business, and civic improvement replacement work.

Q. What is the Company's sewer construction operating procedure?

A. Several documents and tools are used in conjunction with each other to create a safer environment for our construction crews, the customers, and sewer vendors. The Company's Gas Operations Manual contains sections specific to boring and trenchless technology which references: 1) sewer locates; 2) the need to verify 2' of separation; and 3) a construction standard to use sewer data in a way to prevent cross bores. Additionally, there are several quality controls in place including: a sewer locate manual, quality assurance reviews on sewer locate cards and pictures, training to identify and avoid damaging utilities, and a data collecting application that allows information to be shared with internal and external crews performing trenchless installations. Sewer locate data collection, along with strong relationships with sewer vendors, is a key tool that allows information to be shared and used by everyone involved with the construction process.

Q. What is legacy cross bore investigation?

A. Since 1976 Consumers Energy has used directional drilling and other underground boring methods. In the early 2000s, the industry became more aware of the cross-bore potential threat. Using historical data and sewer contractor knowledge the Company has built a risk based approach, as part of the Company's Distribution Integrity Management Program, to identify potential higher-risk areas for cross bores, such as schools, churches, hospitals, and other areas of regular high-volume customer gathering. The Company's legacy program addresses these high-risk areas by retroactively returning to these areas to perform sewer locates and eliminate any found cross bores. The Company's legacy cross bore program began in 2015 and since that time the Company has investigated over 3,000 locations and discovered one significant cross bore that was remediated.

Q. Is the Company planning on expanding or adjusting the legacy cross bore program based on the findings to date?

A. Yes. The Company has identified 68 cross bores or sewer/gas conflicts since the program's creation, of which one was identified through Legacy post inspections and the remainder identified through pre-project locates, municipality notifications and third-party identifications. Although the Legacy program has not yielded the amount that other intake methods of cross bore identification has, it still provides critical information to safely clear high-consequence areas. Expansion of the program will shift our Legacy program from areas of high-consequence, which has been completed in 2021, to areas of high probability. This will be accomplished through risk modeling of already identified and repaired cross bores, areas where sewers are shallow, and other key variables that will indicate high cross bore probability – not relying solely on building type.

Q. What is the increased investment required in 2023 for the expansion?

A. Company witness Fultz's Exhibit A-46 (CTF-1), line 3, and Company witness Pascarello's Exhibit A-124 (KAP-9), line 4, are sponsoring the increased investment for the expansion of the cross-bore program. Below is a summary of those costs.

Table 12. Sewer Locate cost elements

Capital Expenditures (Dollars in 1000s)
Contained within Exhibit A-124 (KAP-9), line 4

Description	Historical 12 Mos Ending 12/31/2020	Projected Bridge Year			Projected Test Year
		12 Mos Ending 12/31/2021	9 Mos Ending 9/30/2022	21 Mos Ending 9/30/2022	12 Mos Ending 9/30/2023
High Probability Expansion	$0	$0	$0	$0	$417

O&M Expense Expenditures (Dollars in 1000s)
Contained within Exhibit A-46 (CTF-1), line 3

Description	Historical 12 Mos Ending 12/31/2020	12 Mos Ending 12/31/2021	12 Mos Ending 12/31/2022	Projected Test Year
				12 Mos Ending 9/30/2023
Legacy Crossbore Program	$0	$0	$190	$609
High Probability Expansion	$0	$0	$636	$1,360

Q. What is Community and Customer outreach/education?

A. As part of the Sewer Program expansion planned in 2023, the customer and community outreach components will be explored for ways the Company can educate and inform affected parties on the risk and remediation of cross bores. This may include direct-to-customer content like mailers, social media ads, billboards, along with incentives for plumbers, municipalities and others to escalate found cross bores to the Company for remediation. The program will also explore educational materials coupled with high risk activities, like root-cutting tool rental at home stores, and direct education to plumbers.

Q. Can you summarize your direct testimony?

A. Yes. The six programs I have described in my direct testimony all enhance Consumers Energy's capabilities for ensuring the Company has the proper controls and oversight to ensure compliance with existing regulations and to continue to improve with compliance to regulations with advancing technology. These controls are essential to operating a safe and reliable gas delivery system and are in alignment with the GSMS and recommended practices within API RP 1173.

Q. Can you summarize the expenditures you discussed above in relationship to the Operations Compliance and Controls O&M expenses in Company witness Christopher T. Fultz's testimony?

A. Yes. The table below summarizes the expenditures that I described in detail earlier that appear on line 3 of Exhibit A-46 (CTF-1).

Table 14. Summary of O&M expense elements

O&M Expense Expenditures (Dollars in 1000s)

Description	**Historical 12 Mos Ending 12/31/2020**	**12 Mos Ending 12/31/2021**	**12 Mos Ending 12/31/2022**	**Projected Test Year 12 Mos Ending 9/30/2023**
Enterprise Corrective Action Program	$1	$222	$0	$0
Risk Based Assessments and Field Compliance Program	$0	$0	$0	$567
Remote Inspection Program	$1	$6	$653	$1,212
Advanced Methane Detection Program	$0	$175	$565	$977
B31Q Implementation	$0	$0	$0	$10
Operations Compliance & Controls Labor and Expenses	$1,686	$2,362	$4,253	$5,794
Total as shown in Exhibit A-46 (CTF-1), line 3	$1,688	$2,765	$5471	$8,560

Q. Can you summarize the expenditures you discussed above in relationship to the Operations Compliance and Controls Capital Expenditures in Company witness Pascarello's testimony?

A. Yes. The table below summarizes the expenditures that I described in detail earlier that appear on line 4 of Exhibit A-124 (KAP-9).

Table 15. Summary of capital elements

Capital Expenditures (Dollars in 1000s)

Description	**Historical 12 Mos Ending 12/31/2020**	**Projected Bridge Year**			**Projected Test Year**
		12 Mos Ending 12/31/2021	**9 Mos Ending 9/30/2022**	**21 Mos Ending 9/30/2022**	**12 Mos Ending 9/30/2023**
Enterprise Corrective Action Program	$0	$1,592	$102	$1,694	$34
Risk Based Assessments and Field Compliance Program	$0	$0	$343	$343	$503
Remote Inspection Program	$0	$0	$0	$0	$169
Advanced Methane Detection Program	$0	$6,837	$2,029	$8,866	$8,199
Sewer Locate Program	$0	$0	$0	$0	$417
Total as shown in Exhibit A-124 (KAP-9), line 4	$0	$8,429	$2,474	$10,903	$9,322

Q. Does this complete 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	)	Case No. U-21148
the generation and distribution of	)	
gas and for other relief.	)	
______________________________________	)	

DIRECT TESTIMONY

OF

ADAM S. CARVETH

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

Q. Please state your name and business address.

A. My name is Adam S. Carveth, and my business address is 14500 Dixie Hwy, Holly, Michigan 48442.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Director of Fleet Strategy.

Q. What is your formal educational experience?

A. I hold an Associate in Applied Science in Automotive Service Technology and a Bachelor of Science in Automotive and Heavy Equipment Management from Ferris State University, located in Big Rapids, Michigan.

Q. What are your responsibilities as Director of Fleet Strategy within Fleet Services?

A. I provide oversight to Fleet Acquisition/Depositions, Fleet Regulatory & Technical, and Internal Electric Vehicle Strategy. I am also the designated Fleet witness in the Company's general rate case proceedings.

Q. Would you please describe your previous work experience?

A. In 2006, I started my career at EK Automotive in Chicago, Illinois, as a Service Advisor. EK Automotive is an automotive repair shop servicing all light duty makes and models. In 2009, I took a position as Work Equipment Analyst for Canadian National Railroad. During my time in that role, I was involved with capital purchase, budget oversight, specification verification, and data integrity. In late 2009, I began a series of changing roles, with increasing responsibility, at Canadian National Railroad that continued through 2014. These roles were as follows: Assistant Track Supervisor, Engineering Track Services, Production Supervisor, and Track Supervisor. In 2015, I accepted the position of

Fleet Field Leader with Consumers Energy in the Eastern Zone. The Fleet Field leader position consisted of oversight of all preventive maintenance and repairs to Consumers Energy's Fleet within the zone. In 2018, I was promoted to Senior Fleet Field Leader for the Southeast Zone. Within the position, I provided oversight to five field leaders, two schedulers, and 29 mechanics. The position also provided oversight to the Company's Enhanced Infrastructure Replacement Program department that contracts all preventative maintenance and repairs. In early 2021, I was promoted to Director of Fleet Strategy.

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 testified on behalf of the Company in its Electric Rate Case No. U-20963 regarding the Company's proposed recovery of its electric business portion of Fleet services.

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 Fleet Services' function and associated responsibilities; and
ii. Describe Fleet Services' Lifecycle approach.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-12 (ASC-1)	Schedule B-5.1	Summary of Actual & Projected Capital Expenditures;
Exhibit A-29 (ASC-2)		Fleet Estimated Maintenance Cost Avoidance;
Exhibit A-30 (ASC-3)		Fleet Estimated Increased Salvage Values; and
Exhibit A-167 (ASC-4)		Fleet Responsibility Dollars.

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 (ASC-1), Schedule B-5.1, which is a Summary of Actual and Projected Fleet Capital Expenditures for the years 2020, 2021, 2022, and the projected test year ending September 30, 2023; Exhibit A-29 (ASC-2), which is the Fleet Estimated Maintenance Cost Avoidance as a result of the lifecycle replacement investment in 2020 and 2021; Exhibit A-30 (ASC-3), which is Fleet Estimated Increased Salvage Values as a result of the lifecycle replacement investment in 2020 and 2021; and Exhibit A-167 (ASC-4), which is Fleet Responsibility dollars for the years 2016 through 2023.

Q. Will you be referring to other exhibits in your testimony sponsored by other Company witnesses?

A. Yes. Throughout my testimony, I will refer to Exhibit A-139 (CS-1), which is the 2021 Consumers Lifecycle Report ("Utilimarc Report") sponsored by Company witness Christopher Shaffer.

<u>Fleet Services Function and Responsibilities</u>

Q. Please explain the Gas Operations Support function.

A. Gas Operations Support consists of the following support organizations: Fleet Services, Facilities, Real Estate, and Administrative Operations. Gas Operations Support provides support by acquiring, constructing, and maintaining assets required to operate the functional areas of the business.

Q. Are you addressing all support organizations related to Gas Operations Support in your direct testimony and exhibit?

A. No. I will be addressing Fleet Services only. Facilities, Real Estate, and Administrative Operations will be addressed in the testimony of Company witness Quentin A. Guinn.

Q. What functions comprise the Fleet Services organization?

A. The Fleet Services organization consists of three groups which collaboratively work together to provide value to Gas Operations in serving customers. The three groups which make up Fleet Services are Fleet Maintenance Operations, Fleet Strategy, and Fleet and Facilities Data and Analytics.

Q. Please explain the responsibilities of Fleet Maintenance Operations.

A. Fleet Maintenance Operations is responsible for maintaining a safe, cost effective, and reliable fleet made up of over 7,500 units. This is completed through preventative maintenance, regulatory inspections, parts inventory management, and maintenance scheduling across 36 garage locations with 112 mechanics. Maintenance operations also oversees mechanic contractor crews for preventative maintenance and repairs performed in the field.

Q. Please explain the responsibilities of Fleet Strategy.

A. Fleet Strategy carries out all functions related to the acquisition and disposition of Company-owned vehicles and related equipment. This includes management of the Fleet capital purchase plan, specification design, license/title and registration, as well as asset retirement. Fleet Strategy is also responsible for meeting all regulations and compliance with the American National Standards Institute, Department of Transportation, and Federal

Motor Carrier Safety Administration. Additional responsibilities include technical support and tooling for Fleet mechanics and the Company's electric vehicle strategy.

Q. Please explain the responsibilities of Fleet and Facilities Data and Analytics.

A. Fleet and Facilities Data and Analytics department provides Fleet with support of data integrity, Telematics data management, departmental metric visual management, process automation, oversight of waste elimination initiatives, and partners with Utilimarc on benchmarking and data analysis.

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 ensure that the Gas Operations Department can deliver reliable and uninterrupted operations. This is accomplished by achieving an appropriate fleet lifecycle and beginning each day with zero fleet impacts to service customers.

<u>Fleet Lifecycle</u>

Q. What is the purpose of a Fleet lifecycle?

A. The purpose is to achieve an even, balanced aging cycle for Fleet vehicles, in order to maximize resale values, minimize repair downtime, and reduce maintenance costs.

Q Does a balanced Fleet lifecycle bring value to the customer?

A Yes. Maximizing resale values allows the Company to reduce incremental capital needs by reinvesting the dollars into new units. Minimizing repair downtime reduces the risk to the Company's ability to respond to scheduled and emergent work. A reduction in maintenance costs supports an overall cost reduction to customers.

Q. What determines an appropriate lifecycle?

A. On page 2 of the Utilimarc Report, sponsored by Company witness Shaffer, the Utilimarc Vehicle Replacement Module ("VRM") mathematically determines when you should replace your assets. The VRM uses the Company's historic practices to predict future ownership and maintenance cost and determines what lifecycle will guarantee the lowest total cost over the life of the asset. This calculation is built on the following variables:

- Historic Maintenance Cost (including Parts, Labor, Outside Vendors);
- Historic Utilization;
- Historic Acquisition Cost and Residual Value; and
- Current Acquisition Cost.

Q. Can you explain how a shorter lifecycle improves reliability and service of customers?

A. In short, reduced repair hours increases unit availability, resulting in more timely and dependable service to customers and higher satisfaction for frontline workforce. The Company is providing its frontline with the tools needed to perform its work in serving customers. While there is always a balance between cost and reliability, the Company strongly believes that its lifecycle decisions strike the right balance and have a data-driven approach in support of customers and its frontline workforce. The Company believes this is further supported by the Utilimarc Report and my direct testimony.

Q. Are there benefits to safety, quality, and the planet when having an appropriate lifecycle?

A. Yes. By replacing vehicles on an appropriate lifecycle, 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 safety for the Company's customers and employees.

- 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, which lead to equipping trucks with larger braking systems so they were able to avoid collisions.

- 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-

- Advances in materials to manufacture vehicles is continuously improving. For example, the Ford F-150 body is a military grade aluminum making the truck lighter which increases the vehicles fuel economy. Another added benefit is corrosion resistance, meaning less money spent on fuel and less time and money spent repairing corrosion problems.

- Exhaust gas recirculation coolers, impacting diesel engines, have improved over the past 10 years, eliminating the need to replace them 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 Administrations 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 these more fuel-efficient vehicles. This benefit will reduce the amount of fuel burned, ultimately reducing the carbon footprint.

<u>Utilimarc and the Utilimarc Report</u>

Q. Who is Utilimarc?

A. Utilimarc is an independent, third-party vendor and industry leader for utility fleet analytics and works as a strategic partner with companies such as Consumers Energy to assist fleet utilities with maximizing their value within the company through the use of data analytics, statistical analysis, and real-world industry experience. Company witness Shaffer is President and CEO of Utilimarc and is supporting the results of the Utilimarc Report in this proceeding.

Q. Has the Company previously partnered with Utilimarc?

A. Yes, the Company has partnered with Utilimarc over the past eight years. In the Company's previous Electric Rate Case No. U-20963, the Company included a report which conducted a study of the Company's fleet to provide the Company with recommendations regarding replacement lifecycle plans for Fleet Services. In this proceeding, the Company is providing an updated report to reflect 2021 data. Explanation of the data used, and manner in which the report was conducted, can be found within the testimony of Company witness Shaffer.

Q. Why is the Company sponsoring a new lifecycle study in this proceeding?

A. An updated lifecycle study provides the Company with an opportunity to reevaluate the current fleet. As lifecycles can extend over a decade, it is imperative for the Company to evaluate environmental impacts, industry trends, and current needs of the business. Through these evaluations, the Company has an opportunity to ensure a safe, compliant, and reliable fleet to serve its customers.

Q. Does the Utilimarc Report present different results from those of the 2017 Utilimarc Report?

A. Yes. The Utilimarc Report presents results that are different from the 2017 Utilimarc Report because of investments made by the Company in its Fleet following the development of the 2017 Utilimarc Report, which resulted in changes in the Company's Fleet inventory and needed maintenance, as well as a re-evaluation of the needs of the Company's Fleet going forward.

Q. Does the Utilimarc Report utilize Company data?

A. Yes. The Utilimarc Report utilizes the Company's data, and recent lifecycle replacement investments, to provide benchmarking reporting that assists Fleet Services in the decision-making process required to support Gas Operations. This includes a recommended optimal lifecycle for the Company's Fleet.

Q. Is the lifecycle modeling driven by data?

A. The lifecycle analysis is data driven. Further explanation of the analysis can be referenced in Company witness Shaffer's direct testimony, on pages 7 through 17, and the Utilimarc Report.

Q. Why did the Company utilize the Utilimarc Report as its cost benefit analysis instead of an internal, Company study?

A. Utilimarc is an industry expert in fleet data analytics and utility fleet benchmarking, as further explained in the testimony of Company witness Shaffer, and has assisted utility fleets over the past 20 years in optimizing fleets to enhance operational performance. An internal Company study will not provide the extensive data analytics and benchmarking insights that are gained from Utilimarc's studies and services. Given Utilimarc's experience with assisting 150 fleets over the past 10 years, Utilimarc has gained quality insights in understanding how to best structure and maintain a utility fleet at the lowest cost to customers.

Q. Does the Utilimarc Report constitute a cost benefit analysis?

A. Yes. The Utilimarc Report quantitatively measures the ownership and maintenance costs of the Company's fleet, and projects savings, or imputed benefits, of different lifecycle approaches. Using the Utilimarc Report, the Company can better determine which lifecycle replacement plan is appropriate in maximizing the value of the Company's fleet while reaching the lowest total cost over the life of its assets.

Q. Has the information provided by Utilimarc for benchmarking purposes been helpful?

A. Yes. As a leader in the fleet industry for benchmarking, Utilimarc is able to provide Consumers Energy with a better understanding of its internal fleet data. This provides the Company with the ability to be more predictive and conscious of its fleet replacement cycles.

Q. Please briefly describe the Utilimarc Report.

A. The Utilimarc Report provides recommendations as to when the Company should replace its fleet assets in order to realize the lowest total cost over the life of the asset. As part of the report, Utilimarc presents three different capital funding scenarios for the Company to consider when determining its fleet replacement strategy, which are: (i) the Even Replacement, (ii) the Out of Lifecycle (OOL) Replacement, and (iii) the Approved

Replacement. Additional explanation of these scenarios, and of the report itself, can be found in the direct testimony of Company witness Shaffer.

Q. Please generally summarize the learnings gained from the Utilimarc Report.

A. The Utilimarc Report shows that maintaining capital spend at the Commission's previously approved amounts, also known as the Approved Replacement within the Utilimarc Report, will lead the current fleet into a situation of increased maintenance hours year-over-year. This maintenance hour increase has a direct impact on the Company's customers. Alternatively, the lifecycle, average age, and spend plan models proposed by the Company in this case, which are based on the analytical models from Utilimarc using Company data, help to ensure that each fleet asset is fully utilized and disposed of before elevated fleet expenses are incurred. These fleet expenses include maintenance expenses required to keep out-of-lifecycle units available for customer service.

Q. Does the Company have any concerns with the Approved Replacement scenario?

A. Yes. At the approved spend allotted, the Company finds that, through the Utilimarc Report, maintenance hours will increase year-over-year as the units fall further out of lifecycle. As maintenance hours increase, unit availability will be negatively affected because such units will be unavailable for use due to required maintenance and will place a strain on day-to-day operations. Ultimately, the increase in maintenance hours can have a direct impact on the Company's timely response to customer service. Further, this increase also presents additional challenges with potential part and resource availability.

<u>Out-of-Lifecycle Impacts</u>

Q. Why is the advancing age of fleet units problematic?

A. Units out of lifecycle experience unpredictable levels of emergent repairs. These emergent repairs require additional maintenance hours and higher-than-average maintenance costs. These unpredicted hours impact daily operations by requiring a rework in the schedule and can ultimately impact the completion of a Department of Transportation inspection or other priority units from being repaired.

Q. What cost implications derive from a lack of capital spending?

A. An increase of additional maintenance hours, including maintenance costs and increased headcount to service Company units, results when the Company's fleet progresses further out of lifecycle year-over-year due to insufficient capital spending to replace such units. The cost implications are related to the increased maintenance hours and headcount to repair these units. The chart provided below, found on page 5 of the Utilimarc Report, shows that maintenance hours, maintenance costs, and required mechanics will continue to rise year-over-year if capital spending is capped at the Commission's previously approved spending level under the Approved Replacement scenario.

Maintenance Difference	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Annual Maint Difference	$434,807	$599,742	$701,083	$975,288	$1,548,026	$2,210,861	$2,667,754	$3,167,718	$3,834,554	$4,542,329
Est. Hour Increase	2375	3383	3955	5502	8732	12472	15049	17869	21631	25623
Est. FTE Increase	1.32	1.88	2.20	3.06	4.85	6.93	8.36	9.93	12.02	14.24

Q. Does an increase in repair hours have an impact on operational metrics?

A. Yes. In general, an increase in repair hours has an impact to Customer on Time Delivery, Vintage Service Replacement, Service On Time Commitment, and Odor Response. Repair hours increase the time a unit is in the garage and not available for scheduled or emergent work. The unpredictable nature of emergent work makes it particularly important that units are available at all times.

Q. How does the Company know there are impacts related to Fleet services?

A. While a unit is down for a repair it is unavailable. In these instances, the Company's gas operations will adjust its schedule or provide alternate transportation for the operator, resulting in additional labor, costs, and customer impacts.

Q. What barriers do mechanics incur when repairing out-of-lifecycle units?

A. A vehicle's body and wiring system do not age well in Michigan's climate due mainly to the salt that is used to mitigate ice on Michigan roads in the winter. The salt has devastating effects to the bodies and frames of Company vehicles as they literally rust away. The electrical wiring also deteriorates over time, which creates hard to diagnose failure points in lighting and/or aerial device systems. Out-of-lifecycle units typically experience an increase in "big ticket" repairs, such as engines, transmissions, fuel injectors, turbos, and major suspension overhauls. Additionally, during these repairs, it is common for units to experience metal fatigue due to years of element exposure. This fatigue can be problematic by requiring additional repairs, extending down time. An example of this would be a broken bolt that requires added down time to extract the base of said bolt. All of these factors contribute to the amount of time and money that is spent on out-of-lifecycle units when a mechanic performs a preventative maintenance inspection or repair. Older units also have an increase in breakdowns in the field, which generates a service call for the mechanic and interferes with the work that the operator is performing. Additionally, mechanics can experience long lead times on parts due to their market availability. This availability is due to market demand. Manufacturers limit their supply on vintage parts to increase their supply of more profitable high-demand parts; thus, parts are more difficult to obtain for older vehicles and equipment.

Lifecycle Replacement Recommendation

Q. After considering the Utilimarc Report, which capital replacement strategy does the Company believe is best for its Gas Fleet and its customers?

A. The Company believes a lifecycle replacement investment scenario that aligns with the Even Replacement scenario from the Utilimarc Report is best for its Gas Fleet and its customers and would achieve an appropriate lifecycle position. Based on the Even Replacement scenario presented in the Utilimarc Report, the Company's gas lifecycle replacement capital expenditures for the test year in this proceeding would amount to $16.508 million, as shown on Exhibit A-12 (ASC-1), Schedule B-5.1. Achieving an appropriate lifecycle position for the Company's fleet is in the best interest of customers because it provides for reliability of fleet assets, maintenance cost avoidance, and a higher resale value at auction.

Q. Is the Company recommending that the Commission approve lifecycle replacement investment based on the Even Replacement scenario from the Utilimarc Report for its Gas Fleet in this proceeding?

A. Yes.

Q. Has the Company incorporated the recommendations of the Even Replacement scenario in its gas lifecycle replacement proposal in this proceeding?

A. Yes. The Company reflected the Even Replacement scenario from the Utilimarc Report in its proposed gas lifecycle replacement expenditures in this proceeding. The Even

Replacement scenario recommends a capital investment of $19.9 million for 2022 and $14.4 million for 2023. Due to the split test year in this proceeding, the Company ultimately recommends $16.508 million of capital investment for the test year ending September 30, 2023.

Q. Why is $19.925 million in 2022 and $14.373 million in 2023 of capital spending for lifecycle replacement a benefit to the customer?

A. The Even Replacement scenario will decrease the out-of-lifecycle units and improve the Company's overall lifecycle plan for its fleet. A fleet that is within the lifecycle model developed by Utilimarc will ultimately require less maintenance hours and costs, which will provide value to customers by reducing the overall fleet unavailability for a timely response to customer service.

Q. Please further explain the Even Replacement Scenario from the Utilimarc Report that the Company proposes the Commission adopt in this proceeding.

A. The Company recommends the Even Replacement scenario in this case because it will allow the Company to align with a more appropriate fleet lifecycle, reduce maintenance hours, and, as a result, will reduce potential impacts to its customers as units will be more available. This recommendation also puts less financial strain on the Company's customers as compared to the OOL Replacement scenario, which replaces every out-of-lifecycle unit during that year. Further, unlike the Approved Replacement scenario, the Even Replacement scenario provides a consistent replacement approach that avoids unpredictable spikes in capital requests, maintenance cost, and vehicle availability which occur when a large portion of fleet is concentrated in a few vintages. While the Even Replacement scenario requires more in capital as compared to the Approved Replacement scenario for the test year, the additional capital provides added value to customers because it reduces maintenance hours that continue to rise with out-of-lifecycle fleet under the Approved Replacement scenario. This reduction in maintenance hours and maintenance costs increases unit availability so that the right unit is available at the right time to address the necessary customer service, especially in first response and emergency response situations.

Q. Why is the Company recommending recovery of $16.508 million in the test year, using the Even Replacement scenario from the Utilimarc Report, instead of the Approved Replacement scenario?

A. The Even Replacement scenario implements an approach that provides for a more consistent lifecycle for the Company's Fleet over the next 10 years. By doing so, the Even Replacement scenario avoids an increase to maintenance hours and expenses at a level that will be experienced through the Approved Replacement scenario. The Approved Replacement scenario does not provide sufficient capital expenditures to maintain an appropriate lifecycle, which would result in a continuous increase of maintenance hours, maintenance costs, and unit unavailability because such units are not being replaced. The Even Replacement scenario ultimately attempts to avoid a replacement bubble. As explained on page 5 of the Utilimarc Report, "[a] replacement bubble occurs when a high number of units are concentrated in a few model years. Bubbles occur for a variety of reasons but are usually formed when a fleet delays replacement on a class for a few years and then purchases many assets to catch up. Replacement bubbles can lead to unpredictable spikes in labor demand, maintenance cost, and capital requirements." This replacement bubble presents negative implications that can directly impact the Company's response time to its customers.

Q. Please explain the Company's gas lifecycle replacement expenditures for the years 2020 and 2021.

A. In 2020, the Company invested $17.264 million of capital expenditures in the gas lifecycle replacement of its Gas fleet. In 2021, the Company invested $22.694 million of capital expenditures in the gas lifecycle replacement of its Gas fleet.

Q. Why did the Company determine that such 2020 and 2021 gas lifecycle replacement expenditures were appropriate and beneficial for the Company and its customers?

A. The gas lifecycle replacement expenditures invested by the Company in 2020 and 2021 provided added value to customers because it avoided increased maintenance hours and maintenance costs that would result from the Company's out-of-lifecycle units. The Company determined that the investments were necessary to replace units far out-of-lifecycle to ensure the availability of those units for customer service needs. Further, these investments allowed the Company to begin to shift toward a more appropriate lifecycle, as reflected in the Utilimarc Report. The reduction in maintenance hours and maintenance costs provides for better unit availability so that the right unit is available at the right time to address the necessary customer service, especially in first response and emergency response situations. In addition to maintenance costs avoidance, the additional capital expenditures allow the Company to receive higher resale values that can reduce incremental capital needs by reinvesting the dollars into new units.

Q. What are the types of units, and unit counts, associated with the gas lifecycle replacement investments in 2020?

A. The unit counts and type of units associated with the Company's 2020 gas lifecycle replacement investments is as follows:

Type	# of Units
Vehicle	162
Trailer	19
Equipment	30
Total	211

Q. What are the types of units, and unit counts, associated with the gas lifecycle replacements investments in 2021?

A. The unit counts and type of units associated with the Company's 2021 gas lifecycle replacement investments is as follows:

Type	# of Units
Vehicle	148
Trailer	14
Equipment	39
Total	201

Q. Are the units being utilized today?

A. Yes. The Company is currently using these units in daily operations and these units are necessary to support customers and their service needs. Without these units, the Company would be hindered in its ability to provide safe and reliable service to its customers.

Q. Have the 2020 and 2021 investments increased the salvage values?

A. Yes, as reflected in Exhibit A-30 (ASC-3).

Q. What were the actual salvage values at auction in 2016 for the Gas fleet?

A. The actual salvage values at auction in 2016 for the gas fleet was $352,091.

Q. Is there an estimated resale value for units purchased in 2022 and 2023?

A. Yes. The projected sale at auction for 2022 is $1.4 million and $1.3 million in 2023.

Q. Can you explain how the Company arrived at the estimated salvage values in 2022 and 2023?

A. Yes. The estimated salvage values provided by Utilimarc are calculated based on the Company's historic salvage values. Based on this historic data, a devaluation rate is calculated for each class. This fixed percentage is subtracted from the book value of the asset each year it is in service. The salvage value is the remaining book value on the asset when it is sold.

Q. What is the estimated increased salvage value for 2022 and 2023?

A. Based on the 2016 actual salvage value, we estimate an increase of $1.09 million in 2022 and $1.01 million in 2023.

Q. Why were the 2016 actual salvage totals used as a comparison?

A. The 2016 actuals were used to reflect salvage value returns on an historical capital spend year. Please reference Exhibit A-30 (ASC-3).

Q. Is there an estimated maintenance cost avoidance due to the capital investments made in 2019 through 2021?

A. Yes, as reflected in Exhibit A-29 (ASC-2).

Q. What model did you use to calculate the percentage of cost avoidance in years 2019 through 2021?

A. The percentages were calculated based on the 2017 Utilimarc report on page 13, which was sponsored by Company witness Kyle P. Jones, as Exhibit A-69 (KPJ-3), in Consumers Energy's Gas Rate Case No. U-20650. It was estimated that the Company would see a cost avoidance with increased capital investment. This was completed by comparing the Utilimarc recommended spend to the $32.5 million historical spend.

Q. What was the reason for the expected cost avoidance?

A. The expected cost avoidance was a result of the capital investments made in 2019 through 2021.

Q. What is the percentage of maintenance cost avoidance from the 2017 Utilimarc report?

A. Following the model of the 2017 Utilimarc report on page 13, when comparing the Utilimarc capital investment to the approximately $32.5 million investment, the following expected maintenance cost avoidance percentages were the result: 7% for 2019, 11% for 2020, and 14% for 2021.

Q. What is the estimated maintenance cost avoidance against Company actuals?

A. As reflected in Exhibit A-29 (ASC-2), using the percentages from the model, the Company was estimated to avoid $1,608,857 in 2019, $2,511,713 in 2020, and $3,325,977 in 2021.

Q. What was the total estimated maintenance cost avoidance for the years 2019 through 2021 due to the capital investments made by the Company?

A. Based off the model, the Company estimated a total maintenance cost avoidance of $7,446,547 for these years.

Q. Why is this important?

A. This is important to note because spending at a historical approved amount showed a cumulative increase in maintenance cost year-over-year.

Q. Are you able to provide the estimated maintenance cost avoidance in excel?

A. Yes. Please reference Exhibit A-29 (ASC-2).

Q. What do the increased salvage values and avoided maintenance costs portray from the Company's 2020 and 2021 investment?

A. The increased salvage values and avoided maintenance costs that result from the Company's 2020 and 2021 investments portray a benefit to the Company and its customers in addition to the other benefits I previously explained in my testimony. The increase in estimated salvage values ultimately provides for a lower future capital request because a unit will have more value when sold by the Company at a more appropriate lifecycle, thereby creating savings for customers. In addition, the avoided maintenance costs provide savings to customers.

Fleet Services Capital Funding

Q. Please describe the capital expenditures related to Fleet Services as shown on Exhibit A-12 (ASC-1), Schedule B-5.1.

A. Exhibit A-12 (ASC-1), Schedule B-5.1, includes Fleet Services Transportation Equipment and Other Equipment capital expenditure actuals for the 12 months ended December 31, 2020, projections for the 12 months ending December 31, 2021, projections for the 9 months ending September 30, 2022, the 21 months ending September 30, 2022, and projections for the 12 months ending September 30, 2023, which is the test year in this case. For the historical year, 12 months ended December 31, 2020, the Company incurred total Fleet Services capital expenditures in the amount of $17.538 million. The Company is projecting total Fleet Services capital expenditures to be $22.905 million for the 12 months ending December 31, 2021; $12.971 million for the 9 months ending September 30, 2022; $35.876 million for the 21 months ending September 30, 2022; and $16.741 million in the projected test year ending September 30, 2023, as set forth in Exhibit A-12 (ASC-1), Schedule B-5.1, line 3, 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 type of expenditures are included in Transportation Equipment?

A. Transportation Equipment includes the purchase of vehicles, heavy equipment, and trailers as part of the Company's Fleet Lifecycle Replacement Program that supports Operations.

Q. Please explain why Fleet does not support an operating and maintenance ("O&M") exhibit.

A. The Company does not provide a Fleet O&M exhibit due to Fleet O&M expenses being billed out to operational departments within the Company that utilize fleet assets. The expenses are separated by operational areas they support and accumulated at Fleet clearing account. The Fleet clearing account balance is subsequently allocated to distribution and transmission work orders via costing sheets as a loading percentage on top of labor charged to that work order.

Fleet operating costs are reported in responsibility dollars. Each fleet unit has an internal order and is assigned a settlement receiver. The receiver (in this case, the cost centers) defined in each order's settlement rule dictate where the costs for the unit are allocated. Fleet responsibility costs are allocated to both capital and O&M expenses.

Q. If the Company does not present a Fleet O&M exhibit, is the Company able to show Fleet responsibility costs?

A. Yes. Please see Exhibit A-167 (ASC-4), which reflects the Fleet Responsibility dollars for the years 2016 through 2023. Fleet responsibility dollars reflect the maintenance costs of the Company's current fleet.

Q. Can you please explain the "depreciation" method used by the Company in comparison to the devaluation method used by Utilimarc for purposes of conducting a fleet lifecycle replacement analysis?

A. Company witness Shaffer explains in his direct testimony the reason why Utilimarc uses a devaluation method, as compared to a depreciation method, when conducting its lifecycle reports. Further, Company witness Heather L. Rayl explains in her direct testimony why the Company uses a depreciation method.

Q. Please explain how the proposed spending levels for the bridge year and the projected test year ending September 30, 2023, were developed.

A. The proposed spending levels for the bridge year and test year are based upon the Fleet Gas Operations' capital investment plans. The bridge year ending December 31, 2021, has projected capital expenditures of $17.383 million for transportation equipment (lifecycle replacement), $5.311 million for Telematics, and $211,000 for Fleet tool purchases. This total amount is reflected in Exhibit A-12 (ASC-1), Schedule B-5.1, line 3, column (c). The 9-month bridge year ending September 30, 2022 has projected capital expenditures of $12.796 million for transportation equipment (lifecycle replacement) and $175,000 in Fleet tool purchases. This total amount is reflected in Exhibit A-12 (ASC-1), Schedule B-5.1, line 3, column (d). The 21-month bridge year ending September 30, 2022 has projected capital expenditures of $35.490 million for transportation equipment (lifecycle replacement) and $386,000 for Fleet tools. This total amount is reflected in Exhibit A-12 (ASC-1), Schedule B-5.1, line 3, column (e). The test year ending September 30, 2023 has projected capital expenditures of $16.741 million. This projection includes $16.508 million for transportation equipment (lifecycle replacement), and $234,000 for

Fleet tools. This total amount is reflected in Exhibit A-12 (ASC-1), Schedule B-5.1, line 3, column (f). This plan was developed using the analytics provided by Utilimarc for replacing out-of-lifecycle units. Consumers Energy is proposing test year spending consistent with the optimized analytical models produced by Utilimarc, utilizing the Company's data, in its recommendation.

Q. How did you determine the appropriate distribution of capital costs among the cost categories shown on Exhibit A-12 (ASC-1), Schedule B-5.1?

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 does not specifically forecast its future capital spending needs by these cost categories. Although the Company has confidence in the total value, it was necessary to allocate the Company's total forecasted capital spending amount among the cost categories set forth in the filing requirements. The Company did so by calculating a five-year historical average of each of the Commission's prescribed cost categories from years 2016 to 2020 as a percentage of total Transportation Equipment investment over that same period of time. 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 (ASC-1), Schedule B-5.1.

Q. Can the cost categories presented in Exhibit A-12 (ASC-1), Schedule B-5.1, be applied to individual projects within the Transportation Equipment programs planned for the test year to determine how each project is broken down by cost category?

A. Yes. It should be noted, however, that the contractor, labor, materials, business expenses, and other costs presented in Exhibit A-12 (ASC-1), Schedule B-5.1, are based on a five-year average of historical information as described above. While the historical information provides a reasonable estimate of the cost components of the projects planned for the test year, it is still an estimate.

Q. Please explain the breakdown of the Company's projected Fleet Services capital expenditures in this case for Gas Operations Transportation Equipment Fleet lifecycle.

A. Chart 2, provided below, references the breakdown of the company's projected Fleet Services capital expenditures for the years 2022 and 2023 following the Even Replacement Scenario.

CHART 2 – Projected Fleet Services Capital Expenditures Purchase Plan

Even Replacement 2022

Type	**# of Units**		**Total Acquisition Cost**
Vehicle	119	$	11,337,606
Trailer	46	$	1,150,000
Equipment	48	$	7,437,444
Total	213	$	19,925,049

Even Replacement 2023

Type	**# of Units**		**Total Acquisition Cost**
Vehicle	78	$	5,397,970
Trailer	1	$	25,500
Equipment	61	$	8,949,933
Total	140	$	14,373,403

Q. What are the purchasing lead times to build Fleet vehicles, equipment, and trailers?

A. Lead times typically vary between 9 to 12 months. Lead time is the period from when a unit is ordered to the day it is delivered.

Q. Are there COVID-19 supply chain impacts to ordering Fleet units?

A. Yes. On average 6 to 12 months have been added to the purchase process.

Q. How does the timing of the test year approval impact the acquisition of new vehicle purchases?

A. Due to the lead time discussed above, a vehicle must be ordered prior to an approved test year spend.

<u>Other Equipment</u>

Q. Please explain the breakdown of the Company's projected Fleet Services capital expenditures in this case for Other Equipment.

A. Other equipment includes fleet garage tooling and other vehicle maintenance equipment required to repair and maintain the fleet.

Q. Why is tooling and other maintenance equipment necessary?

A. To properly repair vehicles in a compliant, safe, and efficient manner, it is necessary to have the right tool for the right job. This tooling can be anything from diagnostic tooling, electronic service information, tool sets, or a new air conditioning recovery/recycle/recharge machine that are required to properly service R1234yf refrigerant. Diagnostic tooling is necessary for the repair of a majority of the vehicle's 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. Maintenance equipment, such as an R1234yf air conditioning machine, are required to meet Environmental Protection Agency (EPA) standards for safely recovering and recharging air conditioning systems on newer model year vehicles.

Telematics

Q. What is Telematics?

A. Telematics is a combination of hardware and software used for monitoring vehicles, equipment, and trailers by using Global Positioning System (GPS), the various control modules within the units, and the vehicles' onboard diagnostics.

Q. What are the overall benefits of implementing the Utilimarc Telematics system?

A. There are multiple components that add value regarding Telematics: Safety, Automation, Data Management, Optimization, and Productivity.

Q. What are the safety benefits of implementing the Utilimarc Telematics system?

A. The safety items of the Telematics system tracks driver behaviors, such as speed, harsh braking, and cornering. Evaluations can be created for each vehicle, using this information, to educate drivers on their performance and the impacts of their driving styles. This is important because in order to serve its customers, Consumers Energy drives approximately 46 million miles per year in the state of Michigan. According to information obtained from other companies using Utilimarc Telematics, the customized educational training developed using Utilimarc Telematics has demonstrated a reduction of driver safety events by approximately 36%. The data provided by the Telematics systems also supports accident investigations. Having the exact location of the vehicle prior to an accident, along with the critical information of vehicle speed and braking supports the investigation process. Another safety benefit is the ability to notify operators of specific threats of violence. This technology has the ability to integrate geofencing with the threats of violence notifications to warn operators, helping avoid operators being placed in harm's way.

Q. What are the automation benefits of implementing Utilimarc Telematics?

A. The system offers an application for drivers to allow them to document the Driver Vehicle Inspection Report ("DVIR"), which is required by the Federal Motor Carrier Safety Regulations. The Utilimarc Telematics application has the functionality for electronic completion of the DVIR. The automation allows this process to be paperless, which eliminates the need to physically track and file forms, it also has valuable capabilities which notifies Fleet personnel and the ability to create work requests when a defect in a vehicle requires maintenance. This technology enables a dashboard to be created showing DVIR completion, as well as vehicles in need of repairs, which notifies Operational planners for scheduling adjustments prior to start of day. It also allows for the opportunity to integrate the electronic driver's log, which allows dispatchers to view available hours prior to scheduling work.

Q. What Data Management benefits are realized by Implementing the Utilimarc Telematics System?

A. The integration between the Company's SAP system and Utilimarc has already been established which benefits the customer. This allows Utilimarc to integrate Operator Qualifications with the vehicle for dispatch to precisely identify the right vehicle, with the qualified operator and tools to respond and serve customers. Having this ability to dispatch the nearest qualified crew to serve customers results in lower expenses as well as increasing the Company's value delivered to the customers.

Q. What optimization benefits are realized by implementing the Utilimarc Telematics system?

A. The optimization portion of the application provides accurate tracking of miles and hours of the asset which gives insight to the utilization of each vehicle as well as ensuring any rental units are being fully utilized. The Telematics will also provide insights to preventative maintenance programs. The programs will have the functionality to be tailored to the specific asset per the manufacturer's recommendations. This technology has the ability to integrate with the Company's fuel card vendors, WEX and Smartfill, as well as the ability to track fuel usage and idle time. The fuel reporting is important because it provides the Company with the ability to track off-road gallons used and accurately obtain credit for the road taxes paid as well as identify maintenance trends due to excessive fuel usage. The idle tracking along with fuel utilization provides an opportunity to reduce fuel consumed by educating the Company's drivers to change their behaviors on how much fuel is used for non-productive idle time. The reduced idle time also helps the Company achieve its environmental goals of reducing carbon. This technology offers engine fault codes and remote diagnostics as well. Having this insight to identify predictive maintenance trends prior to catastrophic repairs or extended downtime allows Fleet the ability to plan the repairs versus having unplanned work. Avoiding unplanned work is important because it increases overtime and additional materials to make the necessary unexpected repairs to avoid impacting Gas Operations from starting their day with zero impacts to serve customers.

Q. What are the costs of Telematics in this proceeding?

A. The projected costs of Telematics in this proceeding is $5.311 million, which is included in the bridge year, 12 months ending December 31, 2021.

Q. Has the Commission previously approved the costs of Telematics?

A. Yes. The Commission approved the costs of Telematics in its December 17, 2020 Order in Case No. U-20697.

Q. When will the Telematics devices be fully installed?

A. The Telematics devices are expected to be fully installed in early 2022.

Q. Has there been a barrier in completing the install in 2021?

A. Yes. Due to semi-conductor shortages, the telematic devices were on backorder, resulting in delivery delays.

Q. What benefits has the Company already started to see with the install of Telematics?

A. The Company is able to locate units in real time and has experienced automated work order creation for low battery diagnostic trouble codes. This integration gives the Company's fleet mechanics insight into vehicles needing service before crews start their day to serve customers, such as low fuel and oil dashboard for fleet to pinpoint units needing to be fueled and oil changed.

Q. When will savings begin to be realized from Telematics?

A. Savings from Telematics are expected to begin after the installation of the software integration, which is expected in mid-2022.

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-21148

DIRECT TESTIMONY

OF

LORA B. CHRISTOPHER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

Q. Please state your name and business address.

A. My name is Lora B. Christopher, 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 Executive Director of Employee Benefits.

Q. What are your responsibilities as Executive Director of Employee Benefits?

A. I am responsible for design, implementation, and administration of the Company's retirement and insurance 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 insurance benefits area, the Company contributes to the cost of these insurance benefits plans – health care (medical/prescription drug/dental including Health Savings Accounts ("HSA") and Health Care Flexible Spending Accounts ("HCFSAs")), life insurance, and Long-Term Disability ("LTD") insurance. Like the retirement plans, my responsibilities for these health care and insurance benefit plans 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, I have 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. These insurance benefit plans also 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. Finally, I manage a 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 2002, I graduated from Western Michigan University in Kalamazoo with a Bachelor of Business Administration degree. In 2008, I graduated from Central Michigan University earning a Master of Science in Administration with a concentration in Human Resources Management. I hold a Professional in Human Resources from HR Certificate Institute.

Q. Would you please describe your previous work experience?

A. In 2004, I began my career focused on employee benefits at CoStaff Services Professional Employer Organization ("PEO") as a Human Resources Specialist. This was a specialized role, offering independent work responsibility for administration of health insurance plans for over 50 PEO clients including plan design, enrollment administration, claim payments, audits, and COBRA administration. Also, I was responsible for Absence Management and Workers Compensation for my clients.

In 2006, I began working for Comerica Bank as a Benefits Specialist. I was heavily involved in the benefit administration of their health care plans. Also, I was responsible for the Absence Management and Workers' Compensation programs. In 2008, I became Assistant Vice President of Employee Benefits/Senior Benefits Specialist. In this role I managed health insurance plans including strategy, plan designs, market analysis, rate renewals, contracts, compliance, and claims management. My responsibilities included open enrollment communications focusing on educational campaigns on health, wellness, and retirement benefits. I was heavily involved in benefit planning committees, reasonable accommodations, HIPAA compliance, and the benefit appeals committee. I supervised the employee staff, which was responsible for the payment administration and reconciliation of all the employee benefit plans. I was the project leader for many Health Care related projects (implementation of Consumer Directed Health Care Plan ("CDHP"), Dependent Audit, Absence Management, etc.).

In 2011, I joined Consumers Energy as a Senior Benefit Consultant in Jackson, Michigan. I took on a project manager role within the Employee Benefits Team. My responsibilities included Annual Enrollment, health care strategy and plan design, union negotiations, Affordable Care Act ("ACA") administration, HIPAA/Compliance, and other health care related projects. In 2017, I became the Manager of Health Care & Retirement with responsibility for health care, retirement, and various other insurance programs for active and retired employees. My insurance responsibilities include health care strategy, premium contributions, plan designs, benefits administration validations, legal compliance, carrier exchanges, eligibility, and rate validations. I oversee management of the retirement benefits plans (Pension Plans, DCCP, and ESP). In 2018, I became responsible for the implementation of our new well-being program, Live Well 365, which focuses on six key elements of total well-being. I continue to manage the Health Care & Retirement team at Consumers Energy. The team is responsible for all aspects of health care and retirement plans administration for our employees and retirees. In 2019, I became the Director of Employee benefits with the responsibility of my previous role as Manager of Health Care & Retirement with the addition of workers' compensation and absence management. In 2020, I became the Executive Director of Employee Benefits which leads the health care, retirement, workers' compensation, occupational health, absence management and well-being teams and I am part of the Company's Strategic People & Culture Leadership Team.

Q. Are you a member of any professional societies or trade associations?

A. I represent the Company as a member of the National Business Group on Health ("NBGH"), an association of over 400, mostly large, employers across the country who provide health coverage to over 55 million individuals. NBGH represents the national voice of large employers dedicated to finding innovative and forward-thinking solutions to the nation's most important health care issues.

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-31 (LBC-1)	Summary of Actual and Projected Benefits O&M Expenses for the Years 2020, 2021, 2022, Test Year 2023;
Exhibit A-32 (LBC-2)	CMS Energy – Pension Plans A and B - ASC 715 Pension Expense Estimates ($ millions);
Exhibit A-33 (LBC-3)	CMS Energy - ASC 715 OPEB Expense Estimates ($ millions); and
Confidential Exhibit A-34 (LBC-4)	CMS Energy – Actuarial Letter of Support for Mid-Year Projections.

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

A. Yes.

Q. Please describe Exhibit A-31 (LBC-1).

A. Exhibit A-31 (LBC-1) summarizes 2020 through 2023, 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 2020 actual expense for each plan. Column (c) provides the projected expense in 2021 for each plan. Column (d) provides the projected expense in 2022 for each plan. Column (e) provides the projected expense for the 12 months ending September 30, 2023. Page 2 provides information on amounts that were projected using the methods discussed in this testimony and included in column (i). I did not project O&M expenses by applying an inflation rate or a merit increase rate to historical O&M expense. Column (j) is the projected test year O&M and is the sum of columns (b) and (i).

Q. Please describe Exhibits A-32 (LBC-2) and A-33 (LBC-3) and Confidential Exhibit A-34 (LBC-4).

A. Exhibits A-32 (LBC-2) and A-33 (LBC-3) provide the Aon actuarial projections for Pension and Other Post-Employment Benefits ("OPEB") expenses for the years identified. Both the Pension and OPEB projections in these exhibits provided by the Aon actuaries are updated from the year-end 2020 measurement of the Pension and OPEB plans and reported in the Company's 2020 Form 10-K filing to more closely align with current market conditions and January 1, 2021 census data. A letter from the actuary regarding the accuracy and completeness of the updated projections is included in Confidential Exhibit A-34 (LBC-4).

I. <u>RETIREMENT BENEFITS PLANS</u>

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-31 (LBC-1), page 1, lines 1 through 3.

Q. How are the Pension Plans, DCCP, and ESP expenses that are common to gas 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 on the basis of the relationship of employee labor dollars charged to gas operations compared to the labor dollars charged in 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-31 (LBC-1), page1.

Pension Plans

Q. Would you please explain your Exhibit A-31 (LBC-1), line 1, which begins with $2,461,000 in 2020?

A. Exhibit A-31 (LBC-1), page 1, line 1, shows the actual 2020 pension expense and the projected expense for 2021, 2022 and the 12 months ending September 30, 2023 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 process is rigorously reviewed by the Company's auditor to ensure compliance with GAAP and ASC 715.

ASC 715 requires an annual determination of pension expense. 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 purposes and updated as of October 15, 2021. The mid-year projections were updated by the Company's actuary, Aon. Pension expense in this case, including 2021 and 2022, is based upon this updated 2021 mid-year actuarial projection of the Pension Plans.

Q. What are the components of the annual pension expense under ASC 715?

A. There are four components of the expense: (i) service cost; (ii) interest cost; (iii) expected return on plan assets; and (iv) amortization of gains or losses, prior service cost, 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 his or her 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 positive or negative.

In order 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 Financial Accounting Standards Board ("FASB") Presentation of Pension/OPEB Costs Standard in this case?

A. Yes, the Company adopted the FASB Presentation of Pension/OPEB Costs Standard as of January 1, 2017 and has applied the Standard in this case for both Pension and OPEB. This FASB 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 FASB 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-31 (LBC-1), page 1, line 1, which begins with $2,461,000 for 2020.

A. Each of the annual pension expense levels shown on Exhibit A-31 (LBC-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 and Pension Benefit Guarantee Corporation ("PBGC") premiums, aggregated for total pension expense. The Consumers Energy pension expense determined by Aon plus administration fees and PBGC premiums 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 $2,461,000 in 2020, projected expense of ($4,873,000) in 2021, and projected expense of ($15,408,000) in 2022. For the 12 months ending September 30, 2023, the gas utility's portion of the projected O&M pension expense is ($21,505,000).

Q. Have there been any significant changes to the Pension Plan structure?

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 as a result 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 PBGC premium variability.

Q. Did the Company make any cash contributions to the Pension Plans in 2020?

A. Yes, the Company contributed $531,000,000 to Pension Plan A in January 2020 and contributed another $169,000,000 in December 2020 for a total 2020 contribution of $700,000,000.

Q. Will the Company make any cash contributions to the Pension Plan in 2021 or 2022?

A. No cash Pension Plan contributions are required in 2021 or 2022 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 2021 from 2020?

A. The Pension expense decreased from 2020 to 2021 due to additional contributions in January and December 2020 that are noted above. The main driver on the OPEB side was better asset experience in the trust assets.

Q. Why is the pension expense expected to decrease for 2022 from 2021?

The Pension expense is expected to decrease from 2021 to 2022 due to higher discount rates currently and higher asset experience in 2021.

Q. Have any changes recently been made to Pension Plans benefits?

A. On September 1, 2015, a change was made to the survivor benefit for a retirement-eligible employee covered by the plan who passes away prior to retirement. In such case, the surviving spouse/beneficiary will automatically receive the employee’s full monthly retirement annuity (rather than 50% of the annuity), even if the employee had not completed the paper application process for this benefit prior to passing away.

While this modest 2015 change was made to the Pension Plans, 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) until there are no longer any employees or retirees covered by the defined benefit Pension Plans.

Effective November 1, 2020, the Company changed the unreduced early retirement from age 62 to age 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. This change has made their pension benefit more generous and was very well received. The additional changes in the projected pension expense estimates from 2021, 2022, and 2023 are primarily the result of economic conditions external to the Pension Plans over which the Company has no control.

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 in the area of 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 defined benefit Pension Plan with the qualified defined contribution 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 defined benefit Pension Plan became participants in the DCCP as of September 1, 2005. As of September 1, 2005, for this specific group of employees, additional pay credits under the Cash Balance version of the defined benefit Pension Plan were discontinued.

Q. Will the Cash Balance version of the defined benefit Pension Plan accept any new employees as participants?

A. No. As with the Final Average Pay defined benefit Pension Plan, the Cash Balance version of the defined benefit 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 of the employee's base pay to the ESP. 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. Effective January 2021 for the Company's union employees, the DCCP provides a 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 a 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 and helps contain the cost of the DCCP for the benefit of the customer as all new union hires starting in 2021 began receiving a 8% (previously 6% for new hires) employer contribution. 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 to the customers.

The Company's exempt and non-exempt employess will continute to receive the DCCP Plan, 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-31 (LBC-1), page 1, line 2, which begins with $5,242,000 in 2020?

A. Exhibit A-31 (LBC-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 2020 was $5,242,000 as shown in column (b). Column (c) shows the projected 2021 gas DCCP expense of $6,562,000. Column (d) shows the projected gas DCCP expense of $7,256,000 for 2022. Column (e) shows the projected gas DCCP expense of $7,909,000 for the 12 months ending September 30, 2023. DCCP costs are projected to increase 12% annually from 2021 to the test year based on the three year average percentage increase from 2017 to 2020. Cost increases to the DCCP plan also reflect the number of new employees joining the Company each year. Additionally the Company added $6 million in 2021 for the plan change to the DCCP for union members as the percentage went up to 10% from 7%. The projections shown in Exhibit A-31 (LBC-1), page 1, line 2, represent the 41% of total expense assigned to Gas Capital expense.

Q. As a result of the revised eligibility requirements for participation in the Final Average Pay defined benefit Pension Plan or the Cash Balance version of the defined benefit Pension Plan, is it correct to say that all new hire employees starting with 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 how the ESP works.

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 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 will change only for Salaried exempt and non-exempt employees to 100% of employee contributions of 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 remain with the 3% of the employee's salary, and then 50% of employee contributions of up to the next 2% of the employee's salary.

Q. Would you please explain your Exhibit A-31 (LBC-1), page 1, line 3, which begins with $4,901,000 in 2020?

A. Exhibit A-31 (LBC-1), page 1, line 3, represents the Company's gas operations expense related to the ESP. In 2020, the actual gas utility O&M expense for the ESP was $4,901,000. For 2021, the projected gas utility O&M expense for the ESP is $4,947,000. For 2022, the gas utility O&M expense projected for the ESP is $6,138,000. For the

12 months ending September 30, 2023, the gas utility O&M expense projected for the ESP is $6,414,000. Savings Plan costs are projected to increase 6% annually from 2021 to 2023 based on three year average, and in 2022 an additional $6 million was added for the increase in non-union match change to take effect in 2022. The projections shown in Exhibit A-31 (LBC-1), page 1, line 3 represent the 41% of total expense assigned to Gas Capital expense.

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 in light of 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. Retaining trained, experienced, and motivated employees works very much to the customers' benefit.

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 new 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 an important issue to the union during the last several labor negotiations, all of which were finally resolved through arms-length bargaining.

With respect to nonunion employees, there is not a similar contractual prohibition against suspension. However, the ESP employer match is part of an overall competitive benefit 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-31 (LBC-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.

<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, LTD, and other benefits expense levels that are shown on Exhibit A-31 (LBC-1), page 1, line 4, which begins with $14,066,000.

A. Exhibit A-31 (LBC-1), page 1, line 4, contains gas operations O&M expenses for the Company-subsidized benefit plans for active employees' health care (including HSAs and HCFSAs), life insurance, LTD, and other benefits. The primary component of this expense is health care. Life insurance, LTD, and other benefits expense make up a much smaller portion of the expense. In 2020, the Company incurred an actual combined expense of $14,066,000 for health care, life insurance, LTD, and other benefits for gas operations. The Company's projected expense for these benefits is $16,259,000 in 2021. The projected gas operation expense for these benefits in 2022 is $17,124,000. For the 12 months ending September 30, 2023, the projected gas utility expense is $17,978,000.

Q. What factors did you consider in projecting the Company's 2021, 2022, and 12 months ending September 30, 2023 expenses for health care, life insurance, LTD, and other benefits?

A. In projecting expected 2021, 2022, and 12 months ending September 30, 2023 health care expenses, a number of factors were considered. Primary factors included review of 2019 and 2020 national health trends/costs survey information, 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 ages of the Company's employee workforce and its retirees, the continuation and improvement of the Company's well-being initiative for employees and retirees, changes to the 2021 through 2025 OM&C/VCC/Steelworkers union employee health care benefit contract provisions, changes to 2021 and 2022 employee health care plans, the current employee headcount, and the continuing cost increase impacts of national health care reform. All these factors are included in the 2020 and 2021 rate studies completed by the Company and Willis Towers Watson ("WTW") actuarial consulting.

Q. Please explain how these factors were used to determine the Company's expected health care costs in 2021, 2022, and the 12 months ending September 30, 2023.

A. To help understand projected health care trends and costs in 2021, the Company and WTW reviewed expected health care trends and costs survey information from several large consulting firms. Recent 2020 health care trend and cost surveys included in the review were Aon and WTW. For 2022, medical health care trend (per capita claims cost) is expected to increase 5.6% on just medical expenses. The leading medical trend contributor is prescription drugs, which is expected to trend 8% higher in 2021. A review of these projected trends in medical and prescription expenses serves as a basis of what to expect in future medical expense increases. The Company's combined medical and prescription annual trend rate is 6.9%.

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 and Express Scripts. The Company's health plans indicate that the Company's workforce is older than the average in their plans, and, as a result, has a higher expected utilization rate of services that is associated with an older covered population. Of the Company's current workforce on October 19, 2021, 45% of employees are over age 45; 31% are over age 50; and 17% are over age 55. The Company understands the older age of its workforce is expected to lead to higher health care expense (primarily due to utilization of services). Most of these discussions with the Company's health plans suggest health care expenses are expected to increase 5% to 8% for 2021. Historical claims experience data for Consumers Energy participants was also gathered from these health care companies to be used in the 2019 and 2020 health care expense impact studies completed with WTW to determine the Company's projected expense increases in 2021 and 2022.

To project future health care expenses, the Company and WTW also considered all the plan changes and programs the Company has already implemented, which are summarized below and detailed later in this testimony. These changes include sharing expected health care expense increases with employees through plan design changes, including 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 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 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.

Based upon the analysis of all of this information, including health plan demographics and current enrollments, the Company and its independent employee health care actuarial consultant, WTW, projected in its rate studies that for 2022, the expected health care expense increase for the Company will be 6.9% after all plan design and premium contribution changes are considered for 2022. The Company will continue to seek to contain expense, and the Company's health care expense is projected to increase 6.9% in 2020 over 2021 expense. The Company used these WTW actuarially based studies to set its projected active health care expenses for 2021. As a result, the Company projects its expected health care expense will increase 6.9% for 2022 (the projected 2022 increase from the 2021 WTW study).

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 much 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, recently enacted national health care reform will increase Company health care costs in the near term as a result of eligibility expansions (e.g., adult children to age 26), mandated benefits, removal of annual dollar limits, additional taxes, fees and 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 large increases in health care costs being experienced both locally and nationally?

A. Yes. While increases in health costs have moderated somewhat, both local and national health care costs continue to increase at rates much 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, reasonably 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-31 (LBC-1), page 1, line 4.

A. For 2021 and 2022, the Company used a 3.5% annual increase in cost for both years. This means 2021 life insurance and LTD expense is expected to be 3.5% higher than 2020 and 2022 expense will be 3.5% higher than 2021. 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 3.5% annual increase reasonably represents the normal, expected merit increase 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 2021 follows:

- 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;
- Streamline all benefit plans to be 80% coverage levels;
- Offered 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 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 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 on several occasions;
- 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 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 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; and
- Secured improved prescription drug pricing and plan consulting services as part of membership in a large prescription drug employer prescription drug purchasing collaborative.

Q. What changes were made to the 2017 health care plans?

A. In 2017, the same health care benefit changes were made for all union and nonunion employees as well as all preMedicare retirees. The Healthy Living health plan designs were changed to comply with new Equal Employment Opportunity Commission requirements. This required only the employee and preMedicare retiree, not covered spouses, to complete their Healthy Living steps under the wellness plan design. Those employees and preMedicare retirees that completed their two Healthy Living steps in 2017 had less cost sharing in their health plans or received a second Company contribution to their Health Savings Account in 2017.

In addition, the ACA expanded nondiscrimination definitions to include gender identity. As a result, the Company added coverage for gender transition benefits to all its health plans.

Finally, all health plan premium contributions for employees and preMedicare retirees were increased to share in expected increased costs in 2017.

Q. What changes were made to the 2018 health care plans?

A. In 2018, deductibles and out-of-pocket limits increased in the majority of plans for all salaried and union employees as well as early retirees. Several prescription drug coverage management programs were added to help participants better manage various chronic and expensive medical conditions. The CDHP increased out-of-pocket limits as well as reduced Company HSA contributions. The prescription drug plans increased specialty drug copays. A refreshed well-being approach was introduced with the new Live Well 365 to encourage and incent plan participants to improve their health and well-being year-round. Premium contributions have increased across all health plans to help manage the expected expense increases for the Company.

Q. What changes were made to the 2019 health care plans?

A. In 2019, deductibles and out-of-pocket limits increased for the HMO plans. The Company introduced a CDHP plan with no HSA seed from the Company. The employee share of health care plans also increased.

The active employee health care expense for the Company, after consideration of all these changes, is expected to increase 3.9% in 2019 as documented in the WTW rate study.

Q. What changes were made to the 2020 health care plans?

A. In 2020, the Company discontinued offering our HMO plans for our active employees. This change was due to declining enrollment and higher medical and prescription costs in the HMO plans. Active employees have 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 our CDHP had the ability for saving options for current and future health care expenses through a health savings account. The employee shared of health care plans increased.

Q. What changes were made to the 2020 health care plans due to COVID-19?

A. The Company incorporated the following health care changes related to COVID-19. 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.

The coverage for COVID-19 Treatment. 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 COVID-19, the Company continued to offer coverage for COVID-19 diagonitc testing, services and testing 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 our customers. The active employee health care expense for the Company, after consideration of all these changes, expected to increase 5.6% in 2021 as documented in the WTW rate study.

Q. What changes will be made to the 2022 health care plans?

A. In response to COVID-19, the Company continues to offer coverage for COVID-19 diagnostic testing and services without imposing any cost-sharing requirements for employees and covered family members. The Company plans to 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 our customers. The active employee health care expense for the Company, after consideration of all these changes, expected to increase 6.9% in 2021 as documented in the WTW rate study.

Retiree Health Care and Life Insurance

Q. Would you please explain your Exhibit A-31 (LBC-1), page 1, line 5, for retiree health care and life insurance, which begins with ($41,634,000) in 2020?

A. Exhibit A-31 (LBC-1), page 1, line 5, reflects the actual 2020 and projected 2021, 2022, for 12 months ending September 30, 2023 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 process is rigorously reviewed by the Company's auditor 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 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 was measured on December 31, 2020 to reflect updated market conditions. The OPEB expense in this case is based upon the December 31, 2020 assumption study of the OPEB plan.

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 expense: (i) service cost; (ii) interest cost; (iii) expected earnings on plan assets; and (iv) amortization of gains and losses, prior service costs, 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 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 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-31 (LBC-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-31 (LBC-1), page 1, line 5.

Q. What changes were made to retiree health care coverage from 2011 to 2021?

A. The same plan changes described previously for active union and nonunion employees from 2011 to 2021 were made to all the preMedicare retiree plans. These changes included the Live Well 365 program requirements, increased plan deductibles, copays and out-of-pocket limits, various plan eliminations, four-tier incentive prescription drug coinsurance plans, self-insured HMO plans, a CDHP/HSA plan option, increased premium contribution requirements, additional prescription drug coverage management programs, and the implementation of MOB coordination. In addition, as described earlier in the ESP section above, all new union hires since September 1, 2010 (nonunion hires since January 1, 2007) may become eligible for an access-only retiree health care plan at retirement which requires

100% retiree premium contribution for coverage at retirement and provides for no Company contribution or subsidy and results in no Company ASC 715 liability or expense.

The Medicare retiree plan was also changed throughout this 2011 to 2018 period with similar changes including increased deductibles and out-of-pocket limits, MOB coordination, a new four-tier incentive prescription drug copay plan and increased premium contribution requirements. Specifically, in 2018, Medicare retirees have increased prescription drug copays and the addition of specialty drug copay in their plan. In addition, premium contributions for most Medicare retirees increased to 10% of the plan's cost.

Q. Were additional significant changes to retiree medical coverage announced during 2013?

A. Yes. The Company made a change to the financing arrangement for providing its prescription drug coverage to Medicare retirees effective January 1, 2015. The Company moved away from the Retiree Drug Subsidy approach and implemented an Employer Group Waiver Plan ("EGWP") with wrap coverage. The EGWP with wrap coverage allows the prescription drug benefit plan to deliver the same or very similar prescription drug benefit coverage and cost sharing to the Company's Medicare retiree supplemental health plan participants. Due to a couple of national health care reform changes involving increased prescription drug subsidies and manufacturer discounts under an EGWP financing approach, the Company's cost for providing Medicare retiree's prescription drug coverage decreases significantly as drug manufacturers' discounts and Medicare subsidy payments will cover a portion of the Company's prescription drug benefit costs.

In addition, the Company announced the implementation of an increasing schedule of premium contributions for its Medicare retirees covered under the Company's Medicare

Supplemental Plan beginning January 1, 2016. The Company indicated it would begin to phase in a schedule of premium contributions for many of its current Medicare retirees and all of its future Medicare retirees eligible for subsidized retiree health care coverage. Medicare retirees on lower fixed incomes, who have been retired for a longer period of time, will not pay premium contributions under this provision. For younger Medicare Supplemental Plan retirees, premium contributions will start at 5% of the plan's cost in 2016 and gradually move to 10% in 2018, while younger Medicare retirees will pay 15% of plan costs by 2020. Premium contributions percentage amounts are dependent upon the retiree's age on December 31, 2013.

Q. Were additional significant changes to retiree medical coverage announced during 2017?

A. Yes. The Company expects that most of its current Medicare retirees and all future Medicare retirees will begin to choose their Medicare retiree health care benefit plans from the individual Medicare Marketplace beginning January 1, 2019 rather than be covered by the Company's one current supplemental Medicare health plan. These retirees will receive assistance in their plan elections and be provided advocacy services by a private Medicare Marketplace company selected by the Company. Medicare retirees eligible to receive subsidized retiree coverage from the Company will instead receive a Company-funded Health Reimbursement Arrangement to reimburse them for their premium and out-of-pocket costs for the plan(s) elected in the individual Medicare Marketplace. This change to the individual Medicare Marketplace offers the Company's Medicare retirees a much greater choice of plans and flexibility to select coverage that best meets the Medicare retiree's individual needs. Also, due to the cost efficiency of the individual Medicare

Marketplace, it will provide more affordable coverage for Medicare retirees now and well into the future.

Q. Were additional significant changes to retiree medical coverage announced during 2018?

A. Yes. The Company announced an improved survivor benefit for retirees. All eligible surviving spouses will continue subsidized healthcare for their remaining lifetime.

Q. What changes were made to the 2019 retiree health care plans?

A. The preMedicare retirees have the same health care plan options as the active union and nonunion employees. The Company partnered with an individual Medicare marketplace provider for specific Medicare eligible retirees to select their own coverage. The Company provided a Health Reimbursement Account ("HRA") to retirees based on years of service and hire date. The retirees worked with a benefits consultant to select the best quality and affordable health care coverage.

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 preMedicare retirees no longer had the option to select the HMO plans. The preMedicare 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 to assist retirees to 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 preMedicare retirees have the same health care plan options as the active union and nonunion employees. The preMedicare retirees no longer have the option to select the HMO plans. The preMedicare 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. The private Medicare marketplace specializes to assist retirees to select the best quality healthcare plan options at the most affordable price. The HRA subsidy amount is allotted based on years of service and hire date.

Q. What changes will be made to the 2022 retiree health care plans?

A. The preMedicare retirees will have the same health care plan options as the active union and nonunion employees. The preMedicare 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, receive a 2% increase into their HRA. These retirees select their retiree health care coverage through an individual Medicare marketplace. The private Medicare marketplace specializes to assist retirees to select the best quality healthcare plan options at the most affordable price. The HRA subsidy amount is allotted based on years of service and hire date.

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 2021 for year end purposes and updated as of October 15, 2021 based upon the 2021 mid-year projections received from the Company's actuary, Aon. OPEB expense in this case, including 2021, 2022 and the 12 months ending September 30, 2023 is based upon this updated mid-year actuarial projection for the OPEB Plan.

Q. Has the Company applied the new FASB Presentation of Pension/OPEB Costs Standard in this case for OPEB?

A. Yes, the Company early adopted this new FASB Presentation of Pension/OPEB Costs Standard as of January 1, 2017 and has applied the new 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-31 (LBC-1), line 5, which begins with ($41,634,000) in 2020.

A. Each of the O&M retiree health care and life insurance expense levels 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 2020 O&M retiree health care and life insurance expense for the gas utility was ($41,634,000). In 2021, the projected gas O&M expense for these benefits is ($51,881,000). The projected gas O&M retiree health care and life insurance expense is ($57,676,000) in 2022. For the 12 months ending September 30, 2023 the projected gas O&M retiree health care and life insurance expense is ($55,605,000).

Q. Why is the retiree health care and life insurance expense so low?

A. Improved 2013 through 2019 prescription drug pricing, the 2013 announcement by the Company of EGWP and Medicare retiree premiums, and the announced change to individual Medicare Marketplace coverage for most Medicare retirees in 2019, are the primary drivers for the significantly reduced OPEB expense for retiree health care and life insurance. These retiree coverage changes are significant and have turned the expense from positive to negative, greatly benefiting customers with reduced costs going forward.

Q. Would you please explain your Exhibit A-31 (LBC-1), page 1, line 6, for Other Benefits, which begins with $1,209,000 in 2020?

A. Exhibit A-31 (LBC-1), line 6, reflects the actual 2020 and projected 2021, 2022, and 12 months ending September 30, 2023 gas utility benefits for absence management and educational assistance program.

Q. Please explain why the absence management program is important to attract and retain employees.

A. A 2018 WTW benchmarking study indicates that 91.7% of 84 energy companies nationwide provide a paid sick leave to their employees. Paid sick leave is needed to attract and retain employees. In 2014, the Company retained Reed Group, an external consultant to manage the Company's absence process. Since the relationship's inception, Reed Group has been able to improve the absence rate and provide tracking information to the Company. The Company's absence rate decreased from 3.88% in 2014 to 3.63% in 2017. The reduction in absences results in lower labor costs. The benefit of the absence management program is clinical nurse case management. This allows for the resources for our employees as they navigate through their illness. The nurse case management provides medical knowledge and assistance to our employees. 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 very much available from Michigan employers as well as from other utility company employers that Consumers Energy competes with for employee talent. A 2018 WTW benchmarking study indicates that 98.8% of 84 energy companies nationwide provide full (16.7%) or partial (82.1%) tuition reimbursement to their employees. 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 in order to continue attracting and retaining competent employees needed by the Company, particularly in light of 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. Retaining trained, experienced, and motivated employees works very much to the customers' benefit. Additionally, educational assistance provides the opportunity for our 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 our 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 of the Company's employees and retirees.

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-21148
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

AMY M. CONRAD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

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 Director of Executive and Incentive Compensation 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 Committee 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 consist of assisting with preparation of materials for the Compensation Committee 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 include administering the incentive plans for CMS Energy, including Consumers Energy.

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, and U-20963.

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 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. Are there any other topics covered in your direct testimony?

A. Yes. My direct testimony is also to provide support for Consumers Energy's use of labor rates for projecting the cost of labor in the bridge and test years in the case for operating and maintenance ("O&M") expense related labor costs.

Q. Please summarize your conclusion regarding labor factors.

A. My conclusion is that the cost of labor should be adjusted based on projected salary increases derived by independent third-party survey sources. This approach aligns the labor rates more accurately with the type of O&M expense.

Q. How is the remainder of your direct testimony organized?

A. The remainder of my direct testimony is organized as follows:

I. OVERVIEW

II. EMPLOYEE COMPENSATION PHILOSOPHY

III. INCENTIVE COMPENSATION PLANS

A. Description of Incentive Plans

B. Assessment of Customer Benefits of the Incentive Compensation Plans

IV. LABOR RATES

V. CONCLUSION

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-35 (AMC-1)	EICP Performance Measures;
Exhibit A-36 (AMC-2)	Target Pay Level Market Analysis;
Exhibit A-37 (AMC-3)	Summary of Actual and Projected Annual Incentive O&M Expenses;
Confidential Exhibit A-38 (AMC-4)	Market Surveys Regarding Labor Rates – Payscale;
Confidential Exhibit A-39 (AMC-5)	Market Surveys Regarding Labor Rates – WorldatWork;
Confidential Exhibit A-40 (AMC-6)	Market Surveys Regarding Labor Rates – Mercer; and
Confidential Exhibit A-41 (AMC-7)	Market Surveys Regarding Labor Rates - Willis Towers Watson.

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 on 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. 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 market-based competitive level. It is not in addition to it. Total compensation is targeted at approximately the market median (50^{th} percentile).

Q. How does Consumers Energy structure officer compensation?

A. Officer compensation levels are determined by the Compensation Committee 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 Committee is advised by an independent third-party consultant and take into consideration market research, experience levels, and individual contributions.

Q. Is Consumers Energy requesting recovery of long-term incentive pay in this rate case proceeding?

A. No. The Company in this case is not seeking recovery for the costs of long-term incentive compensation (sometimes referred to as restricted stock plans) in its rate recovery request.

Q. In this proceeding, is the Company requesting rate recovery of all O&M gas expenses related to short-term incentive compensation plans?

A. No. While the Company believes that both officer and non-officer short-term incentive compensation expenses are reasonable, the Company in this case is excluding the costs of short-term incentive compensation for the proxy officers as identified by the most recent SEC proxy filing from its rate recovery request.

Q. Why is the Company requesting rate recovery of short-term incentive compensation expenses?

A. Consumers Energy uses market data to determine an overall competitive level of compensation. The overall compensation levels, including the officer and non-officer short-term incentive compensation, 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 lower qualified workforce that would not best serve customers. In order to hire and retain qualified personnel, it is necessary to either pay a competitive incentive or increase base salaries. The EICP incentive compensation costs are reasonable costs of doing business and, therefore, should be recovered in rates.

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 as continuous improvement, safety, cost, reliability, and delivery. The incentive compensation program encourages employees to deliver their best performance and service for the Company's customers.

Q. Who is eligible for the EICP incentives?

A. All non-union employees are eligible for EICP incentives, with the exception of an employee who was rated as "under-contributing" or "needs improvement" on their annual performance appraisal. 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 non-officer EICP equally weights the operational measures with the financial measures:

- Half (50.0%) of employees' incentive will be based on achievement of operational performance measures. (For 2020 and 2021, there are nine operational measures.); and

- Half (50.0%) of employees' incentive will be based on the achievement of two financial measures, Earnings Per Share ("EPS") and operating cash flow. Consumers Energy is a vital part of the Michigan economy, and it is important that the utility remain financially strong so that it can provide the utility service that customers expect and deserve. Financial health also leads to reduced costs of capital and greater access to liquidity.

The goals are the same for the officer EICP, but the weightings are different. For the officer EICP plan, the operational goals are a plus or minus modifier to the financial goals. I will discuss this difference in weightings later in my direct testimony.

II. <u>EMPLOYEE COMPENSATION PHILOSOPHY</u>

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. 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 that:

> 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.

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.

Q. How does Consumers Energy determine what level of overall compensation for non-officers is reasonable?

A. First, Consumers Energy's management targets overall compensation to the market median. Second, Consumers Energy's management actively reviews compensation levels so that employees are neither overpaid nor underpaid relative to market. Third, the Company uses a rigorous survey process which uses valid and reliable data from multiple sources to determine median levels 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' total 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 in order 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 is able to 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 overall 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 total compensation (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 overall 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-36 (AMC-2) provides a summary of average exempt and non-exempt pay for Company benchmark jobs compared to market using 2019 data for 2020 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 19% of the workforce) and have a need over the next few years to hire engineers and other personnel to staff various projects and serve customers. The Natural Gas Delivery Plan discussed by Company witness Neil P. Dreisig presents a clear need for competitive, market-based compensation to attract and retain qualified, customer-focused employees to do this work. 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 approximately 5.0% to 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 a number of survey sources to compare to the non-officer salaried workforce. The Company participates in and uses an industry survey performed by Willis Towers Watson, a well-respected, independent third-party compensation expert. This survey is conducted by surveying companies which report data on an anonymous basis. The data from Willis Towers Watson is the Company's primary source of compensation information. The Company also participates and uses EAP Data Information Solutions, LLC, an independent survey firm serving the energy industry, for non-officer hourly workforce market data. To supplement this data, the Company uses a reputable national on-line survey resource, CompAnalyst, which has survey data from a wide variety of independent sources. In every instance when using the survey data, the Company looks at the median total compensation (base pay and incentive) reported for highly populated jobs for which there is a comparable 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 three 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 pay levels and the market's pay levels?

A. Yes. For the Company's Administrative Assistant III (46 employees) job, the Company's average salary plus incentive target (overall compensation target) is 1.9% below the market. For Administrative Specialist II (120 employees) the Company's level is 4.4% above the market. For Technical Specialist II (103 employees) the Company's level is 0.5% below the market. For Senior Technician (120 employees) the Company's level is 3.2% above the market. For Senior Engineer II (163employees) the Company's level is 0.1% above the market. For Gas Field Leader (166 employees) the Company's level is 5.6% below the market. For IT Technical Senior Analyst II (105 employees) the Company's level is 5.0% above the market. For Senior Business Support II (99 employees) the Company's level is 4.1% above the market. For Senior Engineering Technical Analyst II (56 employees) the Company's level is 3.5% above the market. These nine jobs are among the most highly populated of Consumers Energy's salaried workforce. See Exhibit A-36 (AMC-2) for a summary of average exempt and non-exempt 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.

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 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 4,900 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 of 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. The EICP target level for each pay grade was established by measuring the difference between the Company's base salary target and the market's overall compensation level. The EICP compensation is part of the overall market-based competitive level of compensation, not in addition to it.

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. In 2003, an EICP for employees in salary grades 18 and below 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 the incentive plan. But for the incentive plan, the Company's non-officer base salaries would be less than overall competitive market-based compensation levels.

Q. Would elimination of incentive pay be in the best interests of customers?

A. No. With incentive compensation, the employees and the Company as a whole 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.

Q. How does the Company determine the level of overall compensation for officers?

A. A utility must maintain a competitive total compensation package in order 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 Committee 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 Committee 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 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 services 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 2019, both proxy advisory service firms recommended a vote "for" the proxy-named executive officer compensation pay and practices. Also, shareholders voted 96% in favor to approve executive compensation as described in the 2020 Proxy Statement which is above the Russell 300 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 LLC, 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 2021.

A. The EICP for 2021 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 in order to deliver value benefits to customers. 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 2021, there are nine specific operational performance measures and two measures related to being financially healthy. The EICP Performance Measures are summarized on Exhibit A-35 (AMC-1).

Q. Please describe Exhibit A-35 (AMC-1).

A. Exhibit A-35 (AMC-1) identifies the operational performance and financial performance areas that the EICP focuses on and identifies the specific measures that have been adopted for each of these areas. In the last column the year-end target is identified. As I indicated earlier, 50.0% of the non-officer incentive compensation is based on operational performance and the remaining 50.0% is based on the financial performance.

Q. Will the structure of the EICP goals for 2022 be similar to 2021?

A. The specific performance measures and targets for 2022 have not been finalized yet. However, as in prior years, the performance measures will be a combination of measures related to operational performance and financial health. I anticipate that, as for 2022, for non-officers the operational performance and financial health goals will be weighted equally (50% operational and 50% financial).

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 and financial performance measures may vary from 2021, areas of focus will continue to include safety, reliability, cost, delivery, customer care, and financial health.

Q. Will the 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. However, starting in 2022 the Compensation Committee of the Board has approved a shift in the weighting of performance measures based on operational measures for officers. The shift eliminates the +/- modifier link to the non-officer plan operational performance and incorporates the same operational measures as those of non-officers. The operational measures will hold a weighting of 30%, meaning 30% of the officer incentive compensation is based on operational performance and the remaining 70% is based on the financial performance. Also, the Compensation Committee approved the removal of the operating cash flow financial measure. As such, the sole financial measure for both officers and non-officers will be EPS (earnings per share). These structure changes better align to market practice.

Q. Please discuss the strategy and process for developing the EICP goals.

A. Company witness R. Michael Stuart 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-35 (AMC-1) set?

A. When setting payout levels, the threshold is set at a level of achievement that can typically be reached eight or nine times out of every 10 years. Maximum payout is for exceptional performance (one to two times out of every 10 years). These levels are to engage the employees in meeting the goals. Employees, as a whole, 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. Should a refund mechanism be used for goals that are not achieved?

A. No. The goals are a collective package and the results should not be looked at in isolation. In fact, it would be wholly inappropriate to do so. The approach of looking at the goals as a complete package encourages improved performance and greater efficiencies from employees from which customers benefit. Further, the Company is only requesting that target level performance be included in rates.

Q. Why are you including both gas and electric performance measures in this plan as this is an electric 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. Are the financial performance goals that are included in the EICP measures consistent with the Company's responsibilities to its customers?

A. Yes. Consistent financial performance is the result of total company performance including achieving operational success. Company witness Stuart quantifies this customer benefit for operating metrics in his direct testimony in this case. Also, an analysis of the cost of capital is discussed by Company witness Todd A. Wehner in his direct testimony and Exhibit A-14 (TAW-1), Schedule D-5, page 7, in this case. Having a financially healthy utility is important to delivering the energy customers need when they need it and to the state of Michigan as the Company is a vital part of the economy. It is in the customers' interests to have a financially healthy utility. This allows the utility to better meet customer needs at the best price. The financial goals are balanced with operational performance criteria. Financial goals help focus employees on achieving superior results in a cost-effective manner. By focusing employees' attention on goals that encourage improved performance and greater efficiencies, customers are benefited. The incentive compensation goals are designed to help motivate employees to perform at their full potential and exercise discretionary effort to help move the Company forward.

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 are based on the achievement of EPS and operating cash flow goals. These metrics are good indicators of strategy execution. The officer annual incentive award is reduced if there is no award earned under the operational performance measures portion of the EICP, and the award is increased (but in no event shall the award exceed the maximum of the target annual incentive) if the maximum award payout is achieved under the operational performance measures portion of the EICP. This potential adjustment provides linkage of executive compensation with the goals related to operational performance. As indicated above, the officer modifier to the non-officer operational performance measures will be removed in 2022 and replaced with 30% weighting of the same operational goals as non-officers. This strengthens the linkage of officer and non-officer operational performance.

Q. How are the EPS and operating cash flow components determined?

A. EPS is determined in accordance with: (i) generally accepted accounting practices; (ii) excluding asset sales which have been excluded from Adjusted EPS or are >2% of Adjusted EPS; (iii) changes in accounting principles from those used in the budget; (iv) large restructuring and severance expenses greater than or equal to $0.01 of EPS; (v) legal and settlement costs or gains related to previously sold assets; (vi) legacy tax reform; (vii) regulatory recovery for prior year changes; and (viii) changes in federal tax policy. Cash flow means: (i) generally accepted accounting principles operating cash flow with adjustments to include changes in power supply cost recovery from budget (disallowances excluded); (ii) changes in pension contribution; (iii) changes in accounting principles from those used in the budget; (iv) gas-price changes (favorable or unfavorable) related to gas cost recovery in January and February of the following performance year; (v) cash impacts of legal settlement costs or gains related to assets previously sold; and (vi) changes in federal tax policy. The Compensation Committee reviews management's preliminary recommendations and establish final goals.

Q. Is operating cash flow a duplicative financial measure to EPS?

A. No. While earnings and cash flow are related, they are not the same. EPS is a measure of profit generated by a company's daily operations. The figure includes revenues and expenses. Some of the expenses used to calculate earnings are considered "non-cash" items, such as depreciation and amortization, and do not impact cash flow. Moreover, select financing decisions made by the Company such as issuing or repurchasing stock can have a direct impact on EPS without impact to operating cash flow. The operating cash flow is a measure of cash generated from operations and what is needed to make investments in the utility. The cash flow measure in the incentive plan starts with generally accepted accounting principles operating cash flow and then it is adjusted as discussed earlier in my direct testimony.

Q. How are the target amounts for the annual officer incentives determined?

A. The Compensation Committee determine the target amounts of the annual officer incentives. In determining the amount of target incentives, the Compensation Committee consider 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 level of expense is approximately $3.9 million as illustrated in Exhibit A-37 (AMC-3). Incentive compensation for the proxy officers is not included in these amounts.

Q. Please explain Exhibit A-37 (AMC-3).

A. Exhibit A-37 (AMC-3) 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 3, column (b), shows the historical O&M expense. Column (c) shows the historical amount that an inflation rate or merit increase rate was applied to. Columns (e) and (g) show the amounts to which an inflation rate or merit increase rate were applied for each bridge period, respectively. Columns (d), (f), and (h) show the merit 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 merit increases are appliable. No inflation rate was applied.

Q. How are the gas expenses of $3.9 million related to annual incentive compensation calculated?

A. The $3.9 million for EICP incentive compensation is based on the following:

- For officers: The rate case expense amount is based on 2021 salaries (excluding the proxy officers) multiplied by the approved target incentive percentage of salary from the 2021 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; and

- For non-officers: The rate case expense amount is based on an estimate of the number of employees in each salary grade multiplied by the plan prescribed incentive target amount. Progression to higher salary grades 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 costs charge between O&M and capital is based on labor studies performed by each business unit.

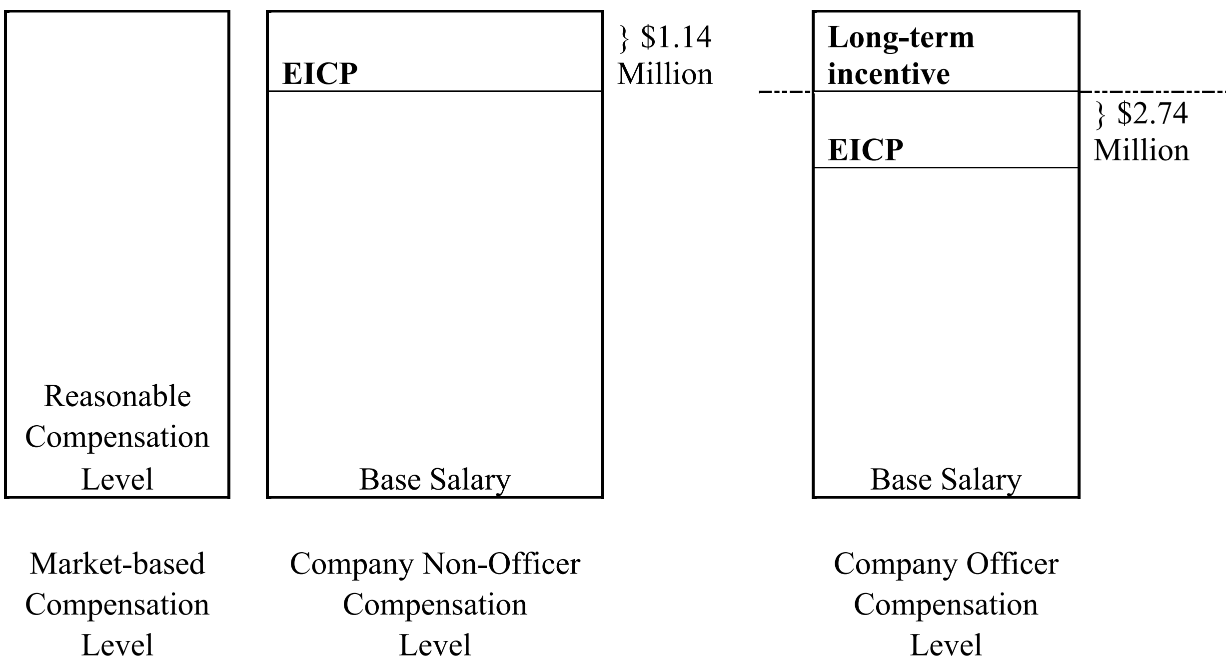
Q. Do Consumers Energy's gas customers benefit from making a portion of employee compensation subject to incentives?

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 his or her 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. Thus, shareholders will absorb any resulting increase in costs arising from above-target performance. If actual payouts in future years are less than target levels due to inadequate financial performance, then the Company's shareholders will absorb the consequence of inadequate performance results along with customers. In addition, the proposal in this case excludes the expenses related to the named officers in the proxy statement. The Company is allocating to shareholders 100% of the costs of incentive compensation for the proxy officers as identified by the SEC proxy rules.

Q. If the Commission concludes that customers should not pay 100% of the portion of the EICP costs that relate to financial measures due to shareholder benefits, is the exclusion of 100% of incentive plan costs that relate to financial measures from the revenue requirement warranted?

A. No. While the Company believes that 100% recovery from customers of the portion of the EICP costs that relate to financial measures is appropriate for the reasons discussed above, a 50/50 sharing of the portion of the EICP costs that relate to financial measures should be adopted rather than a complete disallowance of those costs. This approach provides a balanced approach to controlling costs (financial measures) and efficiently serving customers (operational measures) which both benefit customers. Financial and operating goals are not mutually exclusive.

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 rational and 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.

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 in order 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 as a whole 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 Stuart in his direct testimony in this case.

Further, customers are best served when Consumers Energy can raise capital at the best available rates. The use of earnings and cash flow measures in the EICP and officer annual incentive recognizes that Consumers Energy's financial health is important. Financial health provides appreciable benefits to customers by allowing Consumers Energy to maintain an attractive cost of capital and broader access to liquidity, in addition to any benefits provided to investors. An analysis of the cost of capital is discussed by Company witness Wehner in his direct testimony in this case.

Q. How do customers benefit from the focus on employee safety?

A. Customers directly benefit from having a qualified, talented, and motivated workforce that is focused on areas such as safety. The incentive compensation program encourages employees to deliver their best performance for customers. This is illustrated in the area of safety. For seven of the last 12 years, incidents have decreased: 558 in 2007, 355 in 2008, 258 in 2009, 207 in 2010, 149 in 2011, 119 in 2012, 137 in 2013, 150 in 2014, 106 in 2015, 73 in 2016, 65 in 2017, 102 in 2018, 105 in 2019, and 101 in 2020. This decrease from 2007 to 2020 of approximately 82% can be directly attributed to the significant emphasis Consumers Energy has placed on safety during this period. The decrease in safety incidents helps reduce lost days and helps reduce medical costs from levels that would otherwise occur. The safety components of the EICP performance measures have been an important part of keeping all employees focused on safety. This is an example of how all employees can be motivated and engaged in achieving a common Company goal through use of the EICP.

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 $3.9 million for the test year. The benefits illustrated in Company witness Stuart's direct testimony are $97.9 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 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. LABOR RATES

Q. What are labor rates?

A. Labor rates are factors that are considered when anticipating the cost of labor. Such factors or influences included in determining labor rates are paying competitively, paying for performance, and attracting and retaining critical skills and financial health. Labor factors are not just about keeping employees whole with inflation adjustments. Consumers Energy uses salary survey data to gauge the market prospective on labor factors. This data aids in the determination of merit budgets for paying for performance and the need for pay adjustments to pay competitively.

Q. What is the difference between cost of labor and cost of living?

A. Cost of labor is determined by the supply and demand of labor across industries and jobs by geographic location. It represents the cost to hire and retain employees. Cost of living measures the required costs to maintain a certain standard of living within a geographic location (based on goods and services including consumables, transportation, health services, housing, and taxes paid by an employee).

A comparison of the cost of living and the cost of labor can result in very different percentages. For example, the table below compares the percent difference in the cost of living and the cost of labor between the home base of Atlanta, Georgia and three other locations in Manhattan, Chicago, and Los Angeles:

City	Cost of Living	Cost of Labor
Atlanta, GA (Base Location)	100.0%	100.0%
New York (Manhattan), NY	216.9%	123.0%
Chicago, IL	126.1%	106.9%
Los Angeles, CA	140.8%	113.0%

Based on ERI Economic Research Institute's Geographic Assessor as of July 1, 2019.

For example, Manhattan is 116.9% higher in cost of living and 23.0% higher in the cost of labor than Atlanta, Georgia. Cost of living increases are typically based on increases in the Consumer Price Index ("CPI") for a geographic location.

Q. What is the difference between cost of labor and inflation?

A. Cost of labor is what a particular geographic market offers as the "going rate" or compensation for its jobs. Inflation is a measure of the rate of rising prices of goods and services in an economy. One of the most commonly used inflation indexes is the CPI.

Q. Why does the Company use separate rates to project labor and non-labor expenses?

A. Labor rates and inflation rates can change based on different factors or influences and at different rates. Labor rates follow what companies are doing to stay competitive, inflation follows economic trends which can be unrelated to how people are paid. For example, a low supply in the housing market may increase the CPI used for determining inflation but could have no impact to the cost of labor. Therefore, using rates that align with the type of expense, as the Company does to project O&M labor expenses, is a more accurate method than using a single inflation rate. Consumers Energy's compensation is designed to be competitive with what is seen in the labor market including rewarding and motivating talent rather than trying to keep up with inflation. A 2011 WorldatWork Article entitled "What to Consider When Setting your Merit Budget" stated:

> One factor you shouldn't include in your decision framework is the CPI. The rate of inflation may be interesting or even concerning, but it shouldn't influence your merit budget decision.

WorldatWork is the leading global nonprofit organization for professionals. I agree with their conclusion.

Q. Upon what factors are merit increases based?

A. Merit increases are based on the cost of labor and reflect the external labor market based on what other companies plan for their annual pay increases.

Q. How do customers benefit from the use of separate rates to project labor and non-labor costs?

A. 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 compensation linked to labor rate changes could result in Consumers Energy's employee compensation being below market, which could hinder the Company's ability to attract and retain a qualified workforce.

Q. What is the projected rate for cost of labor increases used in this case?

A. The assumed rate of labor used to project O&M labor expense is 3.2%, which applies a projected salary increase of the same percent. The increase of 3.2% is consistent with the Company's planned merit budget, hence it is not actually an inflation-based increase. The labor rate is derived from independent third-party survey sources. See Confidential Exhibits A-38 (AMC-4) through A-41 (AMC-7) for survey data from PayFactor, WorldatWorld, Mercer, and Willis Towers Watson.

Merit increases illustrated in Confidential Exhibits A-38 (AMC-4) to A-41 (AMC-7) are associated with projected average or median salary increases depending on the survey source. The rate does not include increases with respect to promotions. The Company currently does not include promotional pay increases in its revenue request. Other factors that influence the cost of labor would be included in the “other adjustment” column of Summary of O&M Expenses Projected Using Merit and Inflation Exhibits A-37 (AMC-3) for each O&M witness, if applicable.

Q. Does the Company control its labor costs?

A. The Company sets it merit budget; however, this merit budget is determined by what is occurring in the labor market based on independent salary survey data. The cost of labor needs to remain competitive to attract and retain qualified talent to deliver to customers. Besides the merit increase data illustrated in Confidential Exhibits A-38 (AMC-4) to A-41 (AMC-7), the Department of Labor provides data on wage increases. Below is a table shown in the June 29, 2020 Bureau of Labor and Statistics report titled “County Employment and Wages in Michigan — Fourth Quarter 2019.”

Table 1. Covered employment and wages in the United States and the 10 largest counties in Michigan, fourth quarter 2019

Area	Employment			Average weekly wage (1)			
	December 2019 (thousands)	Percent change, December 2018-19 (2)	National ranking by percent change (3)	Average weekly wage	National ranking by level (3)	Percent change, fourth quarter 2018-19 (2)	National ranking by percent change (3)
United States (4)	149,857.1	1.2	--	$1,185	--	3.5	--
Michigan	4,385.3	0.4	--	1,115	18	3.4	22
Genesee	139.0	0.9	184	987	245	7.5	10
Ingham	155.6	0.9	184	1,126	131	4.6	60
Kalamazoo	121.5	-0.6	322	1,052	186	0.8	336
Kent	414.0	0.4	241	1,026	207	3.7	133
Macomb	334.1	0.7	204	1,147	118	3.2	181
Oakland	753.0	-0.1	295	1,311	53	3.6	140
Ottawa	128.6	1.1	160	1,002	228	1.7	304
Saginaw	84.9	-0.4	305	943	287	2.4	255
Washtenaw	224.0	1.4	132	1,204	82	2.6	234
Wayne	746.1	0.7	204	1,264	64	4.1	98

Footnotes:
(1) Average weekly wages were calculated using unrounded data.
(2) Percent changes were computed from quarterly employment and pay data adjusted for noneconomic county reclassifications.
(3) Ranking does not include data for Puerto Rico or the Virgin Islands.
(4) Totals for the United States do not include data for Puerto Rico or the Virgin Islands.
Note: Data are preliminary. Includes workers covered by Unemployment Insurance (UI) and Unemployment Compensation for Federal Employees (UCFE) programs.

Source: County Employment and Wages in Michigan — Fourth Quarter 2019 : Midwest Information Office : U.S. Bureau of Labor Statistics (bls.gov)

The table shows that when you compare the 4th quarter 2018 to 2019 the average weekly wage increased 3.4% in the state of Michigan and 3.5% in the United States. This is also evidence of the cost of labor not directly corelated to the rate of inflation.

Further, compensation advisory firm Empsight's August 2020 Policies, Practices & Merit Survey Report analyzes results from a survey of 248 large U.S. companies, which asked participants to forecast their merit increase budget for 2021. The table below illustrates the results of the survey.

Forecasted Merit Increase Budget for 2021
(includes companies planning no merit budget increase for next year)

	Mean	25th Percentile	Median	75th Percentile
Overall Forecasted Merit Increase Budget	2.66%	2.50%	3.00%	3.00%
Executive	2.49%	2.44%	3.00%	3.00%
Management	2.66%	2.50%	3.00%	3.00%
Professionals	2.67%	2.50%	3.00%	3.00%
Support / Nonexempt	2.62%	2.50%	3.00%	3.00%

Source: Empsight, *Policies, Practices & Merit Survey Report*, August 2020.

V. 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 $3.9 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 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. Since the total level of compensation – including both base pay and incentive pay – is market based, competitive, and reasonable, incentive pay expense is justified and recoverable. Customers do not pay more than the reasonable level of market-based compensation.

Q. Please summarize reasons that a labor rate should be allowed in this case for projecting O&M Labor Rate.

A. The reason that a labor factor should be used for projecting O&M labor rate is that a labor factor best aligns with the type of expense. The labor rate used by Consumers Energy for projecting O&M labor costs is based on independent survey data on expected salary or labor cost increase. The Company's cost of labor needs to remain competitive to attract and retain qualified talent.

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-21148

DIRECT TESTIMONY

OF

AUDRA L. CUMBERWORTH

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

Q. Please state your name and business address.

A. My name is Audra L. Cumberworth, and my business address is One Energy Plaza, Jackson, MI 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. My current position title is Technology Director with responsibility for leading the Program Management Team in the Company's Security organization.

Q. Please state your educational background.

A. I hold a Bachelor of Science Degree from Eastern Michigan University with a double major in Psychology and Communications. Additionally, I am currently Project Management Institute certified in good standing since 2004.

Q. Please state your work experience and current responsibilities.

A. I have over 25 years of expertise in leadership, Project Management Office development and management with hands-on experience in Proposal, Vendor, Project, Program and Portfolio Management. I spent the first 12 years of my career working for a large IT consulting firm supporting a multitude of industries spanning the globe, including: insurance, automotive, manufacturing, gas and oil, state and local government, healthcare, and higher education.

The latter half of my career has been spent at the Company taking on various roles with increasing responsibilities. I started out managing projects as part of the Smart Energy implementation, I then moved into a leadership role in the IT Project Management Office where I supervised a large team of employees and contractors, finally landing in my current role six years ago as a leader in the Security Organization. In this role I have responsibility for the Company's Privacy Program, Security Risk Management, Security Project Management, Security Awareness, and Security Quality Assurance. As a member of the Security Organization's leadership team, I participate in the development of Security visioning, strategy, and goal setting.

Q. What is your regulatory experience?

A. Throughout my career, I have had responsibility for implementing regulatory mandates and providing governance and oversight of the ongoing adherence to regulatory mandates. In my current role, I have participated in gathering data and developing documentation to support rate case testimony. I have also participated in Security annual review meetings with the Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff").

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

A. The purpose of my direct testimony is to describe the Security Department's Operating and Maintenance ("O&M") expenses and capital expenditures needed to maintain existing security systems and enable future capabilities. In addition, this direct testimony provides an overview of threats that are increasing in both Cyber Security and Physical Security spaces and how they have evolved over time. This evolution, coupled with a changing regulatory landscape, leads to a required need for increased staffing and O&M funding. These increases are needed to support 24 hour a day and seven days a week ("24/7") security monitoring through the Fusion Center, a move to increased cloud computing solutions, and a pressing need to continue to mature security capabilities, and to protect the Company's technology and physical infrastructure.

Furthermore, my direct testimony provides an explanation of the Security Department's plans for deterring threats prior to impacting the Company and the customers the Company serves, detecting when malicious activity does occur, and recovering quickly with minimal impact while complying with all regulations.

Q. What Exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

Exhibit A-12 (ALC-1)	Schedule B-5.2	Summary of Actual & Projected Gas and Common Capital Expenditures;
Exhibit A-42 (ALC-2)		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 2020, 2021, 2022, and 2023;
Exhibit A-43 (ALC-3)		Summary of Actual and Projected Security Operations O&M Expenses for the years 2020, 2021, 2022 and Test Year 12 Months Ending September 30, 2023; and
Exhibit A-44 (ALC-4)		Summary of Actual and Projected Security Investments O&M Expenses and Summary of O&M Expenses Projected Using Inflation.

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

A. Yes.

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

Q. Please provide an overview of the utility's Security Department.

A. The Company's Security Department's purpose is defined in four simple words: Deter, Detect, Recover, and Comply. Fundamentally, the organization exists to: deter threats prior to impacting the Company, detect when malicious activity does occur, recover quickly with minimal impact when impacted, and comply with all regulations. The Security Department achieves its purpose by focusing on specific areas that can be thought of as the midpoint between strategic and tactical items. Security sets standards based on external threats and guides security work required by the Information and Operational Technology teams.

To achieve our purpose, the Security Department is made up of five key teams that include Compliance, Corporate Security, Engineering, Program Management, and Fusion Center. Compliance ensures all security related rules and regulations are followed. This includes Commission rules, industry regulations, executive orders, state and federal laws. Corporate Security provides physical security services to the enterprise including: perimeter protection, guards, card access, cameras, executive protection, and investigative services. Engineering designs and deploys new security technology, ensures Company projects meet enterprise security standards and conducts vulnerability assessments and penetration tests to find relevant system vulnerabilities. Program Management provides enterprise security awareness, quality assurance, project, program, and financial management, as well as risk management and privacy program services. The Fusion Center is a 24/7 combined cyber and physical operations center responsible for all security monitoring, operational support, identity and access management, event detection, and incident response.

Part of the Company's funding request in this case is to formally staff the Security Department's Fusion Center team. The core functions of this new team are to prevent the impact to the Company's business and customers by delivering actionable intelligence and responding to the right events in the right way through a dedicated 24/7 team. This team combines the domains of physical and cyber security monitoring, security/identity operations, and cyber security incident response into one organization in order to streamline the detection, response, and resolution processes so the Security Department can better meet the Company's operational and security needs.

Investing in the maturation of the Security Department's capabilities, providing 24/7 security monitoring, and improving on the ability to secure the Company's critical assets benefits not only the Company, but also the Company's customers. Customers experience the benefit in knowing that the Company has invested to ensure their data is safe and secure, their privacy is protected, and they can count on the Company to secure both critical technology assets as well as critical infrastructure assets in order to serve them.

Managing security risks and combatting associated threats requires a robust, dedicated security program focusing on people, process, and technology. Security can no longer be thought of as simply an operational (physical) or technology (cyber) issue, but an enterprise risk worthy of specialization and focus.

Q. Please provide an overview of the Security challenges utilities face.

A. 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 grid resources become more distributed. Cyber security concerns include privacy, data breaches, ransomware, and critical infrastructure attacks. A 2019 research study by Protiviti named cyber security in the top 5 risks for the energy and utility sectors.[1] While cyber security is no longer a new area, each year, impacts from cyber security incidents increase. There is no better example

[1] https://www.protiviti.com/US-en/insights/top-risks-2019-energy-and-utilities

than that of the ransomware attacks which occurred in 2020. Ransomware is not a new issue, but 2020 saw a significant escalation in ransom payments as attackers became more sophisticated and targeted larger organizations, including Fortune 500 companies. Ransomware incidents have seen a seven-fold increase in 2020 reaching demand costs over $1.4 billion dollars, according to ITSECURITY WIRE, a leading cyber security knowledge sharing platform.

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

A. Cyber threats are increasing. The most glaring example is ransomware, as addressed 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 that they now conduct cyber-attacks 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. Certain industry sources estimate that the average ransomware payment climbed 82% since 2020.[2]

The Kaseya Virtual System Administrator ("VSA") ransomware event shows the increase in sophistication. A zero-day vulnerability (one where no patch is available and previously unknown) was used to compromise a remote access software vendor, Kaseya VSA, and, ultimately, hundreds of its clients. Zero-day vulnerabilities have historically been capabilities reserved to nation state actors, not criminal groups. The amount of money being made has allowed these groups to invest in finding such vulnerabilities and dramatically increasing their capabilities. Consumers Energy alone receives about one

[2] https://www.paloaltonetworks.com/blog/2021/08/ransomware-crisis/

thousand unique ransomware attacks each month. This volume illustrates why a robust security program is necessary with various layers of defense. No single tool, person, or process can be right 100% of the time, therefore the Company must rely on multiple lines of defense to meet these challenges.

Beyond ransomware, it is clear that 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 recently released a memo titled "National Security Memorandum on Improving Cyber Security for Critical Infrastructure Control Systems" ("National Security Memo").[3] The implications of the National Security Memo are clear.

First, the threat to critical infrastructure is real and no longer theoretical, as seen with the Colonial Pipeline incident. Even Consumers Energy has seen intrusion attempts from nation state level actors. The National Security Memo further 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 could cause significant harm to the national and economic security of the United States."[4] Utilities have had strong cyber security programs and Consumers Energy is no different. However, in stating cyber security of critical infrastructure as a national

[3-5] https://www.whitehouse.gov/briefing-room/statements-releases/2021/07/28/national-security-memorandum-on-improving-cybersecurity-for-critical-infrastructure-control-systems/

security issue, the Biden Administration is asserting that the Company, as an owner of critical infrastructure, needs to meet a much higher standard moving forward. The National Security Memo implies that we need to have capabilities like that of the top government agencies and contractors. This increased expectation will take time to develop and increased funding to achieve.

Third, the Biden Administration has called for "performance-based metrics for cyber security"[5] to be developed over the next year. This 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 gas, as well as additional requirements in electric.

Ultimately, the issues of ransomware and attacks against United States critical infrastructure converged in June 2021 when the Colonial Pipeline was shut down for five days after a ransomware attack. This is the first publicly disclosed, successful cyber-attack impacting critical infrastructure in the United States. This event has changed the security environment forever and expectations have adjusted accordingly. For instance, the Transportation Security Administration ("TSA") has released two security directives requiring immediate actions from gas owners and operators. The latter requiring numerous security controls be implemented in very aggressive timeframes.

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 of 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 incidents where attempts are made to tamper with gas assets. In addition, Consumers Energy has seen incidents that could have had similar impacts. 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 been thousands of customers without gas and over 10 million dollars in costs to repair.

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 are straightforward and 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. Consider a substation, city gate, or critical valve with thousands of sites to protect, each with a relatively small footprint. The human resources to place guards would be untenable from a cost perspective. Technology solutions have historically been challenging because of limited feature sets and network capacity at many of these remote locations. These limitations have meant most utilities have implemented basic physical protections and have accepted some level of risk. Responses to security issues in these environments are, therefore, reactive and have become insufficient. These factors have made these assets, while critical, 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 an outage, safety, and cost perspective.

For assets such as city gates the Company needs proactive solutions that can detect, in real time, when someone is inside an asset that should not be there, watch them, and verbally communicate with them in real-time. Consider the previously described incident at a city gate where a Company-owned excavator was stolen. The individual then used an excavator to dig dangerously close to gas lines. The individual and Company were very fortunate that nothing happened as a result, however, if the Company had the ability to communicate in real time directly with the individual the Company could have warned the individual of the dangers and possibly could have prevented the excavator from digging near the gas lines. Based upon recent pilot testing of solutions, there are now technology options capable of meeting these objectives. Also, where more traditional locks are the only practical option for items such as a critical valve, the Company needs appropriate key management and locks made of materials that cannot readily be cut. These more proactive approaches will allow the Company to better protect its assets, increase safety, and reduce costs to customers.

Q. What is changing in the regulatory landscape requiring more funding?

A. Specific to gas, the regulatory landscape is changing significantly. Gas pipelines are regulated by the Department of Transportation through the TSA. The TSA has a set of cyber and physical security guidelines with which operators are expected to comply. These guidelines must be applied to gas facilities based upon their defined criticality. Based upon the TSA's directive to the gas utility industry, Consumers Energy went through a classification exercise and has determined four additional sites must now meet the definition of critical and therefore require enhanced security upgrades as defined by the TSA. This will double the Company's number of critical facilities requiring enhanced physical security controls. The total cost of these upgrades is $2 million in 2022 and $2 million in 2023 as detailed in the business case titled "12443 TSA Critical Facility Structure." Additional information on this investment can be found in the investment capital and O&M expenditures section of this testimony. Also based on the criticality study, there are approximately 1000 city gates, regulator stations, and other gas infrastructure sites that fall into the class 3 criticality that will need to have enhanced security controls in place within the next five years (albeit, not at the same level/cost as the four sites that the Company is updating through 2023). The TSA continues to update guidance on criticality and more regulation of these sites can be expected.

In addition, as a result of the Colonial Pipeline cyber security incident, the TSA has released two directives requiring immediate action from gas asset owners. The directives require a significant number of additional security controls and processes be implemented in a very short timeframe in both the Company's corporate and operational networks.

At the state level, the MPSC has required implementation of the American Petroleum Institute's 1164 standard version 2. This multi-year implementation started in 2020 and will conclude in 2023.

Beyond the immediate items above, the industry is expecting additional mandatory cyber security standards for gas, a form of national reporting requirements for cyber security incidents and national privacy legislation in the next 12 months.

Q. How does the request for increased O&M (Operational and Investment) funding benchmark in the industry?

A. Determining the right level of investment in cyber security can be challenging. The lack of robust data, metrics, and consistency in spending create challenges in benchmarking peers. The question is not often "are we spending too much?", but more likely stakeholders such as board members, executives, legislators, and regulators are wondering "are we spending enough?".

By any measure available, Consumers Energy's current spending level on cyber security is among the lowest in the industry. Consumers Energy is a member of a utility consortium that benchmarks security costs per user account. Consumers Energy has one of the lowest costs per user. Another measure discussed in assessing cyber security spend is the percentage of Information Technology ("IT") budget spent on security, for which Consumers Energy historically lands in the 10% range. A 2019 report by Forrester (a leading global technology market research company) titled "Security Budgets 2019: The Year of Services Arrives"[6] breaks down security spending of larger companies as a percentage of IT spend. Utility and telecommunication companies were grouped together and resulted in the following results: 18% of companies spent between 0-10% on security, 38% spent 11-20% on security, 32% spent between 21-30% on security, and 12% were marked as "other." This demonstrates that *82% of companies, in the sector, are spending more on security than Consumers Energy.* This survey is of note because it is focused on similarly sized companies. Smaller, significantly less complex companies certainly do spend less on security.

[6] https://www.forrester.com/report/Security-Budgets-2019-The-Year-Of-Services-Arrives/RES141372

If the Company's request is approved in full in this case, the Consumers Energy Security Department's cyber security spending would be 14% of the IT spend in the test year. While this is a 4% growth from the Company's historical spend on security, this puts the Company's security spend just below the mid-point of peer utilities.

Q. What value will customers receive for the projected test year expenditures?

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 for the purposes intended. The discipline which addresses these concerns is broadly referred to as privacy which is also in scope for the Consumers Energy Security 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 such as during a gas leak. An attack against the Company's operational systems could lead to a loss of electricity or gas service for large portions of the service territory. Interruption of gas or electric service due to a cyber-attack is not acceptable and customers expect the utility to have all the protections necessary to ensure this does not occur.

SECURITY DEPARTMENT OPERATIONS O&M EXPENSES

Q. Please explain Security Department Operational O&M Expenses.

A. The Company uses Operations O&M expense to provide the required level of operational support for both physical and cyber security, maintenance for security facilities and systems to ensure system reliability, vulnerability assessments and penetration tests, and fulfillment of all state and federal laws/regulatory mandates/rules perimeter protection, guards, card access, cameras, executive protection, and investigative services. Operations expenses include fixed and variable ongoing costs. Fixed costs include software vendor maintenance agreements, cloud subscription contracts, annual license contracts, and technology 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, 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/rules/requirements, and additional security system improvements. The activities associated with the fixed and variable costs are required to keep the Company's physical and information assets protected and performing at sufficient levels. The Company's customers continue to benefit from the physical and cyber security activities provided by the Security Department's O&M expense. Any gap in the recovery of Operations O&M cannot be recovered in future rate case filings, which is why any disallowance is so impactful to the Company's ability to maintain and secure its facilities and systems.

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

A. There is a variety of operational work required to keep physical and information assets protected from security threats aside from fulfilling emerging regulatory requirements. First, regarding physical assets and employee safety, routine assessments must be performed on all assets/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/forums. Third, additional security guard support is needed at facilities on an adhoc basis to ensure the safety of employees and any visitors to the Company's facilities.

Regarding information assets, security tools must be kept functional on all relevant systems, including software to collect logs, look for vulnerabilities, detect intrusions, and provide antivirus and encryption services. Second, vendors regularly release security updates that then must be tested to ensure these updates do not introduce negative impacts to Company-specific configurations, and then deployed to associated information assets. Third, as cyber security best practices change, the security teams must make changes to existing security systems to meet new security requirements. These requirements evolve and adapt as threats change in our environment. On average, Security publishes six new standards and updates another six each year, which increases operational costs while continuing to best protect Company assets.

Q. Please explain the Operational O&M expenses shown on Exhibit A-43 (ALC-3).

A. Exhibit A-43 (ALC-3) is a Summary of Actual and Project Security Operations O&M Expenses for the years 2020, 2021, 2022, and 12 months ending September 30, 2023. Page 1 provides a summary of the gas allocation of actual and projected Security Department operational expenses. Specifically:

- Column (a) provides the Operations and O&M Expense Category;
- Column (b) identifies the 2020 Historical Operations O&M expense as $2,858,000;
- Column (c) identifies the 2021 projected Operations O&M expense as $3,600,000;
- Column (d) identifies the 2022 projected Operations O&M expense as $4,714,000;
- Column (e) identifies the 3 months ending December 31, 2022 projected Operations O&M expense as $1,178,000;
- Column (f) identifies the 9 months ending December 31, 2022 projected Operations O&M expense as $3,819,000;
- Column (g) identifies the 12 month Test Year projected Operations O&M expense as $4,998,000;
- Column (h) identifies the 12 months ending December 31, 2023 projected Operations O&M expense as $5,093,000; and
- "Labor" line items include employee labor, and "contracts" line items include hardware and software licenses and maintenance, staff augmentation, the Company's managed services contract, and other contracted services.

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

- Column (a) is a description of the categorical expense;
- Column (b) provides the historical O&M expense;

- Column (c) provides the historical amount to which an inflation rate or merit increase rate were applied for each bridge period, respectively;
- Column (e) and (g) provide the amounts to which an inflation rate or merit increase rate was applied to;
- Column (d), (f), and (h) provide the merit and inflation increases for each respective period;
- 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 indicated in Exhibit A-43 (ALC-3), page 2.

A. Security does not apply inflation in all categorical spend projections for Operations O&M expense. Merit increases are the primary method for labor projections; however, the projection is adjusted by $422,000 for anticipated increases in headcount. Inflation is not used to project any other categorical spend projections for Operations O&M expense. Future contract expenses are projected based on annual increases for current commitments for contract expenses and the addition of new contracts as a result of ongoing and new project implementations before or during the test year period. Contracts is projected based on historical spend, known annual increases and expected new contracts. Business Expense is projected based on historical spend and known adjustments for employee training needs, wireless plans, and supplies. The other adjustments for material include projected decreases due to efficiencies gained from a new virtual working environment and revised business practices implemented as a result of the COVID-19 pandemic that are expected to continue into 2022 and 2023.

Q. Please describe the projected Security Department Operations O&M expense for 2022 and 2023.

A. The 2022 projected Operations O&M expense is $4,714,000; the 3 months ending December 31, 2022 projected Operations O&M expense is $1,178,000; the 9 months ending December 31, 2022 projected Operations O&M expense is $3,819,000; the 12 months Test Year projected Operations O&M expense is $4,998,000; and the 12 months ending December 31st, 2023 projected Operations O&M expense is $5,093,000. As explained in more detail below, the drivers increasing Security Department Operations O&M expense is the Company's move to 24/7 cyber security monitoring, labor increases spread across other multiple areas of the Security Department teams, a move to more cloud/Software as a Service ("SaaS") based security products, and third-party assessments and consultants.

Q. Please explain why the Company needs 24/7 security coverage.

A. Cyber-attacks have evolved significantly in recent years with regard to their speed to execution. Historically, an attacker would have been in an environment for weeks to months in order to execute a large-scale data breach. Given that, the Company felt confident in its ability to detect and respond to such attacks using a traditional workday coverage model. Ransomware has completely changed this model. Ransomware attacks are being fully executed, from initial access to full environment encryption, in hours. Industry sources suggest that "the speed of ransomware groups is also startling, with 56% saying ransomware actors managed to take over their data and send a ransom demand in under 12 hours."[7] In addition, according to FireEye, "27% of ransomware attacks take

[7] They Come in the Night: Ransomware Deployment Trends | Mandiant

place on the weekend and 49% take place after hours during the week."[8] The pace at which ransomware executes coupled with the criticality of the services the Company provides to its customers (life safety services such as gas leaks and downed wires) necessitates an investment beyond the current operational model. The Company must have staff monitoring and responding 24/7. In addition, 24/7 coverage is the standard for the utility industry. After benchmarking across industry peers, the Company found all had moved to 24/7 cyber security monitoring. While there is a cost to move to 24/7 cyber monitoring, the Company is combining both physical and cyber monitoring into a single function in order to be most cost effective. This single function is the Fusion Center, which was initially included in a previous electric rate case filing (2018 Electric Rate Case, Case No. U-20134). The previous filing request was for purchasing and building out the Fusion Center facility and technology where this filing focuses on staffing it and maturing the capabilities within.

Q. Please explain the additional labor-related increases you are requesting as part of this filing?

A. A large portion of the O&M labor increase sought in this case is spread across multiple other areas of the Security Department teams. The remaining amount is focused solely on 24/7 monitoring, as explained above. There are multiple reasons for this labor increase. First, the Company will need more compliance staff to manage numerous new regulatory requirements. Second, the Company has reached a point where resources to implement cyber security capabilities is its single most limiting factor and, therefore, will be increasing its engineering teams accordingly. For example, the Company has a backlog of

[8] https://www.zdnet.com/article/most-ransomware-attacks-take-place-during-the-night-or-the-weekend/

approximately 50 security enhancements ready to be implemented which are only waiting on resourcing. Third, in order to maintain a proactive security posture, the Company needs additional staff to develop new capabilities within the Security Department around threat intelligence, threat hunting, and insider threat. Finally, some incremental costs are necessary to continue maturing existing areas such as third-party risk management and privacy.

Q. Please explain why the Company is proposing to use more cloud/SaaS based security products?

A. Cloud/SaaS based offerings are often the only option for certain security 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 IT 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.

SECURITY DEPARTMENT INVESTMENTS O&M EXPENSES

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

A. Investments O&M is used by the Company to fund the O&M portion of security technology upgrade projects, asset refresh projects, and technology investments to provide new capabilities for internal security operations in order to protect the Company's assets, employees, and customers. The O&M portion of upgrade projects makes up activities that, according to Federal Energy Regulatory Commission ("FERC") accounting rules, cannot be categorized as capital work.

Q. Please describe the importance of upgrading Security systems for operational stability and mitigation of security vulnerabilities.

A. Upgrading security devices such as cameras, card readers, in addition to applications, appliances, and operating systems, is essential to delivering safe, reliable, and affordable service to the Company's customers. New versions of technology and software upgrades enable the Company to maintain vendor support, remediate security vulnerabilities, address defects that impair stability and functionality, and address version interdependencies and compatibility between systems.

Q. What could happen if the Company did not keep its security devices and systems upgraded?

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

Q. Please explain Exhibit A-44 (ALC-4).

A. Exhibit A-44 (ALC-4) is a Summary of Actual and Projected Security Investments O&M expenses for the years 2020, 2021, 2022, and 12 months ending September 30, 2023. Page 1 provides a summary of the gas allocation of actual and projected Security Department Investments O&M Expenses. Specifically:

- Column (a) provides the Investments O&M expense category;
- Column (b) identifies the 2020 historical O&M expense as $395,000;
- Column (c) identifies the 2021 projected investments O&M expense as $816,000;
- Column (d) identifies the 2022 projected investments O&M expense as $647,000;
- Column (e) identifies the 3 months ending December 31, 2022 projected investments O&M expense as $162,000;
- Column (f) identifies the 9 months ending September 30, 2023 projected Investments O&M expense as $470,000;

- Column (g) identified the Test Year projected Investments O&M expense as $631,000;
- Column (h) identifies the 12 Months ending December 31, 2023 projected Investments O&M expense as $626,000;
- For Investment 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 investment 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, and "Overhead and Others" line items include overheads and business expenses.

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

- Column (a) is a description of the categorical expense;
- Column (b) provides the historical Investment O&M expense;
- Column (c) provides the historical amount to which inflation rate or merits increase was applied;
- Columns (e) and (g) provide the amounts to which an inflation rate or merit increase rate was applied for each bridge period, respectively;
- Columns (d), (f), and (h) provide the merit and inflation increases for each respective period;
- 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-44 (ALC-4), page 2.

A. Security does not apply inflation for categorical spend projections for Investments Planning expense. The investments planning projection is adjusted by $70,000 for anticipated increases in the test year for investments planning activities that directly support business case development and cost estimate refinement for projects that support the Company's Security Departments purpose 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 are based solely on expected project costs for the test year as compared to the historical period, as detailed in Exhibit A-42 (ALC-2)

SECURITY DEPARTMENT INVESTMENTS CAPITAL EXPENDITURES

Q. Please explain the capital expenditures shown on Exhibit A-12 (ALC-1), Schedule B-5.2.

A. Exhibit A-12 (ALC-1), Schedule B-5.2 identifies the gas allocation summary of projected capital expenditures to procure, install, and implement the software and infrastructure described in this testimony to fulfill the Company's Security Department purpose to Deter, Detect, Comply, and Recover. Specifically,

- Column (a) (pages 1 and 2) provides the program designation for the capital expenditures, using programs that have been used historically to categorize Security Department projects:
    - Enhancements; and
    - Security;
- Page 1 provides historical and projected capital expenditures as follows:
    - Column (b) identifies the 2020 historical capital expenditures as $2,912,328;
    - Column (c) identifies the 2021 projected bridge year capital expenditures as $5,113,233;
    - Column (d) identifies the 9 months ending September 30, 2022 projected bridge year capital expenditures as $4,963,716;
    - Column (e) identifies the 21 months ending September 30, 2022 projected bridge year capital expenditures as $10,076,948; and

  - Column (f) identifies the 12 months ending September 30, 2023 projected test year capital expenditures as $6,171,772;

- Page 2 provides projected capital expenditures as follows:
  - Column (b) identifies the 9 months ending September 30, 2021 capital expenditures as $1,890,517;
  - Column (c) identifies the 12 months ending September 30, 2022 capital expenditures as $8,186,432;
  - Column (d) identifies the 12 months ending September 30, 2022 capital expenditures as $6,171,772; and
  - Column (e) identifies the 33 months ending September 30, 2022 capital expenditures as $16,248,720.

Q. Please explain Exhibit A-42 (ALC-2).

A. Exhibit A-42 (ALC-2) identifies the gas allocation of projected capital and O&M expenditures to procure, install, and implement software and infrastructure requested in this testimony to meet the Company's Security Department's purpose. 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 Security 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 program category;
- Column (d) identifies the FERC category relative to the line item project's asset type;
- 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 implementation date;
- Column (g) provides the project's cost/benefit ratio;

- Column (h) provides the project's gas portion total capital expenditure for the applicable year;
- Columns (i) through (m) provides the details of the categorical spend that sum to the total line item Project capital Spend for the applicable year broken down by:
    - Software costs (i);
    - Material costs (j);
    - Labor Costs (k);
    - Contractors costs (l); and
    - Overhead and other costs (m);
- Column (n) provides the project's gas portion total O&M spend for the applicable year; and
- Columns (o) through (s) provide the details of the categorical spend that sum to the total line item Project O&M Spend for the applicable year by the following categories:
    - Software costs (o);
    - Material Costs (p);
    - Labor Costs (q);
    - Contractor costs (r); and
    - Overhead and other costs (s).

DESCRIPTION OF INVESTMENT PROJECTS

Q. Please provide a description of the various Security Department investment project areas.

A. Costs, descriptions, alternatives, and other relevant project information for each individual project can be found in Exhibit A-42 (ALC-2). The Security Department investment projects are grouped into the following areas for explanation in testimony:

- Regulatory Compliance projects ensure that Consumers Energy achieves full compliance with all federal and state regulatory requirements. Whenever a new regulatory construct emerges, the Company endeavors to meet requirements with existing solutions, however that is not always possible, and investment may be required;

- Physical Security projects include physical deterrence, detection of intruders, and responding to those threats. It also includes real time visibility that allows the Security team to be proactive instead of reactive. Projects are also meant to mitigate interruptions to Company operations. This applies to keeping people, whether external actors or potential insider threats, from accessing areas or assets they should not access;

- Cyber Security projects implement technologies required for security controls or capabilities. These technologies are aimed at deterring, detecting, and responding to cyber-attacks; and

- Annual Program projects aim to maintain and improve upon past investments Security has made. These programs are detailed into three specific areas which include: (1) Asset Refresh, (2) Application Currency, and (3) Enhancements.

Q. Please explain the capital expenditures and O&M expenses enabling regulatory compliance.

A. The summary table below defines security investment projects with direct ties to achieving regulatory compliance. Following the table, a problem statement for each investment with its value is included. Cost, descriptions, benefits, alternatives, and other relevant project information can be found in Exhibit A-42 (ALC-2).

Investment	Test Year Capital	Test Year O&M
Pipeline Scada Security	$1,072,250	$125,500
TSA Critical Facility Structure	$2,500,000	$24,000

The Pipeline Scada Security project was chartered because the MPSC requires the implementation of pipeline cyber security regulations pursuant to American Petroleum Institute (“API”) 1164 on the Company’s gas pipeline system. The Company’s distributed gas Supervisory Control and Data Acquisition (“SCADA”) systems are outdated and non-standardized, requiring significant modifications to be compliant with API 1164. Without the technology updates, the gas SCADA system is vulnerable to cyber-attacks that potentially risk disrupting delivery to customers. Interruptions in gas delivery and non-compliance to API 1164 mandated requirements could be subject to fines and penalties from the MPSC and other regulatory entities (i.e., the TSA). This project will add value to the Company by: (1) modernizing and standardizing the gas SCADA network at the Company's gas compressor stations and control rooms; (2) mitigating cyber security vulnerabilities in the gas SCADA network; (3) allowing the Company to fully comply with API 1164 requirements; and (4) fulfilling the commitment to the MPSC to provide a secure gas system that meets customer needs.

The second project enabling regulatory compliance is the TSA Critical Facility Structure project and is planned to start during the bridge period. This was an emergent regulatory request since the Company's last gas rate case filing. Pipeline facilities that are deemed critical are required to apply enhanced security measures. Today, Consumers Energy 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 assets that were not previously subject to evaluation will now fall into scope. As the Company continues to analyze the remainder of it gas assets, the Company believes an additional 1000 pipeline facilities (pipeline interconnections, metering and/or regulating stations, pump stations, compressor stations, operational control facilities, main line valve, tank farms, and terminals, etc.) may be deemed critical. Consumers Energy will be taking a phased implementation approach and will begin the process by implementing the enhanced security measures at the remainder of its compressor stations. Failure to update sites will put the Company out of compliance with the updated guidelines. The objective of the project is to implement enhanced security measures outlined by the TSA for the following four critical assets: (1)

Freedom Compressor, (2) Muskegon River Compressor, (3) Overisel Compressor, and (4) Northville Compressor. This project will bring these locations up to enhanced status, avoid non-compliance, and increase the security and reliability of gas delivery to customers while also meeting federal requirements.

Q. Please explain the capital expenditures and O&M expenses enabling regulatory compliance occurring in the bridge period.

A. The investments enabling regulatory compliance occurring in the bridge period can be found in Exhibit A-42 (ALC-2).

Q. Please explain the capital expenditures and O&M expenses enabling physical security.

A. The summary table below defines security investment projects with direct ties to enabling physical security. Following the table, a problem statement for each investment with its value is included. Cost, descriptions, benefits, alternatives, and other relevant project information can be found in Exhibit A-42 (ALC-2).

Investment	Test Year Capital	Test Year O&M
Radar Intrusion Detection	$597,109	$36,000
Lock and key Management System	$300,925	$56,880

The Company is asking for funding in Radar Intrusion Detection solutions as the Company currently lacks the ability to detect potential intruders at Company sites across the state, including critical infrastructure sites such as city gates, compressor stations, sub stations, generation plants, and hydro sites. Currently, three sites have flawed fence intrusion detection technology that result in the recurrence of multiple false alarms and require an employee to investigate. Additionally, the current detection technology is unable to identify the difference between animals and humans, cannot set different boundaries, and prohibits the expansion of intrusion detection at many other critical sites. Any investigation that has to be done is hampered by the limitations of the current system, requiring manual frame by frame review of video playback, which is manually intensive and time consuming. Completion of this project will provide value to the Company through evaluating and selecting a more reliable intrusion detection solution that reduces the number of false alarms and prevents resources from being sent to a site for unnecessary investigations. Additionally, the project will improve the efficiency of investigations by reducing the amount of time it takes to review playback to develop a suspect or investigative lead. In most cases this will be eliminated completely.

The Lock and Key Management project will implement a technology to provide a comprehensive management tool. Current estimates show there are approximately 12,000 locks throughout the state, and the Company does not have a system to properly manage ownership of the associated physical keys or control over who uses the keys. Locks are not unique in nature and can be easily duplicated. The current lock and key system allows for 24-hour site access without having the ability to limit outside contractor access. Lack of key control makes facilities, specifically in Gas operations, vulnerable to accidental or intentional adjustment of valves which could cause large scale outages. Completion of this project will provide value to the Company by: (1) providing an extra layer of protection which is the first defense against criminal acts; (2) determining core functionalities needed to ensure proper lock and key management state-wide; and (3) implementing a smart lock and key solution that will provide the physical security team remote deactivation capabilities and is easily audited.

Q. Please explain the capital expenditures and O&M expenses enabling physical security occurring in the bridge period.

A. The investments enabling physical security occurring in the bridge period can be found in Exhibit A-42 (ALC-2).

Q. Please explain the capital expenditures and O&M expenses enabling cyber security.

A. The summary table below defines security investment projects with direct ties to enabling cyber security. Following the table, a problem statement for each investment with its value is included. Cost, descriptions, benefits, alternatives, and other relevant project information can be found in Exhibit A-42 (ALC-2).

Investment	Test Year Capital	Test Year O&M
Workstation Temporary Administrative Access	$254,560	$32,454

The workstation temporary administrative access project will help resolve the problem of once a local administrative account is provisioned, the Cyber Security and IT teams do not have controls in place to restrict the usage of these accounts or monitoring capabilities to detect misuse without human intervention. This creates an environment for misuse where broad admin access could be leveraged for data breaches and ransomware. A successful attack would impact the Company's ability to serve its customers. The Company will gain value from this project through: (1) reduced risk by eliminating over 1,000 local administrative accounts; (2) the ability to implement security controls and restrictions on local administrative functions; (3) increased productivity by reducing the time and resources needed to provision, manage, and audit local accounts for security compliance; and (4) the ability to provide administrative access for a specific and limited duration of time, thereby increasing the Company's security posture which reduces cyber security risk of workstation compromise.

Q. Please explain the capital expenditures and O&M expenses enabling cyber security occurring in the bridge period.

A. The capital expenditures and O&M expenses enabling regulatory compliance occurring in the bridge period can be found in Exhibit A-42 (ALC-2).

Q. Please explain the capital expenditures and O&M expenses occurring in annual security programs.

A. The summary table below defines security investment projects that are considered in scope for annual security programs. Following the table, a problem statement for each investment with its value is included. Cost, descriptions, benefits, alternatives and other relevant project information can be found in Exhibit A-42 (ALC-2).

Investment	Test Year Capital	Test Year O&M
Application Currency – Capital	$30,010	$3,600
Application Currency – O&M	$0	$21,874
Enhancements - Capital	$210,070	$28,800
Enhancement – O&M	$0	$188,662
Asset Refresh – Physical Security	$669,367	$2,160
Asset Refresh – Cyber Security	$173,610	$9,000

The security team is planning both capital and O&M expenditures for its Application Currency Program. The Company manages many 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 cyber threats, 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. Maintaining the appropriate versions of applications through application currency upgrades in the Security portfolio 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; (4) addressing version interdependencies and compatibility between systems; (5) allowing the Company to leverage new functionality available in the upgrades; (6) provides customer value through closing the gaps on vulnerabilities that can impact reliability; and (7) provides a mechanism for proactive actions to stay ahead of evolving cyber threats. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

The security team is planning both capital and O&M expenditures for its Annual Enhancement Program. 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. The value of technology enhancements in the Security Portfolio lies in: (1) enhancing security protections by funding emerging or unplanned cyber security activities resulting from audits, incidents, or a changing threat landscape; (2) lessening the number of incidents associated with outdated software; (3) increasing application stability, leading to fewer incidents due to outdated software; and (4) allowing the Company to leverage additional functionality available in the technology.

The security team is planning both capital and O&M expenditures for its Asset Refresh Program. 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. 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.

Q. Please explain the capital expenditures and O&M expenses enabling the annual security programs occurring in the bridge period.

A. The capital expenditures and O&M expenses enabling the annual security programs occurring in the bridge period can be found in Exhibit A-42 (ALC-2).

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-21148
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

NEAL P. DREISIG

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

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 a Manager of Asset Strategy in the Gas Strategy Department, a position I have held since March 2020.

Q. What are your responsibilities as Manager of Asset Strategy?

A. As Manager of Asset Strategy, I am responsible for the cross-functional research, analysis, and oversight of decarbonization related assets and portfolio management strategy. This 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 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 Manager of Cost Engineering position in the Enterprise Project Management Department for three years. In this 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, and in Case No. U-21141, the Company's Voluntary Carbon Offset Program.

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 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-45 (NPD-1). I will also explain the request for rate relief related to a renewable natural gas ("RNG") production facility the Company is contracting to construct.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-45 (NPD-1)		Natural Gas Delivery Plan; and
Exhibit A-12 (NPD-2)	Schedule B-5.3	Projected Capital Expenditures, Transmission and Distribution Plant, RNG Facilities – Summary of Projected Gas Capital Expenditures.

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

A. Yes.

OVERVIEW OF THE NATURAL GAS SYSTEM

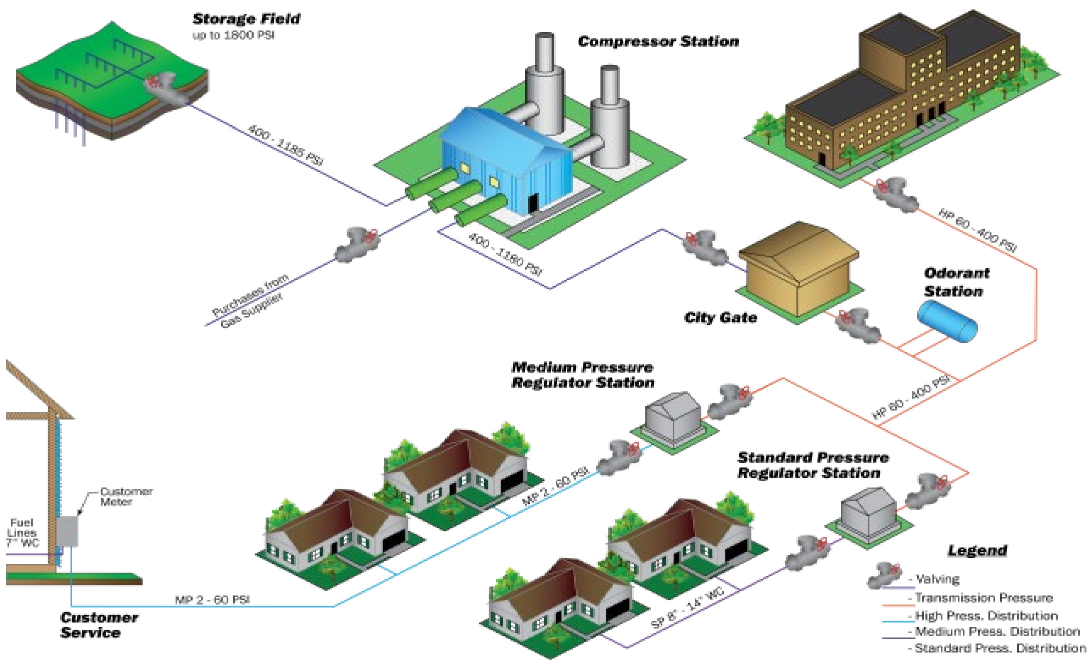
Q. Can you describe Consumers Energy's Natural Gas System?

A. Yes. Consumers Energy's natural gas system contains 2,392 miles of transmission pipelines, more than 28,065[1] miles of distribution mains, and approximately 1,595,427[2] 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 ("MAOPs"). 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 also is the source of supply for city gates. The city gate stations deliver gas to the distribution system that generally operates up to 400 psig. How the transmission and distribution systems work together is depicted in Figure 1 below.

[1] Source: U.S. Department of Transportation, Gas Transmission & Gathering System Annual Report for Calendar Year 2020 submitted 03/11/2021

[2] Source: U.S. Department of Transportation, Gas Distribution System Annual Report for Calendar Year 2020 submitted 03/11/2021

Figure 1: Transmission and Distribution Systems



Q. Can you provide additional statistics regarding the gas distribution system?

A. Yes. Described below is information regarding the gas distribution system composition based on the Company's United States Department of Transportation annual filing for 2020 year-end with the gas distribution system composition summarized in Figures 2, 3, and 4.[3] Figure 2 below shows how many miles of pipe in the distribution system are made of particular materials. Figure 3 depicts how many miles are operated as high pressure main, which includes transmission pipe operated as part of the distribution system and generally operates with a MAOP between 60 psi and 400 psi. Figure 3 also provides mileage on medium pressure main which operates between 1 psi and 60 psi and standard pressure which operates under 1 psi. Figure 4 breaks down the mileage of distribution main by the range of years it was constructed in.

[3] Source: U.S. Department of Transportation, Gas Distribution System Annual Report for Calendar Year 2020 submitted 03/11/2021

Figure 2: Miles of High Pressure Distribution Main on Consumers Energy System

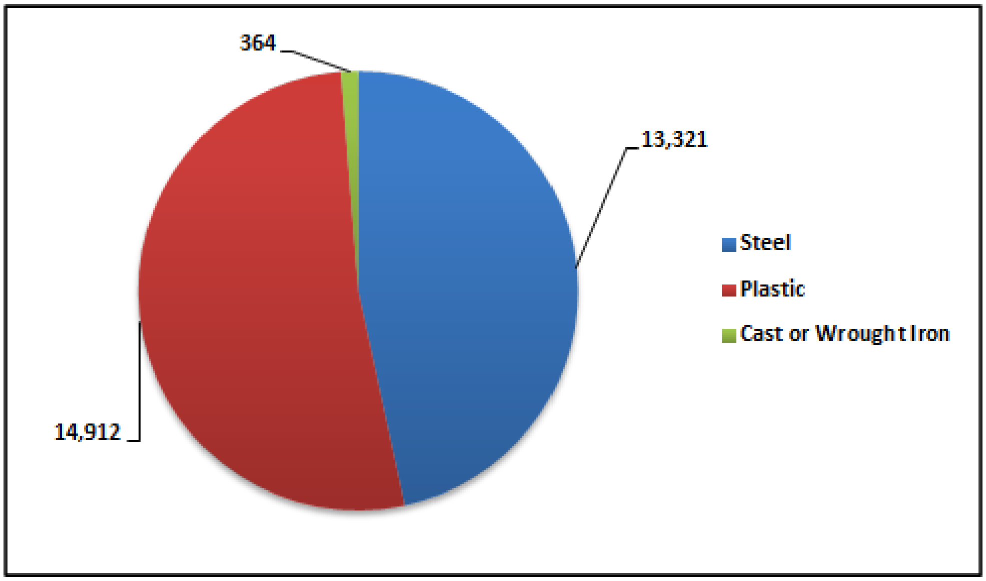


Figure 3: Miles of Medium & Standard Pressure Mains on Consumers Energy System

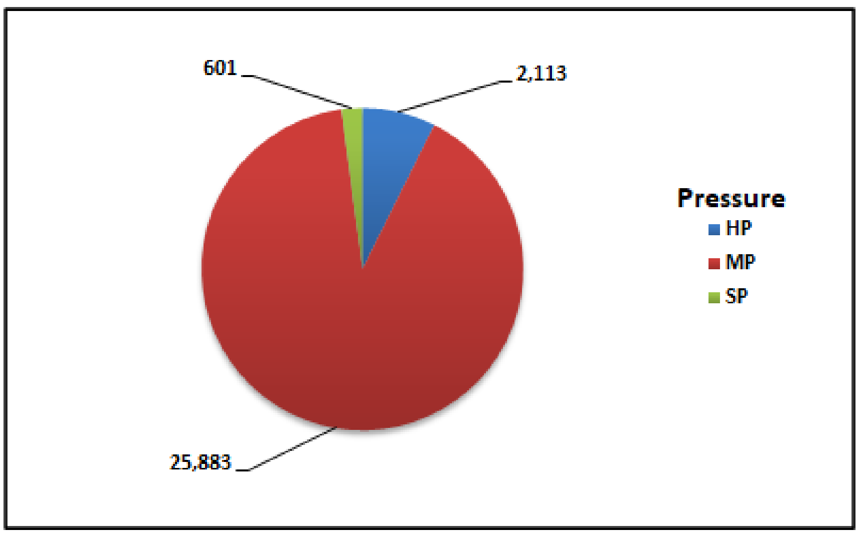
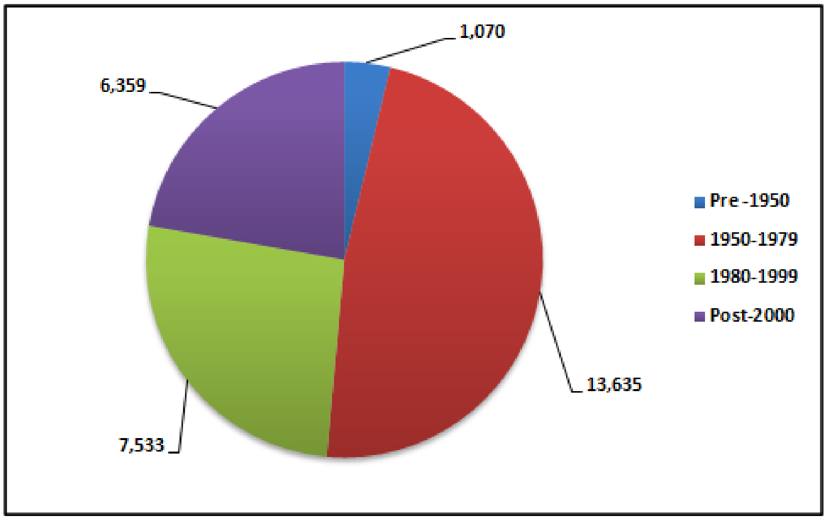


Figure 4: Miles of Main on Consumers Energy System by Install Date



Q. Please describe investments the Company has been making and how they benefit customers.

A. Over the last five years, Consumers Energy has prudently invested over $3.9 billion in its gas system for safety, reliability, deliverability, system integrity, and customer service. Past and future system investments ensure continuous reliable service as customers' peak demands continue to change and/or grow. Between the years 2016 and year-end 2020, the Company connected 34,183 new gas customers. Between the years of 2012 and year-end 2020, the Company replaced 448.7 miles of higher relative risk pipe via the Enhanced Infrastructure Replacement Program ("EIRP") including 180.4 miles of cast iron and more than 43,751 services replaced and retired to improve customer safety and reliability.

Large areas of cast iron systems that are prone to water infiltration and interruption have been replaced and converted to medium gas pressure, improving reliability to customers. Included in this filing is a continuation of the EIRP Program to replace higher relative risk pipe. Under the Transmission Enhancement for Deliverability and Integrity ("TED-I") Program, transmission pipe segments are replaced to reduce risk, increase capacity, and to better control gas flow. Investments in city gates, gas storage wells, and compressor stations improve public safety and ensure reliability. In addition, the Company projects to connect over 33,018 new customers from the beginning of 2020 through the year 2023.

<u>OVERVIEW OF LONG-TERM GAS PLAN</u>

Q. Earlier in your direct testimony you describe the Company's 10-year plan called the *Natural Gas Delivery Plan.* Why has the Company developed this plan?

A. The NGDP was developed to provide a clear and transparent investment plan framework 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 ("API RP 1173") Pipeline Safety Management Systems ("PSMS") framework, and to develop a strategic framework in response to decarbonization goals and future policy. The Company's program in response to the PSMS is called the Gas Safety Management System ("GSMS"). Further, in its September 26, 2019 Order in Case No. U-20322, the Commission directed Consumers Energy to develop a plan addressing the long-term operational and investment needs for the supply and delivery of natural gas that includes comprehensive treatment of the Company's storage, transmission, compression, and distribution systems. The Company's most recent update to the NGDP is included in this rate case as Exhibit A-45 (NPD-1).

Q. Were there external drivers considered as the Company developed the NGDP?

A. Yes.

Q. Please describe these external drivers.

A. The main external drivers are as follows:

1. **Safety** – Employees, customers, and the public must be able to safely co-exist with natural gas assets, and the Company must continue to anticipate risks and mitigate them proactively;

2. **Increasing Regulation** – Major incidents across the nation's gas infrastructure and changing policies regarding carbon and methane emissions will continue to result in new rules and increased regulatory oversight at the state and federal levels;

3. **Changing Supply and Demand Patterns** – The plan anticipates supply growth adequate to meet increases in demand, led by the safe and efficient continued production of natural gas supported by mid-stream investment. This will limit significant commodity price increases as the North American natural gas market expands, led by demand growth in exports and gas-fired electrical generation; and

4. **Environmental Focus** – The natural gas system can contribute greenhouse gas emissions to the atmosphere through carbon dioxide and methane emissions. Limiting the impact of system emissions, from source to end-use combustion is a focal point of environmentally conscious customers, regulators, and policymakers.

Q. Has the Company considered the MPSC's Statewide Energy Assessment ("SEA") in its NGDP?

A. Yes.

Q. Please describe how the NGDP has incorporated elements of the SEA.

A. The NGDP is founded on the Company's commitment to providing a safe, reliable, affordable, and clean natural gas system for the people of Michigan. In addition, it also incorporates the suggestions discussed in the SEA final report, in Case No. U-20646, particularly Section 4 on natural gas, issued on September 11, 2019. The Commission's SEA includes recommendations that gas utilities develop safety management systems, use probabilistic risk models to prioritize investment across natural gas investment portfolios, limit risks associated with commodity supply, and enhance natural gas delivery through the development of demand response and remote gas shutoff systems. These elements are incorporated in the NGDP.

Q. Has the Company provided its long-term gas plan in this proceeding for review?

A. Yes. The Company's NGDP is provided as Exhibit A-45 (NPD-1).

Q. What are the main objectives for the NGDP?

A. The Company has four main objectives for the NGDP. These are:

1. **Safe** – Safety remains Consumers Energy's top priority. This means:
    - Continuously reducing system risk;
    - Focusing on process safety;
    - Modernizing the system by remediating distribution and transmission assets and replacing higher-risk vintage distribution mains and services;
    - Emphasizing implementation of best practices in GSMS and records management, and continuing to use operational metrics to measure factors spanning the safety of the Company's personnel, assets, processes, and physical and cybersecurity; and
    - Accelerating remediation of high-risk materials, while moving to system-wide risk management to reduce overall system risk and better quantify the necessary spending priorities.

Therefore, the Company is currently undertaking a number of system upgrades to improve the safety of the natural gas system. Some of these system upgrades include:

- EIRP - Distribution is the program focused on replacing aging infrastructure within the gas distribution system. EIRP-distribution 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 Distribution Integrity Management Program ("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. This is discussed by Company witness Kristine A. Pascarello in her direct testimony;
- Vintage Service Replacements ("VSRs") Program allows the Company to actively replace vintage service materials, reducing the risk of gas leakage. The VSR Program is a program to replace all of the Company's copper and bare steel vintage service materials. This approach continues to eliminate

the highest risk vintage services on the Company's distribution system, which reduces risk to the Company, customers, and the general public. This is discussed by Company witness Pascarello in her direct testimony;

- Well Logging Program assesses gas storage well integrity. Well logging includes the use of gamma ray logs 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. Storage well integrity is a critical component to ensuring public safety. This is discussed by Company witness Timothy K. Joyce in his direct testimony;

- Pipeline Integrity Program identifies, inspects, and evaluates pipelines according to Pipeline and Hazardous Materials Safety Administration ("PHMSA") requirements, and then prioritizes, and carries out remediation activities. This ensures continual safe operation of the largest and highest-pressure pipelines. This is discussed by Company witness Paul M. Wolven in his direct testimony;

- TED-I projects advance public safety and improve system performance during winter operations and the summer outage season especially during injection operations. These projects replace or retire higher-relative risk pipe transmission pipeline segments, as discussed in my direct testimony. The newly replaced pipelines include enhanced remote control valves ("RCVs") for flow control. RCVs minimize the time needed to stop the flow of gas if a failure occurs. This is discussed further by Company witness Michael P. Griffin in his direct testimony;

- GSMS - which is in response to the September 26, 2019 Order in Case No. U-20322, in which the Commission stated that it expected Consumers Energy to develop and implement a PSMS in accordance with API RP 1173. The implementation and sustainment of the GSMS is necessary to assure enhanced safety of pipeline activities, and to provide greater certainty that the natural gas system will perform as expected. This is discussed in the NGDP section V.B.3 and further in the direct testimony of Company witness Stephanie V. Watson; and

- The Company plans to implement new corrective and preventative processes that will enhance the Company's capability for reducing system risk, and implementing sustainable controls, in alignment with API RP 1173 and the GSMS to improve safety and reliability to customers and Michigan. The direct testimony of Company witness Sarah H. Bowers includes descriptions of new programmatic solutions to enhance safety, controls, and compliance.

Overall, the primary safety outcomes are to accelerate the retirement of vintage materials throughout the gas system to reduce the probability of incidents that would adversely affect public safety, customers, and employees.

2. **Reliable –** Consumers Energy is continuing to create a reliable system through dependable assets, measured through metrics such as gas flow deliverability to avoid unplanned outages, and analyzing the Company's natural gas system to provide resilient customer supply plans. The Company continues to work on demand response to reduce peak demand with the implementation of its gas demand response pilots. 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 is essential for safe and continuous customer service. The Company will consider how to balance system reliability, resilience, and optimization by improving asset reliability as well as improve the system;

3. **Affordable** – Consumers Energy's planned system investments improve safety and reliability, which can be made while maintaining stable, predictable, and reasonable growth in total bills. These investments along with projected natural gas commodity costs will continue to represent a small percentage of a customer's household spending. Overall, the primary affordability outcomes are to provide stable, predictable, and reasonable growth in total bills so that natural gas remains a small percentage of household spending while providing a highly valuable product that improves quality of life; and

4. **Clean** – Consumers Energy is committed to reducing greenhouse gas emissions across its systems, thereby minimizing the Company's and its customers' impact on climate change. 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. Achieving this objective has the potential to remove up to 1,000 tons of methane from the atmosphere each year. This equates to approximately 52,000 thousand cubic feet ("mcf") of gas retained in the system for use by customers, reducing gas loss, and improving customer value;

    - Customer Programs: In 2021, the Company filed Case No. U-21141which seeks to create a voluntary program for natural gas customers to offset carbon emissions associated with natural gas use; and

    - RNG development: The Company is investigating how to cost-effectively produce and deliver RNG as part of its supply portfolio. RNG captures, conditions, and repurposes greenhouse gas emissions as a drop-in fuel for use across the system.

Please refer to the NGDP, Exhibit A-45 (NPD-1), for further elaboration on the Company's efforts to improve its performance in this key area.

TECHNOLOGICAL CAPABILITIES

Q. Does the NGDP discuss needed technological capabilities to ensure the successful execution of the NGDP?

A. Yes.

Q. Please describe the Company's technological capabilities that are necessary to facilitate the successful completion of the work stated herein.

A. As Consumers Energy moves forward with the NGDP, there will be 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. Therefore, as described in the NGDP, Exhibit A-45 (NPD-1), the technology (i.e. information technology ("IT")) or digital projects are essential to enabling the expected NGDP outcomes in the future. Company witness Duncan D. Patterson includes in his direct testimony and exhibits a number of technology projects that are critically important in supporting the gas functions within the Company. The expenditures for these projects are contained within the exhibits sponsored by Company witness Patterson.

Q. Will all of the projects in this testimony support achieving the objectives and outcomes in the NGDP?

A. Yes, as described in the NGDP, Exhibit A-45 (NPD-1), the activities outlined above represent the Company's 10-year plan. Fully funding both the capital and operating and maintenance ("O&M") costs for the NGDP technology projects described in the testimony of Company witnesses Pascarello, Griffin, Bowers, Joyce, Christopher T. Fultz, and

Paul M. Wolven, and executing the projects, will set the stage for predictable, prudent, and affordable outcomes throughout the 10 years of the NGDP.

Renewable Natural Gas

Q. What is RNG?

A. RNG is any pipeline compatible, gaseous fuel derived from biogenic or other renewable sources that has lower lifecycle greenhouse gas emissions than geological natural gas. Most commonly, RNG is biogas that has been upgraded or conditioned to meet existing pipeline standards for gas quality. Raw biogas is a mixture of carbon dioxide and hydrocarbons, mostly methane gas, released from the decomposition of organic materials (i.e., feedstock), including but not limited to animal manure, food waste, wastewater residues, agricultural and forestry residues, and municipal solid waste. In many circumstances, the industries and processes that create biogas release methane and/or carbon dioxide directly into the atmosphere. RNG projects capture those atmospheric emissions and repurpose them for end use thereby reducing greenhouse gases, while at the same time providing useable energy. Due to the composition and scale of those captured emissions, the result is often a carbon negative fuel, which also displaces traditional fossil gas. Because RNG captures and repurposes emissions otherwise vented to the atmosphere, it possesses valuable environmental attributes.

Q. What is the Company proposing related to RNG?

A. The Company is proposing to build, own, operate, and maintain an RNG production facility based on dairy manure feedstock. The production facility will produce a net output of 56,000 mcf of RNG per year, while eliminating approximately 18,000 tons of carbon dioxide equivalent ("CO2e") per year. Eliminating 18,000 tons of CO2e is equivalent to pulling approximately 3,900 gasoline vehicles off the road for a year.

Q. What value to customers is associated with owning and operating an RNG production facility?

A. Dairy-based RNG provides unique value in that it is not only a distributed energy source but its environmental attributes can be sold into existing carbon markets to reduce the revenue requirement and/or be retained and retired to reduce emissions associated with delivery and use of natural gas. Additionally, these versatile attributes mitigate price risk associated with future policy or regulation that may require such emissions to be reduced or eliminated. Should these changes occur, the ownership of an RNG production facility will reduce the cost of compliance. Additionally, a Company-owned RNG production facility provides access to a potentially cost neutral, renewable, and low carbon fuel supply for all customers.

Q. Are there any additional benefits associated with RNG?

A. Yes. RNG has additional environmental, economic, reliability, and societal benefits. Environmentally, if biogas is not captured from the decomposition of naturally occurring organic waste, the methane would be released directly to atmosphere. Methane is conservatively estimated to have a global warming potential 25 times greater than that of carbon dioxide.[4] Converting these organic waste sources to RNG results in the beneficial reuse of otherwise wasted methane to atmosphere. Additionally, RNG feedstock sources and production facilities are often co-located and can be sited locally, thereby reducing emissions associated with upstream development activities and transportation of

[4] United States Environmental Protection Agency. https://www.epa.gov/gmi/importance-methane#:~:text=Methane%20is%20more%20than%2025,due%20to%20human%2Drelated%20activities

conventional natural gas supply. RNG supports the State of Michigan's Executive Directive[5] to develop the MI Heathy Climate Plan, which seeks to achieve economy-wide carbon-neutrality by 2050 with an interim goal of a 28% reduction economy-wide by 2025. It also supports the Federal Government's commitment to a 50-52% reduction in greenhouse gases economy wide by 2030 as part of the Nationally Determined Contributions under the Paris Agreement.

RNG has the potential to create other economic benefits. Similar to other infrastructure projects, RNG facilities offer job opportunities for engineering, design, construction, and operations roles. Additionally, managing waste material via RNG has the potential to lower operational expense for the agriculture industry (feedstock owners), while reducing emissions and future regulatory burden for sectors like agriculture and solid waste management.

From a reliability perspective, RNG production can be seen as a distributed renewable energy resource. As a distributed energy resource, geographically dispersed in nature, RNG supports distribution-level capacity and improves local resilience of the natural gas system.

From a societal perspective, RNG facilities that use decomposing organic waste as a fuel source help improve air and water quality, while reducing decomposing waste odor. Specifically, organic solids from agriculture and wastewater systems are occasionally managed by direct land application. This can lead to nonpoint source runoff into surface water, affecting local water quality if not applied responsibly. Redirecting raw solids into digesters reduces this runoff risk while maintaining the ability to provide post-digestion

[5] Executive Directive 2020-10 and Executive Order 2020-182. Available at https://www.michigan.gov/whitmer/0,9309,7-387-90499_90705-540277--,00.html

value as fertilizer. Diverting organic waste from landfill systems into digesters for RNG production retains space in existing landfills and reduces the demand for additional landfill installations.

Q. What is the current state of RNG throughout the industry?

A. RNG has generated high interest across the country in the last decade. Historically, biogas was used initially for on-site heat or electric generation. The industry has expanded, since the early 2010s as carbon policy in the transportation sector developed. This policy development created significant demand for RNG as a renewable fuel source to meet compliance obligations. For this reason, gas operators, customers, investors, developers and policymakers have rapidly pursued RNG supply recognizing it as a relatively scarce resource. Over the past two years, the Company has received approximately 50 interconnection requests for RNG projects within its service territory to take advantage of supply incentives associated with the carbon compliance markets. Since 2017, the RNG industry has grown 39% annually and is forecast to continue growing at approximately 18% through 2030 making existing feedstock sources valuable[6].

Q. What are the carbon markets?

A. Carbon markets trade and track verified reductions in greenhouse gas emissions (i.e., carbon "credits") and exist as a mechanism for entities to meet regulatory compliance targets or climate-related voluntary goals. Regulatory compliance markets can be sector specific, like those described below for transportation fuels, or they can be broad to support "net-zero" policies at the local, state, or federal level. Carbon credits are also a valuable commodity in voluntary markets, driven primarily by individuals and corporations with

[6] Argonne National Lab (ANL), EIA, experts interviews

similar net-zero ambitions or industries looking for low-carbon fuel alternatives for high heat processes. RNG creates carbon reductions that can be applied across all sectors, either as a purely environmental benefit, or as a direct-use fuel alternative, delivering thermal energy. The demand for carbon credits is expected to remain strong in support of climate related policies and sustainability goals.

Q. What are the primary renewable transportation fuel carbon markets?

A. Currently, there are two primary carbon credit markets: the Federal Renewable Fuel Standard ("RFS") and California's Low Carbon Fuel Standard ("LCFS"). Renewable attributes created through RNG qualify for both of these markets as a renewable fuel. It is possible to participate in both markets, using the RNG and environmental attributes from a single project.

The RFS is part of the 2007 Clean Air Act which classifies refiners and importers of petroleum-based fuels as obligated parties to blend a specific percentage of renewable fuel into the overall fuel supply. These obligated parties are regulated to demonstrate compliance with blending requirements.[7] For this reason, the RFS is volumetric in nature, similar to electric renewable portfolio standard programs.

The LCFS program is designed to reduce the carbon intensity ("CI") of California's transportation fuel supply by incorporating a range of low carbon fuel alternatives. The program works by requiring obligated parties to achieve established CI targets by either

[7] RNG, Cellulosic Fuels And The Renewable Fuel Standard (2017) Biocycle. Accessible at: https://www.biocycle.net/rng-cellulosic-fuels-renewable-fuel-standard/

producing lower CI fuel or purchasing credits from lower CI fuels sold in the California market.[8]

Whether environmental attributes are sold into existing or a number of emerging markets, the demand for certifiable reductions in greenhouse gas emissions (i.e., carbon offsets) is expected to remain strong, as any carbon policies seeking to achieve "net zero" will require a commensurate supply to do so. As discussed, should regulatory or policy compliance obligations arise, environmental attributes could be used to meet those obligations at a likely lower cost than purchasing through external markets.

Q. How does the Company intend to use environmental attributes?

A. The Company intends to monetize environmental attributes by selling them into carbon markets to reduce the overall revenue requirement for the RNG production facility. Accordingly, all revenue received from the sale of environmental attributes would be returned to the customer via a reduction in the revenue requirement. It is possible that the monetary value of environmental attributes would be greater than the Project's revenue requirement itself, making RNG a cost negative fuel alternative with other versatile benefits.

Q. What are the components to the RNG production facility?

A. The RNG production plant has four main components: (1) collection and digestion, (2) gas upgrading, (3) compression, quality measurement and interconnection, and (4) digestate management. Each of these components is further described below:

1. **Collection and Digestion:** At a plant that uses dairy cow manure, the feedstock is collected and placed into a bio-reactor tank commonly called an anaerobic digester. The anaerobic digester is a system for biological conversion of organic matter into biogas through a process called "anaerobic digestion." In this process, bacteria breaks down organic matter in a controlled environment,

[8] 101 For Low Carbon Fuel Standard. Accessible at https://www.biocycle.net/101-low-carbon-fuel-standard/

absent of oxygen. Anaerobic conditions can be created in an engineered digester, or through existing processes and systems, like landfills. The two primary outputs of anaerobic digestion are (1) biogas and (2) digestate. The main constituent of biogas is methane, which can be used interchangeably with natural gas to provide heat, electricity, and energy for other industrial processes;

2. **Gas Upgrading:** To produce pipeline-compatible RNG, biogas is upgraded by removing contaminants and the inert or low-value constituents. This is done so through various removal technologies including H2S removal vessels, moisture removal vessel, oil/gas separator, CO2 removal vessels, and O2 removal process;

3. **Compression, Quality Measurement, and Interconnction:** Following gas upgrading, the gas would meet applicable pipeline quality specifications for customer end-use. The RNG moves through a meter station to monitor gas quality and measurement with mechanisms to redirect gas out of specification back to the upgrading system. Assets in this section include electric driven compressor, odorizor, ultrasonic meter, supervisory control and data acquisition, remote thermal unit, and various piping; and

4. **Digestate Management:** Digestate is the material left after the anaerobic digestion process. The digestate has many beneficial uses and should be managed accordingly. Typically, digestate can be used for either fertilizer or bedding for livestock. The digestate management process helps maintain proper operation of the RNG facility and health of the herd should it be used as bedding. The primary assets in this process include solids separation and dryer equipment.

Q. What is the Company's projected capital spending level association with the RNG production facility?

A. As shown on Exhibit A-12 (NPD-2), Schedule B-5.3, line 5, the capital expenditures for the RNG production facility were $0 in 2020, and are projected to be $228,000 for 2021; $7,026,000 for the 9 months ending September 30, 2022; and $10,552,000 for the 12 months ending September 30, 2023. These expenditures are shown in Table 1 below.

Table 1: RNG Production Facility Capital Expenditures

($000)	(a)	(b)	(c)	(d)	(e)	(f)
		Renewable Natural Gas Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line		12 Mos Ended	12 Mos Ending	9 Mos Ending	21 Mos Ending	12 mos. Ending
No.	Program Description	12/31/2020	12/31/2021	9/30/2022	9/30/2022	9/30/2023
1	Digester		54	2,084	2,138	2,073
2	Gas Upgrading		70	2,696	2,765	2,680
3	Measuring and Metering		58	2,246	2,304	2,234
4	Manure and Digestate Management		46	-	46	3,565
5	**Total Renewable Natural Gas Capital**	**-**	**228**	**7,026**	**7,254**	**10,552**

Q. Is the Company projecting O&M expenses related to the RNG production facility in this case?

A. No O&M expenses are projected for this case. There will be future costs to operate and maintain the facility such as feedstock supply costs, operations, and routine maintenance.

Q. What impact does this RNG production facility have on the revenue requirement?

A. Monetization of environmental attributes will be used to reduce the revenue requirement as shown below in Table 2. Revenue forecast, based on today's carbon market forecast, is shown at approximately $3.1 million per year, achieving a net revenue requirement, in $/MCF, below zero within three years.

Table 2: RNG Revenue Requirement

Revenue Requirement Calculation - RNG

	2021	2022	2023	2024	2025	2026	2027	2028
Capital Spending	$227,555	$10,269,624	$7,308,272					
Average Rate Base	$113,777	$5,362,367	$13,967,161	$17,062,656	$16,313,684	$15,564,711	$14,815,739	$14,066,766
Times Pre-tax Cost of Capital	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%
Return	$8,249	$388,772	$1,012,619	$1,237,043	$1,182,742	$1,128,442	$1,074,141	$1,019,841
Depreciation Expense	$0	$0	$368,308	$748,972	$748,972	$748,972	$748,972	$748,972
Property Tax	$1,138	$73,552	$191,578	$234,037	$223,763	$213,490	$203,217	$192,944
Total O&M	$0	$0	$500,000	$1,050,000	$1,050,000	$1,050,000	$1,050,000	$1,050,000
Revenue Requirement	$9,387	$462,323	$2,572,505	$3,270,052	$3,205,478	$3,140,904	$3,076,331	$3,011,757
Gas Production Mcf				56,000	56,000	56,000	56,000	56,000
Carbon market revenue forecast				$3,100,000	$3,100,000	$3,100,000	$3,100,000	$3,100,000
Net Revenue Requirement				$170,052	$105,478	$40,904	-$23,669	-$88,243
Net $/Mcf				$3.04	$1.88	$0.73	-$0.42	-$1.58

Q. How does the Company intend to utilize the gas itself?

A. The gas produced will be used and classified as *internal use gas,* as described in Company witness Hannah L. Patton's direct testimony.

Q. How will the costs associated with the RNG production facility be treated in the cost-of-service study?

A. The assets associated with RNG and expenses will be included in production and allocated using gas cost recovery throughput as described in Company witness Alex M. Gast's direct testimony.

Q. What steps has the Company taken to mitigate the risks associated with RNG production quality?

A. RNG facilities will have gas processing equipment to purify the raw biogas. Gas purity will be monitored through online gas analyzers so only gas that meets pipeline quality specifications and quality requirements will be allowed on the Company's gas system.

Q. Has the Company entered into any contracts with third parties associated with constructing an RNG facility?

A. Yes. The Company has entered into a contract with a 3,500 head dairy farm in November 2021. Construction is expected to start in 2022, with an in-service date expected in fall 2023.

Q. What is the Company's summary proposal for RNG in this docket?

A. The Company is proposing to build, own, operate, and maintain an RNG production facility using dairy cow manure as feedstock. The production facility will be located adjacent to an existing dairy farm, generating a carbon negative fuel with a net output of approximately 56,000 mcf per year. RNG would be injected into an existing, Company-owned distribution main located on the Farm's property. All assets and gas are to be included in base rates. Any monetization of environmental attributes will be used to reduce the overall revenue requirement.

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-21148

DIRECT TESTIMONY

OF

CHRISTOPHER T. FULTZ

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

Q. Please state your name and business address.

A. My name is Christopher T. Fultz, and my business address is 1945 W. Parnall Rd., 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 Executive Director of Gas Operations, Transmission & Storage.

Q. Please describe your educational background.

A. In 2001, I received a Bachelor of Science degree in Electrical Engineering from Michigan Technological University. In 2007, I received a Master of Science degree in Electrical Engineering from Michigan Technological University. I am currently enrolled in an Executive Master of Business Administration program at Oakland University with an expected graduation in Spring 2022.

Q. Please describe your business experience.

A. In 2001, I began employment at Black & Veatch Corporation in Ann Arbor, Michigan as an Electrical Engineer. My responsibilities included designing transmission substation upgrades for the high voltage electric grid for utilities throughout the United States. In 2004, I progressed to the position of Project Engineer, in which I oversaw a team of engineers and technicians performing transmission system upgrades, while managing overall project scope, schedule, budget, and quality. Also, in this role I supported electric utilities with Project Management services including scope development, permitting support, preparing regulatory filings (outside of Michigan), estimating, schedule management, and risk management. In 2007, I progressed to the position of Power Delivery Section Manager and Chief Engineer. My responsibilities included supervisory and technical leadership for a department of multi-discipline engineers and technicians focusing on electric substation and transmission line projects. I then spent a year supporting a large Air Quality Control System project at a coal-fueled electric generation facility, before progressing to the Business Development Manager role for Black & Veatch's global renewable energy business in 2013. In this position, I developed growth strategies in each target market segment, developed and maintained relationships with strategic clients, led proposal development efforts, and helped develop entry into new markets. In 2014, I joined Consumers Energy as a Project Manager for electric infrastructure projects. Duties included cost, scope, schedule, risk, and quality management for all phases of the projects. In 2015, I was promoted to the manager of the Electric Project Management team, where I led the development of tools and processes, resolved project issues as they were escalated, set performance goals, and completed performance reviews, ensured successful project execution for internal and external customers. In 2016, I assumed the role of Director of Project Management overseeing gas and electric transmission and distribution projects. In 2018, I was promoted to Executive Director of Enterprise Project Management – Electric & Facilities. In this role, my leadership responsibilities expanded to include execution of capital renewable energy electric generation projects; that role was further expanded in 2020 to include development of new electric generation projects. In March 2021, I assumed the role of Executive Director of Gas Operations, Transmission & Storage. In this role, I oversee the operations and maintenance of gas transmission pipelines, gas storage fields, and metering and regulation assets including city gates. Additionally, I am a licensed professional engineer in Michigan and a Project Management Professional as certified by the Project Management Institute.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I provided testimony in the Company's 2017 gas general rate case, Case No. U-18424. I also provided testimony in the Company's 2021 electric general rate case filing, Case No. U-20963; this testimony was subsequently adopted by Company witness Jennifer S. Rose.

Q. Are you a member of any professional societies or trade associations?

A. I am a certified Project Management Professional and belong to the Project Management Institute.

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 September 30, 2023. My direct testimony is divided into three parts: (i) Gas Operations O&M expenses, (ii) Information Technology ("IT") projects, and (iii) a "Gas City" training facility.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-46 (CTF-1)	Summary of Actual & Projected Gas Operations Division O&M Expenses - For the Years 2020, 2021, 2022 and Test Year 12 Months Ending September 30, 2023
Exhibit A-47 (CTF-2)	Summary of Actual & Projected Operations Maintenance & Metering O&M Expenses - For the

	Years 2020, 2021, 2022 and Test Year 12 Months Ending September 30, 2023
Exhibit A-48 (CTF-3)	Summary of Actual & Projected Field Operations Services O&M Expenses - For the Years 2020, 2021, 2022 and Test Year 12 Months Ending September 30, 2023
Exhibit A-49 (CTF-4)	Summary of Actual & Projected Other Gas Operations O&M Expenses - For the Years 2020, 2021, 2022 and Test Year 12 Months Ending September 30, 2023

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

A. Yes.

<u>**GAS OPERATIONS O&M EXPENSES**</u>

Q. How has the Company projected its Gas Operations Division O&M expenses for the test year 12 months ending September 30, 2023?

A. The Company has identified its O&M expenses for the test year 12 months ending September 30, 2023, 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 that time period is $133,465,000 as shown on Exhibit A-46 (CTF-1), line 6, column (e). The Company forecasts Gas Operations O&M expenses for five unique program cost categories as detailed Exhibit A-47 (CTF-2), Exhibit A-48 (CTF-3), and Exhibit A-49 (CTF-4). 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 2020 actual and derivation of the projected test year O&M expenses for the Gas Operations expenses shown on Exhibit A-46 (CTF-1).

A. The 2020 actual O&M expense amount of $100,948,000 for Gas Operations O&M 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 12 months ending September 30, 2023, were calculated using a weighted average of the 2022 and 2023 forecast amounts, which reflect the Company's recent historical experience of monthly O&M expenses for individual programs. The Company's Gas Operations experienced abnormally low expenses in 2020 due to COVID-19 pandemic related impacts, such as moratoriums on customer turn-offs, ceasing to enter customer homes and the related work, etc. The 12 months ending September 30, 2023 expense levels for the Gas Operations Division O&M of $133,465,000 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 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 Karen M. Gaston contain the Gas Operations Division Injuries and Damages 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, 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 Gas Operations Division manages O&M programs described more fully below.

Q. Please define and discuss the term Standard Labor Rate (or "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. Forecasts developed for future year SLRs generally reflect current payroll costs levels with an annual forward-looking adjustment of three percent per year, which is consistent with the contractual agreement between the Company and our operating employee's 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 that are 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 Gas Operations O&M 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. Please explain the merit increase and inflation calculations that have been provided in (a) Exhibit A-47 (CTF-2), page 2; (b) Exhibit A-48 (CTF-3) page 2; and Exhibit A-49 (CTF-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. Column (b), which is titled "2020 Actual" shows the historical O&M expense. Column (c), which is titled "Base O&M for Merit and Inflation 12 Mos Ending Dec 31, 2020" shows the amount of historical expense that 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. Therefore, column (i) represents the increase (or decrease) 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. The projected increases from 2020 to the test year period ending September 30, 2023 are explained for each sub-program as part of my direct testimony.

Q. What are the major O&M programs that are managed within the Gas Operations Division?

A. The five major O&M programs within the Gas Operations Division are as follows:

1. Operations, Maintenance, and Metering;
2. Field Operations Services;
3. Compliance and Controls;
4. Operations Performance; and
5. Operations Management.

<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-47 (CTF-2).

A. 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 distribution employees are primarily focused 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.

Q. Please describe the O&M expenses related to the Operations and Maintenance – Distribution sub-program.

A. Operations and Maintenance - Distribution sub-program includes multiple activities that ensure safe and reliable delivery of gas to customers' homes. Work activities related to the condition of Company assets include non-leak maintenance activities such as repairing or replacing lockwing valves to allow emergency shut-offs, replacing pipeline markers, installing meter protections, lowering facilities if grade has changed, installing water pump-drips on the standard (low) pressure system to alleviate water infiltration and freezing of lines, and property restoration after underground maintenance work is performed. This sub-program also includes site checking personnel who ensure customer locations are ready for work, which improves efficiency and on-time delivery by avoiding unnecessary field trips by distribution crews. These site checking personnel confirm that jobsite requirements for underground facility staking, sewer lead locations, grading, hydro vacuum excavation, and temporary traffic control are complete prior to the arrival of distribution construction crews. Gas mains and services alterations for customer-requested work (such as new business branch services, meter moves and service moves) are included in this program. Where the entire service (stub, extension, and riser) is replaced, the costs become capital and are not included in this program. Lowering of facilities is also part of this program where the current location of the main or service is shallow due to a customer initiating a grade change. Many of these instances are near the road where the customer is installing a driveway. The electric utility costs for gas distribution regulation facilities and inspections at the Huron Compressor Station are also included here. The historical year costs and projected test year costs for this program are summarized in the following table:

Operation & Maintenance – Distribution Projection Breakdown by Activity Type		
Work Type	**2020 Actual**	**Test Year**
Inspections	$ 19,135	$40,777
Main Repairs & Lowering	$1,157,619	$1,562,036
Service Repairs & Lowering	$1,832,506	$2,327,841
Meter Stand and Riser Repairs	$ 1,607,460	$1,931,758
Relocations and Branch Services	$1,306,575	$1,085,983
Property Restoration	$1,150,692	$1,072,501
Site Checks	$257,064	$95,657
Pre-fabrication Costs	$ 179,965	$265,796
Other including utilities	$339,017	$480,324
Total Program	$7,850,034	$8,862,674

Q. What is the basis for determining the $8,862,674 of projected O&M expenses in the test year 12 months ending September 30, 2023, for this sub-program?

A. Projected test year spending in this sub-program is greater than the 2020 expense and is primarily driven by increasing employee labor rates and unit/order volume. The test year amount is a weighted average of the forecasts for 2022 (22.32%) and 2023 (77.68%). In 2020, the $7,850,034 expense amount in this sub-program was impacted by the COVID-19 pandemic, which limited the amount of work that could be completed. It also impacted average labor rates by reducing the amount of overtime worked by Company crews. The 2022 and 2023 forecasts anticipate more normal levels of workload completion and average labor rates. This historical and projected activity in this sub-program is summarized in the following table:

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
Forecast 2021	14,659	58,474	$10,179,185
Forecast 2022	9,048	37,335	$7,670,003
Forecast 2023	10,203	43,503	$9,205,345

Q. Please describe the O&M expenses related to the Operations and Maintenance – Pipeline sub-program.

A. The Operations and Maintenance – Pipeline sub-program includes expenses related to performing: (a) Code Inspections, (b) Third-party oversight and staking (MISS DIG), (c) Demand Maintenance, (d) Preventive Maintenance & Operations, (e) Restoration/Right-of-Way ("ROW") & Encroachment Resolution, 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.

Code Inspections include completing Michigan Gas Safety Standards (or "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 (or "PLD") inspections, Remote Control Valve (or "RCV") 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. The maintenance pigging portion of the sub-program expects four maintenance pig runs in 2022 and four or five maintenance pig runs in 2023. This level of activity is similar to the four maintenance pig runs that were completed during 2020. This work is included as part of the Company's Transmission Integrity Management Program.

The Facilities Locating for Third Parties (MISS DIG) portion of the sub-program is primarily comprised of labor hours required to evaluate, locate, stake, and oversee third-party activities near transmission pipelines.

The Demand Maintenance portion of the sub-program accounts for labor, materials, and contractor-supported activities 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) right-of-way access maintenance; (d) third-party damage repairs; and (e) snow plowing. 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 our 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, (g) site maintenance and other general functions. An additional $40,000 is included for two maintenance pig runs not required by MGSS (but necessary based on operational history of solids and liquid buildup) that were not performed in 2020.

The Restoration/ROW Encroachment Resolutions portion of the sub-program generally includes contractor and property owner settlement payments necessary to remove the public safety risk associated with existing and anticipated encroachments to Company pipelines. Restoration at existing encroachments and prevention of future encroachments are a priority to increase pipeline and public safety from third-party activities. Encroachment resolution also ensures access to Company easements and ROWs for MGSS-required inspections and repairs. There were more than 170 documented encroachments on the Transmission Pipeline system as of August 2019. Since that time, the Company has been able to resolve a majority of the open easement and ROW encroachments, with only 31 open encroachments documented as of October 2021.

The Allocation of Miscellaneous Expense portion of the sub-program includes labor, internal departmental chargebacks, and materials not directly associated with a specific work order. These costs include 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. In 2021, cost of salaries and expenses associated with the Exempt and Non-Exempt employees who support and/or oversee the execution of pipeline activities were included in this sub-program.

The historical year costs and projected test year costs for this program are summarized in the following table:

Operation & Maintenance – Pipeline Projection Breakdown by Activity Type		
Work Type	**2020 Actual**	**Test Year**
Code Inspections	629,794	965,410
Facilities Locating for Third Parties (MISS DIG)	1,070,273	1,486,586
Demand Maintenance	306,509	402,841
Allocation of Miscellaneous Expenses	483,600	427,768
Misc Exp: Exempt & Non-Exempt Sal/Exp	0	329,916
Restoration/ROW/Encroachment Resolutions	0	223,399
Preventive Maintenance & Operations	521,885	574,898
Total Program	3,012,604	4,410,818

Q. What is the basis for determining the $4,410,818 of projected O&M expenses in the test year 12 months ending September 30, 2023, for this sub-program?

A. As shown in the table above, projected spending in this sub-program is primarily driven by known units for regulatory driven code inspections, preventative maintenance, and maintenance pigging activities. Demand maintenance (conditions requiring short-term response), facility locating for third parties (MISS DIG), restoration and ROW encroachment resolutions, and direct allocation of miscellaneous expenses are projected based on historical trends and anticipated needs.

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. With the onset of the COVID-19 pandemic in 2020, efforts were focused on maintaining a safe, reliable system and balancing that with employee and public health and safety. As a result, the code inspection schedule was adjusted to reduce employee risk during the pandemic, resulting in an estimated O&M reduction in 2020 of $397,000.

Also included are additional hours to address revised maintenance requirements primarily for valve and operators. These revised requirements are based on the inclusion of new activities and frequencies in accordance with the equipment-specific manufacturer recommendations to ensure reliable and predictable performance during normal operations and emergency situations. Examples include more frequent hydraulic operator fluid flushes, removal of gear and mechanical covers to inspect internal hardware and remove water from poor seals or condensation and reseal, and full flushing of the valve to remove old grease prior to adding new grease. Additional projected labor hours also include maintenance related to investments providing system and customer benefits such as RCV, which are sponsored by Company witness Michael P. Griffin. These valves require their own maintenance schedule along with any emergent Demand Maintenance. In addition to the required base valve and operator inspection, additional labor is required for transducer and communication inspections associated with the RCVs at five hours annually per new RCV for a total of $65,300 annually (2021- 37 additional RCV's, 2022- 40 additional RCV's, 2023 – 40 additional RCV's).

The projected expenses associated with Facilities Locating for Third Parties (MISS DIG) activities is comprised of historical data and projected trends. There was a steady increase from 2017 to 2019 in this area in both locate ticket volume and hours required for oversight of construction activities near the Company's pipeline system, largely due to economic growth in Michigan. Based on this trend and anticipated resuming economic growth in 2022, it is anticipated that demand for third-party locating responses will increase (see below table).

Miss Digs 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
Trend 2021	19,860	9,266
Trend 2022	21,846	10,219
Trend 2023	23,853	11,473

Increases in Demand Maintenance projected expenses over 2020 actual expense are due to additional RCV equipment added to the system. This Demand Maintenance expense is critical to ensure timely repair of assets on the transmission pipeline system.

Projected amounts for Allocation of Miscellaneous Expenses are based on historical spend increasing only for inflation. Additionally, $329,916 is required for salaries and expense associated with the Exempt and Non-Exempt employees that support and/or oversee the execution of pipeline activities. These costs were managed separately from this sub-program in 2020 and were moved from the Gas Operations Supervision sub-program in 2021.

The historical and projected activity in this sub-program is summarized in the following table:

Operations & Maintenance - Pipeline Units/Orders, Hours & Dollars			
Year (Jan-Dec)	Units/Orders	Hours	Dollars
2016	12,937	24,033	$2,675,390
2017	15,865	21,865	$2,131,709
2018	20,056	23,556	$2,670,236
2019	20,242	26,639	$3,121,709
2020	19,896	23,634	$3,012,604
Forecast 2021	21,668	21,053	$3,700,383
Forecast 2022	23,625	22,827	$3,814,976
Forecast 2023	25,638	26,043	$4,612,094

The projection for the 12 months ended September 30, 2023 of 4,410,818 is a weighted average of the 2022 and 2023 forecast amounts. The test year amount is a weighted average of the forecasts for 2022 (25.25%) and 2023 (74.75%), which reflect the Company's historical experience of program expense timing.

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. It 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 and is critical for system operations and public safety. The Regulation Distribution sub-program is responsible for the statewide inspection, maintenance, and repair of:

- 686 Distribution Regulation Stations
- 1637 1-inch and larger high-pressure regulation stands
- 100 Odorant Injection Facilities
- 4537 Designated Pipeline Valves

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

Operation & Maintenance – Regulation Distribution Projection Breakdown by Activity Type		
Work Type	**2020 Actual**	**Test Year**
Designated Valves	$1,644,418	$2,631,115
Regulation Inspection	$2,808,592	$2,900,928
Regulation Repairs	$1,565,272	$2,003,273
Vegetation Management	$342,323	$383,807
Total Program	$6,363,894	$7,919,123

Q. What is the basis for determining the $7,919,123 of projected O&M expenses in the test year 12 months ending September 30, 2023, 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 Griffin. These new or upgraded facilities have additional equipment and technology installed that requires annual inspection and maintenance, which is a driver for the increased test year expense when compared to the 2020 actual amount. 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 ("TOD") pipe, and poly valves as required on all new gas main installed. Increased labor hours are necessary to complete the required inspection and maintenance. As a result, additional trained and certified Company-employed gas mechanics are needed to perform the increased workload. Currently, half of the current gas mechanics are 60 years or older. Thus, a regulation apprenticeship program was implemented in 2021 to attract the highly skilled workforce necessary in this field. Projected spend for the actual training of these new mechanics is accounted for in the Training Program. Also, gas mechanics received a $2/hour increase in pay related to the apprenticeship program, accounting for an additional $100k of increased labor expense.

Distribution regulation inspections and repair units have increased each year with new facilities added to the regulation system. With new units added, and some adjustments for time to complete jobs, labor hours are projected to increase through the test year. Furthermore, cost per unit will show a slight elevation due to increased contractual labor costs over the next two years.

The historical and projected activity in this sub-program is summarized in the following table:

Operations & Maintenance – Regulation Distribution Units/Orders, Hours & Dollars			
Year (Jan-Dec)	Units/Orders	Hours	Dollars
2016	5129	41,366	$4,609,086
2017	5009	38,058	$4,330,964
2018	6240	40,943	$6,169,182
2019	7672	40,350	$5,909,548
2020	8246	42,432	$6,363,894
Forecast 2021	13044	44,632	$7,234,762
Forecast 2022	13744	46,632	$7,133,803
Forecast 2023	14444	48,832	$8,177,832

The projection for the 12 months ended September 30, 2023 of 7,919,123 is a weighted average of the forecasts for 2022 (24.78%) and 2023 (75.22%), which reflects the Company's recent historical experience with the timing of program expenses.

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"), Pipeline and Hazardous Materials Safety Administration ("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, odorization, gas quality analyzers, and gas conditioners. These inspections can include piping, regulators, transducers, SCADA, valves, operators, emergency shut down devices, separators, heaters, meters, 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), 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.

The historical year costs and projected test year costs for this program are summarized in the following table:

Operation & Maintenance – Transmission Measurement & Regulation Projection Breakdown by Activity Type		
Work Type	**2020 Actual**	**Test Year**
Code Inspections & Preventative Maintenance	$1,425,009	$1,468,181
Demand Maintenance	$1,040,722	$1,094,129
Operations	$5,375	$228,723
Direct Allocation of Miscellaneous Expenses	$391,043	$720,778
Lead Abatement Program	$35,627	$137,847
Total Program	$2,897,776	$3,649,658

Q. What is the basis for determining the $3,649,658 of projected O&M expenses in the test year 12 months ending September 30, 2023, for this program?

A. 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, accounts for much of the cost projection. In total, the Company projects jobsite labor hours to be 18,475 hours during the test year in this proceeding. The standard labor rates are expected to be $64.21 per jobsite hour in 2022 and $66.13 per jobsite hour in 2023. Indirect labor rates are expected to be $18.62 per jobsite hour in 2022 and $19.18 per jobsite hour in 2023. Vehicle rates are expected to be $30.18 per jobsite hour in 2022 and $31.08 per jobsite hour in 2023.

The projection for Code Inspections is calculated based on 1,071 maintenance units needed to meet the criteria of regulatory code inspections, which have increased from 677 units in 2020. The projected amount 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 have increased since 2020 as a result of new equipment (gas filtration, liquid separation, gas analyzers, chromatographs, and regulation) 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 code 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 Preventative Maintenance projected expense supports performing 3,921 proactive and necessary inspections that do not fall under the code requirements but are necessary for maintaining safe, reliable, and predictable system operations; these have increased from 3,704 units in 2020. 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 changes, 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 Demand Maintenance projected expense accounts for labor, material, and contractor supported activities to perform 1,067 repair units on Measurement and Regulation assets, which have increased from 807 units in 2020. 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 Operations portion of the sub-program is primarily comprised of labor necessary to operate 269 units in the test year to address the general operations of the Transmission Measurement and Regulation Operations workforce, which have increased from 262 in 2020. This includes general housekeeping, snow removal, instrumentation lab certification testing, and Operator Qualification ("OQ") on the job training and testing. The projected expense is based on historical data and trends indicating increasing costs.

The Allocation of Miscellaneous Expenses 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) storeroom 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. O&M portions of supervision salaries were relocated to this sub-program in January 2021. 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 plus 3% inflationary consideration and $87,406 transfer from Gas Storage to bring this program's supervisory costs into the program.

Lead Abatement is part of a multi-year program to eliminate all lead-based paint at the city gate facilities. This is a complete blast and spray program that is managed and coordinated to align with other asset maintenance schedules. A complete comprehensive testing and documentation initiative was completed in 2016 identifying sites that contain lead paint. Thirty-one (31) sites have been abated during the period 2016 through 2020, leaving six sites remaining in the program. Once completed, Measurement and Regulation facilities and equipment will achieve required lead levels. The focus is to meet State of Michigan Lead Abatement Act requirements and to improve work site conditions. The costs are projected based on costs per facilities completed through 2020 as part of the program.

This historical and projected activity in this program is summarized in the following table:

Operations & Maintenance – Measurement & Regulation Transmission Units/Orders, Hours & Dollars			
Year (Jan-Dec)	Units/Orders	Hours	Dollars
2016	5,294	18,233	$4,609,086
2017	5,313	20,497	$3,461,000
2018	5,331	20,497	$3,074,000
2019	5,450	20,722	$3,005,000
2020	5,192	18,540	$2,897,776
Forecast 2021	6,213	20,330	$3,537,406
Forecast 2022	6,356	18,475	$3,472,453
Forecast 2023	6,356	18,475	$3,724,603

The test year amount of $3,649,658 is a weighted average of the 2022 and 2023 forecast amounts shown above. The 2022 forecast was weighted 29.72%, and the 2023 forecast was weighted 70.28% to reflect the historical calendar month timing of annual program costs. The increase in the test year from 2020 actual is $751,882, driven by increases in Code Inspections, Operations, Allocations of Miscellaneous Expense, and Lead Abatement, as described above and shown in the earlier table.

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 Commission monitors Company performance on response times with a targeted average annual response of 30 minutes and with less than 1.2% of the response times over 60 minutes 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 ("RE") 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:

Odor Response Projection Breakdown by Activity Type		
Work Type	**2020 Actual**	**Test Year (2023)**
Odor Response	$5,506,217	$6,458,811
Total Program	$5,506,217	$6,458,811

Q. What is the basis for determining the $6,458,811 of projected O&M expenses in the test year 12 months ending September 30, 2023, for this sub-program?

A. The Company has projected the costs of the Odor Response sub-program based on expected workload associated with 51,516 odor response orders. Each odor response call is expected to require gas service worker jobsite time of 0.72 hours, or about 43 minutes. This expected time requirement is based on reviews during 2021 of jobsite time per order completed. During 2020, the average jobsite time was 0.70 hours, or about 42 minutes. The increase in jobsite time per order is the primary factor driving jobsite hour increases from 36,442 hours in 2020 to 37,092 hours in the test year. This small, incremental increase per order is the result of standard work modifications that included additional steps for each investigation. This increase in jobsite hours accounts for approximately $98,212 of the test year increase from 2020.

Increases from 2020 to the test year also reflect projected gas service worker hourly standard labor rates, indirect labor rates, and vehicle rates. Gas service worker hourly standard labor rates for the odor response program are expected to increase from $59.05 in 2020 to $64.99 in the test year. Indirect labor rates are expected to increase from $74.88 in 2020 to $85.79 in the test year. Vehicle rates are expected to increase from $19.07 to $22.10 in the test year. Standard inflation expectations are shown on Exhibit A-47 (CTF-2) of approximately $456,000. Increases in hourly rates exceed normal annual inflation expectations by approximately $452,000 due to temporary COVID-19-related reductions experienced during 2020.

The test year amount is a weighted average of the forecasts for 2022 (9.48%%) and 2023 (90.52%%) The historical and projected activity in this program is summarized in the following table:

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
Forecast 2021	52,873	37,958	$6,150,000
Forecast 2022	51,516	37,092	$6,113,067
Forecast 2023	51,516	37,092	$6,495,000

Q. Please describe the O&M expenses related to the Leak Repair and Survey subprogram.

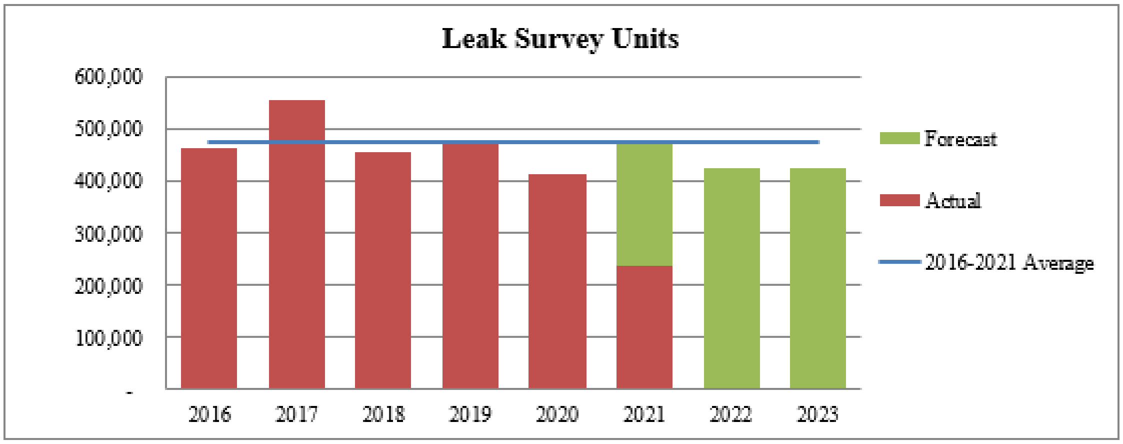
A. The Leak Repair and Survey sub-program includes Company labor and contractor services for annual mobile and walking leak surveys and classification of leaks on mains, services, and meter stands called in by customers or found during leak survey activity. The sub-program also includes leak repairs 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 has historically included 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).

Leak Repair and Survey Projection Breakdown by Activity Type		
Work Type	**2020 Actual**	**Test Year (2023)**
Leak Survey	$4,067,815	$4,799,734
Leak Classification	$3,874,929	$2,730,590
Leak Assessments	$363,826	$342,256
Leak Repairs – Meter Stands and Regs	$4,011,576	$3,872,494
Leak Repairs – Services	$3,984,029	$3,865,501
Leak Repair – Mains	$3,500,689	$4,670,474
Total Program	**$19,802,868**	**$20,281,048**

Q. What is the basis for determining the $20,281,048 of projected O&M expenses in the test year 12 months ending September 30, 2023, for this sub-program?

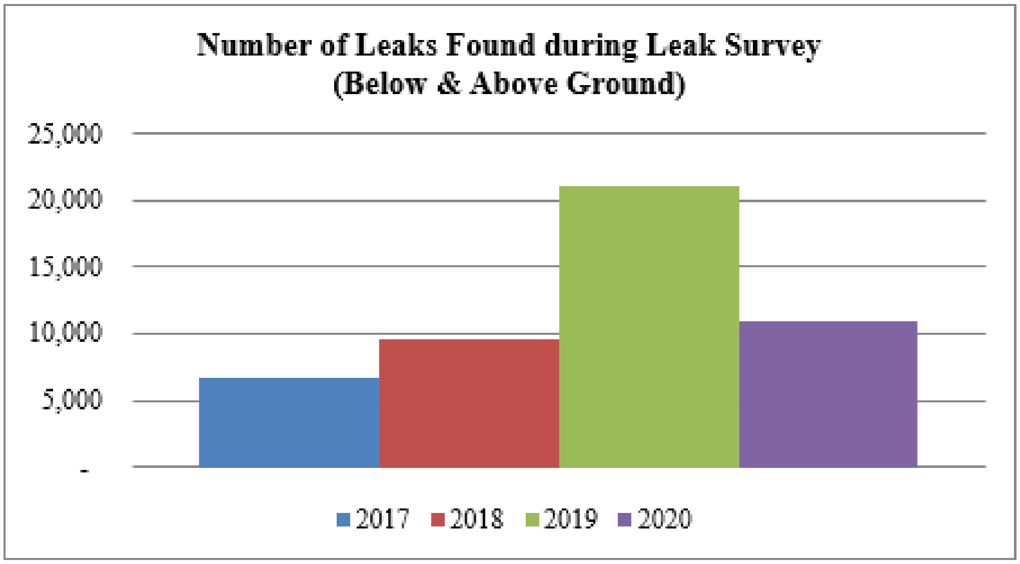
A. The projected expense in this sub-program is primarily driven by leak survey requirements, leaks found during leak survey, current actionable leaks, and leaks requiring repair. Leak surveys are compliance driven per MGSS 192.481, 192.557, 192.613, 192.705, 192.706, 192.721, 192.723, and 192.935, which 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; and
- Discretionary leak surveys — Performed on an as-needed basis.

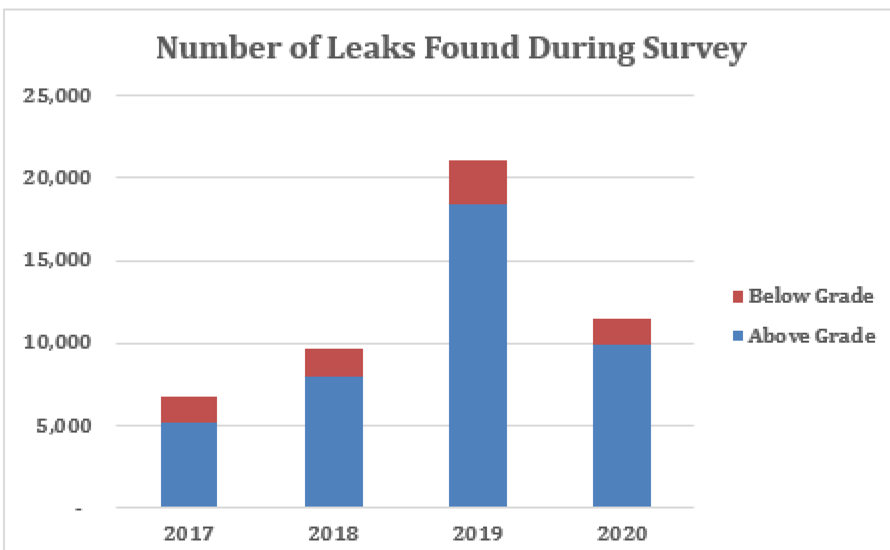


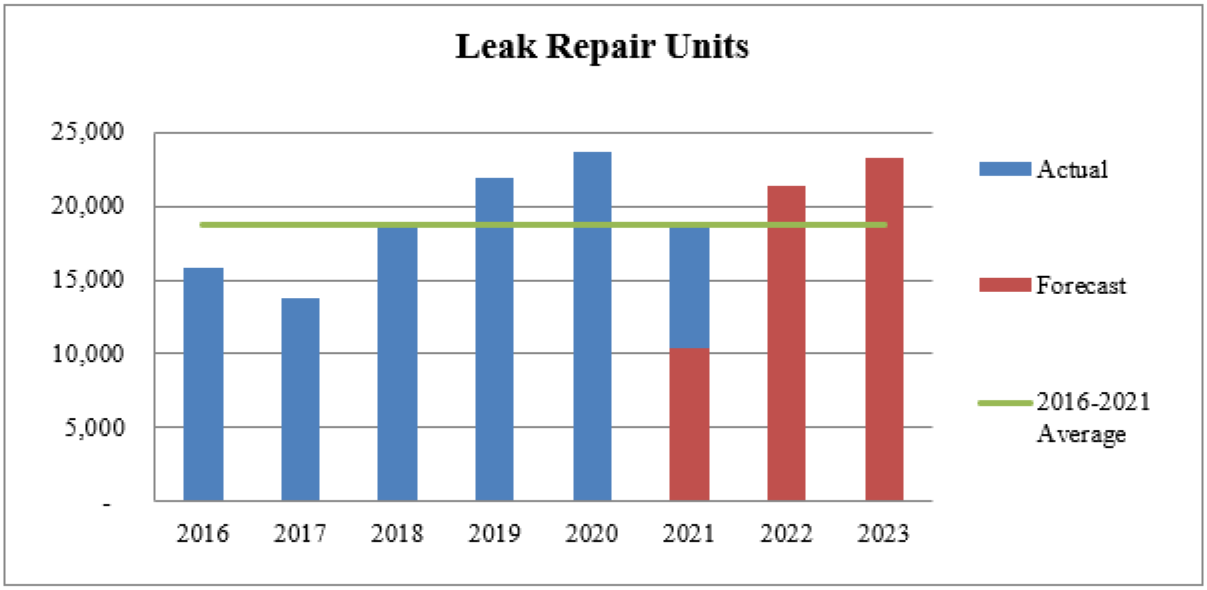
LEAK SURVEY	2016	2017	2018	2019	2020	2021	2022	2023
Actual	462,334	556,249	457,641	480,394	415,305	239,424		
Forecast						234,187	427,002	427,002

Leak Survey for the test year is forecasted to be similar to 2020 with approximately 430,000 units. This is based on the code required schedule and frequency of the gas facilities to be surveyed. The Company has seen an increase in the number of leaks found by annual survey. In 2017, 6,775 leaks were found, compared to 9,646 in 2018, 21,083 in 2019, and 10,913 in 2020. 2021 is trending higher than 2020 with 7,724 through June. The increase in leaks found drives increased required leak repairs.



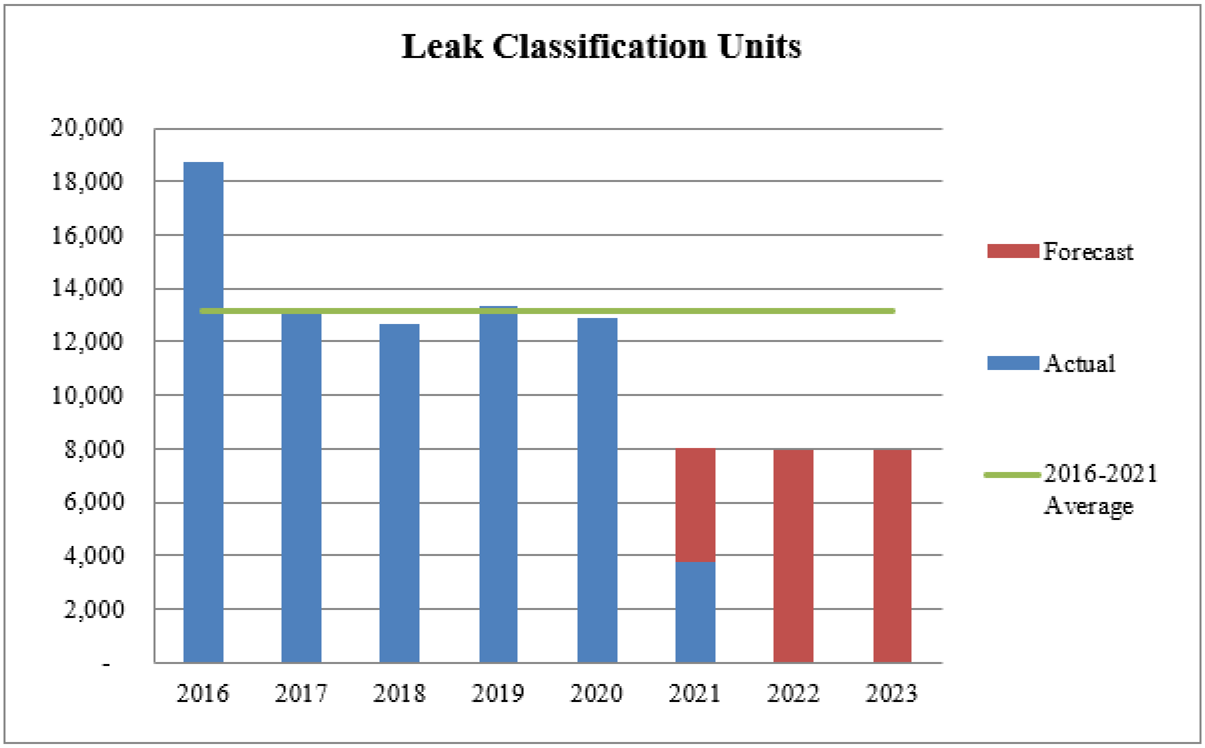
Leaks found during Survey				
	2017	2018	2019	2020
Above Grade	5,220	7,931	18,393	9,842
Below Grade	1,555	1,715	2,697	1,589
Total	**6,775**	**9,646**	**21,090**	**11,431**





Leak Repair	2016	2017	2018	2019	2020	2021	2022	2023
Actual	15,814	13,815	18,556	21,970	23,649	8,268		
Forecast						10,423	21,402	23,276

Leak Repair Scheduling is required per code by MGSS 192.703, 192.709, 192.711, and Michigan Rules 318 and 327. 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. In addition, as discussed in the direct testimony of Company witness Kristine A. Pascarello, the Company has been increasing investment in its capital replacement program that focuses on gas services with existing leaks. 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. By repairing and/or replacing more leaking gas services, less re-classifications of leaks will be required due to permanent repairs, which is depicted in the chart below.



Leak Classification	2016	2017	2018	2019	2020	2021	2022	2023
Actual	18,734	13,079	12,650	13,374	12,923	3,746		
Forecast						4,305	7,940	7,940

The table below shows a comparison of the units between 2020 and the test year.

	2020	Test Year
Survey Units	415,305	427,002
Classification Units	12,923	7,940
Repair Units	23,649	22,907
Total Cost	**$ 19,802,868**	**$ 20,281,048**

Despite the decrease in classification units and repair units from 2020 to the test year (though the test year leak repair is still projected higher than the 3-year average), it is important to note that the repair units are showing a shift from service repairs to main repairs. This is based on leaks that have been identified through 2021. The below table shows this projection.

Units	2020	Test Year	RE
Leak Repairs - Mtr Stands & Regs	19,238	18,571	1.5
Leak Repairs - Services	3,654	3,316	8.0
Leak Renew Main	757	1,020	30.0

As shown, the Reasonable Expectancies RE for gas main repair hours is much higher than that of gas service repairs. As a result, despite declining unit counts in some of the other parts of the program, the costs associated to repair main leaks is driving an increase to the total cost of the sub-program.

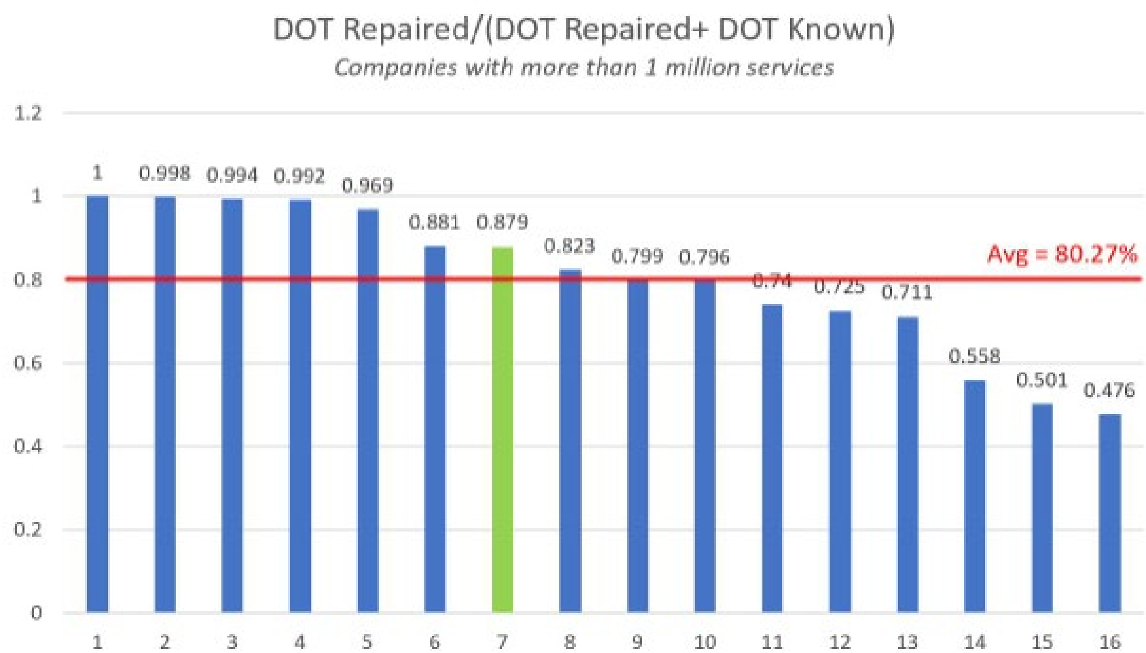
Test Year	Units	RE	Cost (thousands)	Cost (unit*RE*rate)
Leak Repairs - Mtr Stands & Regs	18,571	1.5	$ 3,872	$ 3,872,494
Leak Repairs - Services	3,316	8.0	$ 3,866	$ 3,865,501
Leak Renew Main	1,020	30.0	$ 4,670	$ 4,670,474
Leak Assessments	665	3.5	$ 342	$ 342,256
Survey Units	427,002	(n/a - CE/Contracto	$ 4,800	$ 4,799,734
Classification Units	7,940	(n/a - CE/Contracto	$ 2,731	$ 2,730,590
Totals	**458,514**		**$ 20,281**	**$ 20,281,048**

RE shown above are not calculated. They are determined based on tracked historical times to complete units or tasks and may be adjusted through subject matter expertise. Adjustments account for known factors such as changes to tasks (i.e., additional equipment to be inspected), exceptional working conditions (i.e., having to remove pavement over gas facilities), or human performance (i.e., employee experience levels).

The graph below depicts a comparison of natural gas utilities with more than 1 million customers and 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 87.9%% as of April 2021, which is above industry average. Based on benchmarked data, the Company is seeking to position itself in the top of the first quartile, which drives improved system integrity and public safety.



The additional leak repairs planned for 2022 and 2023 will ensure that the Company permanently repairs a greater portion of the leaks and will not continue to classify actionable leaks. Current Company practices for managing gas leaks are within the requirements of State of Michigan Code as well as internal standards. However, by reducing the number of actionable below- and above-grade leaks being tracked on the gas system (Grade 2 and Grade 3 leaks), the Company can enhance public safety, increase the integrity of the natural gas system, and begin lowering long term costs.

Due to the increased plan to repair and renew gas services with leaks 2021-2023, there will be fewer actionable leaks compared to prior years (2018 and 2019). However, the Company will still carry a backlog of actionable leaks, although reduced, out of 2023 and into future years. The Natural Gas Delivery Plan 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 2020 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 for the leak repair and survey sub-program are expected to be $65.31 in 2022 and $67.27 in 2023, compared to $59.05 in 2020. Indirect labor rates are expected to be $32.66 in 2022 and $33.64 in 2023, compared to $38.84 in 2020. Vehicle rates are expected to increase from $29.73 in 2020 to $36.57 in 2022 and $37.67 in 2023. The total labor and vehicle rate is projected to increase from $128.39 in 2020 to $134.54 in 2022 and 138.58 in 2023. The test year dollar amount is a weighted average of the forecasts for 2022 (32.48%) and 2023 (67.52%) The historical and projected activity in this program is summarized in the following table:

Leak Repair and Survey
O&M Units/Orders, Hours & Dollars

Year (Jan-Dec)	Survey Units	Classification Units	Repair Units	Jobsite Hours	Dollars
2016	462,334	18,374	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
Forecast 2021	473,612	8,052	18,691	88,141	$19,004,715
Forecast 2022	427,002	7,940	22,907	73,738	$17,217,668
Forecast 2023	427,002	7,940	22,907	73,738	$21,754,340

Q. Please describe the O&M expenses related to the Staking & Locating sub-program.

A. The Staking & Locating Program involves Company labor and contractor services for the staking and locating of the Company's gas distribution pipeline facilities in accordance with the MISS DIG law (Public Act 174 of 2013 ("Act 174")), a key component of securing public and employee safety. Work is typically performed by a contracted outside vendor on a multi-year contract with the Company. The Staking & Locating sub-program expenses for 2020 and the test year in this case are identified in the table below:

Staking and Locating Sub-program Projection Breakdown by Activity Type		
Work Type	**2020 Actual**	**Test Year**
Outside Services – Staking and Locating	$5,718,560	$7,320,786
Gas only Oakland County	NA	$4,455,505
Outside Services - supplemental retainer vendor	NA	$185,000
Company labor	$1,513,835	$2,295,750
Licenses, Permits & Fees	$74,061	$382,636
Total Program	$7,306,455	$14,639,677

Q. What is the basis for determining the $14,639,677 of projected O&M expenses in the test year 12 months ending September 30, 2023, for this sub-program?

A. Spending in this sub-program is primarily driven by staking request volume (units). The table below shows the change in staking volumes realized year over year. Most of the staking is completed by an outside contracted vendor and billed based on contractual unit costs.

As shown in Exhibit A-47 (CTF-2), page 4, line 8, column (i), spending in this sub-program is $6,893,000 more than would be accounted for by inflation from 2020 actuals. The primary drivers for this increase in spending include (a) modification of low-cost vendor due to performance challenges to improve timeliness and quality, (b) transitioning of Oakland County to natural gas only asset locating, (c) anticipated volume increases, (d) implementation of supplemental retainer mechanism, (e) Company labor increases due to standard labor rate and (f) anticipated volume and increases in MISS DIG 811 membership fees.

An anticipated volume increase of 5% annually is included in the test year projection for contractor services in alignment with the historical data and staking forecasts for the state of Michigan. MISS DIG 811 data 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:

MISS DIG 811 Statewide Annual Growth			
Year	Annual Ticket Requests	Prior Year Requests	% Change
2016 to 2017	872,896	814,303	7.2%
2017 to 2018	923,993	872,896	5.8%
2018 to 2019	1,015,753	923,993	9.9%
2019 to 2020	994,573	1,015,753	-2.1%
2020 to 2021 YTD + Forecast	1,089,545	994,573	9.5%
2021 to 2022 YTD + Forecast	1,144,022	1,089,545	5%
2022 to 2023 YTD + Forecast	1,201,223	1,144,022	5%

An anticipated unit cost increase is included in the test year projection for contractor services in alignment with the historical data and supplier with enhanced capability to manage increased demand and quality performance metrics.

	Stake & Locate Services		
	2021	**2022**	**2023**
Base Unit cost	$ 17.64	$ 21.50	$ 22.58
Base Unit Forecast	400,000	412,000	432,600
	$ 7,056,000	$8,858,000	$ 9,768,108
Oakland County			
Unit cost Increase			$16.01
Unit Forecast			125,454
Oakland County			$2,008,183
Stake and Locate Total			$11,776,291

Volume and hours are included in the test year projection for Company labor to support standby and abnormal operating condition efforts:

OM&C Labor Breakdown – Advanced Locating & Standby		
Year (Jan-Dec)	Units/Orders	Hours
2016	6,914	12,771
2017	2,771	7,262
2018	2,988	7,281
2019	2,880	7,272
2020	2,366	10,933
Trend 2021	3,252	14,634
Trend 2022	3,304	14,868
Trend 2023	3,403	15,314

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 2020 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 for the staking and locating sub-program are expected to be $65.31 in 2022 and $67.27 in 2023, compared to $59.05 in 2020. Indirect labor rates are expected to be $32.66 in 2022 and $33.64 in 2023, compared to $38.84 in 2020. Vehicle rates are expected to increase from $29.73 in 2020 to $36.57 in 2022 and $37.67 in 2023. The total labor and vehicle rate is projected to increase from $128.39 in 2020 to $134.54 in 2022 and 138.58 in 2023.

Additionally, Licenses, Permits & Fees covers the fees that Consumers Energy pays to the state MISS DIG 811 system as part of the Act 174 with the fees increasing approximately $310,000. This includes the increasing monthly MISS DIG 811 fees and the variance from 2020 due to a credit in this sub-program related to a reversal in accrued staking invoices.

Historical and forecasted expenses for the Staking sub-program are provided in the table below. The test year projection of $14,639,677 includes $2,441,580 from the 2022 forecast and $12,198,097 from the 2023 forecast to estimate the amount of expense during the test year.

O & M – Staking & Locating

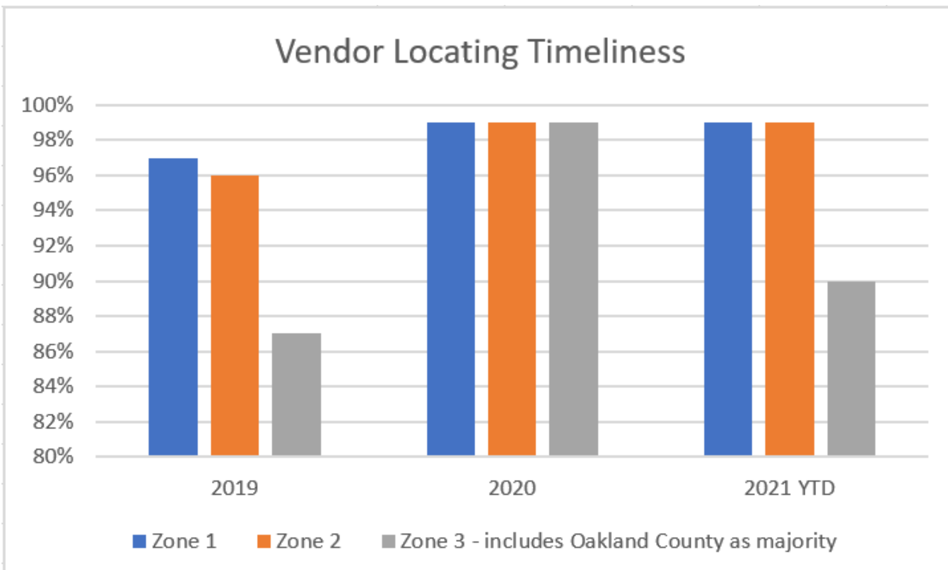
	Total
Year (Jan-Dec)	Dollars
2016	$5,145,070
2017	$5,828,563
2018	$6,754,042
2019	$8,200,186
2020	$7,306,455
Forecast 2021	$10,997,963
Forecast 2022	$10,523,424
Forecast 2023	$15,610,038

Q. Please describe your test year costs related to the Gas Only Oakland County and Supplemental retainer line items.

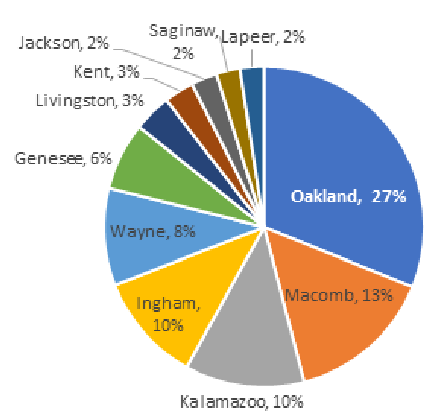
A. In the interest of public safety, damage prevention, and in compliance with a facility owner's obligation under Act 174, the act of placing marks to indicate approximate facility location in response to a MISS DIG ticket requested in advance of excavation activity, an anticipated increase in volume and costs are included in the test year projection for gas only locating in Oakland County. This includes resources to locate only gas facilities for Consumers Energy compared to the existing method of vendors locating several other additional external facilities. This focus for Oakland County highly mitigates public safety, damage, timeliness, quality, and communication risks with excavators in the highest areas for staking requests for Consumers Energy encompassing 29% of requests. Costs were calculated based on vendor information, which are typically more expensive than shared utility staking vendor work. The increased cost for the enhanced timeliness and quality is approximately $2 million. Additionally, costs and units are included in the test year projection for additional contractor services for Statewide supplemental support to alleviate unforeseen short-term demand increases that the contractors are not able to support. An example of this type of short-term increase is in 2021; volume was 26% higher in March and 14% higher in April than anticipated in the staking forecasts for the State of Michigan MISS DIG 811 data. This forecast variance, along with market labor challenges, created the need for additional staking support to ensure timely staking. The Company was able to mitigate this challenge by bringing on additional contract services and shifting Company labor resources. This challenge was also experienced in 2019. This plan to include costs for demand-related supplemental support mitigates public safety and damage risk related to timeliness.

Q. Why is the Company now looking at the additional strategies?

A. Public safety, staking accuracy, and timeliness are the key pillars to a successful stake and locate program. Looking beyond one to two years, these changes in the program are necessary to improve in timeliness and accuracy of staking for public safety, especially given the continued increase in ticket volume. Consumers Energy and the State of Michigan are in the 4th quartile for third party gas distribution damages per 1000 tickets. When the accuracy and timeliness of staking are off target, this can create negative behaviors with excavators resulting in unsafe digging practices. A critical step in ensuring safe digging practices is having excellence in stake and locate timeliness and accuracy. The tables below demonstrate room for continuous improvement in Oakland County.

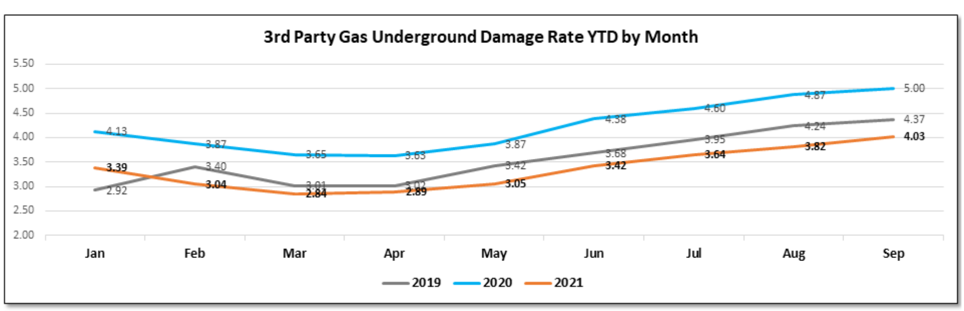


3rd Party Gas Damage w/Locate Contractor Fault - 2019/2020/2021 Combined YTD through Sep 30th



Q. What other activities does the Company perform to reduce dig-in damages beside stake and locate?

A. In addition to 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 our staking contractors for accuracy in locates. The Company has 10 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 recently also 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 and the ability to prioritize tickets and field activities, which help to mitigate the highest risks. This solution was implemented in Spring 2021 and is a contributing factor in the decrease in damages in 2021 compared to prior years.



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 bring the system back into service in a timely manner. Consumers Energy 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 various 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:

Operation & Maintenance – Damage Repair Projection Breakdown by Activity Type		
Work Type	**2020 Actual**	**Test Year**
Service/Meter Stand Repair	1,904,233	983,209
Main Repair	886,947	898,339
Main/Service Repair: Midland Flood Event	854,415	0
Damage Assessment	297,533	153,561
Credits	-1,392,809	-718,849
Total Program	2,550,320	1,316,258

Q. What is the basis for determining the $1,316,258 of projected O&M expenses in the test year 12 months ending September 30, 2022, 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, which seeks 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 slightly lower in 2022 and 2023. 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. In addition, the highest damaging party is that of individual homeowners. The Company has determined not to bill homeowners who cause damage to a gas facility and instead informs the homeowner to call MISS DIG in the future. As a net result, costs for this program are decreasing from 2020 through the test year. This historical and projected activity in this program is summarized in the following table:

Operations & Maintenance – Damage Repair
Units/Orders, 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
Forecast 2021	17,940	$997,600
Forecast 2022	17,023	$951,671
Forecast 2023	18,437	$1,392,870

The test year forecast of $1,316,258 was calculated as a weighted average of 17.36% of the 2022 and 82.64% of 2023 forecast amounts to reflect historical calendar month timing of expenses in the Damage Repair sub-program. The forecasts for 2022 and 2023 reflect projected gas distribution worker hourly standard labor rates, indirect labor rates, and vehicle rates. Gas service worker hourly standard labor rates for the damage repair sub-program are expected to be $65.31 in 2022 and $67.27 in 2023, compared to $59.05 in 2020. Indirect labor rates are expected to be $32.66 in 2022 and $33.64 in 2023, compared to $38.84 in 2020. Vehicle rates are expected to increase from $29.73 in 2020 to $36.57 in 2022 and $37.67 in 2023. The total labor and vehicle rate is projected to increase from $128.39 in 2020 to $134.54 in 2022 and 138.58 in 2023. The atypical costs related to the May 20, 2020 flooding in Midland County are not expected to recur in 2021 through 2023.

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:

- 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.

- Customer and Company Requested Service activities include Company labor and contractor services for meter and meter stand work and appliance relights 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, Inspections, and Transportation Read activities include gas meter inspections, battery exchanges, and transportation customer meter reads. This work is associated with the metering equipment for commercial and industrial customers. The charts and inspection requirement help 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.

- 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 AMR/AMI meters.

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

Operations & Maintenance - Customer Requested Services Projection Breakdown by Activity Type		
Work Type	**2020 Actual**	**Test Year**
Meter Work	$3,761,482	$6,053,811
Customer & Company Requested Svcs	$5,329,153	$7,281,620
Charts & Inspections	$1,445,921	$1,189,099
Transportation Meter Reads	$691,736	$801,092
Routine Meter Exchange Program	$275,137	$610,997
Smart Meter Work	$610,570	$767,289
Total Program	$12,114,000	$16,703,908

It should be noted that while the test year increase is $4,589,908 above 2020, this program was impacted in 2020 due to the COVID-19 pandemic as the actual sub-program cost for 2020 is $4,597,744 less than the actual sub-program cost in 2019. Work restrictions during this year resulted in lower levels of sub-program spending compared to a typical historical year. Major drivers for lower labor costs include limited meter work related to shut-off for non-payment, less meter routines completed due to a waiver that took into account the amount of time the field was unable to complete this job activity, and lower customer requested work.

Q. What is the basis for determining the $16,703,908 of O&M expenses in the test year 12 months ending September 30, 2023 as requested for this sub-program?

A. The costs of the sub-program are primarily driven by Company gas service worker labor and vehicle expenses. In addition, the sub-program includes costs for materials and contractors/vendors (contractors used in general investigations for no-gas or low pressure).

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.

Increases from 2020 to the test year also reflect projected gas service worker hourly standard labor rates, indirect labor rates, and vehicle rates. Gas service worker hourly standard labor rates for the customer-requested services sub-program are expected to increase from $59.05 in 2020 to $64.70 in the test year. Indirect labor rates are expected to increase from $74.88 in 2020 to $85.40 in the test year. Vehicle rates are expected to increase from $19.07 to $21.51 in the test year. As shown in Exhibit A-47 (CTF-2), page 2, line 9, column (i), spending in this sub-program is $4,417,000 more than would be accounted for by inflation from 2020 actuals. The reason for this increase in spending is driven primarily by a return to pre-COVID-19 pandemic unit and hour levels, as shown in the table below, as well as the projected increases in standard labor rates, indirect labor rates, and vehicle rates.

This historical and projected activity in this program is summarized in the following table:

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
Forecast 2021	172,969	84,845	$15,208,000
Forecast 2022	198,607	91,913	$16,410,533
Forecast 2023	198,607	91,913	$16,910,331

The test year forecast of $16,703,908 was calculated as a weighted average of the 2022 and 2023 forecast amounts. The 2022 forecast was given a weight of 25.81% and the 2023 forecast was given a weight of 74.19% to reflect historical calendar month timing of expenses in the Customer Requested Services sub-program.

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. 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 October 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 $5,478,332 projected O&M credit in the test year 12 months ending September 30, 2023?

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 47,079 new gas meters. The expected credit from these purchases is approximately $3,978,000. 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 41,000 existing gas meters. The expected credit from these meter retirements is approximately $1,500,000. 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 September 30, 2023, are shown in the table below:

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
Forecast 2021	51,457	48,816	$6,683,109
Forecast 2022	45,844	41,000	$5,361,743
Forecast 2023	47,491	41,000	$5,516,213

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, and 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 $1,841,572 will permit the continued clearing 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 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 ROW's 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 time frame 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 cost of the clearing program.

Right-of-Way Clearing
Projection Breakdown by Activity Type

Work Type	**2020 Actual**	**Test Year**
Mechanical Clearing Treatments	1,147,835	1,147,835
Herbicide Treatments	0	693,737
Total Program	1,147,835	1,841,572

Q. What is the basis for determining the $1,841,572 of projected O&M expenses in the test year 12 months ending September 30, 2023, 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 at an O&M expense of $1,814,000. For the first full year of the plan implementation in 2020, the Company spent $1,147,835 and is targeting and on track to spend $1,835,400 in

2021. The 2021 program includes implementing 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 treatment as part of the integrated vegetation management program for ROW Clearing at the projected test year spending of $1,841,572. The projected cost increase reflects an expansion in the staffing required to accomplish both the clearing work and the herbicide treatment work. The 2020 Actual miles and expense through the 2023 Plan miles and expense are shown in table below.

Right of Way Clearing Units/Orders, Hours & 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
Forecast 2021	400.0	$1,864,375
Forecast 2022	400.0	$1,887,680
Forecast 2023	400.0	$1,911,276

The test year value of 1,841,572 is a weighted average of the 2022 and 2023 forecast amounts provided in the table above. The 2022 forecast was weighted 47.56%, and the 2023 forecast was weighted 52.56%, based on a historical analysis of the calendar month timing of actual expenses in recent historical calendar years.

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 utilizing the Company's AMI meters; and
3. The manual collection of meter indexes by walking up to meter installations to obtain reads.

The Company has been transitioning from manually reading meters to Gas AMR technology for a large portion of its gas service customers. The Company achieved overall year-end gas meter read rates of 99.06% in 2019 and 99.54% in 2020. The year-end meter reading results for 2019 and 2020 for the various processes used by the Company are as follows:

	Meters Available		Meters Read		Meter Read Rate	
Year	2019	2020	2019	2020	2019	2020
Gas AMR	12,481,471	13,521,615	12,461,339	13,502,603	99.84%	99.86%
Gas AMI	7,987,678	7,975,771	7,977,610	7,968,412	99.87%	99.91%
Manual Gas Reads	1,341,546	207,095	1,231,313	163,433	91.78%	78.92%

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 ending September 30, 2023, is projected to be 40% Electric and 60% Gas; in 2020 the allocation was split 25% Electric and 75% Gas. The difference between the 2020 actual and projected test year electric and gas allocation considers the optimization of AMR and manual routes during 2021. A comparison of the 2020 actual and test year projection is provided below:

Meter Reading Projection Breakdown by Activity Type		
Work Type	**2020 Actual**	**Test Year**
Meter Reader Salaries	2,386,657	1,687,941
Supervision & Administration Salaries	771,715	570,535
Meter Reading Expenses	938,481	839,574
Training	530	7,200
Total Program	4,097,383	3,105,250

Q. What is the basis for determining the $3,105,250 of projected O&M expenses in the test year 12 months ending September 30, 2023, for this sub-program?

A. Spending in this sub-program is primarily driven by Company employee labor and business and technology expenses. Due to the implementation of AMR technology, the 12 months ending September 30, 2023 test year projected expense of $3,105,250 is less than the 2020 actual expense of approximately $4,097,383, as shown on Exhibit A-47 (CTF-2), page 2, line 12. Reduction in Meter Reading sub-program O&M expense, improvements in actual meter read rates, and enhanced customer experience (accurate bills, fewer estimated bills, and fewer inquiries concerning bills) are being realized as a result of the deployment of AMI meters and AMR mobile collection technology. For the test year ending September 30, 2023, 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 17,166 gas meters due to the following reasons: opt-out customers, out of scope meters (i.e., commercial/industrial meters), rate not eligible accounts, and non-communicating meters. The table below shows this breakdown as well, separated between Legacy and Smart meter customers.

Gas Customers Not Cut Over To AMI/AMR as of July 19, 2021	
Description	**Manually Read Meters Count**
Legacy Not Cut Over	4,674
Legacy Opt Out Not Cut Over	6,034
Legacy Rates Ineligible for GCM	3,556
Total Legacy Not Cut Over	14,264
GCM AMR Not Cut Over	1,187
GCM AMR Opt Out Not Cut Over	0
GCM AMR Rates Ineligible	770
GCM AMI Not Cut Over	837
GCM AMI Opt Out Not Cut Over	0
GCM AMI Rates Ineligible	108
Total Smart Not Cut Over	2,902
Grand Total Not Cut Over	17,166

The test year O&M expense was calculated using a weighted average of the calendar year projections for 2022 and 2023. Approximately 23.29% of 2022 and 76.71% of 2023 are included in the calculation of the test year O&M based on the Company's recent historical experience with the calendar month timing of meter reading expense. The following table provides the actual meter reading O&M cost for 2016 through 2020, as well as forecasted amounts for 2021 through 2023:

Meter Reading Equivalent Staffing & Dollars		
	Average	
Year (Jan-Dec)	Gas Staff	Dollars
2016		$13,582,033
2017		$12,328,228
2018	112.0	$10,499,528
2019	67.0	$7,633,272
2020	31.0	$4,097,383
Forecast 2021	22.0	$3,338,377

Forecast 2022	22.0	$3,045,867
Forecast 2023	22.0	$3,123,280

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 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 of the equipment, order creation, and Information Technology ("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 meter interrogations.

The 2020 historical expense and the test year projected expense are summarized in the following table:

Meter Tech & Mgmt Sys Support Projection Breakdown by Activity Type		
Work Type	**2020 Actual**	**Test Year**
Exempt/Non-Exempt Salaries	$376,714	$301,306
OM&C Salaries	$663,575	$1,009,334
Expenses	$45,134	$25,291
Meter Correctors previously included in Meter Purchases Capital Program		$991,550
Replacement project for 100 obsolete Meter Pressure and Temperature Correctors		$1,635,150
Total Program	$1,085,423	$3,962,631

Q. What is the basis for determining the $3,962,631 of projected O&M expenses in the test year 12 months ending September 30, 2023, for this sub-program?

A. This sub-program expense is primarily driven by labor, operating, and minor material costs. With the implementation of the AMI and AMR gas metering deployments in 2012 through 2019, in addition to gas meters, the MTC began processing gas communication modules that are integrated with meters. This implementation has resulted in a slight increase in both labor and expenses. The amount of labor increase between 2020 and the test year reflects the filling of two vacancies that were carried in year 2020, the absence of employee overtime during the pandemic and efforts to focus labor resources on the completion of capital work during 2020. Each gas meter communication module, prior to being installed at a customer premise, must be programmed with security keys and either an AMI or AMR interrogation protocol. This is a new process and must be performed one meter at a time. Additionally, as the modules have lithium ion batteries, when a meter is scrapped, the extra step must be taken to remove the module from the meter and dispose of the module according to hazardous material disposal requirements. This is another new activity that has increased the handling time for each meter/module. Finally, in addition to capturing the mechanical index read for the meter, test facility employees also must capture an electronic read from the module. The electronic read is used for customer billing. The mechanical and electronic reads are used to identify if there are potential issues with the electronic read. 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 are considered replacement parts and will be purchased under the O&M program going forward, starting in 2022. This change results in $991,550 of the 2022 increase. In addition, the Company will be conducting a project in 2022/2023 to replace 100 obsolete pressure and temperature correctors which reflects an incremental purchase of correctors of $1,635,150 in the 4th quarter of 2022. This is reflected in the test year projection. The 2023 projected program requirement represents normal business expenses with the change in categorization of the gas meter corrector purchases.

As shown in Exhibit A-47 (CTF-2), page 5, line 13, column (i), spending in this sub-program is $2,838,000 more than would be accounted for by inflation from 2020 actuals. The reason for this increase in spending is described in the paragraph above.

Actual and projected amounts for 2016 through September 30, 2023, are shown in the table below:

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
Forecast 2021	$1,164,612	$224,362	$1,388,974
Forecast 2022	$1,288,935	$2,617,069	$3,906,004
Forecast 2023	$1,318,627	$1,029,687	$2,348,314

The test year value of $3,962,631 includes two components of the 2022 annual forecast noted in the table above: (a) $1,635,150 related to the replacement project for 100 obsolete Meter Pressure and Temperature Correctors, and (b) 26.9% of the remaining 2022 forecast, or $610,748. The test year value also includes 73.1% of the forecasted 2023 expense. The respective weightings of 26.9% of the 2022 forecast and 73.1% of the 2023 forecast were determined based on a historical analysis of the calendar month timing of actual expenses in recent historical calendar years.

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; and (iii) the gas portion of a technical support contract with the Company's AMI/AMR vendor. These costs are contractually based through 2022 on a per meter or communication module basis, assuming the 2023 rate remains the same.

Smart Energy MTC – Gas Projection Breakdown by Activity Type		
Work Type	**2020 Actual**	**Test Year**
Communication Charges	$250,793	$267,900
GCM Software Maintenance	$166,791	$169,500
Technical Support Services Contract	$125,000	$125,000
Other Miscellaneous Charges	$35	
Total Program	$542,619	$562,400

Q. What is the basis for determining the $562,400 of projected O&M expenses in the test year 12 months ending September 30, 2023, 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 2022 (though the pricing scale extends to 2032), the software maintenance expense per unit increases 3% per year. Actual and projected amounts for 2016 through September 30, 2023, are shown in the table below:

Smart Energy MTC – Gas Dollars	
	Total
Year (Jan-Dec)	Dollars
2016	0
2017	$846,677
2018	$598,586
2019	$606,147
2020	$542,619
Forecast 2021	$546,981
Forecast 2022	$562,400
Forecast 2023	$562,400

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 fifteen gas storage fields, 927 gas storage wells, and 260.8 miles of gathering lines, with associated valving, conditioning systems, and access roads. The program funds approximately 39,500 hours annually to ensure completion of critical tasks associated with operability and ensuring regulatory compliance. Tasks that are executed annually through this sub-program include valve and operator inspections, integrity monitoring, inspection and maintenance of regulators and relief valves, surf ace 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.

Code inspections and compliance work is in adherence to all applicable local, state, and federal laws, including those implemented by the MPSC, EGLE, PHMSA, Bureau of

Land Management, and Michigan Occupational Safety and Health Administration. Regulatory Maintenance activities include pigging activities, corrosion prevention through chemical treatment, dehydrator and separator preventative maintenance, valve and operator inspection and repair, access road maintenance, line patrol, and leak survey to ensure deliverability and public safety.

Operation and integrity work includes the bi-annual pressure survey of all fifteen fields for reservoir integrity and inventory verification, 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:

Gas Storage O&M
Projection Breakdown by Activity Type

Work Type	**2020 Actual**	**Test Year**
Code Inspections	$1,856,474	$2,105,844
Facilities Locating for Third Parties (MISS DIG)	$144,253	$129,600
Demand/Preventive/Compliance Maintenance	$576,866	$654,353
Operations	$3,378,591	$3,738,433
Less: Facility Chargebacks	-$134,836	-$134,836
Total Program	**$5,821,348**	**$6,493,404**

Q. What is the basis for determining the $6,493,404 of projected O&M expenses in the test year 12 months ending September 30, 2023, for this sub-program?

A. The projected expense for this program is historically based and is primarily driven by known units (labor hours) and historical actuals execution of tasks association 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. The cost projections for the test year shows 11.5% increase over the 2020 historical year amount of $5,821,348. The increase in code and operational costs is specifically driven by increase of code and operational tasks associated with gas storage risk program management in adherence to the Federal Protecting our Infrastructure of Pipelines and Enhancing Safety Act 2016/2020. These tasks include monthly well site visits and operational support of the Annular monitoring program, including well intervention.

The historical and projected activity in this sub-program is summarized in the following table:

Gas Storage O&M Dollars						
Year (Jan-Dec)	Code Inspection	Facility Locating	Maint-enance	Oper-ations	Less: Facility Chargebacks	Dollars
2016	3,021,541	79,540	1,491,594	2,604,172	-134,826	$7,076,974
2017	2,128,627	102,869	922,838	2,641,361	-128,356	$5,667,340
2018	2,069,288	118,191	627,200	3,672,299	-181,171	$6,305,807
2019	1,924,781	127,385	613,486	3,657,814	-135,640	$6,187,826
2020	1,856,474	114,253	576,866	3,408,582	-134,826	$5,821,348
Forecast 2021	2,173,678	133,775	675,431	3,957,261	-134,826	$6,940,010
Forecast 2022	1,958,966	120,561	608,713	3,461,729	-134,826	$6,149,833
Forecast 2023	2,105,844	129,600	654,353	3,737,071	-134,826	$6,626,733

The calculation of the test year amount in this case includes the portion of the 2022 forecast expected to be incurred during the fourth quarter of 2022, or $1,715,655, and the portion of the 2023 forecast that is expected to be incurred during the first three quarters of 2023, or $4,777,749. The timing of calendar year expenditures included in the test year is based on the Company’s experience over recent historical time periods.

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:

Replace Vintage Services Projection Breakdown by Activity Type		
Work Type	**2020 Actual**	**Test Year**
Replace Vintage Services	$83,994	$88,453
Total Program	$83,994	$88,453

Q. What is the basis for determining the $88,453 of projected O&M expenses in the test year 12 months ending September 30, 2023, for this sub-program?

A. The forecast for 2022 and 2023 anticipates that a small percentage of Replace Vintage Service construction orders will be returned from the field as non-constructible. The Company plans to replace 3,800 services in 2022 and 4,700 services in 2023. The expected non-constructible rate is expected to be 1.25% of planned units and the average cost per non-constructed unit is expected to be $1,700 in 2022 and $1,734 in 2023. The test year amount is the weighted average of the 2022 (64.51%) and 2023 (35.49%) forecasts. The historical and projected activity in this program is summarized in the following table:

Operations & Maintenance – Replace Vintage Services Units/Orders, Hours & Dollars			
Year (Jan-Dec)	VSR Planned Units	Return Rate	Dollars
2016			NA
2017			NA
2018			523,782
2019			90,072
2020			83,994
Forecast 2021			272,100
Forecast 2022	3800	1.25%	80,750
Forecast 2023	4700	1.25%	101,873

<u>**Gas Operations Field Operations**</u>

Q. Regarding the Gas Field Operations sub-programs shown on Exhibit A-48 (CTF-3), 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 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, and since 2015, the Company has improved its employee safety performance in gas field operations every year. 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:

Operation & Maintenance – Training Projection Breakdown by Activity Type		
Work Type	**2020 Actual**	**Test Year**
Gas Operations OM&C Training	$3,655,902	$5,505,807
Athletic Trainers	$238,056	$280,551
Gas Training Non-Labor Expense	$804,261	$818,970
Total Program	$4,698,219	$6,605,329

Q. What is the basis for determining the $6,605,329 of projected O&M expenses in the test year 12 months ending September 30, 2023, for this sub-program?

A. Spending in this sub-program is primarily driven by the hours of training that are conducted for Gas Operations employees. This training is required to allow for a skilled and qualified field operations workforce that can complete all customer requested and compliance-based tasks.

As shown in Exhibit A-48 (CTF-3), page 3, line 1, column (i), spending in this sub-program is $1,785,000 more than would be accounted for by inflation from 2020 actuals. The primary reason for this increase in spending is a return to normal annual training hour levels, as 2020 was abnormally low due to the COVID-19 pandemic (as shown in the table below) with an estimated impact of $1,691,000. Other drivers include new hire training, $300,000 annually for new competency-based training (e.g. Gas City training), and general labor/expense inflationary pressures.

The historical and projected activity in this program is summarized in the following table:

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
Forecast 2021	96,298	$6,788,459
Forecast 2022	112,912	$7,138,739
Forecast 2023	86,483	$5,963,902

The test year forecast of $6,605,329 includes (a) the fourth quarter 2022 estimate of $1,891,291, which includes employee training needed for planned new hires in Gas Distribution and Gas Service & Meter Reading, and (b) $4,714,038 of training expenses for the first three quarters of 2023.

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 allows employees to 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 that are in the field and 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 $1,968,960 of projected O&M expenses in the test year 12 months ending September 30, 2023, 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 for the test year period.

As shown in Exhibit A-48 (CTF-3), line 2, column (i), spending in this sub-program is $20,000 more than would be accounted for by inflation from 2020 actuals. The reason for this increase in spending is driven primarily by new hiring and increased tool reconditioning spending to continue efficient and prudent reuse of existing tools versus purchasing new.

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
Forecast 2021	$1,954,000
Forecast 2022	$1,911,101
Forecast 2023	$1,989,032

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. General OM&C expenses in this sub-program were abnormally low in 2020 compared to the two prior years due to COVID-19-related work/travel restrictions. Details regarding the actual O&M expenses during 2020 and the projected test year expenses are provided in the table below:

Field Operations Expenses Projection Breakdown by Activity Type		
Work Type	**2020 Actual**	**Test Year**
Field Ops OM&C Gas Expenses	$1,212,416	$1,578,873
Field Ops OT Meals Gas	$272,474	$347,612
Gas Amends Program	$100,274	$91,477
Pipeline User Fees	$638,154	$654,975
Permits	$85,493	$102,454
Gas Field Mobility Exp	$193,322	$186,613
Gas Bonds	$462,063	$715,084
Total Program	$2,964,197	$3,677,089

Q. What is the basis for determining the $3,677,089 of projected O&M expenses in the test year 12 months ending September 30, 2023, 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 test year dollar amount is derived using a weighted average of the 2022 and 2023 calendar year forecasts. An 8.19% weighting applied to 2022 and a 91.81% weighting was applied to 2023 based on the historical expense timing experience associated with Field Operations Expenses.

As shown in Exhibit A-48 (CTF-3), line 3, column (i), spending in this sub-program is $441,000 more than would be accounted for by inflation from 2020 actuals. The reason for this increase in spending is driven primarily by increased net bond costs of $253,000 (more purchases and less backlog recovery), Echelon Front leadership training for $165,000 annually, and other general OM&C labor related expenses, which were abnormally low in 2020 due to COVID-19-related work/travel restrictions.

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
Forecast 2021	$3,561,161
Forecast 2022	$3,378,706
Forecast 2023	$3,703,719

Q. Please describe the Indirect Labor/Labor Variation O&M Expense.

A. The Indirect Labor/Labor Variation expense supports the difference between what the Company actual operating employees and the amount of salary cost that are 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 have 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.

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 of 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. These employees oversee work prior to and during construction and resolve issues where applicable to support work being performed correctly the first time.

Q. What is the basis for determining the $4,823,277 of projected O&M expenses in the test year 12 months ending September 30, 2023, for this sub-program?

A. The projected expense in this sub-program is primarily driven by labor and expenses. Merit increases were the primary driver for the moderate increase from the historical year to the test year.

Q. Please describe the O&M expenses related to the Dispatch & Scheduling sub-program.

A. The Scheduling and Dispatch 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 associated over time hours as work volume fluctuates through the year. Emergent work consists of odor response investigations, emergent leak repairs, third party damage response and repair. Compliance work consists of work order coordination, creation, and assignment of gas meter routine exchange program, 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 assignment meter reading routes to technicians and associated troubleshooting. It is also responsible for the gas meter Consecutive Estimate Program which manages customer accounts (approximately 1,500) with three or more consecutive estimates through an escalation process which 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.

Q. What is the basis for determining the $1,704,491 for Scheduling and Dispatch expenses in the test year 12 months ending September 30, 2023, 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 this 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. The Company projects costs for personnel labor and expenses to meet customer demand to increase modestly through 2023 because of organization restructuring that supports a more balanced organizational focus on emergent dispatching and coordination and scheduling of work activities along with inflationary increases. The $1,704,491 amount for the test year includes two components: (a) fourth quarter 2022 forecasted expense of $607,773, which includes $219,401 for facility modifications and relocations that improve office space safety; and (b) the first three quarters of 2023 forecasted expense of $1,096,718

Q. Please describe the O&M expenses related to EIRP.

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.

EIRP O&M Projection Breakdown by Activity Type		
Work Type	**2020 Actual**	**Test Year**
EIRP Supervision & Admin Sal/Exp	$497,829	$851,679
EIRP Tools	$117,631	$228,697
EIRP OM&C Expenses (Non-Labor)	$156,507	$66,615
EIRP Facilities	$61,693	$121,723
EIRP Labor OM&C Training	$2,460,543	$5,541,702
3/30 - 4/17 COVID-19 Work Shutdown	$2,168,533	
Other		-$10,231
Total Program	$5,462,735	$6,800,185

Q. What is the basis for determining the $6,800,185 of projected O&M expenses in the test year 12 months ending September 30, 2023, 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 nearly all gas asset replacement and relocation programs as well as the Infrastructure Replacement Program). The EIRP workforce continues to experience an increasing level of employees transferring to other operating departments within the Company. Along with this employee movement, a considerable amount of hiring and training is planned, which will allow for appropriate staffing as the Company implements the Natural Gas Delivery Plan. This need for increased staffing to move more employees to higher skill levels is resulting in increased spending projections compared to 2020. As the Natural Gas Delivery Plan 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 three headquarter sites for the group (located in Bellevue, Birch Run, and Wixom), but also covers real estate expenses for project yards and needed facilities (such as construction trailers). These costs are driven by the planned work activities, which are based on the amount of vintage pipe to be replaced. This program expense also experiences inflationary effects as nearly all sites are leased or rented.

Leadership oversight of the approximately 550 field employees 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 and marketplace levels with an inflationary increase.

The historical and projected cost summary is shown in the below table.

EIRP O&M Units/Orders, Hours & 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
Forecast 2021	$3,455,898
Forecast 2022	$5,279,265
Forecast 2023	$4,717,235

The Company expects to incur test year expenses during the fourth quarter of 2022 of $3,351,671 and expenses of $3,448,514 during the first three quarters of 2023. As a result, the test year expenses for the EIRP O&M sub-program are projected to be $6,800,185.

<u>**Gas Operations Compliance and Controls**</u>

Q. Please describe the O&M expenses related to the Operations Compliance and Controls O&M sub-program.

A. The Compliance and Controls sub-program represents a newer department within the Consumers Energy Operations organization beginning in 2019. This department consists of areas that were already in the business under other function and some new departments that are enhancing the Company's compliance to regulatory requirements and ensuring proper controls. Compliance and Controls includes the following functions:

Existing Departments that Transferred under Compliance & Controls:

- OQ and the gas operations certification training program management to ensure the Company's field workforce is qualified to perform its work obligations on the gas system. These activities are projected to cost $105,807 in the test year. There are no historical 2020 actuals identified for this activity.

- Contractor oversight and management for construction contractors performing work on the behalf of the Company on the gas system. This also includes new expenses for technology and standardization to achieve remote inspection and advance methane detection technology. These activities are projected to cost $5,956,377 in the test year. There are no historical 2020 actuals identified for this activity.

- Damage prevention and damage claims program including oversight of the Company's stake and locating of underground facilities in accordance with 811 MISS DIG regulations. These activities are projected to cost $1,344,637 in the test year, compared to $873,013 in 2020.

New Operations Compliance and Control Departments

- 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. This department consists of a program management and support consultants who are implementing and supporting a standardized CAPA management. These activities include new expenses which are projected to cost $27,729 in the test year. There are no historical 2020 actuals identified for this activity.

- Management of the Company's operational compliance quality assurance processes and systems for identification of risks and opportunities across the Company's 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. It also has oversight for implementing a proactive management of preventative and detective actions for deviations from state and federal compliance requirements. The management of the Company's operational compliance quality assurance processes and systems includes the following activities:

  - Compliance Assurance;
  - Standard Adherence and Verification;
  - Compliance Management Action Plan Execution; and
  - Contractor Center of Excellence.

These activities are projected to cost $1,125,632 in the test year, compared to the historical 2020 actual amount of $814,774.

The new corrective and preventative processes that will enhance the Company's capability to reduce risk and implement sustainable controls, in alignment with American Petroleum Institute Recommended Practice 1173 to improve safety and reliability to our customers and Michigan along with the programmatic solutions to enhance safety, controls and compliance is further explained in Company witness Sarah H. Bowers' testimony.

Q. For the existing areas that transferred into Operations Compliance and Controls, please provide the program areas that the expenses were tracked in previous rate cases.

A. Please see the table below for where the program areas were tracked prior to Operations Compliance and Controls being formed.

Department	Case No. U-20322	Case No. U-21148
Operation Qualification	Gas Supervision & Admin	Operations Compliance & Controls
Gas Operations Certification Program	Gas Supervision & Admin	Operations Compliance & Controls
Gas Contractor Oversight	Gas EIRP	Operations Compliance & Controls
Quality Assurance	Operations Performance	Operations Compliance & Controls
Damage Prevention	Engineering Gas Regulatory & Compliance	Operations Compliance & Controls
Damage Claims	Customer Operations	Operations Compliance & Controls

Q. What is the basis for determining the $8,560,181 of projected O&M expenses in the test year 12 months ending September 30, 2023, for this program?

A. The projected expense in this program will primarily support Company personnel in adhering to state and federal compliance regulations and assuring safe performance of work on the gas system. This is achieved by using a common methodology for identifying risks and opportunities for improvement across the Company's facilities and operating system. The Company uses this methodology to track trends and patterns to inform plans to both detect and prevent compliance or safety concerns. This program includes personnel resources to manage as well as responsibility for audits, assessments, and verification that the Company OQ Program is being followed. The program gains insights from industry best practices to inform Company implementation of processes for compliance requirements.

Program actual costs and forecasted costs are summarized in the following table:

Operations Compliance & Controls Units/Orders, Hours & Dollars	
Year (Jan-Dec)	Dollars
2016	$0
2017	$0
2018	$0
2019	$818,106
2020	$1,687,787
Forecast 2021	$2,764,795
Forecast 2022	$5,470,775
Forecast 2023	$8,031,280

The test year amount of $8,560,181 includes (1) $2,688,950 of O&M costs projected for the fourth quarter of 2022, and (2) $5,871,231 of O&M costs projected for the first three quarters of 2023. The test year forecast includes $1,116,130 for the Advanced Methane

Detection program, $2,037,357 for the Sewer/Crossbore Program, $1,472,825 for the Remote Inspection program, and $3,933,870 for various sub-program salaries and expenses.

Q. Are there any other costs associated with this program beyond support personnel?

A. Yes. This program requires technology and resources to support tracking and management for controls, audits, and corrective and preventative action completion for Enterprise Corrective Action Program and Risk Based Assessments. In addition, there are costs associated with the advanced methane detection program to advance public safety and methane reduction, remote inspection and sewer locate program to enhance safety and construction controls. These expenses are detailed in the testimony of Company witness Bowers.

Gas Operations Performance

Q. Please describe the O&M expenses related to the Gas Operations Performance O&M Program.

A. The Gas Operations Performance Program is responsible for implementing process improvement projects to improve efficiency and quality that will allow the Company to accomplish the increased workload as it continues to invest in system improvements for customer safety and reliability. This includes business plan deployment for increased visual management, problem solving, and standard work to achieve key Company objectives of Safety, Customer Experience, On-Time Commitments, and Waste Elimination. The Planning and Scheduling, Contract Administration, and Closeout teams were brought into Operations Performance in February 2021. These teams include the labor and expenses for personnel who are responsible for efficiency and consistency in statewide planning and scheduling of long-cycle work in field operations. This includes new business requests, gas facility relocates, alterations, demolitions, gas leak repair, capacity/augmentation, emergency calls, service calls, and gas meter service.

Contract Administration conducts bidding, contracting, and field administrative support of contracted maintenance and construction operations to ensure that the Company is effectively using its contractors.

Additionally, this team administers resource planning and closeout to support the accuracy and completeness of work order documentation and accounting. Closeout activity is in support of compliance with SOX requirements. The program ensures efficient completion of field work through confirmation of site readiness and proper crewing.

In May 2020, the Meter Reading Performance & Technology team, which monitors performance by tracking and reporting various performance indicators, completes meter reading route optimization, identifies specific meter reading system issues, and troubleshoots system issues, was brought into Operations Performance to improve the organization's maturity with waste elimination.

The Operations Performance Program also includes technology expenses in the form of labor, field work order system upgrades, data and analytics systems, field call-out system maintenance and upgrade vendor fees of $280,000 per year, meter reading system maintenance and upgrade vendor fees of $61,000 per year, hardware and software, navigation subscriptions, and technical support services.

Operations Performance will benefit customers by improving the Company's ability to provide high-quality gas operations service in an efficient manner. This, in turn, will provide more predictable schedules for customer appointments, increased efficiency for customer work, and better first-time resolution of a customer's request or inquiry.

Q. What is the basis for determining the $3,165,000 of projected O&M expenses in the test year 12 months ending September 30, 2023, for this program?

A. The Gas Operations Performance team includes experts in data analytics, data science, lean operating systems, process engineering, industrial engineering, standards management, and systems and technology. The projected expense is primarily the salary and expenses for this team and other associated costs (such as vendor or material costs) in support of the Company achieving the objectives I previously discussed. The increase from 2020 to the test year is primarily driven by inflationary increases for the personnel labor, and includes restructuring in 2020-2021 that increased the focus on gas and work plan optimization

<u>Gas Operations Management</u>

Q. Please describe the O&M expenses related to the Gas Operations Management O&M Program.

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.

Q. What was the 2020 actual expense for the Gas Operations Management Program?

A. The 2020 actual expense for the Gas Operations Management Program was $1,943,237. The historical actual amount of program expense is detailed by labor and various non-labor expense components in Exhibit A-49 (CTF-4), page 1, line 3, column b.

Q. What would the Company's test year projection be for the Gas Operations Management Program if the 2020 actual expense were adjusted only for expected merit increases on labor costs and the Consumer Price Index ("CPI") inflation on non-labor costs?

A. The merit increase and CPI Index inflation projections for 2021 to 2023 would increase the Gas Operations Management Program expense to a test year value of $2,083,199. The detailed support for this calculation is provided in Exhibit A-49 (CTF-4), page 2, line 4, columns (b), (d), (f), and (h).

Q. What test year value is the Company projecting for the Gas Operations Management Program?

A. The Company's projected test year expense is $1,343,000 as shown on Exhibit A-49 (CTF-4), page 2, line 4, column j. The calculated historical plus inflation value exceeds the Company's projection by $740,000.

Q. What is the basis for determining the $1,343,000 of projected O&M expenses in the test year 12 months ending September 30, 2023, for this program?

A. The projected test year decrease from 2020 actual expense is primarily the result of a large inventory write-off of $822,000 in October 2020 based on an annual supply chain review of material.

<u>IT PROJECTS</u>

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 D. Duncan Paterson includes in his 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 Mr. Paterson. The projects providing customer benefits for the areas which I am sponsoring are described below:

- The Field Contractor Work Management Technology Enablement project requires $153,794 in capital and $4,100 in O&M in the test year. The project provides the ability to electronically manage contractor work and increases accuracy and timeliness of information processing for field work deliverables. This project additionally creates new opportunities to measure and optimize field work processes supporting customer on-time delivery goals. Contractor field employees use manual, paper-based processes, and generic communication technologies (phone, radio, email, collaboration sites) to perform work for the Company. Due to the non-electronic format, inaccuracy, and delay of information processing, there are negative impacts to the availability and accuracy of work status. This limits the opportunity to measure and optimize field work processes that support customer on-time delivery and other goals. The project will add value by: (1) improving on-time delivery of customer work by providing electronic work order information to contractors; (2) improving customer satisfaction through efficiency in scheduling work and reporting on the progress electronically; (3) increasing safety by tracking work and contractor status providing visibility into the last known location of the contractor; (4) improving material management; (5) making it easier to move emergent work to contractors to balance workloads and meet customer commitments; and (6) enabling real time updates to work order information, increasing data accuracy and reducing invoice reconciliation time. The project scope includes: (1) identifying requirements for a Bring Your Own Device ("BYOD") field contractor work management technology solution and process; (2) developing, configuring, and testing interfaces, hardware, and software for the solution; (3) implementing the solution and process for the following work groups: Electric High-Voltage Distribution, Electric Low-Voltage Distribution, Mutual Assistance, Forestry, Gas Distribution, Gas Code Compliance, and Substation Operations Construction/Metro; (4) updating the following vendor contract types to support BYOD field contractor work management: zone, specific bid, ancillary, electric storm, and mutual assistance; and (5) training field contractors on the new technology and processes. The alternatives considered include: (1) Continue with the current paper-based process. (This alternative was not selected because this approach does not allow for the timely, data-driven work management metrics required to improve service to customers.); (2) Use the current Company mobile application. (This alternative was not selected because the solution is not expected to receive long term investments by the vendor and the mobile application would require more upfront investment than the proposed option.); (3) Use off-platform options such as ServiceBench. (This alternative was not selected because contractors would not be able to leverage the benefits and integrations with the existing platform and it would require additional new integrations.); (4) Provide Company-funded field devices to contractors. (This alternative was not selected because the investment in hardware, management of on-boarding and off-boarding of devices to contractors, and training and change management is cost-prohibitive and introduces a risk of the loss of control of information security and corporate assets. Leveraging the existing field work management solution was chosen because it uses existing well-developed functionality while leveraging cloud-based, BYOD capabilities to move short-term and long-term contractors from paper processes to the established, standard work management system.).

- The Field Mapping and Graphics project requires $43,361 in capital and $4,930 in O&M in the test year. This project will implement a solution for the mobile field mapping and data collection that can search and view facility map data, view work order designs, and create work order as-built construction drawings in the field. This software technology increases process efficiency by consolidating field graphics functionality, reducing IT complexity and testing, and increasing adoption in the field through ease of use. In addition, it allows the Company to move to a supported application platform and retire the unsupported ArcPad solution. The current mapping and graphics application was implemented in 2002 and is no longer sold or supported in any capacity, and the customizations developed for the application cannot be changed. Due to the improved accuracy of the Consumers Energy landbase (streets, political boundaries, etc.), the outdated electric maps that are referencing that data causes the map to be unreadable which causes a safety issue. Additionally, field employees have considerable challenges when attempting to use the software due to slowness, an aged interface, and dated processes. The project will add value by: (1) providing more accurate geospatial data, including facility map data, pre-construction designs, and as-built construction drawings; (2) consolidating daily tasks into a more simplified process; (3) eliminating the process waste from duplicating asset data in two systems; (4) enabling the adoption of the Geographic Information System ("GIS") standard; and (5) making mapping and graphics data available on field devices. The project scope includes: (1) installing a new mobile field mapping and graphics application; (2) creating the ability to search and view the facility map data in

GIS format along with the ability to search by address; (3) viewing pre-construction work order designs in a new GIS format; and (4) creating as-built construction drawings in GIS format for assigned work orders. Four alternatives were evaluated and three were determined non-viable for the project: (1) Continue maintaining the current ArcPad application. (This option was not selected because the Company is no longer able to make changes to the ArcPad application to mitigate issues if the application has critical defects. A total failure of the application could revert field crews back to paper-based facility maps, risking safety using static, outdated data; or require the creation of as-built construction drawings on paper documents.); (2) Use the Adobe or Snagit applications for creating as-built construction drawings. (This option was not selected because field users would have to use one solution for viewing facility maps and use rudimentary drawing tools like Adobe or Snagit for creating as-built construction drawings. This option was also not selected because it introduces additional costs due to the complexity and customization needed to integrate the applications.); (3) Build a custom Mapping and Graphics solution. (This option was not selected as existing industry solutions are available at a much lower cost with much less risk.); (4) Implementing the new field mapping and graphics software was selected as this option will consolidate field graphics functionality into an efficient process and provide a current, supported solution.

- The Gas Construction Operations Enablement project requires $272,860 in capital and $45,560 in O&M in the test year. The project will implement an electronic work management solution that will enable Gas Construction Operations employees to assign, manage, and complete field work orders, eliminating the manual processes used. The work management system will also enable improved time tracking and reporting. The Gas Construction Operations department has operated on a paper process for work order completion since their initiation. Originally the work group was to be a temporary workforce; however, ongoing improvements for the gas network have extended the need for the department. The current paper process creates additional work to produce and distribute to field operations. Also, the return of the completed paper process has a risk of human errors, lost paperwork, data lags, and readability. These manual processes often require additional contacts to field leaders and field employees to post-verify information. This project will allow the electronic system to automatically process meter orders in SAP, improving accuracy for Customers. The project will add value by: (1) improving visibility to work locations of crews and job status updates in real time, (2) standardizing employee time-sheet management, (3) reducing closeout time by reducing data entry, (4) eliminating efforts to hand off paper copies of meter work orders, (5) reducing billing processing lag time for customers through direct updates on electronic forms, and (6) improving customer satisfaction with more timely meter installation dates. The scope of the project includes: (1) implementing an electronic work management solution for Gas Construction Operations, (2) enabling Gas Construction employees to assign, manage, and complete field work orders, and (3) developing the interfaces for management of the Gas

Construction business unit. Alternatives considered include: (1) continuing with the existing paper process, and (2) SAP direct form order entry and completion. These two alternatives were not chosen because manual workarounds will not improve safety or reduce job and administrative time, and SAP does not support entry of information without cellular connectivity. In addition, with direct SAP, a method of work assignment would need to be developed. The electronic work management solution was chosen because it will improve safety and reduce job and administrative time, while supporting information entry without cellular connectivity. This solution is a Company standard which simplifies the implementation and keeps ongoing maintenance costs down.

- The Gas Measurement, Regulation, Pipeline, and Storage ("MRPS") Field Work Management Enablement project requires $301,081 in capital and $2,738 in O&M in the test year. The project will move gas MRPS work orders from the current paper process to an electronic solution that includes work management, compliance scheduling and tracking, mobile dispatch and work completion functions. The current field processes and activities within Transmission Operations are hindered by lack of technology. MRPS does not currently have a technology solution for work order processing, parts ordering, dispatch and scheduling, Global Positioning Service routing, and access to Company applications. As a result, employees rely on manual paperwork processes, handoffs, and work order management. The current field device could be better utilized if not for technology limitations that hinder customer benefits and employee engagement. The project will add value by: (1) increasing efficiency of order entry and management reporting through a digital solution rather than paperwork handoffs; (2) maintaining key compliance records without depending on paper processes and records; (3) improving productivity by eliminating the duplication waste of managing asset and compliance records management using paper binders; (4) reducing risk of MPSC non-compliance by digitizing system data, making it readily available for review and analysis by leadership; (5) increasing visibility to asset health using data available from a digital system to enable reporting and analysis; and (6) improving Safety by reducing risk to gas storage assets and adherence to standards by moving to digital systems and data. This enables future Safety initiatives such as a monthly well monitoring program that ensures accurate and timely data capture for identification and mitigation of asset risk, analysis, and data trending. The project scope includes: (1) SAP updates to enable gas MRPS work processes; (2) prioritizing agile methodology to evaluate and convert paper forms (up to 75 for compliance work, up to 75 for work order completion); (3) alignment of use with the compliance scheduling and tracking solution on routing and documenting work, tracking time, and work order costing; and (4) development of Training materials and train-the-trainer activities. Alternatives considered include: (1) utilize an SAP module to migrate field work orders to an electronic platform; (2) implement a new solution - Field Manager Solution, Go Canvas, ESRI, and Smart Sheet were evaluated; (3) continue manual paper-based process currently used by the gas

MRPS work force; and (4) implement a Service Suite solution. The first alternative was not selected because it did not offer a scheduling solution or support information entry in offline setting, location and time tracking would need added integration, and a method of assignment and dispatch would need to be developed. The second alternative was not selected because the ad hoc applications that were evaluated were significant deviations from the field work management standard solution, reducing field crew usability through lack of integration and user adoption while increasing support complexity and cost. The third alternative was not selected because it does not eliminate the current process waste, rework, and human error risk. The alternative to implement the Service Suite solution was selected because it is the current field work management standard, providing work management scheduling capabilities, real time validation of field work order forms, and proven field crew adoption and usability resulting from four years of Service Suite usage by 2000+ Company field crews.

- The Work Management Scheduling Analytics and Reporting project requires $255,251 in capital and $27,006 in O&M in the test year. The project will implement a solution to optimize the key components of the Distribution Planning and Scheduling functions including forecasting, work order intake, resource identification, work schedule creation, work execution preparation and associated work order analytics. The Distribution Planning, Scheduling and Administrative Support & Financial Services (Work Plan Strategy) teams are utilizing manually intensive work methods, systems, and forecasting models. These inefficiencies impact the creation of work plans, lack predictive capacity planning, and reduce productivity of operational partners. The project will add value by providing: (1) streamlined processes tied to workload review and preparatory analysis, leading to increased focus on workload priority, execution of work and a reduction of human struggle; (2)increased accuracy in crew work schedules, leading to improved customer satisfaction and on-time delivery of customer requested work, system integrity work, and gas compliance requirements; (3) reduced manual scheduling steps, reporting and analysis of data associated with work management processes and systems; thereby minimizing the risk of human error hours spent developing and updating crew route sheets; and (4) improved forecasting accuracy, that results in greater transparency into the weekly schedule and associated work plan. The project scope includes: (1) implement a solution to facilitate the review of work orders from various engineering organizations, allowing for streamlined check-in of work orders; (2) implement a scheduling tool that utilizes predictive modelling and advanced analytics and streamlines daily schedule modifications; (3) enhance integration with the ARCOS application to bring in employee capacity and availability information; (4) integrate with SAP to retrieve work order data and manage record keeping requirements; (5) enhance integration with Field Service Suite for quicker access to MISS DIG information and work order assignments; and (6) implement associated analytics and reporting. Three primary alternatives were considered for this project: (1) Automating manual data movement across excel and current systems through Robotic Process

Automation. (This option was not chosen because it will not meet base requirements and will not provide desired insights into whether the schedule supports operating priorities and metrics, financial scenarios, first time completion of work, and daily goals.); (2) Integrating an off-the-shelf planning and scheduling system. (This option is not preferred due to associated up-front and long-term costs.); and (3) Implementing a hybrid of an off-the-shelf planning component with custom built scheduling functions. (This is the preferred option to provide a more cost-effective and targeted fit for the organization.).

Gas City Facility

Q. Is the Company planning any training enhancements in support of ensuring that a trained and competent workforce is available to work on gas infrastructure?

A. Yes. Although the current gas technical training program will produce qualified employees, there is an opportunity to improve the real-world experience in the training resulting in a more competent workforce. Consistent with industry best practices, the Company is developing a holistic learning platform, in the form of Gas City, to allow employees in training to understand and experience the work from start to finish. This will allow employees to engage in realistic case scenarios to increase comprehension of skills in order to safely work on gas infrastructure.

Q. How will Gas City improve the workforce's skills and competencies?

A. Studies show that students retain 90% of training when they "do the real thing." Gas City accomplishes this by allowing students to learn in a classroom and then perform tasks in a neighborhood that include staged customers, obstacles such as dogs, slippery or uneven terrain, responding to gas emergencies, and many more circumstances that directly correlate to providing excellent service to our customers. This experience enhances critical thinking capacity for variable scenarios, including when things might not go as planned.

Q. What value does Gas City provide to customers?

A. Current state of training for employees consists of 45% of the time in classrooms, 45% of the time in labs, and 10% of the time in outdoor simulations. The objectives of Gas City are to improve the skills and competency of the field employees to safely serve customers and respond to emergencies. By adjusting training to 75% outside simulation and 25% in a lab or classroom, employees will experience the "do the real thing" learning platform which is proven to increase retention of learning. This objective directly ties in with the American Gas Association's most recent Workforce Development Compendium that discusses retirement projections as well as a need to expand investments in workforce development due to difficulty in hiring trained workforce. Areas that would be directly impacted include:

1. Improved Gas Leak Investigations - Currently employees are in a lab, simulating a gas leak with a detector that is directly managed by the instructor. The instructor will simulate a leak, expecting the employee to react to the situation. With Gas City, natural gas leaks will be live, in a controlled setting, with a number of scenarios such as a customer planting a tree and they hit their service line, leaks under sidewalks, and leaks in basements and drains. Gas City will allow much more in-depth scenarios for the employees to experience. They will use the exact equipment used in the field, which will make more successful transfer of knowledge from training to field.

2. Records Accuracy - Gas City will help employees better visualize the importance of accurate records by seeing the pipe in the ground and documenting it at the work site. Currently employees in training are only able to talk about what the piping looks like and document accordingly, but they cannot see the piping in a jobsite setting and document accordingly. A safety risk exists if changes are made to the pipeline and are not documented. If a contractor or a Company crew goes to a worksite and the records are wrong, they will not know if there is gas piping in the location they are excavating. This creates a safety risk to the public and our employees, as well as the potential for damage to property. The Gas City training will help in avoiding these situations by ensuring that the records are accurate.

3. Customer Service – While gas employees currently receive some customer service training, with Gas City, employees would have the opportunity to participate in different scenarios in a setting with "customers" placed in the

homes. This will allow employees to experience what it is like to approach a door to greet a customer, hear a dog barking, or navigate obstacles they would see in the field. Gas City will also provide a safe place for employees to learn how to react to potential hostile situations.

4. Gas Service and Main Damage – These activities are generally the most dangerous for our gas employees. Currently this situation is simulated with air in a lab setting. Gas City would place employees in real natural gas emergency scenarios which would enable them to learn to control gas in these tense situations. This is critical to public safety. Giving employees the opportunity to actually work in a fire or blowing gas situation, and control the flow of natural gas, will support their ability to respond calmly and follow procedures in these situations.

5. First Responders – This platform will allow the Company to work with local fire departments and other first responders to help them understand the properties of natural gas and how to respond, which will help to increase public safety.

6. Appliance Lightups – Appliance lightups are one of the most failed qualifications as a part of the OQ program. Gas City will have appliances in each of the "homes" that vary in age to allow employees to light up multiple appliances, multiple times, during their training period. Currently employees are only able to train on small groups of appliances in a lab setting.

7. Just in Time Learning - To reinforce what students have learned in training, videos will be included of certain activities that can be accessed directly from the gas manuals. This will provide employees with a quick refresher on the task to ensure procedural compliance and safe work practices prior to doing the work. This can be done on the jobsite from field computer devices.

8. Big Picture – Scenarios will be built to support the start of day, completing the job, and end of day. Currently training is very segregated based on lab and classroom space. Gas City will allow employees to see how all that they have learned ties together, and the reasons for what they do. Employees who understand the big picture will be more productive once they are working in the field. This approach is in support of establishing a skilled workforce for the successful implementation of the Company's Natural Gas Delivery Plan.

Q. What risks will Gas City training help mitigate?

A. There are several risks that can be mitigated by implementing Gas City:

1. Record Accuracy – Gas City will support improved accuracy of records through the simulation and scenario style training. Accurate records allow for contractors and Company crews to perform work on the pipeline with confidence, which reduces risk to the public and employees.

2. Ergonomics Injury - Gas City training will allow for ergonomics coaching on the task that Company crews are doing as they would experience in the field. In the lab settings ergonomics is discussed but the environment does not provide the most realistic conditions. Gas City will allow for more challenging ergonomic activities with more intense coaching around safety. This will result in fewer injuries and a more productive and safer workforce.

3. Compliance - Gas City training activities are expected to support the Company's compliance activities and requirements by providing simulated training. This reduces potential public safety issues as well as fines associated with noncompliance.

4. Public Safety – The Company regularly performs Incident Command System ("ICS") practice to keep participants up to speed on the process. ICS is a nationally recognized system of organization, process, and procedures for managing, documenting, and resolving emergency situations. Currently, a practice activity is staged in a local neighborhood. Gas City would allow the ICS teams to regularly practice on Company property in a controlled and stable environment. ICS response times and accuracy directly support public safety.

5. Skilled Employees - Currently OQs contain 167 qualifications, of which only 41 are performance based. Gas City will allow a significant number of qualifications to move from knowledge based to performance based, which will increase the verification of competencies by observing employees performing the required qualifications rather than just verbally verifying and will support a higher retention by the employees of the skills they will use on the job. This is an industry best practice that will improve employee performance and get the employee trained and in the field 90 days faster than the current process. Faster time to field creates a more productive workforce, which improves customer satisfaction and reduces costs to customers.

Q. Did the Company consider any alternatives to Gas City?

A. Yes. Alternatives considered include:

- Alternative 1 - Continue training as is – 45% classroom, 45% lab, and 10% outdoor simulations.

  - This alternative poses a risk with increasing Company retirements resulting in employees with long-term knowledge expected to leave the Company at high rates over the next several years. Without improved training to match the generational changes of the workforce, the Company will be challenged to see improvement in productivity, efficiency, safety, and compliance.

- Alternative 2 – Redesign current training in current training space with an emphasis on more outdoor simulations.

– This would result in a decentralized training. This would not give employees the opportunity to experience the work from start to finish and would likely not result in any positive change in workforce skills and abilities.

Implementing the Gas City training solution is the best option to improve the skills field employees need to perform their jobs in varying field conditions in a safe, accurate, and efficient manner.

Q. Are you sponsoring any O&M or Capital expenditures for Gas City?

A. No, I am not. The capital and O&M expenditures for the Gas City facility are sponsored by Company witness Quentin A. Guinn. The O&M costs for the facility are sponsored by Company witness Gaston.

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 and Grid Management, Compliance and Controls, Operations Performance, and Operations Management, ensure that the Company adequately prepares for the future circumstances required to continue serving the needs of our customers and the communities in which they live.

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-21148

DIRECT TESTIMONY

OF

ALEX M. GAST

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

Q. Please state your name and business address.

A. My name is Alex M. Gast, 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. In 2011, I graduated from Central Michigan University with a Bachelor of Science degree in Business Administration, with a major in Accounting. In 2013, I graduated from Spring Arbor University with a Master of Arts degree in Business Administration. I am also a Certified Public Accountant registered in the state of Michigan.

From 2012 to 2014, I was employed by Plante & Moran as a Staff Auditor. My responsibilities included the planning and execution of financial statement audits, reviews, and consulting engagements for a variety of non-profit, healthcare, and manufacturing clients.

In 2014, I joined Consumers Energy as a Business Support Advisor in the Distribution, Operations, Engineering, and Transmission department. My responsibilities included managing financial budgets, forecasts, and long-term financial plans for natural gas and electric programs. In 2015, I joined the Energy Resources department as a Financial Analyst. My primary areas of focus were business plans and performance metrics. In 2018, I joined the Pricing Section of the Rates and Regulation Department. My current responsibilities include cost of service studies, rate design, research and development of additional services, analyses for Senior Management, and customer-specific rate analyses.

Q. Have you previously filed testimony with 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-20365	2018 Energy Waste Reduction ("EWR") Reconciliation;
Case No. U-20372	2020-2023 EWR Plan;
Case No. U-20650	General Gas Rate Case;
Case No. U-20702	2019 EWR Reconciliation;
Case No. U-20865	2020 EWR Reconciliation;
Case No. U-20875	2022-2025 EWR Plan; and
Case No. U-20893	Investment Recovery Mechanism Reconciliation.

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 gas Cost-of-Service Study ("COSS") for the 12-month period ending September 30, 2023 ("test year") and the Company's proposed rate design. In addition, I am sponsoring a proposal for a Revenue Decoupling Mechanism ("RDM").

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-16 (AMG-1)	Schedule F-1	Gas Cost-of-Service Study – Projected 12 Month Period: October 2022 – September 2023;

Exhibit A-16 (AMG-2)	Schedule F-2	Summary of Present and Proposed Revenue by Rate Schedule;
Exhibit A-16 (AMG-3)	Schedule F-2.1	Summary of Present and Proposed Rates by Rate Schedule;
Exhibit A-16 (AMG-4)	Schedule F-2.2	Calculation of Rate Design Targets;
Exhibit A-16 (AMG-5)	Schedule F-3	Present and Proposed Revenue Detail;
Exhibit A-16 (AMG-6)	Schedule F-4	Comparison of Present and Proposed Monthly Bills;
Exhibit A-50 (AMG-7)		Development of Rates for Transportation ATL Services; and
Exhibit A-51 (AMG-8)		Calculation of Test Year Discount and Carrying Cost Rates for the Customer Attachment Program.

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. COST OF SERVICE OVERVIEW
II. TEST YEAR COST OF SERVICE PROPOSAL
III. SUMMARY OF PROPOSED RATE DESIGN CHANGES
IV. ALLOCATION OF THE PROPOSED REVENUE DEFICIENCY
V. TYPICAL BILLS
VI. CUSTOMER ATTACHMENT PROGRAM DISCOUNT AND CARRYING COST
VII. REVENUE DECOUPLING MECHANISM

I. <u>COST OF SERVICE OVERVIEW</u>

Q. What is a 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' 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 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 Gas Distribution Rate Design Manual.

II. <u>TEST YEAR COST OF SERVICE PROPOSAL</u>

Q. Is the Company proposing any changes to the COSS methodologies previously approved by the Commission?

A. No. The Company has prepared the COSS using the same methodology approved in Case No. U-20650.

Q. How has the Company treated Renewable Natural Gas ("RNG") in the COSS?

A. The assets and expenses associated with the RNG proposal, presented by Company witness Neal P. Dreisig, are all included in the Production functional group in the COSS. Thus, all costs associated with the RNG proposal are consistently allocated. The revenue requirement is allocated to the Residential and General Service rate schedules using the test year annual throughput forecasted by Company witness Eric J. Keaton. The results of this are displayed on Exhibit A-16 (AMG-1), Schedule F-1.

III. SUMMARY OF PROPOSED RATE DESIGN CHANGES

Q. Please describe Exhibit A-16 (AMG-2), Schedule F-2.

A. Exhibit A-16 (AMG-2), 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 (AMG-2), Schedule F-2, are calculated by applying the test year billing determinants provided by Company witness Keaton 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 its September 10, 2020 Order ("September 10 Order") in MPSC Case No. U-20650 to the test year billing determinants in this case to calculate present revenue in Exhibit A-16 (AMG-2), 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 COSS. The Company also considers: (i) establishing rates that promote efficient use of the Company's natural 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. In alignment with item (i) above, and to better reflect the cost associated with serving transportation customers, the Company is proposing a demand charge for all customers in the transportation class. More discussion of the demand charge can be found later in my testimony. The proposed gas delivery revenue and associated rate increases/(decreases) for each rate class are shown on Exhibit A-16 (AMG-2), 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 include a fixed monthly customer charge and volumetric distribution charges. The proposed increase in distribution for Rates A and A-1 is 20.4%, as shown on Exhibit A-16 (AMG-2), Schedule F-2, page 2. The total proposed increase for the residential class is 12.5% when including the forecasted cost of the gas commodity, as shown on Exhibit A-16 (AMG-2), 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 27.6%, as shown on Exhibit A-16 (AMG-2), Schedule F-2, page 2. The total proposed increase for the General Service class is 14.2% when including the forecasted cost of the gas commodity, as shown on Exhibit A-16 (AMG-2), 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 include a demand charge for Rate Schedules ST, LT, XLT, and XXLT so that the rates will include a fixed monthly customer charge, a demand charge, and a volumetric distribution charge. The proposed increase for the Transportation rate class is 29.6%, as shown on Exhibit A-16 (AMG-2), Schedule F-2, page 1. The proposed rates maintain the currently established economic breakeven points between the Transportation Rate Schedules ST, LT, and XLT. To further prevent rate migration, the demand charge would be applied to all transportation customers.

General Lighting Rate GL

Rate GL is a rate dedicated to customers with gas lighting and is closed to new business. Currently, only a few customers are served on this rate. The Company proposes a 36.6% increase for Rate GL using the Company's projected cost of gas of $3.613 per Mcf, which is supported by Company witness Timothy K. Joyce on page 22 of his direct testimony. The cost of gas is included with other distribution costs in the fixed monthly rate for single and multiple gas fixtures.

Q. What is the purpose of the proposed demand charge for transportation customers?

A. Demand costs represent most of the cost-to-serve transportation customers, but today these costs are recovered entirely through volumetric rates. The Company is proposing a demand charge for transportation customers in order to align cost causation with cost collection.

When a portion of demand costs are collected through a demand charge, the revenue that must be collected through a volumetric charge is reduced.

Q. How did the Company determine the proposed transportation demand charges?

A. The proposed transportation demand charges are based on the demand costs allocated to each Rate Schedule in the COSS, as shown on Exhibit A-16 (AMG-1), Schedule F-1. The Company is proposing that 10% of the demand costs allocated to each transportation rate schedule be collected through a demand charge. This allows for a gradual shift to the collection of these costs through a demand charge and minimizes impacts to customers that may pay more through a demand charge.

Q. How will the proposed transportation demand charges be applied?

A. The proposed demand charges will be applied to the highest quantity of gas volume delivered to a customer in the current month or previous 11 months.

Q. Is the Company proposing any changes in terminology associated with rates?

A. Yes. As discussed by Company witness Shawn C. Hurd, the Company is proposing to replace the word "Master" with "Principal" in reference to General Service and Transportation customer charges. The rate design has been modified accordingly, as shown in Exhibit A-16 (AMG-3), Schedule F-2.1. Customer charges for General Service and Transportation rate schedules are no longer considered "Master" or "Contiguous," but instead "Principal" or "Contiguous".

IV. <u>ALLOCATION OF THE PROPOSED REVENUE DEFICIENCY</u>

Q. Please describe Exhibit A-16 (AMG-4), Schedule F-2.2.

A. Exhibit A-16 (AMG-4), 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, as shown in Exhibit A-16 (AMG-1), Schedule F-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 (AMG-4), Schedule F-2.2?

A. As shown on Exhibit A-16 (AMG-4), 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 (AMG-4), 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 (AMG-4), 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 shock for customers on Rates GS-1, ST, LT, and XLT, the Company is proposing to shift proposed revenue to Rates GS-2 and GS-3. Approximately $9.1 million has been shifted into Rates GS-2 and GS-3 with $5.3 million coming out of Rate GS-1 and $3.8 million coming out of Rates ST, LT, and XLT. 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 (AMG-4), 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 (AMG-4), 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. [MPSC Case No. 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. [MPSC Case No. U-15985 Order, page 92.]

Q. Please describe Exhibit A-16 (AMG-5), Schedule F-3.

A. Exhibit A-16 (AMG-5), 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 (AMG-4), Schedule F-2.2, page 1, line 11 for each rate schedule, based on the billing determinants provided by Company witness Keaton. Both the present and proposed gas prices are applied to the billing determinants to calculate the test year revenue on Exhibit A-16 (AMG-2), 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 Hurd 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 $17.57 per month.

Although the Case No. U-4331 methodology supports an increase of nearly $5.00 to the Company's current residential customer charge, the Company proposes a residential customer charge for Rates A and A-1 of $14.60 per month. This proposal reflects a $2.00 increase from the current $12.60 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 allowing 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. This proposed $2.00 increase in the customer charge results in a decrease to the volumetric distribution charge of $0.2504 per Mcf, from $5.3732 to $5.1228, which is 4.9% less than the volumetric charge associated with the $12.60 monthly customer charge ordered in the September 10 Order.

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 (AMG-5), Schedule F-3, page 2, line 2, column (f).

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 September 10 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 (AMG-3), 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 September 10 Order, the Company is proposing principal customer charges, contiguous customer charges, and distribution charges to collect the transportation proposed revenues. As discussed above, the Company is also proposing to collect a minor portion of the distribution revenue through a demand charge. 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 maintain the contiguous customer charge at $60 for all ST, LT, and XLT contiguous accounts. Additionally, the demand charges are calculated on Exhibit A-16 (AMG-5), Schedule F-3, pages 7through 10, using the methodology described above and applied to the peak month gas throughput volume as presented by Company witness Keaton. 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 September 10 Order, the Company is maintaining Rate XXLT's minimum annual eligibility requirement of 4 Bcf. These rate changes are shown in Exhibit A-16 (AMG-3), 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, and Case No. U-20650.

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 its cost-basis and maintaining the current breakeven points are no longer appropriate.

Q. Please explain Authorized Tolerance Levels ("ATL").

A. An ATL is a percentage of a transportation customer's annual contract quantity. A transportation customer's annual contract quantity is the greatest contracted quantity of natural gas that can be delivered for transportation on the customer's behalf for any given year as specified in the customer's transportation contract with the Company.

Q. Is the Company proposing changes to the ATLs offered?

A. No. Rate Exhibit A-50 (AMG-7) provides the credit calculation, and Exhibit A-16 (AMG-5), Schedule F-3, provides the revenue calculation for each transportation rate class, consistent with the structure approved in the September 10 Order.

Q. Is the Company proposing changes to the transportation charge adjustment associated with the ATLs?

A. No. Consistent with the September 10 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 6.5%. 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-50 (AMG-7), 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 September 10 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 6.5%.

V. <u>TYPICAL BILLS</u>

Q. Please describe Exhibit A-16 (AMG-6), Schedule F-4.

A. Exhibit A-16 (AMG-6), Schedule F-4, provides the impacts resulting from the proposed natural 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.

VI. CUSTOMER ATTACHMENT PROGRAM DISCOUNT AND CARRYING COST

Q. Please explain Exhibit A-51 (AMG-8).

A. Exhibit A-51 (AMG-8) 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 Hurd.

VII. REVENUE DECOUPLING MECHANISM

Q. What is an RDM?

A. EWR programs reduce the sale of natural gas, which impacts the Company's ability to collect its distribution revenues. Some form of adjustment mechanism is required to counter this disincentive for utilities to support energy efficiency. Decoupling is one mechanism used to remove this disincentive by separating the amount of revenue a utility receives from the amount of natural gas it sells. This provides a benefit to both the utility and its customers by enabling the Company to encourage energy waste reduction, while allowing for a reasonable opportunity to collect its authorized revenue requirements.

Q. Does Consumers Energy currently have an approved RDM in place?

A. Yes. The September 10 Order included an RDM that will be effective at the end of the test year, or October 1, 2021, and continues until the Company implements new rates.

Q. Is the Company proposing an RDM in this case?

A. Yes. The Company is proposing an RDM using the same methodology that was included in the September 10 Order.

Q. Please describe the RDM approved by the Commission in Case No. U-20650.

A. The calculation of the RDM approved by the Commission in Case No. U-20650 compares the weather-normalized actual revenue realized by the Company to the approved qualifying rate case revenue by rate schedule and subject to the following conditions: (i) for full service customers, revenues reflected in the calculation will be equal to total rate schedule revenue less monthly customer charges and excess peak revenues, gas cost recovery revenue, and other surcharge revenue; (ii) for gas choice customers, revenues reflected in the calculation will be equal to total rate schedule distribution revenue less monthly customer charge revenue and other surcharge revenue; (iii) all months associated with the projected test year will be excluded from true-up; thus, (iv) the first annual reconciliation period commences with the first month following the end of the general rate case projected test year (i.e., commencing October 1, 2021); (v) operation of the mechanism will terminate upon utility implementation of new rates and must be reapproved in the next general rate case order; (vi) allocation of the qualifying revenue shortfall will be by rate schedule, consistent with the calculation; (vii) the actual revenue used in the calculation will be weather-normalized in a manner consistent with the weather-normalization method proposed by Consumers Energy in this case; and (viii) Rate Schedule GS-3 and all Transportation Rate Schedules (ST, LT, XLT, and XXLT) will be exempt from the calculation. The Company proposes no changes to the RDM methodology in this case.

Q. When would the RDM reconciliation be filed?

A. The RDM reconciliation would be filed three months after the end of the 12-month period following the end of the projected test year, or three months after new rates are implemented, whichever comes first. The Company would file subsequent RDM reconciliations at the end of each 12-month period if new rates have not been implemented. With respect to the first annual reconciliation period, the qualifying revenue shortfall, by rate schedule, is capped at 1.5% of the rate case qualifying revenue; with respect to the second and succeeding reconciliation periods, the qualifying revenue shortfall, by rate schedule, is capped at 3.0% of the rate case qualifying revenue.

Q. **What is the basis for the revenue caps?**

A. As stated in the direct testimony of MPSC Staff witness Nicholas M. Revere in Case No. U-17643, page 23, lines 11 through 13, "the [revenue] caps reflects a reasonable estimate of the maximum qualifying revenue shortfall (or excess) that could be experienced by the Company, i.e., assuming the utility generated Energy Optimization ("EO") credits at a level equal to 150% of the statutory minimum." The revenue cap reflects the additional spending in gas energy efficiency approved in Case No. U-18261, which will achieve an annual reduction in gas use of 1.0%. The 1.5% qualifying revenue cap during the first RDM reconciliation is equivalent to 150% of the EO generated sales loss during the first annual reconciliation period, or 1.5*[½*1.0% + ½*1.0%]. For the second and succeeding periods, the 3.0% cap is equal to 1.5*[½*1.0% + 1*1.0% + ½*1.0%]. It should be noted that the EO targets are annualized numbers; thus, actual sales losses are approximately half of a given year's EO target, if efficiency measures are implemented by customers uniformly throughout the year.

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-21148
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

KAREN M. GASTON

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

Q. Please state your name and business address.

A. My name is Karen M. Gaston, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am the Director of Corporate Budget, Planning and Analysis and Data Systems and Standards for Consumers Energy Company ("Consumers Energy" or the "Company").

Q. Please state your educational background.

A. I graduated from Grand Valley State University with a Bachelor of Business Administration with majors in accounting and finance. I also graduated from Spring Arbor University with a Master of Business Administration.

Q. What are your responsibilities in your current position?

A. As Director of Corporate Budget, Planning and Analysis and Data Systems and Standards, I am responsible for the development of financial plans, budgets, outlooks, forecasts, and analysis for corporate departments as well as maintaining the data systems and standards used to support these processes at Consumers Energy.

Q. Please describe your prior work experience.

A. I have held my current position since February 2018. Prior to this role, I held various manager, lead, and accounting analyst roles within the finance organization, including in the Accounts Payable, Payroll, General Accounting, and Property Accounting departments. In these roles, I have been responsible for processing vendor and employee payroll payments, expense reporting, tax filing and remittance, property records and depreciation analysis, financial results including accounting entry, and reporting and analysis, including Federal Energy Regulatory Commission ("FERC") and Michigan

Public Service Commission ("MPSC" or the "Commission") report filings. From 2005 to 2008, I was a General Accountant for CMS Enterprises, responsible for accounting and financial reporting and analysis of subsidiary companies.

Q. Have you previously testified before the Commission?

A. Yes. I testified in MPSC Case Nos. U-20650, U-20697, and U-20963, 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 three parts. In Part 1, I am presenting testimony supporting the test year Operation and Maintenance ("O&M") and Capital expense for Corporate Services, uncollectible expense, injuries and damages, and Manufactured Gas Plant ("MGP") direct project management costs. In Part 2, I am presenting testimony requesting accounting approval for the use of regulatory assets or regulatory liabilities, as needed, by the Revenue Decoupling Mechanism ("RDM") and accounting approval as needed, by the deferred capital spending mechanism. In Part 3, I am presenting testimony demonstrating Consumers Energy's compliance with the guidelines for intercompany transactions between affiliates as ordered by the Commission. In Part 4, I am supporting the test year Industrial Products ("IP") and Compressed Natural Gas ("CNG") programs expense.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-52 (KMG-1)	Summary of Projected Gas & Common O&M Expense for the Years 2020, 2021, 2022; and the 12 Months Ending September 30, 2023;

Exhibit A-53 (KMG-2)	Gas Projected Corporate Services O&M Expense for the Years 2020, 2021, 2022; and the 12 Months Ending September 30, 2023;
Exhibit A-54 (KMG-3)	Gas Uncollectible Accounts Expense for the Years 2020, 2021, 2022; and the 12 Months Ending September 30, 2023;
Exhibit A-55 (KMG-4)	Gas Injuries and Damages Expense for the Years 2016 through the 12 Months Ending September 30, 2023;
Exhibit A-56 (KMG-5)	Manufactured Gas Plant Amortization Schedule and Direct Project Management Costs 2005 through the 12 Months Ending September 30, 2023;
Exhibit A-57 (KMG-6)	Organization Chart, Affiliate Group of Companies Doing Business with Consumers Energy Company – 2020; and Purpose of Business, Affiliate Group of Companies Doing Business with Consumers Energy Company – 2020;
Exhibit A-58 (KMG-7)	Summary of Costs Billed to Affiliated Companies for the Year Ended December 31, 2020; and Summary of Payments Made to Affiliated Companies for the Year Ended December 31, 2020;
Exhibit A-59 (KMG-8)	Impact on Gas Operations for Costs Billed to Affiliated Companies for the Year Ended December 31, 2020;

Exhibit A-60 (KMG-9)		Impact on Gas Operations for Payments Made to Affiliated Companies for the Year Ended December 31, 2020;
Exhibit A-61 (KMG-10)		Affiliated Companies – Rate of Return on Common Equity for the Year Ended December 31, 2020;
Exhibit A-62 (KMG-11)		2020 Gas Utilities Ranked by A&G per Customer (less Pension and Benefits);
Exhibit A-12 (KMG-12)	Schedule B-5.4	Gas Projected Corporate Services Capital Expense for the Years 2020, 2021, 2022; and the 12 Months Ending September 30, 2023; and
Exhibit A-63 (KMG-13)		Advisen Insurance Market Publications.

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

A. Yes, they were.

PART 1 – GAS CORPORATE SERVICES O&M EXPENSE

Q. Please describe Exhibit A-52 (KMG-1).

A. Exhibit A-52 (KMG-1) summarizes the Company's total 2020 through the 12 months ending September 30, 2023 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 2020 actual O&M, column (d) provides the 2021 O&M projection, column (e) provides the 2022 O&M projection, and column (f) provides the projected test year 12 months ending September 30, 2023 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-52 (KMG-1), line 1?

A. Corporate Services includes those areas common to the administrative functions of a regulated corporation. These include Governmental, Regulatory, and Public Affairs; General Counsel, Legal, and Risk Management; Human Resources and Learning and Development; Transformation and Operations Support; Chief Financial Officer; Strategy; 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:

- Governmental, Regulatory, and Public 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 determination and management of regulatory filings, and management of the interface between the Company and regulatory staffs;

- General Counsel, Legal, and Risk Management – This area includes the Legal Organization, the Corporate Compliance Department, the Corporate Secretary Department, the Securities Law Group, Corporate Information Governance, and Risk Management. 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;

- Human Resources and Learning and Development (recently reorganized and renamed as People and Culture ("P&C")) – 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 our 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, 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;

- Transformation and Operations Support – This area includes corporate safety and emergency management, security administration, quality, and corporate employee travel services;

- Chief Financial Officer – 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, payroll, fixed assets, and financial and regulatory reporting. In addition, 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 Chief Financial Officer area;

- Strategy – This area is responsible for performing analysis to generate recommendations that shape the Company's overall strategic direction. The Strategy organization manages the Company's long-term strategic planning process. Piloting of emerging technologies and customer offerings is also performed in the group;

- 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, senior management time and expenses; and

- Administrative and Other – These costs are primarily for American Gas Association dues and intervenor funding for the Gas Cost Recovery cases.

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-53 (KMG-2), line 14, provides the Company's gas portion of total Corporate Services expenses, before adjustments. The 2020 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-53 (KMG-2), line 15, column (d), shows the total normalizations of one-time costs from 2020 total Corporate Services expense. There were no normalized items in 2020. Also, the total of items disallowed by Commission order related to advertising, lobbying, and donation payments were removed on Exhibit A-53 (KMG-2), line 18. Total adjusted Corporate Services expense is found on Exhibit A-53 (KMG-2), line 19.

Q. What is the projected rate for labor?

A. The assumed rate of labor inflation used to project Corporate Services labor expense is 3.2%. Company witness Amy M. Conrad's direct testimony outlines and supports the Company's market-based compensation practices. The use of contract labor in the Corporate area is de minimis.

Q. What is the projected rate of non-labor inflation?

A. The assumed rate of non-labor 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 3.3% for 2021, 2.1% for 2022, and 2.0% for 12 months ending 2023. The Company uses these inflation rates to project non-labor Corporate

Services O&M and seeks to limit non-labor Corporate Services O&M increases to the rate of inflation.

Q. What is the source for the CPI?

A. The June 2021 edition of the IHS Markit U.S. Economic Outlook publication.

Q. Why does the Company use separate rates to project labor and non-labor expenses?

A. Labor rates and inflation rates can change based on different influences and at different rates. For example, a low supply in the housing market may increase CPI but could have no impact to the cost of labor. Therefore, using rates that align with the type of expense, as the Company does to project Corporate O&M expenses, is a more accurate method to project expenses than using a single inflation rate. In Exhibit A-53 (KMG-2), labor and non-labor expenses are clearly identified, and test year expenses are projected using separate rates. Further, 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 compensation linked to labor rate changes could result in Consumers Energy's employee compensation being below market, which could hinder the Company's ability to attract and retain a qualified workforce. Company witness Conrad's direct testimony further outlines and supports the Company's market-based compensation practices.

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-53 (KMG-2), Column (m), includes three specific line item changes; (1) ($753,475) to remove expenses included in Case No. U-20875 Consumers Energy Company Energy Waste Reduction (EWR) plan costs; (2) $1,139,238 increase for insurance premium expense; and (3) $4,775,577 for the Gas Safety Management Systems and Talent Enablement project.

Q. Why are specific line item changes necessary?

A. Inflating actual expenses using merit and inflation rates is a reliable method for projecting normal corporate labor and non-labor expenses but does not necessarily cover significant market changes that impact corporate costs or project investments. Therefore, increases or decreases in expenses above merit or inflation rates have been called out in Exhibit A-53 (KMG-2), Column (m) and described in detail below.

Q. Please describe in detail the specific line item changes included in Exhibit A-53 (KMG-2), Column (m).

A. Exhibit A-53 (KMG-2), Column (m) includes adjustments to three lines.

(1) Line 2, includes an adjustment of $753,475 to remove expenses included in the August 2021 filing of the EWR rate case. This adjustment includes labor and non-labor projected expense associated with the EWR and Demand Response programs that were historically included in the Governmental, Regulatory and Public Affairs department. For more details please reference Case No. U-20865.

(2) Line 3, includes an adjustment of $1,139,238 to increase the Company's gas property and liability insurances which insure mainly for: (i) the cost to replace or repair damage to Company facilities such as gas related properties (i.e., compressor stations), service centers, etc.; (ii) the cost arising from third parties who allege that the Company is liable for damages suffered because of the Company's negligent actions or failure to act (i.e., general liability insurance, fiduciary liability insurance, workers' compensation insurance, cyber insurance, etc.). This adjustment is based on market performance and insurance

intelligence, as determined by insurance experts at the Company. The cost of insurance is expected to increase above the rate of inflation due to industry losses, the low interest rate environment, and uncertainty around claims due to COVID-19. Industry publications support this conclusion. A November 23, 2020 Advisen article entitled "More rate increases and tightening up policy terms predicted for property market: Panel" (Erin Ayers) supports the increase of insurance costs by indicating that:

> The property insurance market faces a "crisis of profitability" and rate increases aren't likely to let up until the industry has recovered from an extended soft market, according to a panel of underwriting executives speaking during Advisen's virtual Property Insights Conference. [See Exhibit A-63 (KMG-13).]

A November 20, 2020 Advisen article entitled "P/C hard market conditions will continue into 2021: Willis" (Erin Ayers) states that:

> Commercial insurance buyers in North America should plan for continued increases in nearly every line of coverage through 2021, but some of the hard market impacts should begin to stabilize by mid-year, according to Willis Towers Watson's 2021 Insurance Marketplace Realities report. [See Exhibit A-63 (KMG-13).]

A November 24, 2020 Advisen article entitled "P/C insurance buyers advised to 'challenge the status quo' for 2021" (Erin Ayers) states that:

> "Q2 2020 renewals saw some of the largest pricing increases since 2003, led by umbrella/excess liability, directors and officer's liability, property, and commercial auto. This trend is likely to continue through 2022, although the rate of increase should begin to moderate by late 2021," said Locton in its update. "Any prediction, however, is clouded by ongoing uncertainty." [See Exhibit A-63 (KMG-13).]

(3) Line 4, includes a total adjustment of $4,775,577, which includes a $3,856,137 increase to develop competency-based training for gas operations employees and a $919,440

increase for the talent enablement project that will provide a means for the Company to continue excelling at the basics and building for the future.

<u>**Competency Based Training**</u>

Q. Why is a competency-based training model necessary to the Company and the customer?

A. In conjunction with the establishment of the new Flint Gas City training facility, the Company will develop comprehensive competency-based training programs focused on training current and future gas operations employees with the goals of demonstrating competency through training practice and assessments. In addition, once competencies are established, the Company facilitators will know the precise training and learning that is required to skill up workers to the desired level of competency and provide targeted learning. This will decrease the time it takes to bring employees to an increased level of competency regarding pipeline safety risks and the procedures that must be followed to ensure safety.

Q. What will this investment deliver?

A. This initiative is in direct support of the Company's Gas Safety Management System, specifically element 9, competency, awareness and training which follows the National Transportation Safety Board ("NTSB"), Pipeline and Hazardous Materials Safety Administration ("PHMSA") and MPSC recommendations for implementing API RP 1173 Pipeline Safety Management Systems. Company witness Stephanie V. Watson further describes the GSMS initiative.

- Page 19 Section 13 – "The pipeline operator shall assure that personnel whose responsibilities fall within the scope of the PSMS have an appropriate level of competence in terms of education, training, knowledge, and experience."
- Page 23 Section 15.10 – "The practice of assuring competency at all levels is a form of investment in an organization's employees. Employees see competency as critical to the sustainability of the organization and its success. Investment in building competency, like continuous learning, builds trust and confidence that management care about safety, their employees and contractor personnel, and the public."
- This investment will deliver (1) the development of new curricula for instructor-led classroom training, (2) scenario-based training exercises addressing emergency response actions, (3) structured on the job training with real world training experiences to reinforce classroom training, and (4) ongoing refresher training based on targeted and defined competencies.

Q. How will competency-based training be developed at the Company?

A. Based on benchmarking across the utility industry and the success of other utility programs, the Company has chosen to use the Mosaic Company, an outside contracted service, to assess and develop the competency-based programs. The Mosaic Company has developed and implemented competency-based training platforms at several utilities across the country to establish predetermined "competencies", which focus on outcomes and real-world performance. This has allowed companies to provide more competent employees, at a faster rate of competency, to better serve customers.

Q. What is the length of scope of the project?

A. The project will begin in 2023 and be implemented over a series of seven years, ending in 2029. The investment will include contractor competency training development support as well as four instructors to support the competency-based training model going forward. The financial investment for the test year will consist of $3,856,137.

<u>Talent Enablement Project</u>

The Company is implementing the talent enablement project that is critically important in allowing the Company's Human Resources area to support the Gas business in the delivery of the Gas Strategy. The talent enablement project is part of an overarching, multi-year talent enablement plan that includes both technology and non-technology efforts. The technology project associated with the talent enablement plan is described in Company witness Duncan D. Paterson's direct testimony and described below in the technology projects section. The non-technology projects associated with the talent enablement plan are described below:

- The **Career and Reward Framework** project requires $192,000 of O&M in the projected test year and will utilize an industry expert to develop and implement a framework that creates a seamless experience from hiring process through career development. This framework ensures there are clear career paths and career development opportunities for employees, while engaging in market-based compensation practices to attract, reward, and retain the talent needed to deliver on the Gas Delivery strategy and other Company initiatives while responding in the evolving utility industry. For example, as technology becomes more integrated, the Company will need enhanced and evolving cyber security skills to protect the grid. As customer expectations shift to desire on-demand expert advisement and a more personalized experience, the Company will need a workforce skilled in employing the power of data to meet customer needs. A variety of new skills will be needed to support this transformation, and the Career and Reward Framework project will provide a structure for the Company to continue to build these skill sets, including upskilling current employees and hiring new employees with different talents. The knowledge, skills, and abilities of employees are key determinants in the quality and timeliness of service that customers receive. The ability to deliver what customers expect – such as reliable and safe energy delivery, on-time completion of service orders, energy savings, accurate billing, and easy-to-navigate website and mobile applications – depends upon having the right talent, in the right job, at the right time. Customers benefit when the Company can attract the best people and retain their consistent expertise and growing experience for a long time. Reducing employee turnover also reduces costs and lost productivity associated with frequent recruiting and training.

- The **Co-worker Development** project requires $1,442,560 of O&M in the projected test year and focuses on three critical aspects of development. First, it will expand the Company's training curriculum centered around the new skills required to deliver on the Gas Delivery Strategy. Proper co-worker training will ensure that employees deliver gas service to customers that is safe and reliable. Second, it will expand the current leadership training program to meet the changing needs of leadership capabilities in the utility industry to provide improved employee and customer experiences. This project includes the continued development, implementation, and delivery of an enhanced training program and skills that support an increase in Gas knowledge as well as leadership capabilities. The training program will deliver a tailored curriculum of organizational learning programs designed to develop capabilities and qualifications necessary for leaders to manage effective teams and foster an inclusive and diverse culture, while making decisions aligned with the Company's goals to deliver customer value. The curriculum will be tailored based on a leader's development needs and includes: (1) tools and training to attract and retain the best candidates whose skills fit positions; (2) coaching for developing and career planning of employees; and (3) practical application in the business setting. The benefits of an enhanced and tailored leadership development curriculum include a streamlined plan for upskilling leaders in key areas needed to best serve their teams and customers, lower recruitment and turnover costs, and knowledgeable, engaged, and productive teams that are motivated to deliver first-time quality and on-time service to customers. Finally, this project will also support the addition of five employees within the Human Resources that directly support the hiring and training of the new employees needed to deliver on the work plan supported by the Gas Deliver Plan.

Q. Are the costs associated with restricted stock and the Employee Incentive Compensation Program ("EICP") included in the 2018 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 Conrad.

Q. Is the Company planning technology projects that support the Corporate Services functions?

A. Yes. Company witness Paterson includes in his direct testimony and exhibits, a number of 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 **Career and Reward Framework** project requires $99,108 in capital and $44,388 in O&M in the test year. To realize the goal of becoming the talent magnet of the Midwest, the Company must create clear career paths and engage in Human Resources (HR) practices and processes that effectively attract, reward, develop and retain the talent necessary to deliver on the Company's Integrated Resource Plan ("IRP"), Electric Distribution Infrastructure Investment Plan ("EDIIP"), and Natural Gas Delivery Plan ("NGDP"). The Career and Reward Framework project delivers a job architecture to create a seamless experience from the hiring process through career development, by defining jobs and the required qualifications including the knowledge, skills and abilities to ensure incumbent success as well as improve the accuracy of the benchmarking process to ensure jobs are assigned the correct market value. This architecture will create clear career paths and provide employees the opportunity to own their career development. It will also position the company to hire and develop the talent that will ultimately ensure timeliness and quality of customer service delivery. Technology enablement is required to implement and integrate this new framework into HR processes to deliver value company-wide and ultimately to our customers. Currently the Company does not have a technology system that supports the development, integration or operationalization of a best-in-class Career & Reward Framework. There is currently no technology to deliver a consistent approach to building, maintaining, and managing job descriptions. Furthermore, the current HR system configurations do not facilitate the integration of the new and enhanced framework data which limits the ability to embed the framework into processes to deliver the ultimate value across HR and the company as a whole. The inability to operationalize the new framework data in our current SAP HCM also has a direct impact on the Company's security efforts to enhance our Role-Based Access Controls across our systems. This effort will deliver a technically enabled Career and Reward Framework that is integrated into technologies and processes across HR and Company-wide. The project will deliver value by: (1) defining and creating job descriptions that represent the work employees need to do to deliver on company roadmaps and goals, while ensuring each job has been accurately market-priced to enable the creation and maintenance of a market competitive salary structures can be created and maintained. (2) Delivering a technically enabled standard and consistent process of managing and maintaining job descriptions and job data with minimal manual effort and tracking. (3) Integrating the newly defined job architecture, job descriptions and job data into HR and Company-wide systems and processes to support process optimization and waste elimination. (4) Providing the technical foundation and capability to build HR processes and programs that will support the attraction, development and retention of employees critical to deliver an exceptional customer experience. (5) Delivering transparent and clear career paths and development opportunities for employees to grow through leadership or promotional opportunities, or through cross-functional developmental lateral experiences. The project scope includes implementing technology solutions to (1) technically enable job description and job data management; (2) deliver the technical foundation and capability to integrate the new job architecture into current systems and processes by enhancing and updating applicable systems; and (3) deliver market data on demand to provide insights into changing market conditions and help the HR organization be responsive to the needs of the business. Alternatives considered include: (1) Develop a custom solution. This alternative was not selected because although it could meet some requirements, a custom solution would result in higher overall costs, higher maintenance costs, fewer upgrades and would have limited ability to integrate with current systems and processes. Moreover, an internally built custom solution would not leverage industry best practices or deliver access to extensive market data necessary to complete accurate and timely market reviews of every job in our Company. (2) Investigate implementing career and reward frameworks in the Company's current HR systems and applications. (3) Choose a new solution(s) that is specifically designed for managing job descriptions and delivers the ability to complete job market analysis based on extensive market data. A combination of alternatives (2) and (3) is the most cost effective way to deliver the capability. In order to establish the new Career and Reward Framework, new technologies will be needed (option 3), however, in order to fully integrate the new framework into current systems and processes, enhancements (Option 2) will be needed in our current systems.

- The **EHS Compliance** project requires $27,009 in capital and $5,243 in O&M in the test year. The Environmental Health and Safety ("EHS") Compliance project will implement a comprehensive Company-wide solution to ensure accurate and consistent reporting of health, safety, environmental, and operations compliance regulatory requirements. The Company lacks a central tool to track environmental and safety compliance, which results in having to maintain disparate systems and information, which requires many manual steps to collect and consolidate information for internal and external reporting requirements. The systems used are running on obsolete technology. Much of the knowledge required for compliance reporting is with experienced individuals, versus processes and systems. Institutional knowledge is at risk of being lost as environmental expertise leaves with employee retirements. For compliance purposes, the Company needs to update its Safety incident forms consistent with Company Security policies, which include the encryption of Personal Identification Information/Personal Health Information (PII/PHI) data. This project provides value for the Company and its customers by: (1) incorporating standard workflows and forms for a single source repository of Environmental and Safety data for efficient information collection and analysis for standardized corrective actions; (2) supporting the Company's "Planet" goal through enhanced tracking and reporting for air quality, water, waste, spills, and sustainability; (3) avoiding risk for environmental and occupational safety and health penalties through standard tracking and centralized reporting information; (4) increasing productivity and quality; (5) enabling goal tracking transparency; and (6) creating awareness of and improving response to emerging environmental, health and safety, and operations compliance regulations through the addition of visual management and dashboards. The project scope includes the implementation of a cloud solution and configuring the following modules and features of the solution: (1) task management calendar; (2) inspections and observations; (3) corrective actions tracking and management; (4) incident management; (5) air management; (6) water management; (7) environmental waste and spill management; (8) risk management; and (9) sustainability. The project will develop visual management to track metrics and data through dashboards and reports based on standard business processes. The project will also take advantage of existing systems in the Company by implementing integration to the new solution for: (1) human resources data and metrics; (2) data management and analytics; and (3) web data connectors for access to the data by other internal systems. The project will also migrate historical data to the new solution needed for record keeping and regulatory reporting. Three alternatives were considered for this project: (1) continue with disparate and obsolete technology solutions; (2) pursue separate projects for environmental compliance and for safety and health compliance solutions; and (3) implement a single solution for both environmental compliance and safety and health compliance. The first alternative requires lengthy manual effort with an obsolete technology solution, which introduces risk to accurate and central tracking of EHS data. The second alternative does not meet the cost-effective industry standard practice of combining Environmental and Safety Compliance Incident and Resolution Tracking for these solutions, which use integrated functionality for environmental and safety compliance tracking and remediation. The third alternative was chosen due to the benefit of consolidated data in a single system and the resulting lower ongoing expense. The selected alternative also considered both on-premise and cloud solutions. The single cloud-based solution was chosen due to lower implementation and ongoing maintenance costs.

- The **Expense Reporting Improvements** project requires $128,743 in capital and $38,070 in O&M in the test year. The Expense Reporting Improvements project will increase productivity when creating expense reports, both desktop and mobile; 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. 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. No mobile capabilities exist for the existing expense report creation process. All these problems impact employees leading to poor employee engagement scores in regard to simple processes, productivity, and transparency leading to increased costs, inefficiencies, exceptions to policies, and compliance issues. This project provides value for the Company by: (1) improving expense policy compliance and reducing exceptions; (2) offering a more user-friendly experience leading to improved employee engagement; and (3) enabling mobile capabilities for expense report submission. 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; (3) provides mobile options; and (4) integrates corporate credit card data into expense reports. 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 **Labor Relations Management Software** project requires $7,127 in capital in the test year. The project will deliver complete lifecycle support for critical union-related Labor Relations processes and tasks. Specifically, the software will support management of seniority lists, grievances, arbitration, job bidding, as well as maintenance of electronic Collective Bargaining Agreements (“CBAs”). Advanced reporting and analytics for all supported union labor processes will be delivered along with opportunities for new mobile capabilities. Multiple labor relations processes introduce risk, waste, and errors that may impact the union workforce. Union seniority lists are manually maintained in 72 separate spreadsheets, each with multiple worksheets requiring 500-700 changes per month. Each change requires modifying the spreadsheets in multiple places per negotiated union contracts. The process is time-consuming, prone to potential human error due to the manual nature of each change and requires collating information from various sources. The manual process has a single point of failure risk, with just one employee who has the knowledge of the process and relevant union contract rules. In addition, manual processes for grievance and arbitration have little opportunity for electronic tracking and documentation, cannot automate grievance payouts when applicable, and lack a system to standardize grievance and arbitration letter templates, which result in inconsistencies and additional manual effort for the Labor Relations team. As a result of these manual processes, grievance and arbitration data is not readily available, or requires significant manual effort to achieve even basic reporting or visual management. Although union job postings are electronically available, the process to select the top bidder is manual. Selection is based on union seniority and other rules in the union contract which is time consuming and prone to risks due to human error within the process. Finally, while Collective Bargaining Agreements are housed in a Labor Relations SharePoint site, there is opportunity to enhance the management and accessibility of these contracts, and ensure they are seamlessly embedded into Labor Relations processes without the need to access multiple systems and applications. The project will add value to the Company by: (1) reducing waste and enhancing data accuracy critical to union employees for seniority rights through automation of manual activities associated with maintaining union seniority lists; (2) enabling automation and streamlining the selection of top bidders on job postings per contractual requirements through configuration of seniority and other union contract and business rules; (3) reducing waste and inconsistencies, enhancing documentation, improving tracking, and streamlining reporting by delivering standard grievance, and arbitration, processes; (4) increasing consistency and standardization of union communications through standard templates and workflows; (5) reducing risk by enhancing document tracking and storage for future reference as required for grievances, arbitration, and contract negotiations; (6) enabling increased data insights, analytic capabilities, and visual management through enhanced data gathering and reporting without the need for significant manual efforts to consolidate data; (7) significantly enabling and enhancing user experience for field leaders, union employees, and Labor Representatives by delivering mobile capabilities for Labor Relations processes; (8) providing opportunities for employees who currently manually manage the above mentioned processes to focus on more value-added tasks and projects; (9) decreasing risk of grievances associated with contractual non-compliance resulting from potential human error within manual processes. The project scope includes: (1) creating workflows for grievances and arbitrations; (2) creating job bidding business rules to support automated bidder selection; (3) defining and delivering labor relations analytics; (4) generating letter templates and configurable forms (such as Investigation notices, dismissal letters, leniency documents, and appeal responses); (5) managing seniority lists; (6) enabling mobile capabilities for all functions listed above; and (7) delivering electronic management of all Collective Bargaining Agreements/Contracts Alternatives considered include: (1) Develop a custom solution. Although it 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. (2) Choose an on-premise software tool. This alternative requires internal maintenance, increased infrastructure costs, and less frequent upgrades. (3) Choose a cloud solution resulting in reduced infrastructure costs, less internal maintenance than an on-premise solution, includes best practices, and regular application upgrades. Based on research and vendor demonstrations, alternative 3 is the preferred option.

- The **Legal Case Management** project requires $82,152 in capital and $28,485 in O&M in the test year. This project will implement software to manage litigations, investigations, and discovery requests; eliminate irrelevant data; reduce data volumes; improve self-service capabilities; and facilitate Legal reviews. In late 2016, the Company received a yellow audit finding related to the use of a litigation management platform considered to be insufficient. Since 2015, seven large cases have required the Company to augment the Legal department to accommodate a large review of data. Current capabilities require processing large volumes of data, a manually intensive and time consuming process resulting in larger data review sets than necessary and waste. This project creates value for the Company by: (1) The Legal Department can perform global or custodian specific searches on unstructured documents, and manage and preserve documents related to a legal hold; (2) increasing efficiency of Legal staff with more capabilities to analyze and cull data thereby reducing the total volume of discovery to process, review, or produce; (3) reducing cases sent to Outside Legal Counsel resulting in cost savings; (4) reducing the need to augment the Legal Team in the review phase; (5) responding expeditiously to new initial disclosure and electronically stored information requirements in the new Michigan Civil Discovery Court Rules; (6) providing a more comprehensive tool to manage an inclusive preservation strategy and find key aspects of the litigation quickly and defensibly; and (7) remediating a 2016 yellow audit finding. The scope of this project includes: (1) implementation of a litigation, investigations, and discovery platform; (2) enabling external access for outside counsel; (3) configuring workflows for initial review, review for privilege, review for redaction; review for responsiveness, and final production; (4) creation of new reports to increase visibility into case status; and (5) controlling access to cases internally and externally. Three alternatives were considered for the Legal Case Management project: (1) Continuing the current process. This option is not preferable as it results in developing workarounds when server space is not available, discovery turn around times cannot be met, the current software solution is not an industry leader, and the yellow audit finding is not remediated. (2) Choosing an on-premise software tool which would introduce new licensing, hardware, and ongoing maintenance costs. (3) Choosing a cloud solution. This would save on infrastructure costs, internal maintenance would be less than an on-premise solution, but annual subscriptions costs are high. Based on vendor input and Company analysis, a combination of managing some content on-premise and some in the cloud (Option 2 and 3) is ideal and are reflected in the funding request.

- The **Rates Case Implementation** project requires $105,104 in O&M in the test year. The Rates Case Implementation project will modify SAP billing in accordance with pricing and rate change requirements. 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. 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. 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. 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. 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 **Supplier Portal for Invoice Management** project requires $27,009 in capital and $73,440 in O&M in the test year. The project will expand the Company service portal to implement self-service vendor features to streamline purchase order and invoice management and improve visibility to invoice and payment status. 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. The limitations of the existing portal result in waste and inefficiencies for vendors and Company employees, and creates the potential for late payments or missing early payment discounts. This project creates value for the Company by: (1) providing vendors with real-time invoice and payment status; (2) creating self-service functionality that allows the vendor to select items from a purchase order to create an invoice on demand; (3) increasing employee productivity by eliminating waste by automating the extraction of invoice information; (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 ; and (7) integrating into the OpenText AP Automation solution currently being implemented. The project scope includes: (1) configure ability for vendors to electronically self-submit invoices; (2) configure ability for vendors to self-convert items on a purchase order to an invoice; (3) configure ability for vendors to view invoice and payment status; (4) create new reports and dashboards; (5) enabling method to validate vendors should have access to the portal and removing access when appropriate; and (6) integration to vendor invoice management system and SAP. 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 would not leverage best practices; (3) Building a combination of custom and integration to existing solutions. This option was not selected because it would not follow industry best practices; and (4) expand our current vendor portal (4) 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.

- The **Talent Management Enablement** project requires $243,081 in capital and $49,410 in O&M in the test year. 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 IRP, EDIIP, and 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. 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, which limits pace and effectiveness of talent development. For example, the Company has identified the competencies required to support clean energy delivery. However, the Company has limited visibility of competency gaps within the workforce. Additionally, 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. This project will add value to the Company through: (1) accelerated and targeted talent development of critical skills necessary to deliver on the Company's commitment to clean energy and exceptional customer experience; (2) 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; (3) 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 (4) 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 solutions to support and enhance the following Talent Management processes: (1) Continuous Performance Management and Coaching (including 360 Reviews); (2) Succession Planning and Business Continuity; (3) Career Development and Employee Retention; (4) Badging and Credentialing. 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. 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.

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 S&P Global Market Intelligence ranked Consumers Energy's 2020 gas A&G costs (excluding pension and benefits) the fourth lowest out of the 30 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 is a great indicator of the Company's diligence in managing overhead costs to help keep rates affordable for customers. Please refer to Exhibit A-62 (KMG-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.

Corporate Services Capital Expense

Q. Please describe Exhibit A-12 (KMG-12), Schedule B-5.4.

A. Exhibit A-12 (KMG-12), Schedule B-5.4, summarizes the Company's total 2020 through the 12 months ending September 30, 2023 gas capital expenditures for Corporate Services. Column (a) of this exhibit provides the description; column (b) provides the 2020 actual capital; column (c) provides the projected 2021 capital; column (d) provides the 2022 capital; column (e) provides the projected 24 months ending December 31, 2022 capital; and column (f) provides the projected test year 2023 capital. 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 2020 actual Capital expenses were obtained from the Company's records and projected using labor and non-labor inflation rates as described in my direct testimony above.

Gas Uncollectible Expense

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 $12.4 million as shown on Exhibit A-54 (KMG-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 2018 through 2020, as shown on Exhibit A-54 (KMG-3), page 2. This ratio is applied to the test year gas service revenue, plus EWR surcharge revenue, to arrive at test year uncollectible accounts expense on Exhibit A-54 (KMG-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 times the three-year average BDLR, 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. It is impossible to predict which, and to what extent, the future impact of any one of these factors could have on uncollectible expense. As a result, the Company has consistently used a three-year average BDLR approach in its recent rate case filings. This method most effectively captures the recent trends of the many factors that can impact uncollectible accounts expense. This approach was approved by the Commission in the Company's most recent gas rate case in Case No. U-20650.

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. The benefits of these actions are reflected in the continuous decline in net write-offs from 2016 through 2020.

Gas Injuries and Damages Expense

Q. Please describe Exhibit A-55 (KMG-4).

A. Exhibit A-55 (KMG-4) summarizes the Company's total 2016 through 2020 actual gas injuries and damages expense and projected injuries and damages expense through the 12 months ending September 30, 2023.

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 $2.0 million be included for the test year as shown on Exhibit A-55 (KMG-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-55 (KMG-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 2016 through 2020.

<u>MGP Site Remediation and Direct Project Management Costs</u>

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-56 (KMG-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 2020 and projected expenditures through December 31, 2023.

Q. Why are you including projected expenditures through December 31, 2023 and not through the projected test year ending September 30, 2023?

A. I am including projected expenditures through December 31, 2021 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-56 (KMG-5), page 1.

A. Line 2 shows the third-party insurance recoveries for the years 2005 through 2020 and projected recoveries through December 31, 2023. Lines 3 through 19 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 20 and acts as a credit to the amortization of expenditures identified in this case. Line 21 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-56 (KMG-5), page 1, line 21, is included in the direct testimony and Exhibit A-13 (HLR-43), Schedule C-6, of Company witness Heather L. Rayl.

Q. Please explain Exhibit A-56 (KMG-5), page 1, line 22.

A. Line 22 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 is effective for the calendar year 2006 onward. These costs are carried forward to line 4 of Exhibit A-52 (KMG-1).

Q. Please explain Exhibit A-56 (KMG-5), page 2, related to the rate base treatment of the MGP unamortized balance.

A. Exhibit A-56 (KMG-5), page 2, provides the net unamortized balance of actual deferred MGP remediation costs and third-party recoveries for the years 2005 through 2020 and projected balances for the year 2021. 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 September 30, 2022 and 12 months ending September 30, 2023. 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 actual costs for periods through 2019 as sponsored by Company witness Heather M. Prentice, are reasonable and prudent; (ii) authorize recovery of amortization expense in the amount of $9.7 million as provided on Exhibit A-56 (KMG-5), page 1; (iii) approve test year direct project management costs of $1.4 million as provided on Exhibit A-56 (KMG-5), page 1; and (iv) include the deferred net unamortized balance in the amount of $44.4 million in rate base as provided on Exhibit A-56 (KMG-5), page 2.

PART 2 – ACCOUNTING REQUEST FOR RDM ACCOUNTING

Q. Does the implementation of an RDM, discussed in Company witness Alex M. Gast's direct testimony, require any specific accounting approvals?

A. Yes. The RDM would result in deferred debits or credits until any under-recovery or over-recovery is fully collected or refunded. The Company requests approval to recognize regulatory assets or liabilities as needed to record these deferred amounts.

Q. Would any outstanding regulatory asset or liability associated with an RDM accrue interest?

A. Yes. Any outstanding regulatory asset or liability associated with these mechanisms would accrue interest at the Company's short-term borrowing rate.

PART 3 – AFFILIATED COMPANY TRANSACTIONS

Q. What is the purpose of your direct testimony with respect to Affiliated Company Transactions?

A. I am sponsoring Exhibits A-57 (KMG-6), A-58 (KMG-7), and A-59 (KMG-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-60 (KMG-9) and A-61 (KMG-10), as described below.

Q. Please explain Exhibit A-57 (KMG-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-58 (KMG-7).

A. This exhibit summarizes costs billed to affiliated companies, page 1, and payments made to affiliated companies, page 2, for the year 2020.

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-59 (KMG-8), gas operations were favorably impacted by $661,399.

Payments Made to Affiliated Companies

Q. Please describe the types of goods provided by affiliates and services performed for Consumers Energy as shown on Exhibit A-58 (KMG-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 2020 is $61,284 as shown on Exhibit A-60 (KMG-9).

Q. Please explain Exhibit A-61 (KMG-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.

PART 4 – IP & CNG PROGRAM EXPENSES

Q. Please describe what is included in IP and CNG programs in Company witness Cullen M. Hale's Exhibit A-97 (CMH-3).

A. IP and CGN programs include legacy programs that are winding down. Test year expenses are lower than historical actual expenses and reflect the closing of previous contract obligations and include minimal residual expected costs once the programs are ended. As the costs and complexity associated with the programs have continued to increase, the margins have decreased. As a result, the customer and Company benefit associated with them no longer outweigh the costs of maintaining them.

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-21148

DIRECT TESTIMONY

OF

MICHAEL P. GRIFFIN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

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 Manager of Asset Strategy in the Gas Strategy Department, a position I have held since July 2021.

Q. What are your responsibilities as Manager Asset Strategy?

A. I am responsible for the cross-functional research, analysis, and oversight of natural gas transmission assets and transmission portfolio management strategy. This includes the development, recommendation, and administration of the Natural Gas Delivery Plan.

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, and have held positions of increasing responsibility. Positions I have held include 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 of 2021, I have held the role of Manager of Asset Strategy for the Company's transmission assets.

Q. Are you a member of any professional societies or trade associations?

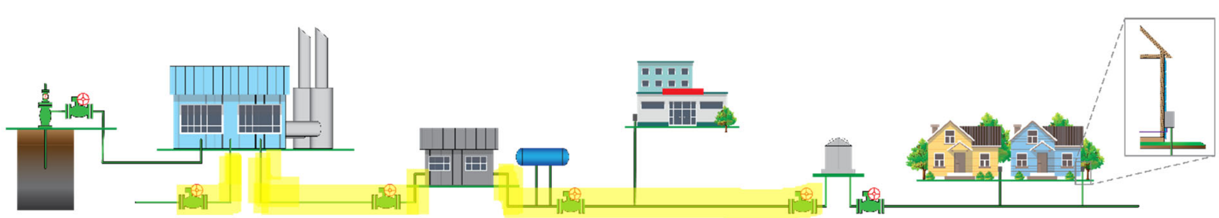
A. No, I am not.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. No, I have not.

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 Natural Gas Delivery Plan ("NGDP"), Exhibit A-45 (NPD-1), sponsored by Company witness Neal P. Dreisig.



I have divided my direct testimony into four sections through the test year ending September 30, 2023: (i) Asset Relocation Transmission capital expenditures; (ii) Regulatory Compliance O&M and capital costs; and (iii) Capacity/Deliverability capital expenditures. In Section (iv) of my direct testimony, I will also discuss certain Information Technology ("IT") Projects that support gas transmission operations.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-64 (MPG -1)		Summary of Actual & Projected O&M Expenses, Regulatory Compliance - MAOP Transmission Program;
Exhibit A-12 (MPG-2)	Schedule B-5.5	Projected Capital Expenditures Transmission & Distribution Plant - Summary of Actual & Projected Gas Capital Expenditures;
Exhibit A-65 (MPG-3)		Actual & Projected Gas Transmission Capital Expenditures - Asset Relocation Transmission Program;
Exhibit A-66 (MPG-4)		Actual & Projected Gas Transmission Capital Expenditures – Regulatory Compliance Program;
Exhibit A-67 (MPG-5)		Actual & Projected Gas Transmission and Distribution Capital Expenditures - Capacity/Deliverability Program;
Exhibit A-68 (MPG-6)		Actual & Projected Gas Capital Expenditures - Transmission & Distribution Plant - TED-I Program Summary:
Exhibit A-69 (MPG-7)		Actual & Projected Gas Transmission Capital Expenditures - TED-I Pressure Limiting Devices (PLDs) Project Details;

Exhibit A-70 (MPG-8)	Actual & Projected Gas Transmission Capital Expenditures - TED-I Remote Closure Valve (RCVs) Project Details;
Exhibit A-71 (MPG-9)	Actual & Projected Gas Transmission Capital Expenditures - TED-I Pipeline and Other Project Details;
Exhibit A-72 (MPG-10)	Summary of Actual & Projected Gas Capital Expenditures - Transmission & Distribution Plant, Saginaw Trail Pipeline Project;
Exhibit A-73 (MPG-11)	2020 Monthly Capital Expenditures for TED-I Gas Pipeline Projects – Saginaw Trail;
Exhibit A-74 (MPG-12)	2021 Monthly Capital Expenditures for TED-I Gas Pipeline Projects – Saginaw Trail;
Exhibit A-75 (MPG-13)	2022 Monthly Capital Expenditures for TED-I Gas Pipeline Projects – Saginaw Trail;
Exhibit A-76 (MPG-14)	2023 Monthly Capital Expenditures for TED-I Gas Pipeline Projects – Saginaw Trail;
Exhibit A-77 (MPG-15)	Projected Capital Expenditures - Transmission & Distribution Plant, Mid-Michigan Pipeline Project, Summary of Actual & Projected Gas Capital Expenditures;
Exhibit A-78 (MPG-16)	2020 Monthly Capital Expenditures for TED-I Gas Pipeline Projects – Mid-Michigan Pipeline;
Exhibit A-79 (MPG-17)	2021 Monthly Capital Expenditures for TED-I Gas Pipeline Projects – Mid-Michigan Pipeline;
Exhibit A-80 (MPG-18)	2022 Monthly Capital Expenditures for TED-I Gas Pipeline Projects – Mid-Michigan Pipeline;

Exhibit A-81 (MPG-19)	2023 Monthly Capital Expenditures for TED-I Gas Pipeline Projects – Mid-Michigan Pipeline;
Exhibit A-82 (MPG-20)	Projected Capital Expenditures - Transmission & Distribution Plant, South Oakland Macomb Network Project, Summary of Actual & Projected Gas Capital Expenditures;
Exhibit A-83 (MPG-21)	2020 Monthly Capital Expenditures for TED-I Major Projects – South Oakland Macomb Network;
Exhibit A-84 (MPG-22)	2021 Monthly Capital Expenditures for TED-I Major Projects – South Oakland Macomb Network;
Exhibit A-85 (MPG-23)	2022 Monthly Capital Expenditures for TED-I Major Projects – South Oakland Macomb Network;
Exhibit A-86 (MPG-24)	2023 Monthly Capital Expenditures for TED-I Major Projects – South Oakland Macomb Network; and
Exhibit A-87 (MPG-25)	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-64 (MPG-1)?

A. Exhibit A-64 (MPG-1) shows the total O&M expenses for Regulatory Compliance - Maximum Allowable Operating Pressure ("MAOP") Transmission Program that I am sponsoring. I will further describe in my testimony the program expenses and projects contained within this program. As shown on line 1 of Exhibit A-64 (MPG-1), the O&M expenses I am sponsoring were $456,000 in 2020, and are projected to be $1,005,000 in

2021; $992,000 in 2022; and $1,261,000 for the 12 months ending September 30, 2023. These expenses are shown in Table 1 below.

Table 1 Total O&M Expenses

($000)	(a)		(b)	(c)	(d)	(e)
Line No.	Description		2020 Actual	2021 Projected	2022 Projected	Projected 12-Mos Ending Sep 30, 2023
	MAOP - Transmission					
1		MAOP - Transmission	456	1,005	992	1,261

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 that I am sponsoring. I will further describe in my testimony 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 $254,510,000 in 2020, and are projected to be $236,461,000 in 2021; $211,023,000 for the nine months ending September 30, 2022; and $351,315,000 for the 12 months ending September 30, 2023. These expenditures are shown in Table 2 below.

Table 2 – Total Capital Expenditures

($000)	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line No.	Program Description	12 Mos Ended 12/31/2020	12 Mos Ending 12/31/2021	9 Mos Ending 9/30/2022	21 Mos Ending 9/30/2022	12 Mos Ending 9/30/2023
1	Asset Relocation	4,314	12,733	8,520	21,253	10,261
2	Regulatory Compliance	1,645	2,543	1,661	4,204	3,823
3	Capacity/Deliverability	248,551	221,185	200,843	422,028	337,231
4	Total Capital	254,510	236,461	211,023	447,484	351,315

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 will move forward with the currently scheduled Transmission Enhancements for Deliverability & Integrity ("TED-I") projects and the re-build schedule for city gate facilities. This information can be found in Section IV, part C, Transmission Asset Plan of the NGDP. The Company is also rebuilding distribution regulator station facilities. This information can be found in Section IV, part 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 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 to 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 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 mains 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 is the 25th Street Line Lowering in Allegan County where the Company coordinated with the County to lower Line 1300 to accommodate a road grading project Another example was the Company's coordination with Oakland and Washtenaw Counties to relocate Line 1020 to accommodate plans for a new traffic pattern at the intersection of 8 Mile Road and Currie Road.

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. The Asset Relocation Transmission Program projects are designed and constructed to comply with minimum soil cover requirements specified by federal regulations, 49 CFR 192.327. 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 $4,314,000 in 2020, and are projected to be $12,733,000 in 2021; $8,520,000 for the nine months ending September 30, 2022; and $10,261,000 for the 12 months ending September 30, 2023. These expenditures are shown in Table 3 below.

Table 3 Asset Relocation Capital Expenditures

($000)	(a)	(b)	(c)	(d)	(e)	(f)
		Asset Relocation Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line		12 Mos Ended	12 Mos Ending	9 Mos Ending	21 Mos Ending	12 mos. Ending
No.	Program Description	12/31/2020	12/31/2021	9/30/2022	9/30/2022	9/30/2023
1	Asset Relocation - Transm	4,314	12,733	8,520	21,253	10,261

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. Examples of asset relocation projects included in these projected expenditures include:

- Line 1600 Lake Park Drive and Eldridge Lane in Oakland County;
- Line 1300 25th Street civic improvement in Allegan County;
- Line 1020 Currie Road civic improvement in Oakland & Washtenaw Counties;
- Line 1200A Wetland BR038 line lowering in Branch County;
- Line 1200A County Drain 15 in Branch County;
- Line 1200A McKale Road line lowering in farm field in St. Joseph County; and
- Line 1200A Wetlands BR014, BR017 and BR032 lowerings 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-65 (MPG-3) provides further details on the expenditures included in this program.

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 and anticipated future replacement under another program (such as TED-I).

Q. Please describe the customer benefit attained from the projects in this program.

A. For the Asset Relocation Transmission Projects that Consumers Energy initiates, replacing and lowering pipeline segments in locations where grading or erosion has reduced cover to less than depths specified by 49 CFR 192.327 (minimum of 3 feet) benefits 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 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 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 $1,645,000 in 2020, and are projected to be $2,543,000 in 2021; $1,661,000 for the nine months ending September 30, 2022; and $3,823,000 for the 12 months ending September 30, 2023. These expenditures are shown in Table 4 below.

Table 4 Regulatory Compliance Capital Expenditures

($000)	(a)	(b)	(c)	(d)	(e)	(f)
		Regulatory Compliance Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line No.	Program Description	12 Mos Ended 12/31/2020	12 Mos Ending 12/31/2021	9 Mos Ending 9/30/2022	21 Mos Ending 9/30/2022	12 mos. Ending 9/30/2023
1	MAOP Pipeline	1,028	2,543	1,661	4,204	3,823
2	MAOP M&R	617	0	-	0	-
3	**Total Capital**	**1,645**	**2,543**	**1,661**	**4,204**	**3,823**

The Regulatory Compliance capital program consists of two transmission programs: MAOP Compliance Pipeline Program; and MAOP Compliance Measurement and Regulation 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 Pipeline and Hazardous Materials Safety Administration ("PHMSA") to direct each owner or operator of a 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 2019 Statewide Energy Assessment, 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 ("SEA") of the Company's Transmission System. The analysis will determine where work is required to meet the traceable, verifiable, and complete criteria, and upgrading 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 a risk-based evaluation that will consider the six methods of MAOP Reconfirmation identified in 49 CFR §192.624. 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
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
- 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. Capital projects planned for 2021 include replacement of Valve 1322 and associated piping at G Avenue valve site in Kalamazoo County. The Company is also projecting, beginning in 2022, a capital project to replace multiple short segments missing TVC pressure tests that are nearby each other, but not necessarily adjacent, where mobilization of resources is practical and efficient.

Q. Please describe the O&M expenses related to the Regulatory Compliance - MAOP Transmission Program as shown on Exhibit A-64 (MPG-1), line 1.

A. As shown on Exhibit A-64 (MPG-1), page 1, line 1, and in Table 1, above, the O&M expenses for this program were $456,000 in 2020, and are projected to be $1,005,000 in 2021, $992,000 in 2022, and $1,261,,000 in the test year 12 months ending September 30, 2023. The test year O&M expense is comprised of three parts. The first part is an annual expense of $500,000 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 that must be completed due to class location changes. The necessity and nature of class location changes are described in the Deliverability Base Pipeline capital program later in my testimony. These two projects are included in this O&M program because the length of pipeline replacement is less than 50 feet, which is the threshold for capitalization. The third part of the test year expense is due to expensing the O&M portion of the Standardization Engineering Analysis ("SEA") costs. The SEA is more fully described above. In 2021, in response to an MPSC 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 2019 and 2020 time period based upon the percentage of orders that have 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 2021, the Company expensed the amount of $720,526 for the annual SEA expenditures for 2017 and 2018. Table 5 below shows the SEA amounts expensed in 2021 and the annual SEA amounts to be expensed in the test year.

Table 5 SEA Expensed in 2021 and Test Year Calculation

Year	Direct Cost	O&M %	O&M Cost	
2017	359,713	100%	359,713	Expensed in 2021
2018	360,813	100%	360,813	Expensed in 2021
Amount Expensed in 2021			**$ 720,526**	

Year	Direct Cost	O&M %	O&M Cost
2019	$ 408,998	27%	$ 111,247
2020	$ 706,114	49%	$ 348,114
Test Year Amount			**$ 459,362**

The projects and expenses in 2022, 2023, and the test year are shown in Table 6 below.

Table 6 Regulatory Compliance O&M Expenses by Project

Regulatory Compliance - MAOP Transmission O&M Expenses	2022	2023	12 Months Ending Sept 30, 2023
GL-02780 - Line 100A (33' of pipe replacement due to class location change)		$ 276,815	$ 207,611
GL-02770 - Line 1400 - (4' of pipe replacement due to class location change)	$ 376,985		$ 94,246
Aerial High Resolution Leaf Off Imagery Survey for Class Location Studies	$ 500,000	$ 500,000	$ 500,000
Standardization Engineering Analysis Expense	$ 114,840	$ 344,521	$ 459,362
Total MAOP Transmission O&M Expense	**$ 991,825**	**$1,121,336**	**$ 1,261,219**

Company witness Heather L. Rayl discusses the reduction to rate base for the 2017 through 2020 amounts.

Q. Please explain page 2 of Exhibit A-64 (MPG-1).

A. Page 2 of Exhibit A-64 (MPG-1) presents an illustration of 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. The expenses that I am supporting are based upon the expenses for the aerial survey, two class location change projects and SEA expense as explained above.

Q. Please describe the MAOP Compliance Measurement and Regulation Program.

A. The MAOP Compliance Measurement and Regulation Program expenditures are for the installation or modification of pressure regulation facilities that limit pressures of downstream pipelines. While projects in this program are undertaken primarily due to the age and condition of the facilities, this work will allow for the reduction of MAOP on pipelines in order to reduce risk. If large volume meter stands are affected as a result of this work, modifications required will be funded in this program. There are no projects projected for the test year. The 2020 and 2021 expenditures are for:

- Line 1012/1014/1017 - Improvements and Supervisory Control and Data Acquisition ("SCADA") pressure monitoring point so that system pressures can be monitored for low point during peak day conditions. This scope also included the rebuild of a large volume customer meter stand to allow for continued service at a lower inlet pressure

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 $248,551,000 in 2020, and are projected to be $221,185,000 in 2021; $200,843,000 for the nine months ending September 30, 2022; and $337,231,000 for the 12 months ending September 30, 2023. These expenditures are shown in Table 7 below.

Table 7

($000)	(a)	(b)	(c)	(d)	(e)	(f)
		Capacity/Deliverability Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line No.	Program Description	12 Mos Ended 12/31/2020	12 Mos Ending 12/31/2021	9 Mos Ending 9/30/2022	21 Mos Ending 9/30/2022	12 mos. Ending 9/30/2023
1	TED-I Projects	186,583	112,805	74,600	187,405	174,835
2	Misc Transmission and Compression	161	(532)	-	(532)	-
3	Deliverability Base Field Measurement	6,159	10,515	20,113	30,628	19,368
4	Deliverability Base Pipeline	12,089	15,006	26,682	41,688	35,072
5	Regulator Stations - Distribution	24,637	50,121	33,142	83,263	53,671
6	T&S City Gates	18,923	33,269	46,305	79,574	54,286
7	**Total Capital**	**248,551**	**221,185**	**200,843**	**422,028**	**337,231**

These capital expenditures address needed increases in transmission pipeline capacity, which help ensure adequate capacity and deliverability throughout the system. These increases 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 inline 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. Gas quality is critical to ensuring that customers' equipment functions properly and safely. Gas measurement accuracy ensures that Consumers Energy is properly measuring and accounting for gas purchased for and delivered to customers, as detailed below.

Q. Please explain the TED-I projects shown on Exhibit A-67 (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. 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 gas transmission system as part of the TED-I projects and how they benefit customers.

A. As described in the NGDP, Exhibit A-45 (NPD-1), Section IV, part C, 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. Major TED-I projects included in this filing are Saginaw Trail Pipeline, Mid-Michigan Pipeline, and the South Oakland Macomb Network ("SOMN") project, which allows for the retirement of a major pipeline. Capacity requirements are factored into line replacements to ensure customer deliverability.

Q. Please describe Exhibits A-72 (MPG-10) through A-86 (MPG-24).

A. These exhibits expand on and provide the project level expenditures for each of the TED-I major projects. These exhibits also demonstrate the monthly capital expenditures for each TED-I major project for the years 2020, 2021, 2022, and 2023. The expenditures are broken out by labor, capitalized engineering and supervision, materials, contractor, overheads, other costs and contingency.

Q. Please describe the Saginaw Trail Pipeline project.

A. The Saginaw Trail Pipeline project increased the diameter of 78 miles of Line 2800, between Zilwaukee city gate in Saginaw County and Clawson Control Station in Oakland County, from 12-inch and 16-inch to 24-inch within the existing pipeline right of way. The project also included construction of an additional 17 miles of 24-inch pipe to re-route Line 2800 around highly populated areas in Saginaw and Flint. Distribution augmentation and city gate connections were also included to ensure supply to the distribution system.

Q. Why is the Saginaw Trail Pipeline project necessary?

A. The project: (i) addressed the high number of corrosion-related defects on Line 2800; (ii) reduces the risk of an unplanned outage on Line 2800; (iii) reduces the risks of supply capacity restrictions and cuts to customers; (iv) enables refilling of storage at lower summer natural gas prices; (v) increases transmission capacity; and (vi) positions the system for future demand growth and required outages.

Q. Has the Company received Commission approval to construct and operate the Saginaw Trail Pipeline?

A. Yes. The Commission issued an Order in Case No. U-18166, on March 28, 2017 approving a Settlement Agreement that authorized Consumers Energy to construct and operate this pipeline.

Q. Please identify the capital expenditures planned for the Saginaw Trail Pipeline.

A. As shown on Exhibit A-68 (MPG-6), line 1, the capital expenditures for this project were $143,548,000 in 2020, and are projected to be $8,733,000 in 2021; $452,000 for the nine months ending September 30, 2022; and $305,000 for the 12 months ending September 30, 2023. In 2020, costs were incurred for constructing 29 miles of pipeline along with associated city gates, distribution augmentation and engineering, design, materials, permitting, surveying, and real estate. Exhibits A-73 (MPG-11) through A-76 (MPG-14) provide a breakdown of the monthly capital expenditures for the Saginaw Trail Pipeline project. A summary of this information is provided in the table 8 below:

Table 8 Saginaw Trail Pipeline Annual Projects & Expenditures

Year	Scope	Length	Projected Spend
2020	- Grand Blanc Jct to Clawson Control Construction - Clean-Up/Restoration for Clio CG to Grand Blanc Jct (Flint Re-route) - Zilwaukee City Gate, Flint Branch Rd City Gate, Holly City Gate	29.03 miles	$149.4 million
2021	- Grand Blanc Jct to Clawson Control Restoration		$8.6 million
2022	- Restoration, legal proceedings for property acquisition and closure of environmental permit requirements		$.7 million
2023	- Restoration, legal proceedings for property acquisition and closure of environmental permit requirements		$.4 million

Q. When did the Company complete construction of the Saginaw Trail Pipeline?

A. Pipeline construction of Phase 4, the final phase of the project was completed in October 2020. Remaining projections include restoration, property acquisition, and closure of environmental permit requirements.

Q. Please describe the Mid-Michigan Pipeline project.

A. The Mid-Michigan Pipeline project replaces approximately 55 miles of Line 100A, between Ovid city gate in Clinton County and Chelsea Interchange in Washtenaw County. The project will address 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.

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-68 (MPG-6), line 2 identifies the total capital expenditures for the Mid-Michigan Pipeline project. The capital expenditures for this project were $2,282,000 in 2020, and are projected to be $43,443,000 in 2021; $41,707,000 for the nine months ending September 30, 2022; and $153,502,000 for the 12 months ending September 30, 2023. Exhibits A-78 (MPG-16) through A-81 (MPG-19) provide a breakdown of the monthly capital expenditures for the Mid-Michigan Pipeline project. In 2020 through September 30, 2023, 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 9 below:

Table 9 Mid-Michigan Pipeline Annual Projects & Expenditures

Year	Segment	Length	Projected Spend
2020	Engineering, Environmental, Real Estate	n/a	$2.282 million (actual)
2021	Engineering, Environmental, Real Estate, Permitting, Pipe Procurement Deposit on Pipeline Phases 1 & 2, & Construct Hell Distribution Augment	n/a	$43.443 million

2022	Pipe Delivery, Long Lead Material Procurement, Engineering, Environmental, Real Estate, Permitting, Freedom VS MAOP Upgrade, bypass line @ Chelsea	n/a	$52.763 million
2023	Pipeline Construction Phase 1, Stockbridge city gate & Pleasant Lake city gate Rebuilds, Long Lead Material Procurement, Engineering, Real Estate, Environmental, Permitting	Approx 30 miles	$142.445 million (through Sept)

In 2021, $30 million of the capital expenditures were necessary for the pipe procurement to secure steel pricing. The remaining pipe material spend will be in 2022 as pipe is received on site. Construction will commence in 2023.

Q. Why is 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 will replace 1949 vintage pipe that has demonstrated integrity issues that I will more fully describe below. In May 2015, this line experienced a rupture just north of Chelsea.

The project will also increase the capacity of the Company's natural gas transmission system. The increased capacity will provide 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 was the cause of the 2015 rupture?

A. Post-event analysis indicated the rupture was caused by near neutral pH Stress Corrosion Cracking ("SCC"). This is a form of environmental cracking that requires three conditions to develop. The rupture event did not result in ignition of the natural gas being transported, any injuries, or third-party property damage.

Q. What conditions are required for SCC to develop?

A. First is a pipeline material that is susceptible to SCC. Second are stresses that are higher than the threshold stress for SCC, such as those supplied by pressurized gas. Third are the environmental conditions conducive to cracking, such as local soils or ground water.

Q. What events occurred following the 2015 rupture?

A. SCC conditions on Line 100A necessitated a pressure reduction between Freedom Compressor Station and Ovid Valve Site following the rupture and subsequent analysis. Because SCC caused the rupture, a hydro test of the Line 100A was required prior to returning the line to service. An Electro Magnetic Acoustic Transducer ("EMAT") inspection was performed prior to hydro testing to ensure pipeline integrity. EMAT is used to detect longitudinal surface-breaking cracks and related crack-like features. Following successful EMAT runs, remediation ensued in parallel to commencing hydro testing in sections. At the same time, a project was undertaken to ensure gas supply was not placed at risk by replacing a 6.3 mile section of 20-inch pipe from the Freedom Compressor Station to the Chelsea Valve Site in Washtenaw County.

Q. Has the transmission integrity management plan found other areas of concern on Line 100A?

A. Yes. In 2016, 16 locations were remediated based on in-line inspection data, which found areas with characteristics similar to those that failed during the 2015 hydro test.

Q. Will Line 100A require additional hydro testing?

A. Yes. Line 100A requires hydro testing every five years between the valve sections where the rupture occurred due to the SCC identified on the pipeline per ASME B31.8S2004. The most recent hydro test was completed in 2020.

Q. Are there any integrity concerns regarding the pipeline coating?

A. Yes. Up to 72% of the pipe joints need to be recoated. Based on data from inline inspections, 72% of the coating is fair to very poor, indicating that 13-42% of the surface area, including the joint, is disbonded. Corrosion rates under disbondment are usually higher than in soil due to the lack of cathodic protection. Additionally, disbondment at seams can create interactive threats.

Q. What is the significance of Line 100A in the gas transmission system?

A. Line 100A is one of a limited number of paths for gas entering from southern supply points traveling to customers and storage in the eastern and northern parts of the Company's transmission system.

Q. What advantages are realized by increasing the pipe diameter from 20 inches to 36 inches?

A. A larger size pipeline provides additional transmission capacity during the summer and winter. Additional summer capacity is needed to accommodate required maintenance outages on other major pipelines, in particular Line 2200. Line 2200 (36-inch pipeline between Chelsea and Fenton) is currently the primary path for gas moving from White Pigeon Compressor Station and Freedom Compressor Station to storage fields and customers in the east and north. By increasing the Mid-Michigan Pipeline to 36 inches, another primary path from southern supply points to storage will be available in addition to Line 2200. Scheduling outages on Line 2200 to avoid impacting supply capacity is challenging and is limited to small time windows. In the past, the Company has had to adjust and cancel outages on Line 2200 for system integrity and maintenance work as well as emergent work. Depending upon system conditions, an unplanned outage on Line 2200 could have a significant impact on supply capacity, which could prevent the Company from fully refilling storage in the summer or providing reliable supply to customers in the winter. The 36-inch Mid-Michigan Pipeline size would also offset impacts of other outages that can reduce system capacity.

Q. Were other alternatives evaluated to provide the additional transmission capacity?

A. Yes. Alternatives, including a looped option, were evaluated and determined to be more costly to the customer and did not provide the additional system integrity improvements.

Q. Did the Company's Board of Directors approve the Mid-Michigan Pipeline project?

A. Yes, the project was approved by the Company's Board of Directors in January 2017, and was reviewed based on the revised construction timeline in August of 2019.

Q. Is the Company requesting Commission approval of Mid-Michigan Pipeline project historical capital expenditures in this proceeding?

A. Yes. In Case No. U-20322, the Commission found that capital expenditures of $8,522,000 associated with the Mid-Michigan Pipeline project should not be included in rate base at the time of the Commission's Order, indicating that these expenses maybe sought in a future rate case after the Commission has acted on the certificate of public convenience and necessity. The Company has reasonably incurred actual capital expenditures of $1,322,000 in 2016, $2,095,000 in 2017, $1,134,000 in 2018, $594,000 in 2019 and $2,282,000 in 2020 associated with the Mid-Michigan Pipeline project. The $8,522,000 disallowance included the historic time period expenditures for 2016 and 2017. As described above, the Company has received approval from the Commission of the application for a certificate of public convenience and necessity as requested in Case No. U-20618. The Company respectfully requests Commission approval of all Mid-Michigan Pipeline capital expenditures through the test year in this proceeding, including the 2016, 2017, 2018, 2019, and 2020 actual expenditures.

Q. Please describe the SOMN project.

A. The SOMN project allows for the retirement of Line 3100, a major pipeline serving the Detroit Metropolitan area. This project involves 16 unique projects that will result in the retirement of existing Line 3100, which consists of 9.6 miles of 12-inch pipeline from around 1941-42, and 13.9 miles of 16-inch pipeline from 1963. The project will also allow for retirement of a 5.6-mile segment of Line 600, which consists of 16" Electric Resistance Welded ("ERW") pipe installed in 1951. Projects include rebuilds and enhancements to city gate facilities and pipe installations that will operate under 20% specified minimum yield strength in Oakland and Macomb Counties. These projects will occur in 2018 through 2022, and will be more economical than the replacement of Line 3100, and provide for increased reliability. This reliability benefit to customers in the greater Metro Detroit area provides diversification of supply and regulation facility back-ups in the case of an unplanned outage during peak day conditions. The city gate stations will also include filtration for improved gas quality and emergency shutoff valves and remote monitoring systems for improved public safety.

Q. Please identify capital expenditures for the SOMN project.

A. Exhibit A-68 (MPG-6), line 3 identifies the total capital expenditures for the SOMN project. The capital expenditures for this project were $31,622,000 in 2020, and are projected to be $45,618,000 in 2021; $544,000 for the nine months ending September 30, 2022; and $10,000 for the 12 months ending September 30, 2023. Exhibits A-83 (MPG-21) through A-86 (MPG-24) provide a breakdown of the monthly capital expenditures for the SOMN project.

Q. Why would the Company retire Line 3100 and a segment of Line 600?

A. Line 3100 runs through a highly populated area, with the majority being in a Class 3 location. Through in-line inspection, the Company has data regarding corrosion anomalies on this line from the Company's Pipeline Integrity Program. In 2018, an additional 1,279 anomalies were found on Line 3100 as a result of integrity assessments. Once the SOMN series of projects are constructed, Line 3100 will no longer be necessary. Line 600 also runs through a congested area, with the majority being in a Class 3 location. The Line 600 retirement allows for less transmission pipe, a majority of which is 1951 ERW pipe. This reduces risk by lowering the pressure on the segment and provides significantly less risk of customer loss in the event of a damage due to the looped distribution system.

Q. What type of engineering analysis and alternative analysis was performed to develop the SOMN?

A. The engineering and gas supply team performed several simulations modeling load on the gas transmission and distribution systems. The methodology involved coordination with the transmission and distribution models, and took a number of factors into consideration. These considerations included limiting factors, potential failure, gas supply, and customer demand. Several alternatives were modeled and evaluated until a solution was determined. The selected solution will diversify the load across the network, and resolve the current risk associated with a potential planned or an unplanned city gate outage, especially on a peak day.

Q. What challenges would there have been with replacing Line 3100?

A. There are a number of constructability concerns with replacing Line 3100, which include: customer impacts, area congestion, permitting, tree clearing limitations, and ROW. The SOMN projects mitigate these concerns and will provide benefits to customers and system operations. Moreover, the SOMN project is the more cost effective option and, in this case, a more prudent option than line replacement.

Q. What is the project timeline and projected spend for the SOMN project through the year 2022?

A. The anticipated timeline and projected spend for SOMN project are shown in the Table 10 below. The project will be completed in 2022 so there is no projected expenditures in 2023.

Table 10 South Oakland Macomb Network Annual Projects & Expenditures

Year	Major Project	Length	Projected Costs
2020	Construction of Utica Lateral, Coolidge City Gate Rebuild, Real Estate, Engineering Procurement, Permitting and Site Restoration	1.6 miles	$33.8 million
2021	Construction of West Wayne to Plymouth, 14 Mile Rd Installation, Janet to Groesbeck Installation Pontiac Adams City Gate, Utica City Gate, Plymouth City Gate, Walled Lake City Gate and Site Restoration, Portion of Line 3100 Retirement	4.6 miles	$51.40 million
2022	Restoration of West Wayne to Plymouth, 14 Mile and Janet to Groesbeck, completion of Line 3100 Retirement, Line 600 Retirement	N/A	$7.45 million

Q. Has the Company's Board of Directors approved the SOMN project?

A. SOMN project received approval for $130,000,000 from Board of Directors Finance Committee on January 2019 to perform construction on 2019 and 2020 planned projects. The Company reviewed all the projects in the network solution as a whole in January 2019, and was approved $130,000,000 by the Board of Directors Finance Committee to perform construction of Macomb Corridor Pipeline, Utica Lateral Pipeline, Shelby city gate, Pontiac Trail Odorizer Upgrade, West Wayne city gate and Coolidge city gate with an understanding that a second ask will be requested for other projects in the network on substantial completion of engineering. A second request, of $63,000,000, to perform construction on 2021 and 2022 planned projects was approved by the Company's Board of Directors Finance Committee in November of 2020.

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 recently released Michigan Statewide Energy Assessment, 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." Similarly, the Secretary of the federal Department of Transportation directed PHMSA to prepare a recommendation on rulemaking relevant to installation of Automatic Shutoff Valves, or RCVs on new and entirely replaced transmission pipelines. Recognizing the significance of these devices, the Company has developed a comprehensive RCV installation plan as outlined in Section

IV, part C of the NGDP, Exhibit A-45 (NPD-1). The Company is planning to install RCVs on complete pipeline replacements, such as Line 100A (Mid-Michigan Pipeline Project), which was approved in MPSC Case No. U-20618, November, 2020. RCVs are also being installed to reduce response time on certain Class 4 locations and Class 3 locations within High Consequence Areas to improve public safety. 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 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 2020 the Company installed 15 RCVs, and projected to install 37 in 2021, 40 in 2022 and 40 in 2023. Exhibit A-68 (MPG-6), line 5 identifies the total capital expenditures for RCVs. The capital expenditures for RCVs were $1,299,000 in 2020, and are projected to be $8,337,000 in 2021; $18,707,000 for the nine months ending September 30, 2022; and $16,826,000 for the 12 months ending September 30, 2023.

Q. Please explain the PLD expenditures.

A. The proposed 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 192.609 (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"; and 49 CFR 192.619. 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. 2022 and 2023 Projects include:

- Line 1100 Woodbury City Gate, Lake Odessa
- Line 4060 Vector Hartland, Howell
- Line 2070 Dutton Rd, Rochester Hills
- Line 1500 Rochester Valve Site Sheldon Rd, Rochester
- Line 1200A CE-ANR Stag Lake, White Pigeon
- Line 4070Vector Ray M&R Station, Ray
- Line 100B Ovid Valve Site, Ovid
- Line 2700 Squirrel Rd Valve Site, Lake Orion

The installation of PLDs will improve the operation of the system and provide enhanced public safety. Exhibit A-68 (MPG-6), line 4 identifies the total capital expenditures for PLDs. The capital expenditures for PLDs were $7,426,000 in 2020, and are projected to be $5,494,000 in 2021; $13,190,000 for the nine months ending September 30, 2022; and $4,192,000 for the 12 months ending September 30, 2023.

Q. Why is the Company now seeking to install PLDs on certain pipeline segments?

A. An engineering analysis was conducted, in 2015, on the gas transmission system in relation to MAOP. Each location (where pipelines of differing MAOP are connected) was evaluated to determine if pressure relieving or pressure limiting equipment was present. The review took into account plans to replace portions of Line 2800 and Line 100A with the Saginaw Trail Pipeline and the Mid-Michigan Pipeline projects, respectively. The review also identified locations where installations of PLDs were necessary. Public safety risk is reduced when PLD equipment 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.

Q. What other projects are included in the TED-I program?

A. Also included in this program are projects that are smaller in cost and scope related to other TED-I projects that are not RCVs nor PLDs. These include valve site junctions so that the Company can use the existing pipelines for outage or other emergent situations. Two examples are the SAG-2800 Thetford Road Valve Site Pipe Installation and the SAG-2800 Wilson Road Valve Site Pipe Installation, which were completed concurrently with the Saginaw Trail Pipeline to assist in gas deliverability, system flexibility, and to realize the full potential of the Saginaw Trail Pipeline. The Saginaw Trail Pipeline now parallels the existing Line 2100, and construction of these two projects provides the flexibility of using both pipelines to draw gas from the northern storage fields to serve customers in the winter, and fill the northern storage fields in the summer.

Q. Has the Company provided a project-level basis for the TED-I capital expenditures for PLDs, RCVs, and the other miscellaneous projects including expenditures for material, labor, contractor, engineering, and other costs?

A. Yes. Exhibit A-69 (MPG-7) through Exhibit A-71 (MPG-9) identifies the PLD, RCV, and miscellaneous projects in the TED-I Program included in this filing, which includes the cost detail for material, labor, contractor, engineering, and other costs. These projects are typically installed between May and November, as this is when the Company can sectionalize areas of the system to perform work of this nature; however, it must be coordinated with other outages and work on the system, so specific installation times are not known at this time. Additionally, pipeline integrity inspections and remediation outage windows need to first be determined before the project outages can occur. There will be engineering and material procurement expenditures prior to installation.

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. 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 gas quality, measurement accuracy, and Lost and Unaccounted For ("LAUF") gas. Additional projects in this program include measurement equipment upgrades which will 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 ensure improved 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. Major projects included in this filing include:

- Lyon 29/34 (formerly called Northville Reef) site moisture removal and metering site upgrade projects (Salem Township). While still in development, this project is planned to be engineered and designed in 2021-2022 and built in 2022-2024;
- Michcon Goose Creek and Blue Lake 36 metering system upgrades (Blue Lake Township) project year 2021.
- Ray storage facilities gas quality filtering and monitoring equipment installations (Armada Township). Project year 2022.
- Ray compression station orifice metering upgrade (Armada Township). Project year 2022.
- Plainwell Junction site gas quality monitoring and metering system upgrade project (Gunplain Township). Project year 2021.

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 pre-mature 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 2020, the expenditures were for project engineering and design. The 2021 expenditures will be for engineering and design. The 2022 expenditures are for concluding engineering, design and securing materials and construction for relevant phases. The 2023 expenditures are for securing materials and construction for the final phases 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. 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 with corrosion identified by direct assessment or other means, which may have either external or internal corrosion that requires its replacement; (iii) the replacement of piping due to MAOP revisions identified as a result of class location changes (49 CFR 192.5 and 192.611); (iv) construction of new sectionalizing valves and tap valves to improve system deliverability, and help meet valve spacing requirements defined by 49 CFR 192.179; (v) reconfiguration of tap piping (i.e., laterals) and associated valving upstream of city gate facilities as companion projects to city gate rebuilds; and (vi) installation or retirement of pipeline taps to TMS facilities being attached to the Company's system. Expenditures associated with the activities and projects within this program can be found in Exhibit A-67 (MPG-5), line 4.

Q. Please explain why the Deliverability Base Pipeline expenditures are increasing from the 2020 historical year to the test year.

A. The Deliverability Base Pipeline expenditures are increasing from the historical year due to a number of factors. In 2019, the Company conducted an aerial survey to enhance the GIS data set to provide more accurate building data along with more accurate occupancy data. There were a number of class location changes indicated by the aerial survey. Per 49 CFR 192.611, there are segments of pipeline that need to be replaced in order to operate the pipeline under the published MAOP. These segment replacements are included in the projection for this program. Secondly, the Company conducted a system wide valve spacing study in 2021 that reviewed each Transmission Pipeline segment against the current class location to determine if the pipeline segments are in compliance with 49 CFR 192.179. This study indicated the valve(s) required in order to be compliant with rule 49 CFR 192.179.

Q. Please further 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). The scope of the expenditures in this program is aimed at maintaining the integrity of 692 regulator stations. The Company has developed a comprehensive regulator station installation plan as outlined in Section IV, part D of the Company's NGDP, Exhibit A-45 (NPD-1), sponsored by Company witness Dreisig. The Company currently has 89 odorizers, which are considered distribution assets that are 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, and electrical improvements at regulator stations. Investments being made to regulator stations improve employee safety and ergonomics. Regulator stations that are located in pits may be difficult to enter, and pose risk for operators. In 2020, the Company began to use a quantifiable risk ranking for City Gate and Regulator Station future planning of these investments as a factor for project selection. This ranking will take into account the variables that the Company currently uses in project selection. The major projects in this filing include:

2020

- Ransom (Rebuild - Wheeler)
- Grand River & Waverly (Rebuild – Lansing)

- Patrick & Waldo (Rebuild - Midland)
- Beaverton (Rebuild - St. Louis)
- Dutton Road Odorizer (Rebuild – Rochester Hills)
- Lawton (Rebuild - Lawton)
- Leonard (Rebuild - Leonard)

2021

- Corunna & Dye (Rebuild - Flint)
- 10 Mile & Kelly (Rebuild - Eastpointe)
- Adams & Junction (Rebuild - Plymouth)
- Waldo (Rebuild - Midland)
- Wildwood & Chestnut (Rebuild - Jackson)
- Barberry (Rebuild - Jackson)
- Harrison & Railroad (Rebuild - Lansing)
- Akron (Rebuild - Akron)
- Isbell & Marion (Rebuild – Howell)
- Wayne & Stacey (Rebuild – Westland)
- Morton & McConnell (Rebuild – St. John)
- Tisdale & Railroad (Rebuild – Lansing)

2022

- 10th & Trumbull (Rebuild – Bay City)
- Montrose & Ridgeway (Rebuild – Mount Morris Twp)
- Southgate (Rebuild – Bay City)
- Attica & Lake Pleasant (Rebuild – Attica Twp)

- Blanchard (Rebuild - Blanchard)
- Bayport (Rebuild – Bayport)
- Manchester (Rebuild - Manchester)
- North Water & Atlantic (New Station – Bay City)
- Woodward & Nebraska (Rebuild – Royal Oak)
- 21st & Jefferson (Rebuild – Bay City)

2023

- Verlinden & Shiawassee (Rebuild -Lansing)
- Elizabeth Lake & Broadway (Rebuild – Lake Orion)
- Plymouth & Sheldon (Rebuild – Plymouth Township)
- 5 Mile & Cleat (Rebuild – Plymouth)
- Vienna & McKinley (Rebuild – Montrose Twp)
- Walnut & Mosher (Rebuild – Bay City)
- Fisher & Kiesel (Rebuild – Bay City)
- State & Hemmeter (Rebuild – Saginaw)
- M36 & Buckshore (Rebuild – Hamburg Twp)
- Grand River & Challis (Rebuild – Brighton)
- 9 Mile & Schonherr (Rebuild – Warren)
- Lake George & Indan Lake (Rebuild – Lakeville)
- Sheridan & Lansing (Rebuild– Gaines Township);
- Herbison & Wacousta (Rebuild – Watertown Twp)
- Freeman & Dale (New Station – Tobacco Twp)

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, 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 and are funded in the Regulator Station program, they are co-located due to federal code requirements (49 CFR 192.625) to odorize distribution systems. 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 can also be closed to restrict delivery as a mitigation if serious situations develop. The Company has developed a comprehensive city gate work plan as outlined in Section IV, part C of the Company's NGDP, Exhibit A-45 (NPD-1). As identified in the NGDP, many city gates are 40-50 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. This program also funds remote terminal units ("RTU") and electrical improvements at transmission sites. 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:

2020

- Woodbury (Rebuild - Woodbury)
- North Lyon City Gate (Rebuild – Lyon Twp)

2021

- Mt. Pleasant City Gate (Rebuild – Mt. Pleasant)
- Marshall Lansing City Gate (Rebuild - Marshall)
- Lansing - Turner City Gate (Rebuild - Dewitt)

2022

- Greenfield City Gate (Rebuild – Royal Oak)
- Kalamazoo - Nazareth City Gate (Rebuild - Kalamazoo)
- Rochester City Gate (Rebuild – Rochester)
- Napoleon-Brooklyn (Rebuild – Brooklyn)
- Akron City Gate (Rebuild - Akron)
- Lansing – Airport City Gate (Partial Rebuild – Lansing)
- Bear Lake City Gate (Rebuild – Bear Lake)

2023

- Exelcior City Gate (Rebuild - Excelsior)
- Highland City Gate (Rebuild - Highland)
- Orion City Gate (Rebuild - Lake Orion)
- Kalamazoo – M Ave City Gate (Rebuild - Kalamazoo)

Q. Please explain the Miscellaneous Transmission and Compression Expenditures shown on line 2 of Exhibit A-67 (MPG-5).

A. This line represents legacy expenditures in programs that are no longer used, and final settlement costs for projects as they are closed out. In 2020, the expenditures are primarily for Right-of-Way ("ROW") expenditures for compression projects. In 2021, the expenditures are for ROW offset by credits related to moving project costs from prior years to O&M.

Q. Are there contingency costs included in these capital expenditures?

A. Yes. It is a common and prudent practice to include project contingency costs and is recognized as an accepted Project Management practice, especially when contingency covers the expansion of work approved. It is a real item in a project estimate like any other cost, and should be included in estimates of major projects. For these reasons, contingency costs are appropriate and should be included in the capital expenditures and rate base in this filing. The Mid-Michigan Pipeline project contains contingency expenditures in the amount of $2,461,000 in the 12 months ending September 30, 2023 and the SOMN project contains contingency expenditures in the amount of $3,000 in the 9 months ending September 30, 2022. These contingency expenditures are identified in Exhibit A-68 (MPG-6), lines 2 and 3.

Q. Please describe Exhibit A-87 (MPG-25).

A. Exhibit A-87 (MPG-25), 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 am sponsoring to the Company's most recent general gas rate case, Case No. U-20650.

Q. Can you explain why columns (c), (e), and (f) of Exhibit A-87 (MPG-25), do not contain any data?

A. Yes, the information for column (c), the "Last Rate Case Approved Spending Plan Case No. U-20650," cannot be provided because Case No. U-20650 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. Since there is no data to display in column (c) the information for columns (e) and (f), which seek information concerning the variances from (c), cannot be completed.

Q. Are there certain projects related to correcting MAOP document gaps, replacing pipe and fittings, for which the Company is not seeking cost recovery in this case?

A. Yes. Pursuant to the Settlement Agreement approved by the Commission in Case No. U-18424, the Company is not seeking recovery for the cost of correcting MAOP document gaps for the pipe segments on Lines 1070, 1020, 1600 and Line 3070, and for replacing pipe and fittings for the Lahser Lateral, which was in service prior to 1965, where: (i) the highest operating pressure was not used; or (ii) the line segments were not tested after July 1, 1965, to establish the MAOP in accordance with Subpart J of 49 CFR Part 192. The Company continues to make progress on reducing the documentation gaps for the projects stated above. In 2018, the Line 1070 hydrotest was completed. In 2019, the Lahser Lateral piping, and 1020 hydrotest were complete. The 1600 hydrotest is projected to be complete in 2021, and the 3070 hydrotest in 2022.

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 transmission system for its customers?

A. Yes. Company witness Duncan Paterson includes in his 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 Company witness Paterson. The project and the benefits of the project which will provide benefits for the area which I am sponsoring is described below:

- The **Gas SCADA Software Solution** project requires $1,884,469 in capital and $320,410 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 software 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; (7) improving Natural Gas Delivery Plan efficiencies; and (8) 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 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 software 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 Natural Gas Delivery Plan. 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.

Q. Can you summarize your direct testimony?

A. Yes. The three programs described in my direct testimony span the major areas of Gas Transmission operations 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, which help ensures 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.

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-21148
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

QUENTIN A. GUINN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

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 60 buildings and includes the corporate office, storerooms, distribution centers, maintenance garages, service centers, welding and fusion workshops, learning and development buildings, coal generation, gas compression, and hydroelectric sites. My responsibilities include regulatory compliance, rate case strategy and execution, corporate policy administration, organizational vision, and resource planning for field execution.

Q. What is your formal educational experience?

A. I hold a Bachelors in Economics from Yale University, located in New Haven, Connecticut and a Juris Doctorate 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 who were responsible for a broad range of construction, maintenance, consulting, information technology and engineering contracts. Responsibilities of these teams included sourcing and evaluating contractors and consultants, developing scopes of work, competitively bidding work and negotiating final agreements. 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. I will:

- Describe the Gas Operations Support function;
- Describe the methodology employed by Facility Operations ("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, 2020, the bridge period beginning January 1, 2021 and ending September 30, 2022, and the projected test year for the 12 months ending September 30, 2023; 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, 2020, the bridge period beginning January 1, 2021, and ending September 30, 2022, and the projected test year for the 12 months ending September 30, 2023.

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-88 (QAG-2)		Summary of Actual and Projected Operations Support O&M Expenses for the Year 2020 and Test Year 12 Months Ending September 30, 2023;
Exhibit A-89 (QAG-3)		Detailed List of Projected Gas and Common Capital Expenditures For the Years 2022, 2023, and 12 months ending September 30, 2023;
Exhibit A-90 (QAG-4)		Facility Assessment – Lansing Service Center;
Exhibit A-91 (QAG-5)		Conceptual Site Plan – Lansing Service Center;
Exhibit A-92 (QAG-6)		Facility Assessment – Kalamazoo Service Center;
Exhibit A-93 (QAG-7)		Conceptual Site Plan – Kalamazoo Service Center;
Exhibit A-94 (QAG-8)		Facility Assessment – Hastings Service Center; and
Exhibit A-95 (QAG-9)		Conceptual Site Plan – Hastings Service Center.

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-88 (QAG-2) details the O&M costs related to Gas Operations Support. Exhibit A-89 (QAG-3) identifies Gas Operations Support Programs and the projected capital expenditures related to those projects and programs. Exhibit A-90 (QAG-4) is the Facility Assessment of the Lansing Service Center utilized to evaluate the need for capital expenditures. Exhibit A-91 (QAG-5) is the conceptual site plan of the proposed new Lansing Service Center. Exhibit A-92 (QAG-6) is the Facility Assessment of the Kalamazoo Service Center utilized to evaluate the need for capital expenditures. Exhibit A-93 (QAG-7) is the conceptual site plan of the proposed new Kalamazoo Service Center. Exhibit A-94 (QAG-8) is the Facility Assessment of the Hastings Service Center utilized to evaluate the need for capital expenditures. Exhibit A-95 (QAG-9) is the conceptual site plan of the proposed new Hastings Service Center.

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 Adam S. Carveth.

Q. What is the function of the Facilities organization?

A. Within Gas Operations Support, Facilities manages, maintains, and operates 63 buildings comprising 3.5 million square feet of building space across the state of Michigan that allow co-workers 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. Of its 63 buildings, the majority were built or acquired during this period and remain in operation today. As a result, these buildings are now well over 50 years old.

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, 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 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.

Q. What concerns or problems do the Company's aging structures and facilities create for the Company's workforce?

A. These aging structures no longer adequately accommodate the way work is done. The needs of the Company's workforce have changed significantly since the 1950s and 1960s and modern workspaces must now provide for greater collaboration and efficiency (i.e., there is a greater need for open office environments, collaborative work group spaces, computers in the workplace, and internet and wireless communication networks).

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 9,987,000 with much of the growth since the 1960s having occurred in suburban areas. The locations of some of the Company's facilities no longer allow the Company to optimize service to customers. Longer response times and increased drive times make meeting service delivery standards difficult for the Company's employees who are dedicated to providing the best service to Consumers Energy's customers.

Q. What process does Consumers Energy utilize to evaluate whether to make capital investments in facilities?

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 Facilities Department has experts in heating, ventilation, and air conditioning ("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 possible 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 is needed; and a score under 48 is designated as "Poor," meaning that there are multiple systems failing at the facility.

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, is targeted for renovation or replacement.

Q. What is the purpose of the evaluation process?

A. The intent of the evaluation or assessment process is to prioritize facilities for investments to bring the score, or quality designation, for each Company facility within an acceptable range (48 to 80 points). The cost to bring a facility within the acceptable range can vary greatly. There are numerous factors involved such as size and scale of an individual facility, the extent of the renovation/redesign needed, etc. For example, the Benzonia Service Center has approximately 5,698 square feet of space, versus the Kalamazoo Service Center which has approximately 140,884 square feet of space. These factors greatly impact the associated investment required to renovate or replace individual facilities. The differences in required level of investment lead to differences in the annual investment required to perform renovation or replacement work.

Q. What programs are included in the projected capital expenditures for Facilities?

A. There are approximately 17 separate programs which contribute to the projected Facilities capital expenditures for the projected bridge period ending September 30, 2022, and 12-month projected test year ending September 30, 2023. These programs are identified on Exhibit A-12 (QAG-3).

Q. Please describe the capital expenditures set forth on Exhibit A-12 (QAG-1), Schedule B-5.6.

A. As demonstrated on Exhibit A-12 (QAG-1), Schedule B-5.6, capital spending is divided into two programs: (i) Asset Preservation, and (ii) Other Equipment. Asset Preservation is then broken down into multiple cost categories, including contractor, labor, materials, business expenses, and other (loadings, chargebacks). The majority of capital spending, as reflected on Exhibit A-12 (QAG-1), Schedule B-5.6, is for Asset Preservation, which encompasses the Company's facilities investments.

Q. Please generally explain the types of Asset Preservation facilities investments that are included in the projected costs for the projected test year ending September 30, 2023.

A. Asset Preservation of the Company's facilities investments generally includes new construction, remodeling of existing facilities, emergent work, lifecycle replacement of infrastructure equipment, and system failures. The estimated costs are based on current construction estimating and planning with the known requirements. These estimates can vary as changes to the scope, initial design, materials, or possible unseen issues arise, such as environmental remediations.

Q. What categories of facilities investment are included in the Company's Asset Preservation?

A. The Company's Asset Preservation of facilities investments includes: (i) infrastructure investments; (ii) upgrades and maintenance; and (iii) purchase, new construction, and renovations. These facilities investments allow for the Company to be strategically placed to safely and efficiently respond to customers' requests.

Q. What capital expenditures are included in "infrastructure investments?"

A. Infrastructure investments include removing conditions that contribute to potential health and safety hazards, proactively repairing emergency backup systems, and repairing failed capital components of buildings, which are comprised of yards, grounds, building envelope, and operating systems. These minimal facilities infrastructure investments mitigate the effects of building depreciation to avoid imminent near-term failures and upgrades for health and wellness.

Q. What capital expenditures are included in "upgrades and maintenance?"

A. Upgrades and maintenance include items such as parking lots, roofs, and elevators at various building and plant sites.

Q. How are "upgrades and maintenance" projects targeted?

A. Condition assessments are performed on a regular basis; for example, a portion of roof sections are inspected annually such that all roofs are inspected once every three years, and a portion of paving sections are inspected annually such that all paving is inspected once every five 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. What capital expenditures are included in "purchase, new construction, and renovations"?

A. The final component of the facilities investment plan is the purchase, new construction, and/or renovation of service centers and other buildings to support operations across the state of Michigan.

Q. Are these types of Asset Preservation projects identified in Exhibit A-89 (QAG-3)?

A. Yes. The proposed Asset Preservation projects are identified in Exhibit A-89 (QAG-3), lines 7 through 17.

Q. What are the major Asset Preservation projects that are planned?

A. Major Asset Preservation projects planned for Facilities include the construction of the Lansing Service Center, Kalamazoo Service Center, Hastings Service Center, Gas City Training Facility, and building renovations associated with the Return to Facilities project.

Q. Does the Company consider environmental impacts when planning for the construction and/or renovation of a structure or building?

A. Yes. New buildings are constructed to meet 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 allows 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 less O&M costs, estimated at a 5% reduction.

Q. Please describe the Lansing Service Center project.

A. In this project, the Company is purchasing land in a new location and constructing a new facility on that property. This facility will allow the Company to retire use of its existing facility (which will be demolished and retained to address and abate environmental concerns related to the property). This new facility will house all employees currently working out of the existing service center, which primarily includes Gas operations and customer operations, as well as a contact center.

Q. Why has the Company chosen to build a new Lansing Service Center?

A. As demonstrated in Exhibit A-90 (QAG-4), a Facilities assessment of the existing Lansing Service Center produced a score of 39. As discussed above, this placed the existing Lansing Service Center in the quality designation of "Poor." As reflected in the scores set forth on Exhibit A-90 (QAG-4), there are a number of reasons that 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. At this time, 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 being located three feet below the major flooding elevation projected by the Federal Emergency Management Agency. All of 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 security and environmental abatement.

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 former use of the current Lansing Service Center site as the location of a former Manufactured Gas Plant ("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 are not feasible (such as carpet replacements and open space enhancements).

Q. The Lansing Service Center project includes the relocation of that facility. 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) 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 a 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 and maximize employee efficiency, which required the relocation of that facility. 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 and reduced employee efficiency due to increased travel times. The location for the new Lansing Service Center will not only be located in a more appropriately zoned area but will also provide both improved customer response times and employee efficiency.

Q. Has the 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. The Conceptual Site Plan for the Proposed Lansing Service Center is included as Exhibit A-90 (QAG-4). Land acquired is located in Windsor Charter Township, southeast corner of the intersection of Canal Road and Billwood Highway, Dimondale, Michigan 48821.

Q. What is the status of the construction of the Lansing Service Center at the time of this filing?

A. The Company is finalizing with Windsor Charter Township and the City of Dimondale the number of Company personnel who will be assigned to this location.

Q. What is the projected size of the replacement Lansing Service Center based on conceptual data?

A. Current projected building area based on conceptual data assembled to date is 125,000 square feet of building space.

Q. Is this larger or smaller than the existing Lansing Service Center?

A. Smaller. The existing Lansing Service Center is approximately 150,594 square feet in area.

Q. What is the projected size of the parking area for the replacement Lansing Service Center, based on conceptual data?

A. Although, at this time, the design programming has not been finalized for the Lansing Service Center project, current projected paved area based on conceptual data assembled to date is 458,792 square feet.

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: Controller/CAO; Customer Experience; Gas Grid Integration; Gas Operations; Enterprise Project Management/Environmental Services; Gas Engineering & Supply; Gas Operations; Generation Operations & Compression; Information Technology ("IT"); Operations; Operations Performance; Operations Support; People & Culture; Public Affairs; Rates & Regulation; and Transformation, Engineering & Operations Support ("TE&OS"). The Company anticipates the new Lansing Service Center will house the same operations. These operations are dedicated to the Company's operations in the Lansing area; a practice that reduces the Company's expenses by locating personnel closer to specific work areas.

Q. Approximately how many employees will work at the new Lansing Service Center as compared to the existing Lansing Service Center?

A. The existing Lansing Service Center houses 412 employees. The Company anticipates the new Lansing Service Center will house a comparable number of employees.

Q. Has the Company engaged in an environmental study for the area contemplated for the new Lansing Service Center?

A. 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. The proposed new Lansing Service Center is also planned to incorporate on-site solar power generation to partially offset building energy consumption.

Q. What benefits will this new Lansing Service Center offer?

A. The new Lansing Service Center will benefit customers by lowering operational costs and will be in a more compatible location which is properly zoned for industrial use, minimizing safety concerns.

Q. Please describe the Kalamazoo Service Center project.

A. In this project, the Company is constructing a new facility on the existing property. Exhibit A-93 (QAG-7) provides the conceptual site plan of the proposed new Kalamazoo Service Center. Upon completion of the new facility, the Company will retire, demolish, and remediate environmental concerns at the existing facility.

Q. Why has the Company chosen to construct a new facility on the existing Kalamazoo Service Center site?

A. As demonstrated on Exhibit A-92 (QAG-6), 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 of the employees at this site have had to be moved to the 2nd floor due to the asbestos concerns on the 1st floor. This limited space is inadequate to operate for the Company's Gas Operations partners. As discussed above, because this score falls below a score of 48, it was targeted for replacement. In addition to the 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. Finally, the space requirements of the existing workforce have significantly changed, requiring open office environments, collaborative work groups, computer technology in the workplace, and the need for internet and wireless communication networks, all of which support the need for a newly constructed, rather than renovated, facility. Even in a post-COVID-19 environment where the need for legacy office space is expected to decline, the net need for space will not decline. Rather, said space will need to be repurposed to allow for collaborative work groups and open office environments as outlined above. Because the Kalamazoo Service Center is optimally located for responding timely to the Company's customers, the new Kalamazoo Service Center will be constructed on the existing site.

Q. Has the Company compared the cost of renovating the Kalamazoo Service Center versus replacement?

A. Yes. The chart below demonstrates that it is more affordable to replace the Kalamazoo Service Center than to renovate it.

Kalamazoo Service Center - Renovation versus New Construction Cost

	New Build	**Renovation**
	2018 pricing escalated to 2021 cost	**2018 pricing escalated to 2021 cost**
Total Project Cost	$50,296,496	$51,709,028
On call parking bays	15 Bucket Trucks	15 Bucket Trucks
Building Sqft	108,460 Sqft	108,460 Sqft
Total $/Building Sqft	$463.73/Sqft	$476.76/Sqft
O&M Costs	Employee Moves	Brick with new metal façade Employee Moves x 2 Trailer city costs 24 months of Fleet costs

Q. What is the status of the construction of the new Kalamazoo Service Center at the time of this filing?

A. The Company is engaging a consultant to perform an alternatives analysis for the purpose of confirming the optimal renovation/reconstruction strategy for the existing site.

Q. What is the projected size of the new Kalamazoo Service Center, based on conceptual data?

A. Square footage of the new Kalamazoo Service Center is anticipated to be 108,545 square feet, as shown in Exhibit A-93 (QAG-7). The anticipated square footage is comprised of the following components: Automotive & Equipment Repair Garage, On-Call Vehicle Parking, Office, and Storeroom.

Q. Is this larger or smaller than the existing Kalamazoo Service Center?

A. This is smaller than the existing Kalamazoo Service Center by 32,339 square feet. The existing Kalamazoo Service Center is approximately 140,884 square feet in area.

Q. Because the new Kalamazoo Service Center will remain on the current premises, will the existing parking lot be utilized?

A. No. The existing parking lot will not be utilized as the proposed new facility is anticipated to be constructed in the location of the existing parking lot. Proposed new paved area is approximately 335,384 square feet, as shown in Exhibit A-93 (QAG-7).

Q. What type of operations departments will work at the new 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; Gas Operations; IT; Operations; Operations Performance; Operations Support; Public Affairs; and TE&OS. The Company anticipates the new Kalamazoo Service Center will house the same operations. These operations are dedicated to the Company's operations in the Kalamazoo area which is a practice that reduces the Company's expenses by locating personnel closer to specific work areas.

Q. Approximately how many employees will work at the new Kalamazoo Service Center as compared to the existing Kalamazoo Service Center?

A. The existing Kalamazoo Service Center houses 248 employees. The Company anticipates the new Kalamazoo Service Center will house a comparable number of employees.

Q. What energy efficiency and waste reduction measures does the Company plan to install at the new Kalamazoo Service Center?

A. The proposed new Kalamazoo Service Center facility is planned to be designed and constructed to achieve certification under the USGBC, LEED version 4 rating system. The proposed new Kalamazoo Service Center is also planned to incorporate on-site solar power generation to partially offset building energy consumption.

Q. What are the benefits of the new Kalamazoo Service Center?

A. This service center will have a new energy-efficient building constructed (with demolition of the old building taking place after all employees have been moved to the new location) and will have a new storm-retention system (the previous water system discharges into the city sewer system). Customers will benefit from reduced operational costs as energy and workspace efficiencies are achieved.

Q. Please describe the Hastings Service Center project.

A. Like the Kalamazoo Service Center, in this project, 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 agreement with the adjacent landowner to transfer a portion of their property to Consumers Energy to increase the available site area for development. Agreement for a property transfer with the adjacent landowner was not reached. The properties on the west and east are fully developed. The Company had preliminary negotiations with the Barry County Road Commission (owner of the adjacent parcel to the south). However, this parcel abuts a shooting range and was deemed to be unacceptable from a safety standpoint; therefore, Consumers Energy is currently seeking to purchase a parcel in the surrounding Hastings area.

Q. Why has the Company chosen to construct a new Hastings Service Center facility?

A. As demonstrated on Exhibit A-94 (QAG-8), a Facilities assessment of the existing Hastings Service Center produced a score of 41. As discussed above, and like the Kalamazoo Service Center, because this score falls below a score of 48, it was targeted for replacement. For the same reasons that the Lansing Service Center and Kalamazoo Service Center were targeted for replacement, including aging infrastructure, which is beyond useful life, the Hastings Service Center was determined to need replacement.

Q. What is the status of the construction of the new Hastings Service Center at the time of this filing?

A. Consumers Energy is currently seeking to purchase a parcel in the surrounding Hastings area.

Q. What is the projected size of the new Hastings Service Center, based on conceptual data?

A. The proposed new building is anticipated to be 23,500 square feet comprised of garage area, Automotive & Equipment repair space, and On-Call Vehicle indoor parking space, as shown in Exhibit A-95 (QAG-9).

Q. Is this larger or smaller than the existing Hastings Service Center?

A. This is larger than the existing Hastings Service Center by 11,183 square feet. The larger facility is required to accommodate current Company work standards (e.g., wellness room, accommodations for nursing mothers, and indoor parking for on-call vehicles).

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; Gas Operations; IT; Operations; Operations Performance; and TE&OS. The Company anticipates the new Hastings Service Center will house these same operations. These operations are dedicated to the Company's operations in the Hastings area; a practice that reduces the Company's expenses by locating personnel closer to specific work areas.

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 44 employees. The Company anticipates the New Hastings Service Center will house an increased number of employees.

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. The proposed new Hastings Service Center is also planned to incorporate on-site solar power generation to partially offset building energy consumption.

Q. What are the benefits of the new Hastings Service Center?

A. The new Hastings Service Center will be designed and constructed for energy efficiency, lowering operating costs and will also be designed to incorporate essential current Company work standards (e.g., wellness room, accommodations for nursing mothers, and indoor parking for on-call vehicles). These Company work standards increase the productivity of Company employees providing service to customers.

Q. Can you quantify the expected reduction in annual O&M expense associated with the construction of the new service centers?

A. Yes. An annual operating expense reduction of 5% is anticipated once the new facilities are in operation, which will include energy consumption reductions and maintenance operations savings.

Q. How is the anticipated 5% reduction in operating expenses to be achieved?

A. Primarily, the savings will result from improved energy efficiency of the facilities. The buildings will be constructed to LEED environmental standards with a goal of achieving a minimum reduction of 30% for energy consumed by the buildings annually when compared to buildings utilizing standard construction. Additionally, when compared to older facilities, new building systems require less maintenance and repairs. These factors, taken in combination, are anticipated to yield the 5% reduction in overall operating costs for the service centers.

Q. Why is the Company pursuing construction of new service centers for Lansing, Kalamazoo, and Hastings at the same time as opposed to one facility at a time?

A. As demonstrated on Exhibits A-90 (QAG-4), A-92 (QAG-6), and A-94 (QAG-8), Facilities assessments of the existing Lansing Service Center, Kalamazoo Service Center, and Hastings Service Center produced scores of 39, 46, and 41, respectively. These scores place all three existing service centers in the quality designation of "Poor" with severe safety, security, and/or environmental deficiencies existing at all three. These deficiencies represent safety and environmental hazards which require amelioration as soon as possible.

All of the employees at the existing Kalamazoo Service Center have had to be moved to the second floor due to asbestos concerns on the first floor. The existing Lansing Service Center site was the location of a former MGP and is currently beset by environmental contamination issues resulting from operation of the MGP, including significant underground impacted soil materials (i.e., coal tar residual). Additionally, the existing Lansing Service Center contains asbestos insulation for pipe and duct work, asbestos flooring, and has significant areas of lead paint in poor and peeling condition.

Q. Please describe the Gas City Training project.

A. A description of the Gas City Training project, benefits and risks will be addressed in the testimony of Company witness Christopher Fultz.

Q. What is the projected cost related to the Gas City Training project?

A. The projected cost related to the Gas City Training project is depicted in Exhibit A-89 (QAG-3).

Q. What is the projected size of the Gas City Training project?

A. Projected size of the Gas City Training project is approximately 3,280 square feet.

Q. Please describe the Building Renovations Program.

A. The Building Renovations Program scope is primarily driven by identified gaps and deficiencies in workplace design that require corrective action to facilitate a safe, effective and collaborative work environment post-pandemic. This post-pandemic work environment includes but is not limited to changes in space management driven by social distancing standards, newly designed collaborative workspaces and the technology required for effective collaboration among individuals working both in the same location and virtually.

Q. What is the projected timeline of the Building Renovations Program?

A. Building Renovations Program planning commenced in July 2021 and is expected to continue until Q4 of 2023.

Q. How does the Building Renovations Program ultimately benefit and bring value to customers?

A. The Building Renovations Program's main benefit is providing a workplace that allows the Company's employees to conduct work safely, in an inclusive, productive, and engaging manner, all of which is needed to support a safe, efficient, and productive work environment. This is essential to drive business results supporting customers' needs.

Q. What was the Company's capital expenditure amount in the historical year ended December 31, 2020?

A. As depicted in Exhibit A-12 (QAG-1), Schedule B-5.6, line 3, capital expenditures for the historical year ended December 31, 2020, totaled $14.544 million.

Q. Please describe the capital expenditures related to Other Equipment for Gas Operations Support as shown on Exhibit A-12 (QAG-1), Schedule B-5.6, line 2.

A. Other Equipment includes the purchase of computers, miscellaneous printers, mechanical equipment, print production equipment, and wellness equipment. These expenditures are depicted in Exhibit A-89 (QAG-3), lines 1 through 6.

Q. What is the Company projecting for project capital spending related to Gas Operations Support?

A. The Company's projected capital spending related to Gas Operations Support is depicted in Exhibit A-89 (QAG-3).

Q. Does Gas Operations Support also have projected O&M expenses?

A. Yes. Gas Operations Support projected O&M expenses are depicted in Exhibit A-88 (QAG-2).

Q. What O&M expenses are included in "facilities" in Exhibit A-88 (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" in Exhibit A-88 (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, land owner 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 system for property ownership and rights-of-way.

Q. What O&M expenses are included in "supply chain in Exhibit A-88 (QAG-2)?

A. Supply chain assists with administration support services for Consumers Energy's Security Command Center, IT, Help Desk, Human Resources, Corporate Safety and Health, Fleet, Facilities, Supply Chain, Learning and Development, Real Estate, Travel Services, Operating Maintenance and Construction Jobline, and its Mail Services. This assistance includes intake and scheduling of maintenance work, scheduling of maintenance staff, vendor and contractor management, purchasing of materials and services, document reproduction, and internal mail distribution.

Q. What is the calculated O&M expense for Gas Operations Support displayed on Exhibit A-88 (QAG-2), page 1, line 3?

A. The O&M expense reflected in the projected test year ending September 30, 2023, totals $10,222,000 and is also shown on Exhibit A-88 (QAG-2), page 2, line 4, column (j).

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-21148
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

CULLEN M. HALE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

Q. Please state your name and business address.

A. My name is Cullen M. Hale, 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 the Director of Customer Strategic Planning in the Customer Experience & Technology Department.

Q. Please review your educational background.

A. I earned a Bachelor of Science in Business Administration from Central Michigan University in 2008, and returned to the university in 2013 to complete a Master of Business Administration.

Q. Please review your business experience.

A. In May 2008, I joined Consumers Energy Company as an Information Technology ("IT") Analyst on the Custom Care Services team. In 2014, I transitioned to the role of Development Team Lead, managing resource allocation for projects that required technical and development resources. I accepted the position of Integration Center of Excellence Manager in 2016, where I started a core team that promoted reusable and efficient integration solutions. In 2019, I accepted the role of Business Architect, where I aligned Company objectives for Customer Experience and Operations ("CX&O") programs into requirements for technology initiatives needed over several years. In 2020, I accepted my current position, in which I lead long-term planning initiatives that align the Company's Clean Energy Plan to customer-focused initiatives with the regulatory framework.

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

A. The purpose of my direct testimony is to describe the CX&O organization and how the work performed within this organization benefits the Company's residential and business gas customers today and into the future. 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 September 2023.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-12 (CMH-1)	Schedule B-5.7	Summary of Actual and Projected Capital Expenditures - Customer Experience & Operations and Demand Response;
Exhibit A-96 (CMH-2)		Summary of Actual & Projected O&M Expenses – Customer Experience & Operations; and
Exhibit A-97 (CMH-3)		Summary of Actual & Projected O&M Expenses – Margin.

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

A. Yes.

Q. Please describe Exhibit A-12 (CMH-1), Schedule B-5.7.

A. Exhibit A-12 (CMH-1), Schedule B-5.7 details the capital expenditures related to work within the CX&O organization, which total $709,000, for the test year ending September 30, 2023. Refer to the direct testimony of Company witness Steven. Q. McLean for a discussion of the demand response capital expenditures reflected on this exhibit.

Q. Please describe Exhibit A-96 (CMH-2).

A. Exhibit A-96 (CMH-2) details the O&M expenses related to work within the CX&O organization, which total $45,857,000, for the test year ending September 30, 2023.

Q. Please describe Exhibit A-96 (CMH-2), page 4.

A. Exhibit A-96 (CMH-2), page 4 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. 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 an inflation rate or merit increase rate were applied for each bridge period, respectively. Columns (d), (f), and (h) show the merit 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).

Q. Please describe the figures shown in column (i).

A. Column (i) reflects "Other Adjustments," which is a variable applied to the expenses shown on my exhibit. It does not represent a separate category of expenses and should not be disallowed as though it does.

The CX&O budget is prepared using a zero-base accounting method, meaning that it is prepared with no reference to a prior year's budget. To accomplish this, CX&O starts from zero and adds the expenses associated with the projects and department operations CX&O plans to complete in the test year to arrive at the final projected test year spend. By contrast, Exhibit A-96 (CMH-2), in order to conform to the Company's exhibit standard, 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 – they merely reflect the difference in calculation methods between the CX&O budget and Exhibit A-96 (CMH-2). The effect of disallowing the amounts shown in the Other Adjustment category would be to eliminate, decrease or in a few cases actually increase the spending in various budget areas across the organization, needlessly distorting the planned work for the test year and cutting resources for essential department functions such as maintaining payment centers. Other Adjustment figures appear solely for the benefit of the rate case stakeholders to ensure the exhibit math accurately reflects the planned test year spend as shown on internal budgets. Disallowing them would throw planning into disarray and hamper the Company's ability to best serve its customers.

Q. Please describe Exhibit A-97 (CMH-3).

A. Exhibit A-97 (CMH-3) reflects the financials associated with the Company's non-regulated Home Energy Products, Industrial Energy Products ("IP") and Compressed Natural Gas ("CNG") programs, as well as the margin revenues for these items. The "margin" refers to the sum by which program profits offset the Company's rate base.

While all of these figures are reflected on my exhibit, my testimony is confined to a discussion of the Home Energy Products program. Refer to the testimony of Company witness Karen M. Gaston for a discussion of IP and CNG.

Q. Please discuss any changes to the structure of the organization since the Company filed its last general rate case where CX&O costs were presented, Case No. U-20963.

A. There were no major changes to the structure of the CX&O organization.

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 $45.9 million in O&M expense for the test year ending September 30, 2023. This amount comprises $27.8 million of O&M expenses for Customer Interactions, and $18.1 million for Billing and Payment. The CX&O O&M expenses are illustrated on Exhibit A-96 (CMH-2). The Company is also projecting $709,000 in capital investments through the test year to support the CX&O infrastructure described below and outlined in Exhibit A-12 (CMH-1), Schedule B-5.7 The 2020 and 2021 costs for these programs are included in Exhibit A-12 (CMH-1), Schedule B-5.7.

DEPARTMENT	**CAPITAL**	**O&M**
Customer Interactions	$709,000	$18.1 million
Billing & Payment	0	$27.8 million
Total	$709,000	$45.8 million

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

II. Home Energy Products Program

I. <u>CX&O</u>

Q. Please describe CX&O.

A. The activities of the CX&O organization define the experience natural gas customers have when interacting with the Company. It has two major segments. 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). Billing & Payment provides customers with accurate, punctual energy bills and consistent payment processes, and arranges personalized payment plans or settings for individual customers (e.g., inability to pay arrangements, pay by phone/website, payment alerts, choose your own bill due date).

The two core strategies pursued by these teams - enabling a customer to interact with the Company in the channel of their choosing, and enabling them to customize their payment preferences – 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 clean energy programs. The Company acknowledges that the energy industry is increasingly expected and committed to pursue clean energy, and asserts that customer participation is critical to accelerating this future.

Q. Please describe the focus of CX&O.

A. Traditionally, a utility's role was simply to provide power to customers and bill them appropriately. However, the industry has shifted to meet the changing needs and demands of its customers and achieve new clean energy commitments. The CX&O organization supports these evolving needs by continuing to provide world-class service to customers in the channel of their choosing. This results in the kind of positive customer experience which will encourage families and businesses to choose the Company's clean energy programs, participate in carbon offset arrangements, partner on new technology to take advantage of the gas storage made possible by Michigan's unique geology, and otherwise help the Company meet its goals of safe, affordable, reliable, and clean natural gas delivery and net zero methane emissions by 2030. The Company and its customers will each be empowered to meet their sustainability goals, all while bettering the climate for every Michigander.

Q. Is the Company's IT witness sponsoring any Customer projects?

A. Yes. Company witness Duncan Paterson is sponsoring funding for three Customer technology projects totaling $2,389,899 in capital expenditures and $739,568 in O&M expenses. Exhibit A-131 (DDP-7). The IT department is a critical enabler of CX&O plans and initiatives. The CX&O organization is highly adept at reviewing its current processes and identifying customer experience pain points, but it relies heavily on the expertise provided by IT to help develop and implement necessary digital solutions. Such solutions might include SAP enhancements and fixes, website enhancements, upgrading end of life technology, or evaluating and choosing vendors and products – all executed as a joint effort between IT and CX&O. Together, these departments ensure customers receive safe, reliable, and positive experiences across all channels of interaction with the Company. IT maintains the Company's technology systems, ensuring they operate efficiently, reliably, and free from cybersecurity risks. IT also supports analytic platforms and solutions which provide deeper insight into customer needs and enables CX&O to establish appropriate targets for metrics, products, and customer programs. This work is necessary to select the most cost-effective and beneficial solutions for customers, and continued investment in technology requires additional ongoing funding to support and maintain these platforms. Further support for the CX&O business technology drivers is documented in the IT Digital Three-Year Plan, which is included as Exhibit A-126 (DDP-1).

PROJECT	**CAPITAL**	**O&M**
Customer Self-Service Online Work Scheduling	$17,328	$16,958
Flexible and Advance Payment Options	$161,304	$42,615
Bill Design & Delivery Transformation Project	$2,211,267	$679,995
Total	$2,389,899	$739,568

A. Customer Interactions

Q. Please provide an overview of Customer Interactions.

A. Customer Interactions is responsible for the execution and ownership of the various channels of customer interactions: website, mobile app, IVR, phone (robocalls, live voice calls), digital correspondence (email, interactive alerts, digital notifications), and paper mail. This work includes the following areas of focus: (i) Digital Customer Operations ("DCO"), Customer Contact Center, Business Customer Care ("BCC"), Credit and Assistance; and Analytics & Outreach ("A&O"). All five are aligned to the larger department goals of providing channel optionality for customers to serve in their channel of choice, and continuously improving the customer experience to allow customers to choose new programs and products to meet customer energy needs and allow the Company to achieve its clean energy goals. To effectively perform in these areas, the Company is projecting $27.8 million of O&M expenses for the test year ending September 30, 2023, as shown on Exhibit A-96 (CMH-2).

1. DCO

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 to enable self-serve in one's channel of choice, including the website and mobile application. Additionally, the DCO team collects over 3,900 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 solution design, development, and launch of monthly releases to add new features or modify user flows, (3) leading major technology projects that add new functionality or modify business rules to better serve customers, and (4) executing the implementation of programs online to help accrue energy savings and clean energy opportunities for customers.

Q. What types of transactions do customers complete online?

A. The most common reasons customers use the Company's website and mobile app are to check the billing status of their account, make a payment, report an outage, view the expected restoration status of an outage, view energy usage information, and view additional service information – such as auto-pay, eBill enrollment, budget billing, and information on products and services. In addition, the Consumers Energy website now 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, especially during peak periods of the year.

Q. Please explain why the Company is continuing to invest in digital methods to allow customers to serve in their channel of choice.

A. Continued investments are needed to keep pace with changes in customer habits and expectations as they continue trending toward more integrated and sophisticated digital services, as well as ensuring channel parity so that customers can complete all transactions in all channels. Between 2018 and year-end 2020, the Company experienced a 14% annual increase in website sessions and a 25% increase in the number of unique users. Customer needs vary widely, from reducing energy for environmental reasons, to having questions about their bill answered, and setting up the right day and time for their move-in. The website also serves as the primary channel for enrolling customers into energy savings programs. Expanding the Company's digital presence enables it to serve a variety of customer options across multiple technology platforms, at a time of the customer's choosing, while keeping internal support costs affordable. The digital channel enables customers to 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, and it helps keep the Company's costs affordable. Online transactions cost approximately $0.11 versus $4.81 per live agent call, making this a cost-effective alternative to expanding the call center service hours.

Q. Is the Company asking for additional funding for projects within DCO?

A. Yes. The Company is requesting $551,000 in O&M expenses to upgrade and expand its digital correspondence channel. (This category includes what was referred to as Alert

Upgrades in the Company's last electric rate case, Case No. U-20963, but has been renamed to more clearly reflect the nature of the work.)

In 2020, Consumers Energy met customer demand for auto-generated email, phone calls, and text messages by sending 52 million notifications to 1.65 million customers who elected to connect with the Company via digital outage and billing/payment alerts. These automatically generated messages cover outage topics (e.g., cause, estimated time of restoration) and billing/payment information (e.g., billing statement availability, payment reminders). The existing suite of features used to generate these messages is outdated and hard-coded, making it exceptionally slow and labor-intensive to use efficiently. The Company plans to introduce new features which will simplify customer interactions, streamline back-end workflows, and provide additional channel support as customers continue to enroll.

Q. What customer benefit is associated with the new digital correspondence features?

A. As the number of customers who wish to receive automatic digital notifications from the Company continues to grow, the technology upgrade will enable a variety of improvements that will help more customers successfully interact with it, including:

- A message template editor. This feature allows DCO personnel to edit the language contained in digital correspondence quickly and easily, without needing support from IT as is currently the case, reducing costs and speed of changes.
- Natural Language Processing ("NLP"). This feature allows customers to respond to auto-generated digital correspondence with common terms and vernacular versus preset response keys.

- Source reporting. This feature will provide a dashboard showing data on what is driving digital correspondence enrollments.
- Ad hoc messaging. This feature will allow the Company to quickly relay outage- and safety-related information, the time and place for water and ice distribution events, or in acute emergencies, such as the Ray Compressor Station fire, where customers must be reached urgently with up-to-the-minute information that is not contained in a preexisting message template.

Consumers Energy will continue to invest in digital correspondence as a key tool in its customer satisfaction portfolio. The Company recognizes that 74% of consumers say that companies offering multiple customer service channels provide better service, that 64% of customers place real-time response of service as a top priority for quality expectations, and that 53% of customers prefer to receive alerts by text message during a blue sky outage. Accordingly, the Company has planned steps to continuously improve the customer experience as the definition of a satisfactory experience continues to evolve and trend more toward digital and mobile channels.

Q. Is the CX&O department proposing bridge period IT costs related to DCO projects?

A. Yes. Company witness Paterson is sponsoring bridge period IT costs for two DCO projects, the Customer Self-Service Online Work Scheduling tool and the Flexible and Advanced Payment Options project, which will require, respectively, $17,328 in capital expenditures and $16,958 in O&M, and $161,303 in capital expenditures and $42,615 in O&M, as reflected on Exhibit A-131 (DDP-7).

Q. Please describe the Customer Self-Service Online Work Scheduling tool.

A. Today, customers who require scheduled utility work at their premises are unable to self-serve much of the information they wish to provide to or obtain from the Company, which drives needless contact center calls and reduces customer satisfaction. Customers must not only call the contact center to schedule work, they must also call back for information related to their appointment time, work progress, nature of the work, and confirmation that the work has been completed. The Company will update the online customer self-service portal to enable order scheduling, to allow customers to select their preferred channel for receiving work order notifications and to make back-end updates that automate work order scheduling in SAP. This will reduce the occurrence of customers making multiple contact center calls regarding their work orders, improve customer satisfaction by allowing them a new, efficient method to complete a common transaction in their preferred channel, and increase the Company's efficiency by supplying blocks of time for like work order types. It is further expected that this update will provide a technical and business process foundation for other similar initiatives in the future.

Q. Please describe the Flexible and Advanced Payment Options project ("FAPO").

A. The FAPO project addresses customer concerns regarding existing payment plan options. Currently, Consumer Energy payment arrangement offerings are insufficient or lack flexibility to support needs of customers with inability to pay. On average, the Company sees these customers account for 874,000 calls into contact centers to resolve payment plan related concerns each year. In order to improve the customer experience, reduce calls to contact centers, and reduce payment plan defaults, the Company needs to offer payment-challenged customers easier and more flexible payment plans. The scope of this project includes updating SAP with eligibility rules for payment plans, updating the customer self-service portal and IVR to align with available payment options and self-service capability, implementing an installment plan guide online for customers to self-serve to select the best plan for them, and improving input screens for Customer Service Representatives ("CSRs") surrounding payment plans.

Q. Does IT sponsor any other projects with important customer benefits?

A. Yes. Company witness Paterson is sponsoring test year IT costs for the Website Redesign Project. The redesign is required for important technical and cybersecurity reasons, but it also offers a host of benefits that will improve the Company's ability to serve customers who choose its website as their preferred channel. Additional description of the project is provided as part of Company witness Paterson's direct testimony and Exhibit 131 (DDP-7).

Q. How else does the Company expect this project to benefit it and its customers?

A. Consumers Energy expects several benefits from redesigning its website. First, reducing site complexity on the back end and improving performance on the front end will drive down the number of calls that Company personnel receive for tech support, and the number of calls that would-be website users make to the contact center for assistance with the task they originally intended to complete online. Faster page load times alone would help customers self-serve quickly and successfully on the website (a 2-second delay in load time can result in website visit abandonment rates of up to 87%). This would be especially useful and important during times of peak website traffic such as outages, when it is critical that the Company reach its customers quickly and reliably. Altogether, the website redesign improvements are expected to produce a $1.2 million savings annually by reducing 220,000 website-driven calls to the contact center.

Second, the Company expects that this redesign will support the success of its clean energy programs and offerings by allowing for a more consistent, credible customer experience on the website. The new site structure will enable Consumers Energy to save money and boost functionality by enabling the integration of third-party hosted microsites with the website, delivering personalized content to users, and encouraging increased program participation, enrollment, and customer cost savings.

In the seven years since its last website update, Consumers Energy has worked to audit and improve individual site pages as needed. While the current solution provides value, continuing to meet customer demands and needs site-wide is limited by the current level of complexity behind the website. However, this website redesign and best-in-class deployment will enable the whole to be easily updated and navigable, safer than ever, and supportive of a fast, easy, and satisfying experience for the significant number of customers who prefer to interact with the Company in this channel.

Q. What additional value will customers enjoy due to the website redesign?

A. The redesign entails redesigning the customer views and moving the website to an improved and modern infrastructure, which offers an array of advantages, as described below and in the testimony of Company witness Paterson:

- Improved security and reliability: the website will be able to accommodate the latest security and architecture standards to reduce the risk of lost or publicized customer data and to improve website reliability and uptime;
- Better accessibility and inclusivity: the website redesign will allow a segment of the Company's most vulnerable customers to fully interact with the site by availing themselves of accessibility features that comply with the guidance of Title III of the

Americans with Disabilities Act, and it will be able to display content in multiple languages; and

- Higher performance and expanded functionality: the website will load significantly faster, especially during high-traffic periods such as outages, reducing lag times and website visit abandonment rates. The redesign will also allow customers to pay multiple accounts at once, and more easily view the offerings and clean-energy programs relevant to their needs.

2. Customer Contact Center

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 2019, call center representatives answered 3.6 million customer calls, a decrease of nearly 600,000 calls from the previous year. Likewise, the IVR system addressed 8.4 million calls during 2019. In 2021 year to date, the call center handled 1.32 million calls, a decrease of 940,000 over the 2.26 million handled in the same time frame in 2019. 2020 data is anomalous due to the impact of the COVID-19 pandemic on the Company's operations, but reflects about 568,000 fewer calls than the previous year. This is due to the Company foregoing the seal for nonpayment ("SNP") process throughout much of 2019 due to COVID-19, meaning that far fewer customers called for service reconnects. To continue this work, the Company is projecting $15.3 million of O&M expenses for the test year ending September 2023. As shown on Exhibit A-96 (CMH-2), this represents an increase in O&M expenses of $1.5 million from the $13.8 million expended in 2020. Moreover, a portion of the increase is due to a Customer Service Representative wage increase as the result of union negotiations.

3. BCC

Q. Please provide an overview of BCC.

A. BCC works directly with the Company's commercial and industrial ("C&I") customers. The organization's main goal is to deliver an exceptional one-to-one experience, while identifying opportunities that add energy value for business customers. Overall, the BCC serves approximately 105,000 customers, which equates to 216,000 contracts. This represents $2.3 billion to the Company's total annual revenue.

This department is comprised of the Business Center, which includes phone agents, and account management, which is responsible for assisting the Company's larger business customers. To continue the work in this area, the Company is projecting $2.1 million in O&M expenses for the test year ending September 2023. As shown on Exhibit A-96 (CMH-2), this represents a decrease in O&M expenses of $900,000 from the $3 million expended in 2020.

Q. What recovery is the Company requesting to better serve small and medium business ("SMB") customers?

A. The Company is seeking recovery for $450,000 in O&M to invest in its SMB customer partnerships in the test year ending September 2023. Each customer segment is a critical collaborator with the Company as the utility business model continues to evolve in support of a safe, clean, affordable, and reliable energy future. The Company's initial market scan revealed pandemic-driven changes to customer preferences that the Company desires to meet (80% of businesses expect real-time responses, 84% expect personalization, and 66%

expect innovative new products and services). Consumers Energy will dedicate resources to communicating more effectively with this class and learning how best to develop both general and industry-specific services that address their particular needs and preferences. Specifically, the Company will:

- Prototype services (modified or new) that may better address customer needs and preferences, such as enhanced engagement during move-ins;
- Activate priority contact quality initiatives to help ensure SMB contact information is current and usable. The Company lacks email addresses for 56% of its SMB customer accounts, which limits its ability to effectively communicate with this customer sector. Consumers Energy will also dedicate a portion of this O&M to hiring another full-time employee to assist with the efforts in this space;
- Initiate communications testing to determine customers' channel preferences and the potential effectiveness of industry-specific messaging for customers in retail, construction, restaurants, light manufacturing, agriculture and others; and
- Conduct interviews and complete other market research to better understand customer challenges and needs.

Q. What benefits does the Company anticipate in response to these efforts?

A. Consumers Energy is planning to eliminate 10% of the roughly 40,000 calls that SMB customers make to the contact center annually by offering them self-service options and improving or enhancing existing services.

It further anticipates increased eBill adoption (targeting 5-10% increased enrollment overall, with at least half of all SMB customers enrolled). It also expects increased awareness of and enrollment in the Company's value-added products and services portfolio as a result of its more tailored marketing and better contact information quality.

Finally, it is expected that at least some SMB customers are currently not on the appropriate rate. Improved ability to reach these customers will increase their awareness of the Company's rate offerings and potentially allow them to improve their rate accuracy and potentially realize cost savings as a result.

Consumers Energy is targeting a 10% improvement to its SMB digital Customer Experience Index ("CXi") score as a result of these efforts.

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 them pay their bills.

The Theft Investigation Team provides the critical service of identifying and ending energy theft in the Company's service territory. Stopping theft is important both for maintaining the safety and integrity of the Company's system and minimizing all customers' costs. In 2020, the team identified 973 confirmed cases of theft and billed for over $340,000 in unauthorized use and investigation costs.

Revenue Operations addresses customer accounts which are past due or 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.

Additionally, this group manages contracts with outside collection agencies to recover payments from customers with outstanding balances. In 2020, the Company recovered $4.41 million of previously written-off gas-only customer balances. Recovery of these payments directly offsets the uncollectible expense discussed in the testimony of Company witness Gaston.

The Energy Assistance team is responsible for administering the Company's Consumers Affordable Resource for Energy ("CARE") Program, which supports low-income customers who are struggling to pay their monthly energy bills. By coordinating with other organizations, in fiscal year 2020, this team obtained $16.3 million of assistance for its customers requested through the Michigan Energy Assistance Program ("MEAP"). Furthermore, this program has helped prevent customers from being disconnected by working with agencies across Michigan to ensure both state and federal assistance is correctly applied to customer accounts. In addition to MEAP assistance, in fiscal year 2020, customers received $18.8 million in State Emergency Relief payments and $17.1 million in Home Heating Credit assistance. Consumers Energy is requesting $3.2 million in O&M to support the activities of this department in the test year. As shown on Exhibit A-96 (CMH-2), page 3, this request represents an increase of $200,000 in O&M expenses from the $3 million expended in 2020. This increase is due to a rise in payments to third-party agencies that perform collection activities on the Company's behalf, both pre- and post-write-off. These activities are necessary to control uncollectible expenses and limit the impact on other customers.

5. Analytics and Outreach

Q. Please provide an overview of the Analytics and Outreach area.

A. The Analytics and Outreach team provides a suite of functions that include customer research, data analytics, and outreach. Work performed by this team supports all of the CX&O organization and the Company generally. The Company is projecting $515,000 of O&M expenses for the test year ending September 2023, as shown on Exhibit A-96 (CMH-2). This represents a decrease of $925,000 from the $1.4 million expended in 2020. This decrease is attributed to the fact that the department's expenses are now being carried by the teams who request their marketing and market research services (Demand Response, Energy Waste Reduction, etc.) and are reflected on those budgets.

By collecting and analyzing data from customers or syndicated and industry sources, the team can provide insights which allow the Company to improve its customer experience, develop new service options, and pursue more effective customer communications. The goal is to communicate and engage customers with the right offer, with the right message, and in the right channel. To accomplish this, the team develops comprehensive marketing, communication, and engagement strategies, which, combined with excellent campaign management, drive decreased costs and improved participation in Company offerings (e.g., payment plans or eBill). In taking steps to better understand its customers, the Company expects to reduce costs and increase efficiency around its programs and engagement efforts, delivering energy savings and supporting the successful implementation of the Clean Energy Plan.

B. Billing and Payment

Q. Please provide an overview of Billing and Payment.

A. Billing and Payment is responsible for leveraging customer feedback to ensure that payment processes are consistent and simple, that monthly energy bills are accurate and easy to comprehend, and that 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 $18.1 million of O&M expenses for the test year ending September 2023. As shown on Exhibit A-96 (CMH-2), this represents an increase in O&M expenses of $2.5 million from the $15.6 expended in 2020.

1. Customer Billing

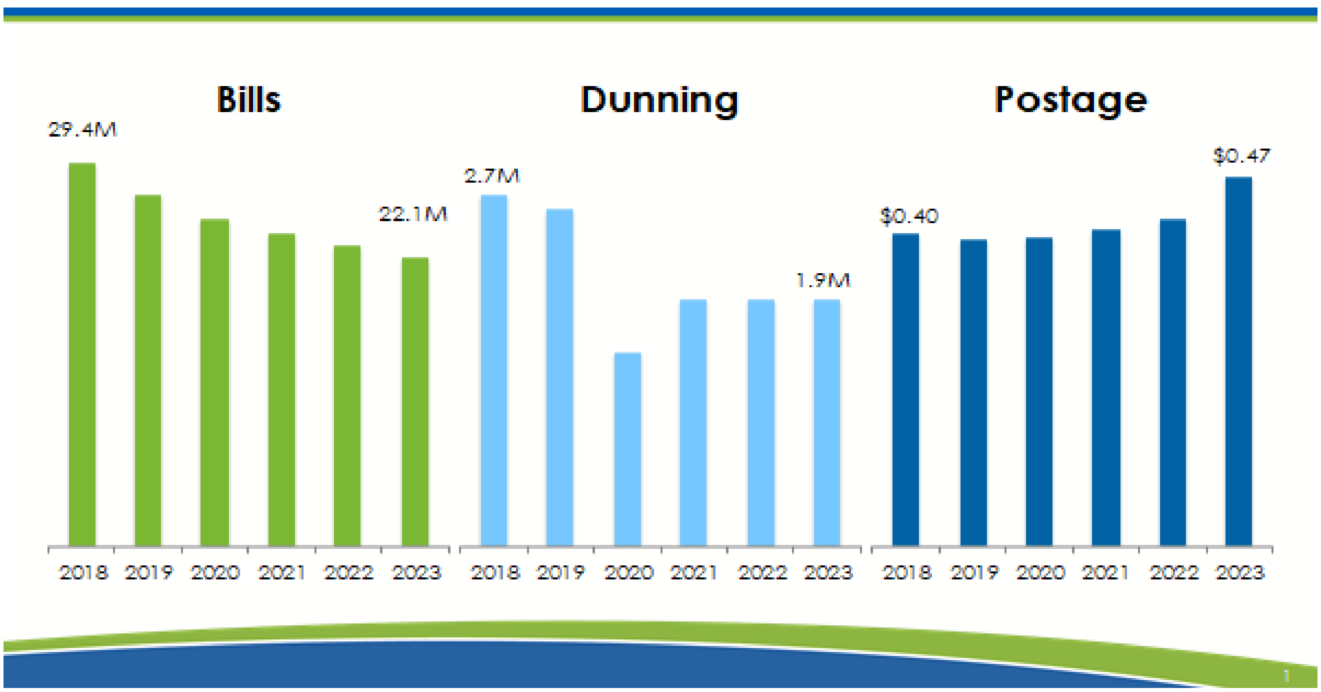
Q. Please provide an overview of Customer Billing.

A. Customer Billing manages the "exceptions" process, which is a quality control process designed to review unusual bills (both digital and paper) before they are sent to customers. This 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 maybe reread as part of the validation process. Rigorous improvement efforts to ensure every customer bill is accurate meaning the Customer Billing team has continually optimized its processes and technology to aid in the review of billing exceptions. Ensuring that customers receive the right bill every time is critical. To continue this work, the Company is projecting $8.4 million of O&M expenses for the test year ending September 2023. As shown on Exhibit A-96 (CMH-2), this represents an increase of $500,000 from the $7.9 million expended in 2020.

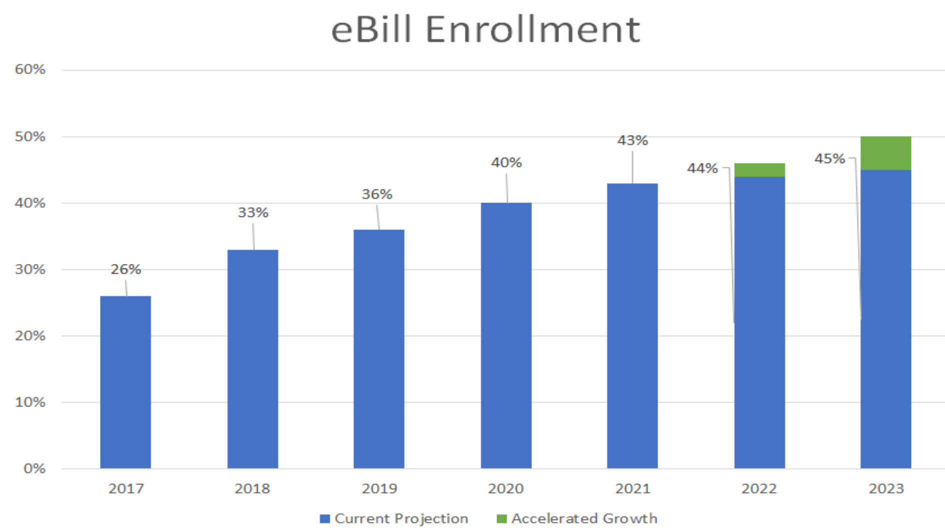
Q. Please explain the costs within Customer Billing.

A. Included in Customer Billing is the cost for stationery, forms, and postage related to the Company's billing and dunning communication processes. In 2020, the Company mailed over 23 million paper bills, and approximately 1.5 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 deliberate action to increase customer enrollment in electronic billing, or eBill (see Figure 2 below). Consumers has successfully increased eBill participation from <27% in 2017 to an anticipated 43% in 2021. This growth has reduced postage costs by over $2.8 million annually by reducing the number of pieces mailed. It expects to continue to increase eBill enrollment over the next two years to 45%, as illustrated below in Figure 2.



However, cost per piece postage has steadily increased over the past three years due to USPS postage increases and is expected to continue to increase, per Figure 3 below, offsetting the savings realized from growing eBill enrollment.

Figure 3. Impact of Dunning and Postage Costs on eBill Savings

	2018	2019	2020	2021 (Projected)	2022 (Projected)	2023 (Projected)
Customer Paper Bills	29.4 Million	26.9 Million	25.0 Million	24.0 Million	23.0 Million	22.1 Million
Dunning Notices	2.7 Million	2.9 Million	1.9 Million*	2.1 Million	2.2 Million	2.2 Million
Postage Rate	$.398	$.391	$.392	$.403	$.415	$.47

*2020 reduction due to COVID

Q. Is the Company undertaking any other efforts to increase eBill enrollment?

A. Yes. In order to achieve first quartile utility eBill adoption, an accelerated growth plan is needed. The accelerated growth plan, if implemented, is expected to grow enrollment by 2-3% annually to 50% enrollment, at which point the Company will have reached the top of Chartwell's utility benchmark for eBill enrollment and participation additions are expected to plateau. This plan includes increased marketing efforts to demonstrate the customer value of eBill. Industry insights recommend that offering an incentive could help drive the Company eBill adoption up by a minimum of 1% for each campaign. The campaign concept would offer a gift card to a customer's choice of a selection of grocery, gas, or retail stores if they choose paperless billing. The annualized postage savings for each campaign is expected be around $80,000. Consumers Energy is requesting $74,000 in O&M to deliver two eBill campaigns that would produce an estimated $160,000 in ongoing annual postage savings beginning in the year proceeding the campaigns.

Q. Is the Company projecting any test year IT project costs related to the Customer Billing?

A. Yes**.** Company witness Paterson is sponsoring test year IT costs that include $2,211,267 of capital expenditures and $679,995 of O&M expenses related to the Bill Design and Delivery Transformation Project in the test year. Exhibit A-131 (DDP-7). The Bill Design and Delivery Transformation project has three primary components: 1) a bill redesign for the most common Company rates and rate/program combinations; 2) replacement of existing software for print correspondence management with a more efficient vendor-hosted solution; and 3) a flexible print and delivery outsourcing initiative reducing internal costs while providing more efficient means to modify and target messages within outbound printed materials. The Company's current billing solution is a limiting factor in many business choices as it is not cost effective and decreases speed of delivery.

Q. Please describe benefits of the project.

A. The Company last redesigned its bill over five years ago. It created a summary-level billing page that made top-line priorities of use and cost more easily understood, but these improvements did not extend to any other rate (of which there are dozens) or rate/program combinations (of which there are thousands). Nor did that bill design sufficiently address the messaging complexity introduced by other rates or rate/program combinations, or clarify the various surcharges and fees included in a bill.

The bill design project proposed in the instant case will address presentation of other major rates (including the new Summer Time of Use ("TOU") on/off peak use and rates), budget plans (including information on billing carry-over and reconciliation), payment arrangements, and program participation such as Demand Response. The project will also provide a platform that will allow Consumers Energy to support modifications to new rates and programs as they are designed, including items supporting renewables, electric vehicles, predictable billing, and on-bill financing. The current platform does not allow billing modifications to economically support bill presentation for any of these types of programs. The new, modular bill will allow Consumers Energy to customize bill presentation for different rates and program enrollments and prioritize placement of information to unique account and customer characteristics. This will include the ability to have flexible messaging and on-bill communications (rather than bill inserts) that cannot be executed today and will better accommodate complex billing conditions. These bill enhancements will increase the customer's ability to interact with their energy usage and current rate structure.

Additionally, a vendor-supplied web portal associated with this project will improve call experience for both CSRs and customers by providing Company representatives with a suite of tools that will allow them to resolve more customer inquiries regarding billing and dunning during the first call.

Finally, the Company will implement an adoption marketing program supported by the vendor, which gives access to a team of marketing professionals that provide campaign strategies and tactics to help achieve optimal eBill conversion rates. This program will help achieve or exceed 50% eBill adoption.

Q. What cost savings does the Company project to accompany this project?

A. Consumers Energy identifies projected savings associated with postage, real estate, call reduction, process waste elimination, and resource reduction. The projected savings are as follows:

Cost Savings Item	**Description**	**Estimated Impact (annual)**
Postage	Savings due to vendor sorting capabilities and volume discounts	$1,051,431.00
Call Reduction	Estimated 200K call reduction Avg. $5.56 ($6.93 Internal Call & $4.20 Contractor)	$1,112,000.00
Returned Mail	Reduction of 50% of returned bills	$100,000.00
Real Estate	Space can be reutilized versus new facility developed	$1,000,000.00
Bill Messaging Controls	Reduction of part-time contractor resource	$25,000.00
Total		**$3,288,431.00**

ii. <u>Customer Payment Programs</u>

Q. Please describe Customer Payment Programs.

A. Customer payments are among the most sensitive and frequent touchpoints the Company has with customers, with approximately 33 million payments made annually. In 2014, the Company initiated a Customer Payment Strategy which 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 improvement in customer experience and reduction of payment-related calls and complaints. The Company continues to make it a priority to accommodate customer preferences with a variety of desirable options that 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 $9.7 million in test year O&M expenses shown on Exhibit A-96 (CMH-2). This represents a $2 million increase from the $7.7 million expended in 2020. Operating costs associated with customer payments continue to evolve with changes in customer behaviors and preferences. Figures 4 and 5 below reflect the trends and forecasts for customer payment behaviors, showing increasing numbers of credit card payments and the associated costs to the Company.

Q. What are the anticipated payment processing fees costs for the test year?

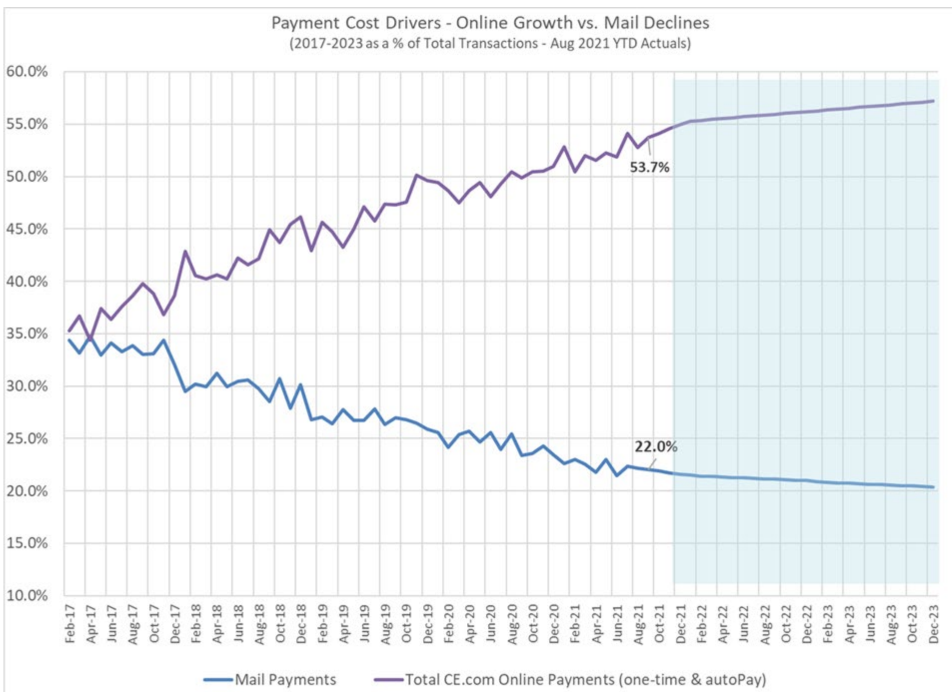
A. The Company is projecting payment processing fees of $8.3 million in O&M expenses for the test year. This represents the actual costs the Company expects to incur from its third-party payment processing vendor. This represents an increase of $1.8 million from the

$6.5 million expended in 2020, which is largely due to increased customer usage of credit cards to pay their bills. These fees are incurred whenever a customer pays through a digital channel, such as the website, the IVR, or text message.

Q. Have customer payment behaviors changed in recent years?

A. Yes. As illustrated in Figure 4 below, the biggest change in payment behavior is the shift away from mail towards electronic payments, the majority of which are online credit card payments.

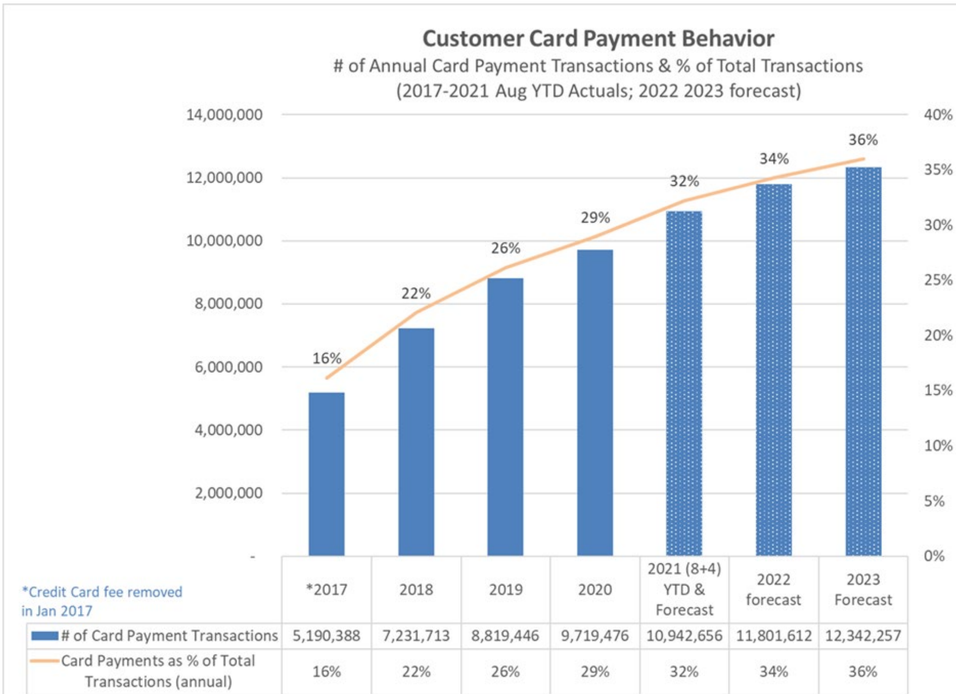
Figure 4. Payments by Channel



Since 2017, payments by mail have fallen from 33% to 22% of total payments in 2021, while online payments have increased from 35% to close to 54% in the same time period. As shown in Figure 5 below, the main drivers of increased online payments are credit cards. The number of annual credit card payments has more than doubled from

5.2 million transactions in calendar year ("CY") 2017 to an estimated 11 million transactions in CY 2021.

Figure 5. Credit Card Transaction Growth



The Company expects the trend of increasing electronic payments to grow as customer behavior continues to move online. To forecast growth, the Company employs a proprietary proven model utilizing current and historical data by payment channel and payment type, integrating relevant customer and transaction growth to adjust the forecast for customer payment behaviors. Figure 5 above, illustrates the growth of electronic payment methods and the decline of "traditional" channels such as mail and in-person over time.

Q. Is it appropriate to apply a 3-year average to credit card costs?

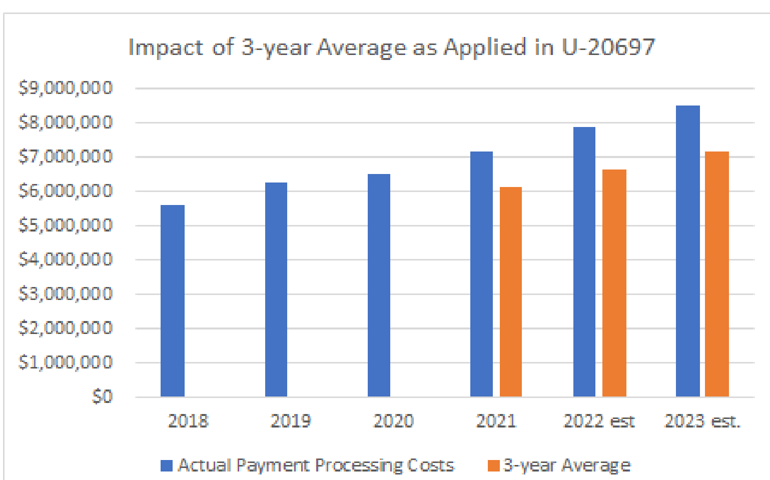
A. No. The Company has accurately forecasted the growth in customer credit card usage, and related Payment Processing Fee expenses over the last 4 years. Applying a historical 3 year average to test year expenses artificially disallows the true costs incurred by the Company. As illustrated in Figure 6 below, the total O&M expense related to credit card payments has steadily increased with volume.

Figure 6. Credit Card-Related O&M Expenses

Description	**2018**	**2019**	**2020**	**2021 est.**	**2022 est.**	**2023 est.**
Credit Card Payments	7.2M	8M	9.9M	11.1M	12.3M	13.2M
Credit Card Payment % of Total	24.1%	26.1%	28.8%	32.7%	36.0%	39.0%
Total Cost of Credit Card Payments	$5.6M	$6.3M	$6.5M	$7.2M	$7.9M	$8.5M

In 2019, the expense was $6.7 million, and the Company expects it to grow to $8.5 million in 2023. Applying the 3-year average only recognizes 73% of projected test year expenses. This equates to a gap of $2.2 million in projected transaction costs in the test year. A similar gap existed when a multi-year historical average was applied in a previous general rate case, as illustrated in Figure 7.

Figure 7. Actual Costs vs. Multi-Year Average



The historical 3-year average approach does not adequately cover the actual costs incurred by the Company given the continued increase in card use over the past few years, and the forecasted increase in the immediate future. The Company further believes its request for the full projected transaction costs is reasonable due to several cost mitigation efforts it has undertaken unilaterally to minimize rate impacts for all customers.

Q. What has the Company done to minimize or reduce credit card related expenses?

A. The Company has taken many proactive actions to mitigate costs related to credit card payments. When the Company began using its current payment processing vendor in 2017, it blocked 108 C&I rate codes from paying by credit card. This action was taken to prevent exorbitant fees associated with these high usage type customers. A recent review of customers within these blocked rates showed that they typically have monthly bills totaling $8,600 for electric service and $11,800 for a combination account. The Company estimates that blocking these customers saves $3.9 million a year in credit card fees. The Company is continually researching new ideas to either reduce credit card fees directly or encourage customers to move to less expensive forms of payment. As a part of this effort, the Company initiated a formal Request For Proposal process in 2021 for payment processing vendors to ensure rates are competitive and consistent with market rates.

Q. Please provide an overview of Direct Payment Offices ("DPOs").

A. Consumers Energy has eight DPOs around the state of Michigan. The Company started 2019 with 13 offices. The Company closed the Traverse City location on July 1, 2020, and four other DPO locations – in Battle Creek, Macomb, Muskegon Heights, and Pontiac - on July 1, 2021, due to declining customer traffic. All eight remaining payment offices are 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.

II. HOME ENERGY PRODUCTS PROGRAM

Q. Please describe the Company's Home Energy Products Program.

A. Home Energy Products refers to a portfolio of value-added products and services ("VAPS") which consists of the Company's non-regulated Appliance Service Plan ("ASP"), appliance repair, and the AllConnect Mover Program. Customers enrolled in ASP pay a monthly subscription fee to cover equipment (furnace, air conditioner, water heater, washer and dryer, and/or kitchen appliances) repairs. In the event a covered appliance malfunctions, a qualified service person is sent to explain and rectify the problem at no additional cost to the customer. This program benefits customers by reducing the risk of potentially expensive and unexpected appliance repair or replacement costs. For instance, consider that a new variable speed blower motor for a modern furnace can cost more than $1,000, compared to a $19.99 monthly fee for coverage under the ASP program. This program is the Company's most popular value-added service.

Consumers Energy also offers an appliance repair service to provide repairs, priced on labor and material, to heating, ventilation, and air conditioning ("HVAC") equipment, water heaters, and other appliances. These services are offered to customers when their equipment issue is not covered under the ASP plan.

AllConnect is a third-party provider contracted to offer one-stop shopping for customers who are moving into or within the Company's service territory. AllConnect's

Mover Program provides a single point of contact to assist customers with transferring cable, internet, and waste management services. After completing a customer's utility account move, a Consumers Energy customer service agent asks whether the customer would like to speak to an AllConnect representative to set up or transfer other household services. The Company receives a commission from AllConnect for customers who agree to speak with an AllConnect representative and contract for their services. The profits from the ASP and AllConnect services are used to offset the Company's revenue requirements, which directly benefit all natural gas customers by reducing their monthly bills. The Company is projecting Home Energy Product revenue of $73.1 million, expenses of $56.1 million, and net margin of $17 million to be used to offset net revenue requirements, shown on Exhibit A-97 (CMH-3) for the test year ending September 2023.

The Company is honored to offer these valued services to provide customers increased customers satisfaction and peace of mind. Customers rely on these programs to meet their needs and look to Consumers Energy as a trusted resource. Additionally, the margins from these programs are used to help offset the utility's revenue requirement.

Q. What is the effect of the Home Energy Products margin on the Company's rates?

A. The Company operates its unregulated VAPS under a traditional profit model. The "margin" refers to the profit garnered from these programs, less the expenses invested to operate them. This margin is applied to offset the Company's revenue requirement and thereby reduce customer rates.

Q. Has the Company operated this program continuously since its last gas rate case, Case No. U-20650?

A. No. Consumers Energy voluntarily suspended its Home Energy Products offerings in March of 2020 after concerns were expressed by Staff arising out of the Company's 2018 Annual VAPS report led to the Company self-reporting certain violations of the Code of Conduct and the data privacy tariff. Consumers Energy opted to exit the market for its unregulated VAPS as a result of the Initial Self-Report. This means that all sales and marketing efforts were stopped. The ASP Program remained out of market for one full year from March of 2020 through March of 2021. The majority of the Company's unregulated VAPS have remained out of market.

Q. Please explain why the Home Energy Products profits have decreased since the Company's last gas rate case.

A. There are several reasons why Consumers Energy is projecting lower profits at this time.

First, the Company lost 53,000 customer contracts during the period that it was out of market, and expects to incur additional expenses as it works to not only replace these lost contracts but expand the program to a larger scale than it was prior to exiting the market and to continue to grow it over time.

Second, the Company's expenses had been increasing since the last gas rate case due to the complexity of new appliances, and the higher costs of labor and materials. This increased complexity of newer appliances requires additional training of service personnel and use of more expensive materials (e.g., electronics, refrigerant) to complete repairs.

Finally, the Company has also seen increases in the frequency of service orders per ASP contract above historic trends, which is attributed to appliance design and added features with higher failure rates.

Q. How have Home Energy Product profits changed over the period you describe?

A. As shown on my Exhibit A-97 (CMH-3), the Home Energy Products net margin in 2020 came to $29.7 million. The Company is projecting a net margin of $17.9 million for the test year in the instant case. The projected test year revenue is $73 million, a decrease of $5.9 million from 2020.

Q. Does the Company intend to expand the Home Energy Products Program?

A. Yes. The Home Energy Products Program is a valued service for enrolled customers who can be sure they will not incur an unexpected appliance- or HVAC-related expense whose cost is potentially many times the cost of their monthly enrollment fee. Consumers Energy is pleased to be able to continue this offering.

To return the program to its prior strength and grow it further, the Company plans to expand its marketing efforts, resume training programs for technicians, continue resolving its Code of Conduct compliance activities, and implement new technology to allow customers to schedule service appointments more quickly and easily.

Q. Describe the customer value associated with maintaining and growing this program.

A. In addition to the positive rate impact this program has on customer bills, the program offers operational support that a customer may not receive from another vendor. Many people – especially our most vulnerable customers - would find it prohibitively expensive or extremely inconvenient to deal with an inoperable refrigerator or furnace. As climate change continues to intensify Michigan's weather extremes, customers will increasingly depend on their household appliances and other equipment to keep their homes safe and comfortable. Consumers Energy is pleased to offer customers an affordable monthly rate to insure against the risk that a customer could not afford an expensive repair bill, especially during severe weather.

Q. Does this conclude 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-21148
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

STEVEN J. HERRYGERS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

Q. Please state your name and business address.

A. My name is Steven J. Herrygers, and my business address is 17000 Croswell, 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 Director of Gas Compression Engineering.

Q. What are your responsibilities as the Director of Gas Compression Engineering?

A. I am responsible for the overall reliability for the Gas Compression fleet. This includes all asset management, planning, engineering, design, system health, and performance of the Company's Gas Compression assets.

Q. What is your formal educational experience?

A. I graduated from Michigan State University with a Bachelor of Science in Engineering. I am a licensed Professional Engineer in the state of Michigan.

Q. Would you please describe your previous work experience?

A. I started my career at HDR (previously Cummins & Barnard) in 2003 as a Mechanical Engineer. While at HDR, I worked with multi-discipline teams to design and implement construction projects for various utilities across the country. I obtained my Professional Engineering license in 2008.

I started a new position with Consumers Energy in 2011 as a Project Engineer assigned to a large Air Quality Control System program. Since that time, I have taken different assignments at Consumers Energy that have included increasing levels of responsibility in Engineering and Project Management. These assignments included design and construction responsibilities in both Electric Generation and Gas Compression.

I was the Director of Project Engineering during the design and construction of the St. Clair and Freedom Compressor upgrade projects. I started my current position as Director of Gas Compression Engineering in July of 2019.

Q. Have you previously sponsored testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I sponsored rebuttal testimony in the Company's last gas rate case, Case No. U-20650, responding to various parties' proposals to disallow the investments for the repair and modification of the Ray Compressor Station after the January 30, 2019 fire that took place at the plant.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-98 (SJH-1)	Ray Station Fire Report;
Exhibit A-99 (SJH-2)	Ray Station Fire Report Company Response;
Exhibit A-100 (SJH-3)	Ray Storage Field Injection Timeline and Facility Repair;
Exhibit A-101 (SJH-4)	Compliance Action Letter, Company Response and Closure;
Exhibit A-102 (SJH-5)	Administrative Settlement;
Confidential Exhibit A-103 (SJH-6)	Ray Station Plant 3 PHA;
Exhibit A-104 (SJH-7)	Gas Industry Lessons Learned Presentation;
Confidential Exhibit A-105 (SJH-8)	St Clair Plant 3 PHA;
Confidential Exhibit A-106 (SJH-9)	Freedom Plant 3 PHA;
Exhibit A-107 (SJH-10)	MPSC Inspection Reports from Ray Station 2011-2020; and

Exhibit A-108 (SJH-11)	MPSC July 30, 2013 Ray Inspection Report.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to: (i) discuss the fire that occurred on January 30, 2019 at the Ray Compressor Station in Armada Township, (ii) support the Company's investments for the repair and modifications to the Ray Compressor Station resulting from the fire, and (iii) to address unresolved concerns raised by MPSC Staff ("Staff") and the Attorney General in Case No. U-20650 regarding rate recovery of the Company's fire-related investments and modifications to the Ray plant.

Q. Please describe the Ray event that occurred.

A. On the morning of January 30, 2019, a fire occurred at the Company's Ray facility in Macomb County. The Ray facility, the largest source of working gas capacity in Michigan, is a combination compressor station and nearby storage field. Plant 3 at the Ray facility detected an abnormal operating condition in the Det-Tronics control system on that day. As part of the emergency safety fire-gate process, the plant released natural gas into the atmosphere through Plant 3 blowdown silencers. The natural gas released from the fire-gate event at Plant 3 migrated to the Plant 2 processing equipment as a result of the wind conditions occurring at the time of the event. A gas plume ignited from the Plant 3 blowdown silencers and the Plant 2 thermal oxidizer's exhaust stream auto-ignited the Plant 3 fire-gate gas plume. The fire reduced the amount of natural gas the Company could deliver to customers from underground storage located in the Ray field near the compressor station. Further details concerning this event can be found in my Exhibit A-98 (SJH-1), Consumers Energy Company's "Ray Compressor Station Fire Report, Jan. 30, 2019," originally filed in Case No. U-20463 on April 5, 2019, and in my Exhibit A-99 (SJH-2), "Consumers Energy Company's Reply to the Commission Staff's Response and Stakeholder Comments," originally filed in Case No. U-20463 on May 30, 2019. Both of these documents provide photographs, illustrations, and additional background related to the incident.

Q. Please discuss the damage that occurred as the result of the Ray Station Event.

A. The fire at the Ray facility damaged equipment in Plants 2 and 3, including the dehydration systems, which are required components for withdrawal. This had the effect of limiting the facility's withdrawal capacity during the remainder of the 2018-2019 heating season, and of preventing storage field injections until certain repairs could be completed. Further details can be found in "Consumers Energy Company's Ray Natural Gas Compressor Station Storage Field Injection Timeline & Facility Repair Update," originally filed in Case No. U-20463 on August 2, 2019, and is my Exhibit A-100 (SJH-3).

Q. What was the cause of the event?

A. The investigation into the origin of the fire has revealed that a grounding fault was the underlying cause of the initial fire-gate event. When the station's well pump started up, its variable frequency drive caused a voltage spike in the grounding system of the Det-tronics panel located in the headquarters building. These high voltages caused enhanced discrete input/output and analog input modules to lose communication with the Det-tronics pilot air system, a fault which triggered the initial fire gate. The natural gas released from the fire-gate event migrated in a northeast direction over the Plant 2 processing equipment as a result of the wind conditions occurring at the time of the event. A gas plume ignited from the Plant 3 blowdown silencers (suction and discharge). The Plant 2 thermal oxidizer's 1,506 degrees F exhaust stream auto-ignited the Plant 3 fire-gate gas plume.

The fire and damage at the Ray Station was precipitated by a safety venting fire-gate process that has been proven safe and effective in the past. Since being placed in service in 2013, Ray Plant 3 has successfully completed both planned and unplanned fire-gate evolutions without incident. But under the unique and extreme weather conditions, the process became hazardous to the station equipment. This new failure mode has now been added and new risk mitigation countermeasures have been implemented at the Ray Station and across the fleet to further enhance resilience and help to avoid failure under extraordinary circumstances in the future.

Q. What capital expenditures did the Company incur in order to repair and modify the Ray Compressor Station?

A. A summary of the capital and operating and maintenance ("O&M") expenditures is included in Table 1 below for reference. For additional details please refer to the capital section of Company witness Timothy K. Joyce's direct testimony.

Table 1: Ray Fire Restoration Total Capital and O&M Expenses

	2019 (actual)	2020 (actual)	2021 (actual)	Total
O&M	5,245,506	(259,318)	-	4,986,188
Capital Restore	11,640,191	938,754	3,043	12,581,989
Capital Modify	1,371,655	3,066,599	(201)	4,438,053

Q. Are any capital investments for the repair and modification of the Ray Compressor Station in connection with the January 30, 2019 fire included in the bridge year or test year in this case?

A. No. The Company incurred all of the investments necessary to repair and modify the Ray Compressor Station in connection with the January 30, 2019 fire during 2019 and 2020.

All repairs and modifications associated with the January 30, 2019 fire were completed before the beginning of the bridge year in this case.

Q. If none of the capital investments for the repair and modification of the Ray Compressor Station are new in the bridge year or the test year in this case, why are you addressing those investments in this case?

A. The Company originally included its investments for the fire-related repair and modification of the Ray plant in the Company's proposed rate base in the Company's last gas rate case, Case No. U-20650. In Case No. U-20650, several parties proposed that the Commission should disallow any rate recovery for those investments. The Company contested those recommendations. Ultimately, Case No. U-20650 was resolved by a settlement agreement among the parties, which included a provision stating that "the investments made to repair and modify the Ray Compressor Station as a result of the January 30, 2019 fire should neither be approved nor disallowed in this proceeding." Instead, the settlement agreement in Case No. U-20650 provided that "any decision on the rate recovery of those costs should be addressed in the Company's next natural gas general rate case filing once any insurance proceeds received by the Company associated with these capital investments are known." In this case, Consumers Energy is once again asking that the Commission include the investments for the repair and modification of the Ray plant in connection with the January 30, 2019 fire in rate base for purposes of setting rates in this case.

Q. Were the Company's capital expenditures to repair and modify the Ray Compressor Station after the January 30, 2019 fire reasonable and prudent?

A. Yes. The capital expenditures to repair and modify the Ray Compressor Station were necessary in order to return the station to full operation after the January 30, 2019 fire. The Ray facility is the largest source of working gas capacity in Michigan. The Ray Compressor Station is a vital part of Consumers Energy's integrated transmission and distribution system and is directly connected to the Company's largest natural gas storage field. The storage field represents more than 30% of the Company's total working gas volume.

As a result of the fire, the Ray Compressor Station was taken offline until the cause of the fire could be determined and understood by means of a root cause analysis. As outlined in the storage capacity and repair timeline, which the Company filed in Case No. U-20463 on August 2, 2019 (Exhibit A-100 (SJH-3)), the Company prioritized repairs to the Ray facility in such a way as to minimize their impact on system operations, meet peak summertime injection demand, and ensure that the natural gas storage field could be filled to capacity.

Q. Would it have been reasonable for the Company not to have repaired the Ray Compressor Station after the January 30, 2019 fire?

A. No. Not repairing the station would have been imprudent and unreasonable for the following reasons:

- Maintaining full access to Ray storage field (supply) capacity is essential for meeting the Company's customers' needs during the winter, particularly during peak day weather events;
- Ray storage field is the Company's largest storage asset in terms of working gas capacity and storage field deliverability. As noted previously, it provides

over 30% of the seasonal working gas. On the coldest days, the Company plans on the field providing gas supply to between 20% to 45% of the Company's peak day system demand. Off peak, Ray can supply as much as 50% to 60% of the total customer demand;

- Ray provides system resilience because its supply capacity is larger than any other supply source on the system. Ray can be used to backstop supply as needed;
- On a winter peak day, the Ray facilities provide access to more supply than is readily available in the market;
- Ray's tremendous storage capacity also helps insulate customers from typically higher gas cost in the winter when customer usage is the highest;
- Not repairing the facility would strand a significant amount of cyclable gas in the field;
- Not repairing the facility would strand past strategic investments in both the storage field and compressor station which were made to benefit customers;
- Compression is needed to refill the storage field. Without adequate operable compression, the field could not be refilled in the summer and thus could not be fully utilized in the winter. This would have affected the Company's ability to adapt to winter customer demand and would result in the Company needing to significantly increase winter pipeline supply purchases, which are typically more expensive; and
- Repairs to the gas conditioning equipment were necessary to ensure the Ray storage supply meets the state's gas quality requirements.

As this information shows, the Ray Compressor Station is a vital component of the Company's integrated gas transmission and distribution system, and, without the repairs, the Company would not be able to maintain reliable gas service to its customers.

Q. **Did any party allege in Case No. U-20650 that the expenditures to repair or modify the Ray Compressor Station were not needed or that it was not reasonable or prudent for the Company to make those expenditures?**

A. No. Two witnesses (one for Staff and one for the Attorney General) offered testimony about the investment for repairing and modifying the Ray plant after the fire in Case No.

U-20650. However, neither witness claimed that the expenditures were not needed, and neither claimed that the expenditures were not reasonable and prudent. Both witnesses appear to recommend that the expenditures should be disallowed despite the fact that they are reasonable and prudent expenditures that were needed in order to return the Ray Compressor Station to full operation.

Q. If the parties to Case No. U-20650 did not dispute the reasonableness and prudence of the expenditures, what reason did they provide for recommending complete disallowance of the capital spending to repair and modify the Ray Compressor Station?

A. Staff's witness in Case No. U-20650 cites a January 31, 2020 "Compliance Action" letter from Staff to Consumers Energy related to the Ray Compressor Station fire, which noted Staff's allegation that the design of the Ray Compressor Station, specifically the placement of the plant's blowdown silencers, constituted a "probable violation" of 49 CFR 192.167(a)(2). See Exhibit A-101 (SJH-4). That regulation is a portion of the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration's ("PHMSA") regulations pertaining to the design of pipeline components. It requires compressor stations to have an emergency shutdown system and specifies that the emergency shutdown system must discharge gas from the blowdown piping at a location where the gas will not create a hazard. Staff's witness took the position that, if the design of the plant was inconsistent with the PHMSA regulation, then the Company is "ultimately responsible for" (see direct testimony of Staff witness Nathan J. Miller in Case No. U-20650, page 17, line 12) the damage and should be required to write-off the capital invested to make the repairs as a loss, rather than to include those capital expenditures in the calculation of its rates. The Attorney General's witness also cited to the "Compliance Action" letter and indicated that the Commission should disallow the investments for the repair and modification of the Ray plant if the Commission determines that the Company violated a safety standard. See direct testimony of Sebastian Coppola in Case No. U-20650, page 67, lines 9 through 12.

Q. Does the Company agree that an alleged violation of 49 CFR 192.167(a)(2) provides adequate justification for disallowing the Company's otherwise reasonable and prudent investment for the repair and modification of the Ray Compressor Station?

A. No. First, Consumers Energy believes that assigning liability to the Company for the January 30, 2019 fire solely on the basis of an alleged violation of an administrative regulation is unlawful for the reasons stated in the Company's Initial Brief in Case No. U-20650. Furthermore, when the regulator has identified a probable violation of a PHMSA regulation, both the federal pipeline safety law and PHMSA rules require the regulator to consider several factors before it may issue a civil penalty for the violation. These factors include: (i) the degree of the respondent's culpability, (ii) the respondent's history of prior offenses, and (iii) any good faith by the respondent in attempting to achieve compliance. See, e.g., 49 CFR 190.225. In other words, the PHMSA regulations recognize that a utility may have little or no "ultimate responsibility" (i.e., culpability) that would warrant a civil fine – even if there is a proven violation of the PHMSA regulations – and that might be particularly true where there has also been no history of violating the specific PHMSA regulation and where the utility clearly exercised good faith in its efforts to comply with the regulation. In contrast, Staff and other parties in Case No. U-20650 incorrectly and unjustifiably assumed that an alleged violation of a PHMSA regulation is tantamount to culpability and that this assumed culpability is sufficient reason to deny rate recovery to the Company for costs that are undisputedly reasonably and prudently incurred.

Q. Did Staff's January 31, 2020 "Compliance Action" letter result in a Commission determination that Consumers Energy violated 49 CFR 192.167(a)(2)?

A. No. Consumers Energy and Staff executed an administrative settlement agreement that resolved the January 31, 2020 "Compliance Action" letter, but the settlement did not ask the Commission to make any finding regarding whether a violation of 49 CFR 192.167(a)(2) occurred. The administrative settlement agreement was approved by the Commission on May 8, 2020. See my Exhibit A-102 (SJH-5) Furthermore, even if the Commission or some other tribunal ultimately determines that the design of the Ray plant was inconsistent with the PHMSA regulation, no party has explained why such a finding should automatically result in the conclusion that Consumers Energy is culpable for the fire such that the Company should be penalized for it. Neither witness offered any evidence in Case No. U-20650 to support that assumption.

Q. Would it be appropriate to assume that a potential violation of an administrative regulation, like 49 CFR 192.167(a)(2) conclusively demonstrates that the design and placement of Ray Compressor Station's blowdown piping was inconsistent with then-existing engineering standards for the proper design of such a plant?

A. No. The design of a plant, such as a gas compressor station, is subject to numerous state and federal regulatory requirements. These are typically written using more general or outcome-based language intended to reflect broad public policy goals, but generally lack the specific engineering or construction detail necessary to provide conclusive direction about how to actually design and build such a facility. To support these requirements, engineering and construction organizations have created codes and standards (e.g., American Society of Mechanical Engineers, the American Petroleum Institute, etc.) to provide significantly more detailed design information and guidance, but even those guides do not, without more, establish the standard of care for the design of a complex plant like a gas compressor station. Those codes and standards are written from the perspective of particular professional disciplines or to address engineering or design considerations that are common to a variety of similar applications across a potentially broad industry classification, but do not provide holistic direction for determining best engineering practice across disciplines or for applications that are not common to a broad industry classification. As a result, it would be incorrect to assume that any of these codes or standards can or should be applied, in its entirety and without qualification, to the design of a particular type of plant. Instead, professional design of a gas compressor station or similar plant requires a qualified engineer to apply specialized expertise, experience, and professional judgment in order to review, synthesize, and harmonize the overlapping, and sometimes inconsistent, body of engineering guidance from private codes and other sources, along with an understanding of standard industry practices that have developed over time, in order to establish the state of the art for designing plants of that kind. The engineering standard of care for designing a gas compressor station is a composite of that specialized expertise, experience, and professional judgment of the practitioners within the field for designing and building gas compressor stations. State and federal regulations are written with input from experts who have an understanding of this process and resulting standard of care, and should be understood to incorporate the standard of care as part of their application. Therefore, a meaningful and appropriate understanding of whether the design of the Ray Compressor Station was fully consistent with then-existing engineering standards cannot be determined solely by reference to PHMSA regulation 49 CFR 192.167(a)(2). It would also require the evaluation of one or more specialized engineers experienced in the standard of care for designing such plants.

Q. Did Consumers Energy rely on its own in-house expertise in designing the Ray Compressor Station?

A. No. As an owner of a gas transmission and distribution system, a utility's in-house expertise is in operating a compression station, not necessarily in designing one. It is common in the natural gas utility industry to hire an outside architect/engineering ("AE") firm with specific expertise and experience in the design of a gas compression station when the utility decides to build a new plant. The AE possesses the expertise, experience, and ability to apply design considerations, design standards, incorporation of industry best practices, and code adherence into the overall station design as discussed previously. With respect to the components of Ray Plant 3 that were initially involved in the fire on January 30, 2019, Consumers Energy hired EN Engineering as its AE firm to provide the overall design for Ray Plant 3, which was constructed in 2013.

Consumers Energy contracted for EN Engineering to provide all design services for the plant, including integration of all equipment, piping, electrical, instrumentation/controls, etc. In this role, EN Engineering was the "Engineer of Record" for the Ray Plant 3 project. The designs were completed under the direct supervision of Michigan licensed Professional Engineers ("PE") employed by EN Engineering. The final approved-for-construction drawings were affixed with their PE stamps.

Q. How did Consumers Energy select EN Engineering to design and build Ray Plant 3?

A. As part of the procurement process for this project Consumers Energy competitively bid the design work to four qualified bidders, all of which had proven experience designing gas compressor stations.

Q. What steps did Consumers Energy take to ensure that EN Engineering was qualified to perform the work?

A. As part of the procurement process, relevant project experience and qualifications of each of the respective bidders were reviewed as well as project specific team member resumes and credentials. The EN Engineering team consisted of highly qualified and experienced engineers. Prior to the award of the contract, Consumers Energy performed reference checks with other plant owners that utilized the firm for similar work.

Q. Assuming for the sake of argument that the Ray Compressor Station design was inconsistent with the requirements of PHMSA regulation 49 CFR 192.167(a)(2), do you agree that Consumers Energy should be treated as culpable for the Ray Compressor Station fire?

A. No. As discussed previously, the issue of culpability is, and should be, a separate consideration from the question of whether the design of the plant was inconsistent with the requirements of the regulation. It cannot simply be assumed as a result of a finding that the plant was not fully compliant with the regulation. The Company did not intentionally, or even negligently, locate the blowdown vents in a place that would present a potential hazard. First, the Company reasonably relied on the specialized expertise and experience of a qualified AE firm to design and build the Ray Compressor Station. The Company had no reason to doubt the engineering efficacy of EN Engineering's design during the construction of Ray Plant 3 or in the years since then. Second, Consumers Energy submits that, as designed, the Ray Compressor Station followed the existing standard industry practice for designing and constructing a gas compression station. In fact, at Consumers Energy's direction, EN Engineering followed certain standard industry practices that exceed the requirements of 49 CFR Part 192 as part of their effort to identify and mitigate hazards during the design of the station.

Q. Please clarify what standard industry practice EN Engineering followed that exceeds the requirements of 49 CFR Part 192?

A. EN Engineering utilized a process hazard analysis ("PHA") in an effort to identify and mitigate hazards. The United States Department of Transportation regulation does not require PHAs. Nevertheless, Consumers Energy regularly practices the use of PHAs according to industry best practice for the design of complex systems.

Q. What is the purpose of a PHA and what were the results of the PHA prepared in conjunction with the design of Ray Plant 3?

A. During the design phase of the project, it is standard industry practice to review potential hazards and either modify the design to eliminate hazards or incorporate engineering controls to address the hazards. This is accomplished by conducting a PHA. The Engineer of Record is responsible to coordinate the PHA and incorporate the findings into the final design of the facility. EN Engineering completed and incorporated findings from the PHA as part of the design of Ray Plant 3. The PHA for the original Ray Plant 3 design is included as Confidential Exhibit A-103 (SJH-6). The specific type of risk that resulted in the Ray Compressor Station fire on January 30, 2019 was not identified by the industry experts hired by the Company to perform this review.

Q. What oversight did Consumers Energy provide for the design and construction work on Ray Plant 3?

A. As the Owner, Consumers Energy oversees the progress of the work to ensure it is being performed in alignment with the expectations defined in the contract. For its efforts specific to the design of the project, Consumers Energy is involved in progress reviews of the AE design as well as provides accessibility to the project site. The owner relies on the expertise of the AE firm to understand and implement design codes, standards, and best practices in order to provide a system that meets the intent of all applicable local, state, and federal codes and regulations. The roles of the owner and AE as I have described them is consistent with standard industry practice.

Q. In hindsight, were there any analytical tools available that could have identified the potential hazard associated with the placement of the Ray Compressor Station blowdown piping?

A. Yes. After review of the video footage of the incident during the Company's root cause analysis, Consumers Energy concluded that a dispersion model of the vent stacks could have identified the potential hazard.

Q. Prior to January 30, 2019, was dispersion modeling considered or utilized as standard industry practice for the design of facilities such as Ray Plant 3?

A. No. While dispersion modeling is a design tool that has been used in various industries in the past, it has not been a standard design tool for gas compressor station blowdown siting design. As discussed previously, standard industry practice utilizes a PHA for risk identification in the design of gas compressor stations. The Company reached out to an industry subject matter expert, Mr. Douglas E. Law of Basic Systems, Inc, for additional insight regarding this topic. Please refer to the direct testimony of Company witness Douglas E. Law for additional discussion on industry standard practice. As with any risk assessment effort, it is impossible to identify all potential risks. When a utility experiences a previously unforeseen risk, industry experts work to incorporate consideration and mitigation strategies for the risk into future planning and design work. While Consumers Energy would have preferred not to have experienced this unforeseeable risk, the Company has worked diligently, openly, and cooperatively with regulators and other industry participants to ensure that this risk is not present anywhere else on the Company's system. Likewise, Consumers Energy shared its learnings with the gas utility industry in order to ensure that the standard industry practice for gas compressor station design will include dispersion modeling in the future. Please refer to my Exhibit A-104 (SJH-7)

Q. Has Consumers Energy had any other experience demonstrating that the use of PHAs, without dispersion modeling, has been the recognized general industry practice?

A. Yes. Over the past 10 years Consumers Energy has completed construction of new plants at its Ray (2013) and St. Clair (2017) Compressor Stations. Also, Freedom Compressor Station Plant 3 is in its final stages of construction. Each of these projects utilized a different AE. However, each design project followed the same process, utilizing a PHA as part of the detailed design phase of the project. None of the AEs involved in those projects have utilized dispersion modeling as part of the hazard assessment for designing the Company's gas compressor stations. These AE firms have done work for gas utilities all around the country. Consumers Energy is not aware of another gas compressor station project designed by any of those AE firms in which dispersion modeling was utilized for hazard assessment. The design approach was consistent for each project. See my Confidential Exhibits A-103 (SJH-6), A-105 (SJH-8), and A-106 (SJH-9) for Ray, St. Clair, and Freedom PHAs, respectively.

Q. Has Staff inspected the Ray Compressor Station after the design and construction of Ray Plant 3 was complete?

A. Yes. Staff regularly conducts on-site inspections of each of Consumers Energy's compressor stations, including Ray. Staff conducted on-site inspections of the Ray Compressor Station multiple times during the construction of Plant 3, as well as numerous occasions since construction has been completed. According to discovery responses that Staff provided to Consumers Energy in Case No. U-20650, Staff inspected the Ray plant 31 times between 2011 (when construction on Ray Plant 3 started) and January 29, 2019 (the day before the Ray fire). Many of those inspections specifically related to the Ray blowdown vents or a fire-gate event. See Exhibits A-107 (SJH-10) and A-108 (SJH-11). Although Staff noted three potential issues during the original Plant 3 construction phase that the Company should address in order to ensure that the plant met all regulatory requirements, it should be noted that none of Staff's notices from the construction phase, or since the initial operation of the facility, assert any violation of 49 CFR 192.167(a)(2). Consumers Energy does not have any communication on record of questions or concerns from Staff as it relates to any potential violation of 49 CFR 192.167(a)(2) after construction at the plant was complete. In fact, Staff conducted an on-site inspection on July 30, 2013 that specifically referenced the code article in question. The question in that report specifically asks "Does ESD system discharge gas at a location where the gas will not create a hazard?" with a documented condition response of "Satisfactory." See Exhibit

A-108 (SJH-11). The location of the Plant 3 blowdown vents has never changed since construction of Ray Plant 3 was completed in 2013. Prior to the Ray Compressor Station fire on January 30, 2019, Staff had never recommended or required dispersion modeling at any of the Company's gas compressor stations.

Q. Has the Company ever experienced an emergency blowdown event at any of its compressor stations in the past?

A. The Company has experienced emergency blowdown events in the past. In fact, the same systems at the Ray Compressor Station have experienced similar blowdown events in the past, in which gas discharged out of the same blowdown vents without experiencing any hazardous consequences. See Exhibit A-98 (SJH-1), Appendix F, page 88, section under "Prior Blowdowns Did Not Result In A Fire." The fire that resulted from the blowdown event at the Ray Compressor Station on January 30, 2019 was unforeseeable based on standard industry practices and the Company's own experience prior to the date of the fire.

Q. Does Consumers Energy have any prior history of violations of PHMSA regulation 49 CFR 192.167(a)(2)?

A. No.

Q. Did Consumers Energy attempt in good faith to comply with 49 CFR 192.167(a)(2)?

A. Yes. As discussed previously, Consumers Energy hired and reasonably relied upon a qualified AE to design and construct the Ray Compressor Station. Consumers Energy required its AE to follow standard industry practices, which exceeded the requirements of the PHMSA regulations, for identifying and mitigating potential hazards during the design and construction of the plant. And, the Company has transparently and cooperatively worked with regulators after the January 30, 2019 fire to update its hazard assessment at all existing and future plants to incorporate the learnings from the Ray Compressor Station fire, including sharing those learnings industry-wide to help ensure that no similar event occurs on other utilities' systems either.

Q. Mr. Herrygers, in your professional opinion, do you feel that the fire experienced at the Ray Compressor Station on January 30, 2019 was a foreseeable hazard?

A. No. Not at the time of the design of the station in 2011-2012, which is where these types of hazards were analyzed, identified, and mitigated. Likewise, there were no instances since its initial operation that would have indicated the presence of a hazard. As outlined in my testimony as well as the testimony of Company witness Law, the industry practice prior to this event was to utilize spacing tables and to complete PHAs in order to identify and mitigate hazards. This event has changed the industry and this type of hazard will be foreseeable and preventable in the future based on the lessons learned shared with industry peers to include dispersion modeling in the PHA.

Q. Please summarize your testimony.

A. In summary, the Company's costs to repair and modify the Ray Compressor Station after the January 30, 2019 fire are reasonable, prudent, and needed to provide reliable service to customers. As such, there is no valid reason to disallow those costs in calculating the Company's rates in this case. Contrary to the claims of other parties in Case No. U-20650, it is unreasonable to regard Consumers Energy as culpable for the January 30, 2019 fire and to use that as a reason to disallow those undisputedly reasonable and prudent costs. Even if the Commission assumes, for sake of argument, that the pre-fire design of the plant was inconsistent with the PHMSA regulation, those same regulations make it clear that culpability is to be considered separately from that question. On that question, the following must be considered: first, the Company's qualified and experienced AE followed the standard industry practice of utilizing PHAs for hazard assessment for the original design and installation of Ray Plant 3; second, the Company has discharged gas out of these vents in the past without experiencing any issues that would have made the circumstances leading to the fire foreseeable; and third, the results of Staff's own inspections regarded the plant as compliant with PHMSA regulation 49 CFR 192.167(a)(2) prior to the date of the fire. Therefore, it is logical and appropriate to conclude that the facility experienced a risk that was not reasonably foreseeable following standard industry practice and that it would be inappropriate to penalize Consumers Energy by requiring the Company to write off the reasonably and prudently incurred costs that were necessary to restore this vital plant to operation. The Commission should include the full amount of the Company's investment to repair and modify the Ray Compressor Station in connection with the January 30, 2019 fire in the Company's rate base for purposes of setting rates in this case.

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-21148

DIRECT TESTIMONY

OF

SHAWN C. HURD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

Q. Please state your name and business address.

A. My name is Shawn C. Hurd 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 Rate Analyst I in the Rates and Regulation Department.

Q. Please describe your educational and professional experience.

A. I graduated from Michigan State University in December 2011 with a Bachelor of Arts and Letters degree in English. In addition, I have attended several courses on utility ratemaking provided by the Institute of Public Utilities located at Michigan State University. In November 2012, I was hired by Consumers Energy as a Customer Service Representative within the Company's Customer Call Center. In March 2014, I was promoted to Administrative Specialist I. In August 2016, I joined the Rate Administration Section as a Business Support Advisor I within the Rates and Regulation Department and have received promotions to my current position, which is Senior Rate Analyst I. My position centers on the development and implementation of the Company's tariffs for both its Gas and Electric business as the Company's business model changes over time. I also perform regulatory research, implement rate orders, review legislation, and analyze the practices and tariff language of other utilities.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I have filed direct testimony on behalf of the Company in the following cases:

Case No. U-18322 Electric General Rate Case, Tariffs;

Case No. U-20028	2017 Energy Waste Reduction Reconciliation, Tariffs;
Case No. U-20372	2020-2023 Energy Waste Reduction Plan, Tariffs;
Case No. U-20649	Voluntary Green Pricing Program, Tariffs;
Case No. U-20165	2018 Integrated Resource Plan, Tariffs;
Case No. U-20984	Renewable Energy Plan, Tariffs; and
Case No. U-21134	Voluntary Green Pricing Program, Tariffs.

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 in this case?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-109 (SCH-1)		Summary of Tariff Changes; and
Exhibit A-16 (SCH-2)	Schedule F-5	Proposed Tariff Sheets(MPSC No. 3 Redlined Version).

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

A. Yes.

Q. Please describe Exhibit A-109 (SCH-1).

A. Exhibit A-109 (SCH-1) provides a summary and explanation of the tariff changes proposed for the Company's Gas Rate Book.

Q. Please describe Exhibit A-16 (SCH-2), Schedule F-5.

A. Exhibit A-16 (SCH-2) Schedule F-5, provides proposed tariff sheets which detail, in redlined format, all proposed tariff language changes, as well as all price changes proposed by Company witness Alex M. Gast to the Company's Gas Rate Book.

Q. Please explain the changes on Tariff Sheet Nos. C-24.00, D-8.00, D-13.00, and E-8.00.

A. These tariff sheets rename the title of a lead Aggregation account from 'Master' to 'Principal'. The language used within the Company's tariff sheets should reflect the times that we live in today. The word 'Master' is associated with racially charged language and is counterproductive to the Company's direction for incorporating Diversity, Equity, and Inclusion (DE&I) into the work that it performs and how it engages with its customers.

Q. Please explain the change on Tariff Sheet No. C-31.00.

A. Tariff Sheet No. C-31.00 aligns the provision's title with its counterpart in the Electric Rate Book. How the provision is applied will not change from what has already been approved in previous Company proceedings. This is an administrative change only.

Q. Please explain the change on Tariff Sheet No. C-38.00.

A. Tariff Sheet No. C-38.00 allows the Company discretion as to whether it wants to provide a customer with a refundable deposit should the customer act as a Land Developer in situations where unpredictable operations can occur.

Q. Please explain the proposed carrying cost and discount rate changes in regard to the Customer Attachment Program on Tariff Sheet No. C-40.00.

A. Tariff Sheet No. C-40.00 proposes changing the Company's carrying cost rate to 9.06% and the discount rate to 7.21%. This change is further detailed in Company witness Gast's direct testimony in this proceeding.

Q. Please explain the changes on Tariff Sheet Nos. D-10.00 through D-14.00, E-8.00, and E-10.00.

A. These tariff sheets reflect the price changes proposed in direct testimony by Company witness Gast.

Q. Are there any other changes that should be mentioned?

A On Tariff Sheet No. E-8.00, the Company is introducing a Transportation Demand Charge for customers that are being served under any of the Transportation Service Rates. This is further discussed in the testimony of Company witness Gast.

Q. Please explain the changes on Tariff Sheet No. E-3.00.

A. Tariff Sheet No. E-3.00 updates the current language so that a customer's authorized representative, acting on behalf of the customer for the purposes of Rule E2.2 – Nominations, Accounting, and Control in the Company's Rate Book, does not have that authorization in perpetuity. This will allow the Company time to review the customer's current authorized representative every five years to determine if administrative changes need to be made.

Q. Please explain the changes on Tariff Sheet Nos. E-4.00 and G-5.00.

A. Tariff Sheet Nos. E-4.00 and G-5.00 revise the Allowance for Use and Loss percent per the testimony of Company witness Timothy K. Joyce.

Q. Please explain the changes on Tariff Sheet No. G-4.00.

A. Tariff Sheet No. G-4.00 updates Rule G3 - Gas Quality within the Group Transportation Service Pilot Program to align with Rule E3 - Gas Quality in the Company's Gas Rate Book so that they are not in conflict. This is an administrative change only to reflect the updated 5 parts per million oxygen language from Rule R 460.2381 Gas Purity that was approved by the Commission on August 20, 2020, in Case No. U-20608, that amended the rules governing the Technical Standards for Gas Service.

Q. Please explain the changes on Tariff Sheet No. G-6.00.

A. Tariff Sheet No. G-6.00 provides proposed updates to the Group Transportation Service Pilot Program based on feedback from some of the Company's Gas Suppliers. It includes the following:

- shortening the enrollment time for customers to join the Group Transportation Pilot Program from once a quarter to 60 days;
- adds language that expands the number of groups that a Supplier can have from one to three, with a maximum enrollment of 100 contract accounts per group; and
- allows for methods in which a customer can de-enroll from the pilot.

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-21148
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

TIMOTHY K. JOYCE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

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 Manager of Gas Asset Strategy 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 Gas Asset Strategy Manager. In this position, my responsibilities include development and support of project costs and benefit analysis for the Long-Term Financial Plan for compression and storage.

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 and Case No. U-20650. In each of these cases I have provided testimony and exhibits concerning capital investments for the Company's Gas Compression and Gas Storage operations, operating and maintenance costs for the Company's Gas Compression and Gas Management Services operations, as well as Lost and Unaccounted for Gas and Company Use Gas expenses.

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") 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, Lost and Unaccounted for ("LAUF") and Company Use Gas for the years 2020 through the projected test year (October 1, 2022 through September 30, 2023). (**NOTE:** Storage O&M is addressed by Company witness Christopher T. Fultz; and GMS O&M is now addressed by Company witness Kristine A. Pascarello);

(iv) A description of GCS capital expenditures (including the Freedom Compressor Station ("Freedom") upgrade project and 2019 Ray Fire Expenses) for the years 2020 through the projected test year for inclusion in the Company's rate base; and

(v) A description of certain Information Technology ("IT") Projects that support gas storage operations.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-110 (TKJ-1)		2020 – 12 Months Ending September 30, 2023 Gas Compression O&M Expenses;
Exhibit A-111 (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 September 30, 2023;
Exhibit A-112 (TKJ-3)		Calculation of Gas Loss Percentage 2016 through 2021;
Exhibit A-113 (TKJ-4)		Calculation of Allowance for Gas Use and Losses for the Test Year 12 Months Ending September 30, 2023;
Exhibit A-12 (TKJ-5)	Schedule B-5.8	Projected Capital Expenditures Gas Compression and Gas Storage Summary of Actual & Projected Gas Capital Expenditures;
Exhibit A-114 (TKJ-6)		Storage Well Rehabilitation Program Detail; and
Exhibit A-115 (TKJ-7)		Storage Fields Month End Summary Storage Field Injection Timeline & Cost of Gas.

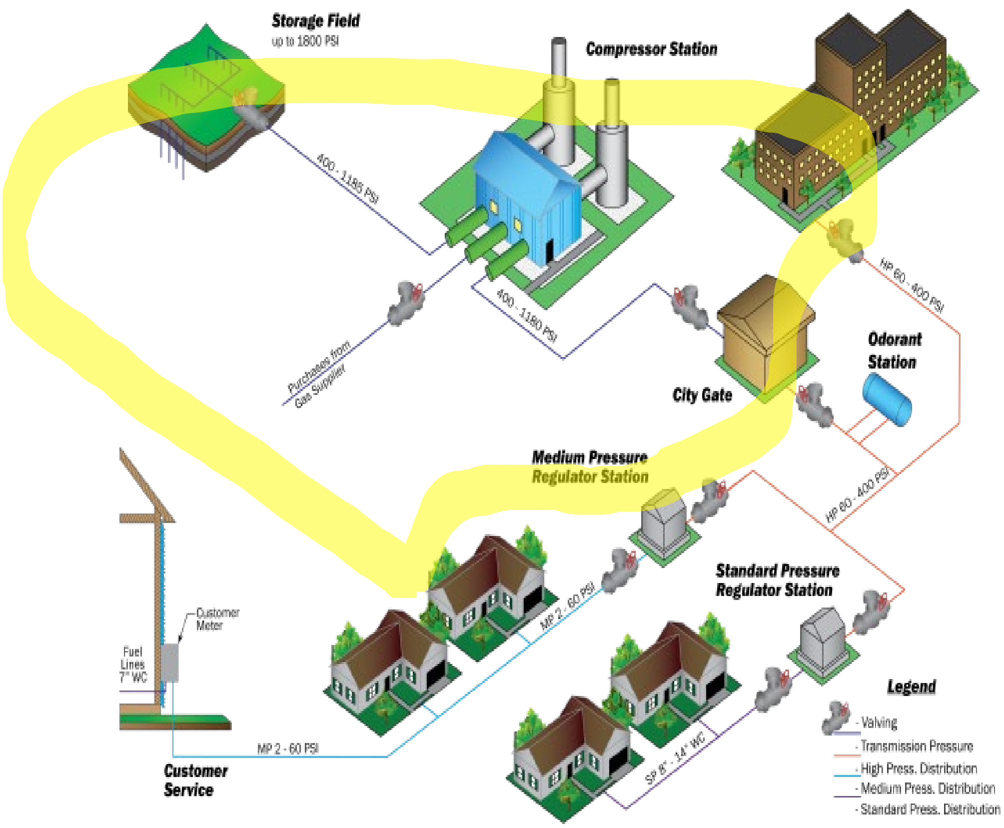
Q. Were these exhibits prepared or assembled by you or under your direction or supervision?

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 eight compressor stations, 15 storage fields, and 905 wells as of January 2021, throughout Michigan's Lower Peninsula. As of October 2021, the compression fleet is comprised of 41 natural gas-fired engines which generate 140,543 Brake Horse Power ("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 compression fleet (and the respective BHP) will change in 2021 as units are retired and new compressor units are added at Freedom. The Freedom upgrade project is discussed in more detail later in my direct testimony.

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 149,040 MMCF. 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:**	**Horsepower:**
Freedom (7 units)	Manchester, MI	12,500 BHP
Muskegon River (7 units)	Marion, MI	27,700 BHP
Northville (4 units)	Northville, MI	10,800 BHP
Overisel (4 units)	Hamilton, MI	10,800 BHP
Ray (5 units)	Armada, MI	23,675 BHP
St. Clair (6 units)	Ira, MI	27,282 BHP
White Pigeon (8 units)	White Pigeon, MI	27,775 BHP
Huron (1 unit)	Sebewaing, MI	1,035 BHP

Gas Storage Fields:

Name:	**Location:**	**Storage Capacity:**
Marion	Marion, MI	
	(Claire, Osceola, Missaukee Counties)	
Winterfield		25,000 MMCF
Cranberry		10,870 MMCF
Riverside		1,480 MMCF
Northville	Northville, MI	
	(Oakland and Washtenaw Counties)	
Northville Reef		490 MMCF
Lyon 29		1,220 MMCF
Lyon 34		600 MMCF
Overisel	Hamilton, MI	
	(Allegan County)	
Overisel		22,720 MMCF
Salem		11,460 MMCF
St Clair	Ira, MI	
	(St. Clair and Macomb Counties)	
Ray		47,520 MMCF
Ira		1,980 MMCF
Lenox		1,190 MMCF
Puttygut		9,390 MMCF
Swan Creek		410 MMCF
Four Corners		2,360 MMCF
Hessen		12,350 MMCF

These storage volumes are listed in 14.65 psia dry pressure base.

(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 different 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"). The Company has also developed another metric, Gas Flow Deliverability ("GFD"). The deliverability metric was developed to measure the ability of the gas system to reliably achieve targeted flow rates, and to identify and assess potential system/customer risk. ROR continues to be used to measure engine/compressor performance. The additional GFD metric allows all compressor station and system equipment performance to be measured. Use of the new metric began in 2019 and is used in development of the compressor station work plans.

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 2014 through mid-2021.

Table 1: System ROR

Year	System ROR
2014	11.9%
2015	7.8%
2016	10.7%
2017	14.8%
2018	15.2%
2019	28.5%
2020	17.5%
2021 (YTD Sept)	17.4%

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 (YTD Sept)	31.3%	19.8%	28.3%

Q. Why is ROR higher in 2019-2021 than previous years?

A. ROR has increased, primarily due to three factors:

1. Intentional limited maintenance on assets that will be replaced as part of the Freedom upgrade project and assets at Ray (2-5, 2-6, 2-7) and White Pigeon (1-5, 1-6) that must be retired in 2021 as part of the fleet optimization. (See Table 2.)

2. The fire incident at the Ray Station that occurred in January 2019.

3. Validation of the newer higher speed equipment and tuning them in to actual operating conditions as well as building experience and increasing crew effectivity in responding to alarms on technology that is decades newer than what they worked on in prior installations.

Q. What is needed for the Company to be able to achieve and maintain its engine performance?

A. Retirement of the units at White Pigeon and Ray occurred in 2021, and will result in an improvement in ROR for 2022. The Freedom upgrade project is nearing completion, as detailed later in my testimony. Equipment repairs have been completed at Ray after the fire that occurred in 2019; the details are also included later in my testimony.

To improve the ROR of the remaining compression fleet and, consequently, reduce downtime and overall maintenance costs, the Company will be more rigorous in execution of maintenance plans and practices, and enhance funding to achieve more efficient preventative programs and eliminate costly reactive events.

Q. Does the Natural Gas Delivery Plan discuss gas compression assets?

A. Yes, gas compression is addressed in Section IV of the Company's Natural Gas Delivery Plan, which is provided as Exhibit A-45 (NPD-1) by Company witness Neal P. Dreisig.

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. In recent history, some of the older compression fleet has not been reliable and starting up the newly installed equipment has required learning for the Company and its equipment suppliers. Based on this experience, Consumers Energy is planning to do the following:

- Improve reliability, operating flexibility, and resiliency of the compression fleet.
- Improve monitoring of operating parameters to better understand equipment health and to optimize maintenance work management.
- Implement lessons learned from the 2019 Ray Compressor Station ("Ray") fire incident to improve resilience of the Ray station as well as overall system resilience.
- Optimize the compression fleet, which may include addition of certain equipment for reliability or resiliency, and retire antiquated compression assets that do not positively affect the Company's plan to provide safe, reliable, affordable, and clean energy.

Please refer to the Natural Gas Delivery Plan shown in Exhibit A-45 (NPD-1), Section IV, for further information on the Company's objectives for gas compression assets.

Gas Storage

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 905 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 logs 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, 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 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 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 can 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. Is the Company projecting O&M expenses related to well logging in this case?

A. No, however, there are certain costs and situations that will result in O&M well logging expenses that cannot be capitalized as part of the Well Rehabilitation Program.

Throughout the course of the 10-year Well Rehabilitation Program, if the Company returns to any well already completed through the program and needs to re-log the well, depending on configuration and the issues found, the costs associated with that logging may not be capitalized.

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-112 (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. Does the Natural Gas Delivery Plan discuss gas storage assets?

A. Yes.

Q. Please describe the Company's objectives for gas storage assets.

A. The gas storage system today includes 15 storage fields totaling approximately149 billion cubic feet of 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 Natural Gas Delivery Plan (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 retirement 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.

Please refer to the Natural Gas Delivery Plan shown in Exhibit A-45 (NJD-1), Section VI, for further information on the Company's objectives for gas storage assets.

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.). <u>O&M EXPENSES FOR COMPRESSION, COST OF GAS, LOST AND UNACCOUNTED FOR AND COMPANY USE</u>

Q. Please describe Exhibit A-110 (TKJ-1).

A. Exhibit A-110 (TKJ-1) identifies the 2020 – 12 Months Ending September 30, 2023, Gas Compression O&M Expenses and Compression Rebuilds (engine and turbochargers). Specifically:

- Column (a) identifies each O&M expense category
- Column (b) identifies the Actual 2020 GCS O&M expense as $17,948,000
- Column (c) identifies the Projected 2021 GCS O&M expense as $24,482,000
- Column (d) identifies the Projected 2022 GCS O&M expense as $23,188,000
- Column (e) identifies the Projected test year GCS O&M expense as $24,092,000

Table 3: Compression O&M

	Projected O&M Expenses				
	(a)	(b)	(c)	(d)	(e)
		Historical	Projected		
Line No.	Description	12 mos. Ended 12/31/2020	12 mos. Ending 12/31/2021	12 mos. Ending 12/31/2022	10/1/2022 - 9/30/2023
1	**Gas Compression**	$ 16,169	**$ 20,052**	**$ 20,445**	**$ 24,092**
2	**Compression Rebuilds**	1,779	4,430	2,743	-
3	**TOTAL O&M**	**$ 17,948**	**$ 24,482**	**$ 23,188**	**$ 24,092**

Q. Please discuss the 2020 Actual O&M expenses incurred by the Company for GCS.

A. The 2020 Actual O&M expenses were taken from Consumers Energy's internal accounting records.

Q. Please explain how the 2021, 2022, 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-110 (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 Fultz. The test year spending was calculated using a weighted average of the 2022 and 2023 forecast. The 2022 calendar year was weighted approximately 37% and 2023 calendar was weighted approximately 63%. This weighting reflects historical spending timing using recent historical actuals information.

Q. Please explain page 3 of Exhibit A-110 (TKJ-1).

A. Exhibit A-110 (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-110 (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.

As previously mentioned in my testimony, this factor includes an increase in workplan spending to support a more rigorous approach to maintenance practices that will enhance performance of the compression fleet, including an increase in headcount from 97 in 2020 to 119 in 2022.

Q. Are there O&M expenditures included to address the Ray Station Event?

A. No. Consumers Energy customers have never paid for O&M costs associated with the Ray Compressor Station Incident, and the Company is not requesting recovery of these costs in this case.

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-110 (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 our system to meet the needs of our customers.

COST OF GAS AND COST OF GAS STORED UNDERGROUND

Q. Please describe Exhibit A-115 (TKJ-7).

A. Exhibit A-115 (TKJ-7) is a listing of the Company's September 2020 through September 2023 underground gas storage volumes and dollars.

Q. Would you briefly explain the background for Exhibit A-115 (TKJ-7)?

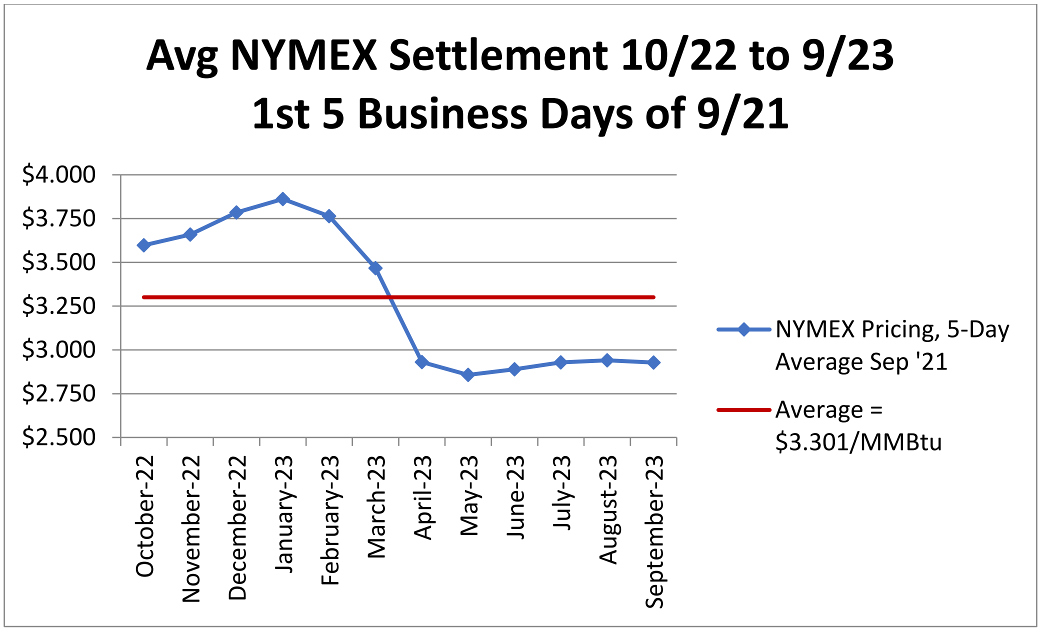
A. Yes. Exhibit A-115 (TKJ-7) reflects the end of the month underground gas storage volumes and dollars that result from the Company's natural gas purchases for its Gas Cost Recovery ("GCR") and Gas Customer Choice ("GCC") customers. The costs and volumes reflect the Company's existing supply and transportation 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-115 (TKJ-7)?

A. Through September 2023, the Company is projecting a 13-month average cost of gas in storage of \$3.333/Mcf (\$424,161,107/127,246,449 Mcf).

Q. What gas prices were assumed for October 2022 through September 2023 in developing your Exhibit A-115 (TKJ-7)?

A. The average New York Mercantile Exchange ("NYMEX") settlement prices for October 2022 through September 2023, as of the first five business days of September 2021, were used. These NYMEX natural gas prices, as shown in the graph below, averaged \$3.301/MMBtu for October 2022 through September 2023.



For the October 2022 through September 2023 GCR requirements (192,231,557 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 2022 through September 2023?

A. The Company is projecting an average cost of gas sold for October 2022 through September 2023 of $3.613/Mcf ($807,423,745/223,466,536 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 addition 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 Natural Gas Delivery Plan.

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-35), Schedule B-4a. The average cost of gas sold of $3.613/Mcf is used in the calculation of the Company's revenue requirement and also used 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-111 (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-111 (TKJ-2). As shown on that exhibit (line 1, column (c)), the test year projected LAUF expense level is $10,557,000. The 2020 historical year amount was $22,071,000 as shown in Exhibit A-111 (TKJ-2), column (b).

Q. Please explain Exhibit A-111 (TKJ-2).

A. This exhibit identifies the projected changes from the historical 2020 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-112 (TKJ-3).

A. This exhibit demonstrates the calculation of the most recent five-year average Gas Loss percentage (line 6, column (g)) of 1.41%. 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-113 (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 2.21%.

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-112 (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-111 (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-111 (TKJ-2), line 2, column (c), the Company Use Gas expense for the test year is projected to be $5,968,000. The calculation supporting this value can be found on Exhibit A-113 (TKJ-4).

Q. Why is there variability in the test year amounts for LAUF and Company Use Gas from the 2020 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 2020 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-20322.

(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-5.8.

A. This exhibit presents the capital expenditures for GCS from the year 2020 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), and Well Data Acquisition (line 17).

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 $101.7 million for 2020 (Actual), $129.2 million for the 12 months ending December 31, 2021 (Projected), $70.5 million for the nine months ending September 30, 2022 (Projected), $199.7 million for the 21 months ending September 30, 2022 (Projected), and $151.5 million for the 12 months ending September 30, 2023 (Projected Test Year). The table below, from page 1 of Exhibit A-12 (TKJ-5), Schedule B-5.8, shows the Compression and Storage capital expenditures I am sponsoring in this docket.

Table 4: Compression and Storage Capital Expenditures

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line		12 Mos Ended	12 Mos Ending	9 Mos Ending	21 Mos Ending	12 Mos Ending
No.	Program Description	12/31/2020	12/31/2021	9/30/2022	9/30/2022	9/30/2023
1	Freedom Upgrade Project	19,724	15,830	7,574	23,404	13,269
2	Compression	35,727	52,174	20,642	72,816	43,328
3	Storage	4,547	8,780	5,257	14,037	18,770
4	New Well	10,580	7,462	9,494	16,956	19,153
5	Well Rehabilitation	19,868	25,115	22,167	47,282	26,039
6	Storage Pipeline Replacement	10,368	16,240	4,680	20,920	27,889
7	Well Data Acquisition	923	3,562	692	4,254	3,006
8	**Total Capital Expenditures**	101,737	129,163	70,506	199,668	151,455

Q. Please identify the capital expenditures projected for the Freedom Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B5.8, 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 2020, costs were incurred for the upgrade project and tool purchases. In 2021 through 2023, costs will be incurred for the completion of the upgrade project.

Q. Please identify the capital expenditures projected for the Muskegon River Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2, line 3, identifies the total capital expenditures for the Muskegon River Compression Station. In 2020, costs were incurred for unit overhauls, fire gate valve replacements, office renovation, and a jet installation project to allow for complete and timely withdrawal of gas from the storage fields after the retirement of Plant 3 units. In 2021 through 2023, examples of projected costs include: unit overhauls, completion of the jet installation and firegate valve replacement projects, and a closed-loop cooling project that will eliminate the need to use Muskegon River water for equipment cooling.

Q. Please identify the capital expenditures projected for the Northville Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2, line 4, identifies the total capital expenditures for the Northville Compression Station. In 2020, costs were incurred for the completion of the back-up generator, and firegate valve replacements. In 2021 through 2023, examples of projected costs include: electrical system upgrades, engine controls upgrades, and firegate valve replacements.

Q. Please identify the capital expenditures projected for the Overisel Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2, line 5, identifies the total capital expenditures for the Overisel Compression Station. In 2020, the Company incurred costs for dehydration system replacement and air compressor replacements. In 2021 through

2023, examples of projected costs include: valve replacements, completion of the dehydration system replacement, and unitized cooling installation.

Q. Please identify the capital expenditures projected for the Ray Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2, line 6, identifies the total capital expenditures for the Ray facility. In 2020, the Company incurred costs for valve replacements and fire damage restoration. In 2021 through 2023, examples of projected costs include: valve replacements, air compressor system upgrades, and piping support restoration.

Q. Please provide an overview of the 2019 Ray fire event.

A. A full description of the event, including a description of the damage that occurred and an explanation of the root cause is included in the testimony of Company witness Steven J. Herrygers.

Q. Please provide an overview of the Ray fire event expenses.

A. The Ray fire recovery efforts are complete and involved both capital and O&M costs. O&M costs included condition assessments, repairs, and replacement of items/scopes that do not qualify as assets, such as replacement of isolated small-bore piping, small valves, painting, heat trace, and insulation. Capital costs included restoration of damaged assets and a modification to the gas vent stacks based on the outcome of the hazard assessment and dispersion modeling analysis. Capital expenses are included in Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2, line 6. The table below provides an overview of the expenses, not inclusive of insurance recovery, thru September 2021.

Table 5: Ray Fire Restoration Total Capital and O&M Expenses

	2019 (actual)	2020 (actual)	2021 (actual)	Total
O&M	5,245,506	(259,318)	-	4,986,188
Capital Restore	11,640,191	938,754	3,043	12,581,989
Capital Modify	1,371,655	3,066,599	(201)	4,438,053

Q. Do the Ray fire capital expenses included in Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2, line 6 include any insurance adjustments?

A. Yes. 2021 Capital spending has been reduced by $4,431,000 for anticipated insurance proceeds. An insurance claim has been filed but has not been finalized. The insurance claim is expected to close by the end of 2021. Company witness Michael A. Torrey also addresses the treatment of insurance proceeds in this case.

Q. Please identify the capital expenditures projected for the St. Clair Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2, line 7, identifies the total capital expenditures for the St. Clair Compression Station. In 2020, the Company incurred costs for valve replacements and suction filter separator installation. In 2021 through 2023, examples of projected costs include completion of suction filter separator installation, gas cooler replacement, and engine controller replacement.

Q. Please identity the capital expenditures projected for White Pigeon.

A. Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2, line 8, identifies the total capital expenditures for White Pigeon. In 2020, the Company incurred costs for valve operator replacements and flame detection equipment replacement. In 2021 through 2023, examples of projected costs include discharge filter separator installation, solar battery installation, and engine operating window envelope upgrades.

Q. Were there any capital expenditures on unit and turbo rebuilds after October 1, 2020?

A. No. Pursuant to the settlement agreement in MPSC Case No. U-20650, expenses related to unit and turbo rebuilds were charged to O&M starting on October 1, 2020 as shown in Exhibit A-110 (TKJ-1).

Q. Are you including any unit and turbo rebuild projected capital expenditures in this case?

A. Yes. Pursuant to the settlement agreement in MPSC Case No. U-20650, the Company met with the MPSC Staff to discuss the opposing positions for accounting treatment of unit, turbocharger, engine, and compressor rebuilds or overhauls to attempt to reach alignment. The Company believes during a meeting on April 22, 2021, that the parties reached an alignment that future projects of this nature would be considered capital expenditures.

Q. Please identify the capital expenditures projected for the Marion Storage Fields.

A. Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2, line 9, identifies the total capital expenditures for the Marion Storage Fields. In 2020, the Company incurred costs for the Winterfield tank fire restoration and well head protection. In 2021 through 2023, examples of projected costs include crew/equipment covered parking upgrade and Riverside storage field retirement work.

Q. Please provide more detail about the Riverside storage field retirement project.

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 retire 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. Due to the current 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 will 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 storage field), continue to provide affordable gas in the Riverside area, and reduce methane emissions with the plugging of the storage wells.

Q. What is the estimated timeline and projected cost for the Riverside retirement project through the year 2026?

A. A breakdown of the projected spending for the Riverside retirement project is shown below and is included in Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2, line 9, this project spending does not include Cost of Removal. Detailed engineering and scheduling will continue through 2021 with the execution and final abandonment of the field to occur tentatively before the end of 2026.

Capital Total and Cash Flow Outlay (in Millions)	Total	2021	2022	2023	2024	2025	2026	2027
Capital								
HP Dist. Feed from 2400 to New Reg Station (10.25mi, 8" Steel)	44.352		1.000	42.852	0.500			
HP Dist. Feed from New Reg Station to McBain CG (4.5mi, 8" Stee	16.236			0.500	15.536	0.200		
New CG near gas supply location	5.321		0.100	5.021	0.200			
Rebuild McBain CG to HP-MP Reg Station	2.733			0.100	2.533	0.100		
Install MP Dist. connecting Forward and Falmouth CG customers (5mi, 6" plastic)	4.356		0.100	4.156	0.100			
Install MP Dist. (0.75mi, 6" plastic)	0.739		0.050	0.639	0.050			
Install Reg Station near SC & M-66	1.767		0.075	1.642	0.050			
Engineering Study	0.600	0.600						
Capital Total	**76.104**							

Q. Has the Company's Board of Directors approved the Riverside retirement project?

A. The Riverside retirement project will be presented to the Board of Directors Finance Committee for approval in October 2022.

Q. Please identify the capital expenditures projected for the Northville Storage Fields.

A. Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2, line 10, identifies the total capital expenditures for the Northville Storage Fields. In 2020, The Company incurred costs for a land purchase. In 2021 through 2023, an example of the projected costs includes a tank battery replacement.

Q. Please identify the capital expenditures that are planned for the Overisel Storage Fields.

A. Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2, line 11, identifies the total capital expenditures for the Overisel Storage Fields. In 2020, the Company incurred costs for disposal well secondary containment replacement and well head protection. In 2021 through 2023, examples of projected costs include completion of disposal well secondary containment and scrubber brine tank replacement.

Q. Please identify the capital expenditures projected for the Ray Storage Fields.

A. Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2, line 12, identifies the total capital expenditures for the Ray Storage Fields. In 2020 through 2023, there were no costs incurred and no costs are projected for projects outside of the programs described later in my direct testimony.

Q. Please identify the capital expenditures projected for the St. Clair Storage Fields.

A. Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2, line 13, identifies the total capital expenditures for the St. Clair Storage Fields. In 2020, the Company incurred costs for land purchase and wellhead protection. In 2021 through 2023, examples of projected costs include a field liquid separator installation and a disposal well facility upgrade.

Q. Please identify the capital expenditures that are planned for Storage New Wells.

A. Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2, line 14, identifies the total capital projected expenditures to complete the Company's new storage well drilling plan. In 2020, the Company incurred costs for drilling new wells in the Northville Reef and Ira fields, also engineering and preparation for future well drilling. Flow testing of the new wells at these locations has shown a five to tenfold improvement in flowrates from comparable existing wells. In 2021 through 2023, 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
2021	St. Clair	Lenox	L-201
	Marion	Winterfield	W-1003
2022	Marion	Cranberry	C-994
	Marion	Cranberry	C-995
	Marion	Cranberry	C-996
2023	Overisel	Overisel	O-305
	St. Clair	Puttygut	P-301
	St. Clair	Puttygut	P-302
2024	Marion	Winterfield	W-1004
	Marion	Winterfield	W-1005
	Marion	Winterfield	W-1006

Q. Please identify the capital expenditures that are planned for Well Rehabilitation.

A. Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2, line 15, identifies the total capital projected expenditures for the Storage Well Rehabilitation Capital Program. Exhibit A-114 (TKJ-6), Storage Well Rehabilitation Capital Program Detail, provides additional detail for this multi-year program that is in response to the federal minimum safety standards that are described previously in my testimony.

Project spending for 2022 through the end for the program was determined using 2020 average cost per wells of similar configuration, exiting condition, and work scope. A description of the different work scopes and associated average costs is shown on the Average Cost Calcs tab of Exhibit A-114 (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 7-year reassessment cycle, into compliance with the API RP 1171, as part of the Storage system objectives as outlined in the Natural Gas Delivery Plan.

Completing the rehabilitation and well logging work simultaneously is prudent, efficient, and directly benefits our 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 10-year cycle.

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 identify the capital expenditures that are planned for Storage Pipeline Replacement.

A. Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2, line 16, identifies the total 2021 through 2023 capital projected expenditures for storage pipeline replacements.

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 safety of our company employees and the public, deliverability, resilience, and integrity of our system.

Table 8: Projected Pipeline Replacement Schedule

Year	Project Location	Project Name	Projected Cost
2021	Marion	Winterfield 54NE & 54 NW	$11,726,000
2021	St Clair	Lenox 16"	$3,605,742
2022	Marion	Cranberry 64E	$5,741,306
2022	Marion	Cranberry 60 E2	$2,148,205
2022	Marion	Cranberry 60 E3	$411,594
2022	Marion	Cranberry 65	$8,465,971
2023	Marion	Cranberry 60 E1	$3,648,776
2023	Marion	Cranberry 62 E	$9,530,216
2023	St Clair	Hessen 4W	$2,014,490
2023	Overisel	Overisel 7W	$6,829,950
2023	Overisel	Overisel Lat 2	$3,299,441

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 1940's and Early 1950's). Leaks have periodically developed on the well lines – average 2-5 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 like the storage mainlines and most laterals.

Q. Please identify the capital expenditures that are planned for Well Data Acquisition.

A. Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2, line 17, identifies the total capital projected expenditures for well data acquisition. In 2021 through 2023, this includes funding for well data acquisition at the Ray 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 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.

In 2020, the Company performed work on approximately 12 Ray wells, with the work on the remaining Ray wells expected to be completed in 2022. Additional fields and wells will be considered for the program once the value of the data can be determined from the pilot project in the Ray field. The program will implement the technology in all peaker and intermediate fields, along with top performing and/or horizontal wells in baseload fields.

Freedom Upgrade Project

Q. Please describe Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2, line 1.

A. Exhibit A-12 (TKJ-5), Schedule B-5.8, 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 $19.7 million for 2020 (Actual); as provided in column (b), line 1, of Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2; $15.8 million for 2021 (Projected), as provided in column (c), line 1, of Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2; $7.6 million for the nine months ending on September 30, 2022 (Projected), as provided in column (d), line 1, of Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2; $23.4 million for the 21 months ending on September 30, 2022 (Projected), as provided in column (e), line 1, of Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2; and $13.3 million for the test year ending September 30, 2023 (Projected), as provided in column (f), line 1, of Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2.

Q. Please summarize the capital expenditures included in Exhibit A-12 (TKJ-5), Schedule B-5.2, included in this direct testimony for the Freedom upgrade project.

A. Exhibit A-12 (TKJ-5), Schedule B-5.8, page 2, line 1, identifies the total capital expenditures for the Freedom upgrade project. Phase 1 of the Freedom upgrade project and engineering for Phase 2 were both completed in 2017. In 2018 through 2022, and the 12 months ending September 30, 2023, the Company will incur costs for completion of construction of a new compressor and auxiliary buildings, relocation of the two temporary compressors to their final locations, and commissioning of the equipment.

Q. What is the projected annual investment for the overall Freedom upgrade project?

A. The projected annual investment for the Freedom upgrade project is currently planned as shown in the table below. These 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	$15.8 (projected)
2022	$11.5 (projected)
2023	$14.2 (projected)
Total	$253.5 (projected)

Q. Please provide further details regarding the phases of the Freedom upgrade project.

A. The Freedom upgrade project will be completed in two phases. Phase 1, now complete, included costs for engineering, procurement of two new compressor engines (that were installed on engine skids and placed in temporary locations to improve plant reliability until the final installation is complete), and the start of construction for a new compressor building.

Phase 2 of the Freedom upgrade project includes costs for continued engineering, procurement of three additional compressor engines, completion of the new facility, and demolition of the old compressor building. When Phase 2 is complete, all five new compressor engines (18,750 BHP) will be permanently installed in the new compressor building and both of the existing compressor buildings will be demolished.

Q. What is the timeline of the Freedom upgrade project?

A. Major milestones for the Freedom upgrade project are shown in the table below.

Milestone	Anticipated Completion Date	Status
Phase 1 compressors complete (first two new compressors installed in temporary location)	December 2017	Complete
Phase 2 air permit received	December 2017	Complete
Phase 2 engineering complete	December 2017	Complete
Phase 2 board approval	May 2018	Complete
Phase 2 construction start	July 2018	Complete
Phase 2 first three compressors complete	October 2020	Complete
Phase 2 move Phase 1 compressors to permanent location	October 2022	On schedule
Demolition of Plant 1 and 2, and site restoration, complete	October 2023	On schedule

Q. What is the operating state of Freedom now that Phase 2 (first three compressors complete) is complete?

A. With the completion of Phase 2 (first three compressors complete), Freedom has five existing compressors in Plants 1 and 2, as well as the three new compressors installed in Plant 3. The two new compressors installed in the temporary location have now been removed from service and are being relocated to their final location in Plant 3.

Based on an assessment conducted in 2015, the Company forecasted about a 75% probability of consistently meeting design day requirements over the next five years with the original existing engines, compared to a target of 95%. Further decreases in overall reliability would have reduced this probability to a level lower than 75%. Phase 1 provided back-up horsepower to offset such an occurrence. It also provided capacity to support an increase in supply requirements at Freedom, which is discussed later in this direct testimony. This phased approach is helping to meet supply requirements until the completion of Phase 2. Further, the increased reliability of Freedom is enabling the Company to meet its primary public service obligation to maintain gas service to its customers.

Q. Please explain the primary considerations that cause reliability concerns?

A. The primary considerations include:

(i) The age and condition of the existing equipment at the station. For example, all components of the existing station (engines/compressors, critical systems, gas conditioning, and support infrastructure) were determined to be in fair to poor health. More specifically, the compressor building, engine, and scrubber foundations show signs of cracking and deterioration. The condition of the Unit 57 foundation led to placing that unit in mothball status. Station valves have obsolete valve operators. Engine control panels, gaskets, and seals are old and replacement parts are difficult to source. The largest engine (TLA-1), Units 13 and 60 have suffered a significant failure and are no longer available for service. Oil and glycol tanks are underground, and Plant 1 relies on water from Pleasant Lake for engine cooling, which is not an optimal configuration for such equipment.

(ii) High actual ROR as shown in the table below.

Year	Average ROR
2012	15.7%
2013	12.5%
2014	22.8%
2015	11.0%
2016	3.0%
2017	5.8%
2018	35.2%
2019	21.8%
2020	21.7%
2021 YTD Sept	31.3%

An ROR between 4% and 5% is needed to meet a 95% probability of meeting station reliability target.

(iii) Increasing supply demands at Freedom. These considerations cause uncertainty related to the Company's ability to consistently meet design supply requirements at the second largest supply location on the system.

Q. Please quantify the increase in supply demand at Freedom.

A. Annual throughput has more than doubled from about 42 Bcf in 2005 to a peak of about 88 Bcf in 2019. The percentage of Freedom's portion of the supply to the total system supply has also doubled from about 12% to about 27% of total system supply due to favorable pricing caused by the shale gas supplied through the Freedom location. In addition, Freedom has experienced an increasing trend in the maximum daily flowrate over that same timeframe. These supply increases also contributed to the decision to complete the upgrade project with a multi-phased approach.

Q. Why is this work necessary?

A. Freedom is the oldest station on the system. When the upgrade project began, Freedom operated nine compressor units—seven of these units were installed in 1948. These units and the remaining station equipment are at the end of their useful operating life and currently fail to meet the required reliability standards for the reasons discussed above. Although the units fail to meet current required reliability standards, it should be noted that the existing compressor engines in Plants 1 and 2 were installed prior to August 15, 1967. As a result, they are considered "grandfathered" and were not subject to New Source Review permitting requirements at the time of installation. In addition, each of these engines are classified as "existing" spark-ignition stationary reciprocating internal compressor engines >500 HP located at a major source of hazardous air pollutants. Therefore, pursuant to §63.6590(b)(3)(i), they do not have to meet the requirements of 40 CFR Part 63 Subparts A and ZZZZ.

Q. What alternatives to this project were considered?

A. Seven station configuration options were evaluated. The options included various configurations of re-building existing and installing new large and small units. The selected configuration outlined in this direct testimony had the most favorable financial results while delivering the required reliability improvements and capacity increases. Option one consisted of re-building existing units and renting interim compression to bridge the gap to installing two new 3750 HP units. Option two consisted of re-building the existing units and renting interim compression to bridge the gap to installing three new large units. Option three consisted of installing four new large units and one small unit. Option four consisted of installing five new large units and one small unit. Option five consisted of building five new large units. Option six consisted of installing 13 smaller new units. Option seven, the selected option, consists of installing five new large units, two of which have been installed early in a temporary location.

Q. What is the priority of the Freedom upgrade project compared to other projects?

A. Freedom is the second largest gas supply location within Consumers Energy's system. If the Company experienced a major unplanned event at Freedom that eliminated the ability to pump, then Freedom could not reliably accept supply at that point, which could negatively affect some customers' supply. The capacity without pumping, if even possible, might range from 0 to 50 MMcf/d depending on the available pressure at the inlet of the station. The total pipeline supply throughput at Freedom in 2016 was 78 Bcf, or 24% of the total pipeline system supply. Of the 78 Bcf, the vast majority, or 51 Bcf, occurred during the summer period, in part to support storage injection operations. Maintaining summer supply capacity to support summer injection operations is critical to realizing the winter gas pricing benefit provided by the storage fields and to supplying customers during the winter. To give some perspective, storage field supply provides about 80% of the total system supply requirements on very cold winter days. For this reason, refilling storage in the summer is a primary operating objective and Freedom plays a significant role in meeting this objective. The summer-winter market natural gas price differential has averaged approximately $0.31/MMbtu in the most recent five-year period (2016-2020).

Q. Will the Freedom upgrade project improve reliability?

A. Yes. The Freedom upgrade project will replace the existing old compressors, the new compressors will move station horsepower from 10,400 BHP to 18,750 BHP which will increase station pumping capacity. The upgrade project will also improve reliability by providing new valves, gas conditioning, separators and emergency generators. The current compression reliability is no longer sufficient to meet customer short- and long-term demands. This improved reliability is critical to ensuring this station can meet system demand for summer injection and winter delivery, thereby providing the winter pricing benefit of the storage fields to our customers. Phase 1 and 2 will improve the probability of consistently meeting design requirements from 75% to over 95%.

Q. Will the project provide additional station capacity beyond its current ability?

A. Yes, the new facilities will provide about 65 MMcf/d of additional design capacity under many, if not most, operational conditions. The station may be capable of higher flows if operational conditions are more favorable than the design accounts for. This additional capacity will allow for the take away of additional gas from the upstream interstate pipelines so that abundant gas supply from northeast shale production sources can be leveraged to benefit the Company's customers. The increased capacity provides additional access to potentially favorable market pricing at that location. These potential savings would be realized by customers. Based on Consumers Energy's supply portfolio for GCR customers, the delivered cost of the Freedom pathway at an undiscounted tariff rate is about \$0.10/dth to \$0.65/dth lower than other existing and future supply pathways. Consumers Energy has leveraged this favorable pricing by contracting for interstate capacity to deliver to Freedom through 2023.

Q. Will the Freedom upgrade project reduce emissions?

A. Yes. Freedom's over 60-year-old compressor units will be replaced with new units that are more environmentally friendly and more efficient.

Q. Has the Company's Board of Directors approved the Freedom upgrade project?

A. The Company's Board of Directors approved Phase 2 in May 2018.

Q. Are the Company's capital expenditures in GCS reasonable and prudent?

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.) <u>IT PROJECTS</u>

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 Duncan Paterson includes in his direct testimony and exhibits, a number of technology projects that are critically important to supporting these gas functions within the Company. The expenditures for these projects are contained within the exhibits sponsored by Company witness Paterson. The projects which will provide benefits for the area which I am sponsoring are described below:

- The **Gas Storage Probabilistic Risk Model** project requires $1,174,250 in capital and $239,313 in O&M in the test year. The Gas Storage Probabilistic Risk Model project will implement a risk analysis model for comprehensive predictive risk analysis and modeling on gas storage wells. The current Gas Storage model is a relative risk model that equates risk to dollars from input information using qualitative data and ordinal scales to produce a "risk ranking." In simple terms, the relative risk model is not capable of creating a statistically significant result. The risk assessment used in the current model provides a ranking for likelihood, consequence, and risk that is relevant only in comparison to other rankings. While the outputs provide a sense of relative risk when comparing one well to another, the ranks do not provide anything qualitative that relates to the failure of wells. Also, the current transmission model does not meet the requirements of the MPSC, as indicated in a letter of noncompliance (dated January 15, 2019), and rule-making for storage systems has historically followed transmission rule-making. Lastly, the current model introduces risk in PHMSA findings as a non-probabilistic model. 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 well improvement projects and improved targeted plug and abandonment projects. Implementing probabilistic risk modelling supports the changes planned for in the Company's Natural Gas Delivery Plan (NGDP), including the Company Gas Management Safety 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, and (2) configure multiple data sources, to make advanced statistical calculations for interacting threats, both of which allow the Company to make more informed financial and strategic decisions based on improved quality inputs and mitigate the risk of PHMSA findings. The probabilistic model will rank the wells in risk-associated dollars, making it easier to interpret risk results for the purpose of making business decisions. Furthermore, the Pipeline and Hazardous Materials Safety Administration (PHMSA) has identified the probabilistic risk model as a potential best practice for storage operators over other risk models (PHMSA Pipeline Risk Modeling white paper, dated May 9, 2018), so the project adds value by aligning with industry best practices. The project scope encompasses the implementation of a probabilistic risk model for gas storage wells. The project will: (1) install and configure risk model; (2) configure multiple data sources; and (3) develop reports and dashboards. Alternatives considered included: (1) continue the use of the relative risk model, but with investment in substantial effort to continually manually managing data inputs and quality checks; (2) implement a custom, Excel-based probabilistic risk model through a consulting effort; (3) implement an on-premise probabilistic risk model; and (4) implement a cloud-based model. The first alternative was not selected because although the manual effort is possible, it is becoming increasingly difficult to complete as the model utilizes more data sources that need to be annually updated and validated. The second 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." The on-premise solutions analyzed are not mature and have not been widely tested with transmission operators, so alternative three was not selected. The fourth alternative of implementing the cloud-based probabilistic risk model was chosen because it is the most cost-effective long-term implementation approach, providing commercial, off-the-shelf capabilities, industry-proven technology, and an ongoing vendor support and upgraded model.

- The **Generation Operations and Compression Digital Work Management** project requires $402,690 in capital and $13,741 in O&M in the test year for the Gas Compression portion. The project provides durable mobile devices, software and digital forms for Electric Generation at Ludington Pumped Storage, wind parks, hydro facilities, and Gas Compression facilities. The current work management process for Electric Generation at the wind parks, hydro facilities, and Ludington Pumped Storage as well as Gas Compression locations is cumbersome and largely paper based outside of desktop kiosks. This system leads to process waste, re-work, and human error. This project provides value to the Company through: (1) increased productivity by reducing the need to return to the desktop kiosk for updates; (2) improved quality through increased accuracy of updates completed at the time and place of the work; and (3) improved safety through real-time information used at work sites rather than printed procedures. The scope of the project includes: (1) replacing the paper-dependent work management process with the ability to access and update maintenance, operations, and safety information at Gas Compression locations, and (2) the initial roll out for Electric Generation at Ludington Pumped Storage, wind parks, and hydro facilities, which would include: mobile devices, software, and enhanced wireless connection. Alternatives considered included: (1) Using an SAP work management mobile solution. An SAP work management solution is not preferred since it is a new solution and requires additional project and support cost. (2) Continuing the manual paper-based process. Continuing the manual paper-based process was not chosen because of process waste, re-work, and human error. (3) Customizing the existing electronic Shift Operations Management System (eSOMS) mobile application to add work management functions. A custom eSOMS mobile application was not chosen because it would require additional project cost and an ongoing support budget for a custom solution that the eSOMS product was not intended to support. (4) Using the existing Service Suite solution currently deployed for Gas and Electric Distribution in combination with digital forms. The combined Service Suite and digital form solution is the preferred option because it is a proven solution at the Company and provides the mobility and digital benefits at a lower cost.

Q. Does this complete your direct testimony?

A. Yes. My direct testimony describes the Company's GCS operations as they correlate to our request for rate relief. The five areas of my direct testimony address the range of services provided by: (i) Compression, Cost of Gas and Company Use O&M (ii) our compressor stations, storage fields, and (iii) the functional descriptions of these assets and the prudent capital expenditures required to maintain and improve them in accordance with the Natural Gas Deliverability Plan. All of these areas are a part of a 10-year plan to make the gas system safer and more reliable while continuing to be affordable and cleaner through these investments.

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-21148

DIRECT TESTIMONY

OF

ERIC J. KEATON

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

Q. Please state your name and business address.

A. My name is Eric J. Keaton, 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 Principal Rate Analyst in the Planning, Budget & Analysis Department.

Q. Please state your educational background.

A. I graduated from Auburn University at Montgomery, Alabama, in November 1999, with a Bachelor of Science in Business Administration degree. In addition, I have attended a number of courses on utility ratemaking, load research, and forecasting.

Q. What is your regulatory experience?

A. Prior to joining the Company, from January 1996 through February 2004, I worked in a variety of positions in technical support, systems analysis and design, database management, programming, and business analysis. I joined Consumers Energy in March 2004 as a Rate Analyst in the Rates and Business Support Department. Since joining Consumers Energy, I have been responsible for completing cost-of-service and revenue requirements studies. I joined the Sales Forecasting team in July 2015, and now perform sales forecasting duties.

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

A. Yes, I provided testimony and exhibits in these recent Consumers Energy cases: Case Nos. U-15645, U-16191, U-16794, U-17087, U-17643, U-17943, U-18124, U-18151, U-18411, U-18424, U-20233, U-20322 and U-20650.

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 (EJK-1)	Schedule E-1	Annual Service Area Sales by Major Customer Classes and System Output 5-Year Historical;
Exhibit A-5 (EJK-2)	Schedule E-1a	Summary of 2020 Historical Year Revenues;
Exhibit A-5 (EJK-3)	Schedule E-2	2020 Historical Year Consumption and Customer Counts;
Exhibit A-5 (EJK-4)	Schedule E-3	2020 Historical Year Operating Revenues;
Exhibit A-15 (EJK-5)	Schedule E-1	Market Outlook: 5-Year Annual Calendar Gas Forecast by Class;
Exhibit A-15 (EJK-6)	Schedule E-2	Test-Year Calendar Gas Deliveries Forecast by Class;
Exhibit A-15 (EJK-7)	Schedule E-3	Test-Year Calendar Gas Deliveries by Rate Schedule;

Exhibit A-15 (EJK-8)	Schedule E-4	Test-Year Authorized Tolerance Levels by Rate Schedule;
Exhibit A-15 (EJK-9)	Schedule E-5	Market Outlook: 5-Year Average Customer Forecast by Class;
Exhibit A-15 (EJK-10)	Schedule E-6	Test-Year Customer Count Forecast by Class;
Exhibit A-15 (EJK-11)	Schedule E-7	Test-Year Total Customer Count Forecast by Rate Schedule;
Exhibit A-15 (EJK-12)	Schedule E-8	Calculation of Test-Year Projected Income Assistance Enrollments;
Exhibit A-15 (EJK-13)	Schedule E-9	Calculation of Test-Year Excess Peak Consumption; and
Exhibit A-15 (EJK-14)	Schedule E-10	Transition from 2020 Historic Actuals to 12 Months Ending September 2023 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 2020?

A. Our weather adjusted calendar deliveries for 2020 totaled approximately 299.9 Bcf, compared to our budgeted cycle deliveries of approximately 298.5 Bcf, or within 0.5% of our anticipated deliveries.

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

A. Exhibit A-5 (EJK-1), Schedule E-1, is a summary of the five-year Historical Annual Service Area Sales 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 2020 operating revenue based on the actual customer and gas delivery levels for the historical year.

A. The 2020 historical operating revenue is presented in Exhibit A-5 (EJK-2), Schedule E-1a, by rate schedule. A detailed summary of customer counts and deliveries is provided in Exhibit A-5 (EJK-3), Schedule E-2, by rate schedule and type of service (sales, customer choice, transportation, and aggregation). The components of the 2020 historical operating revenues are shown in Exhibit A-5 (EJK-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 one 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, and U-20650. 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.

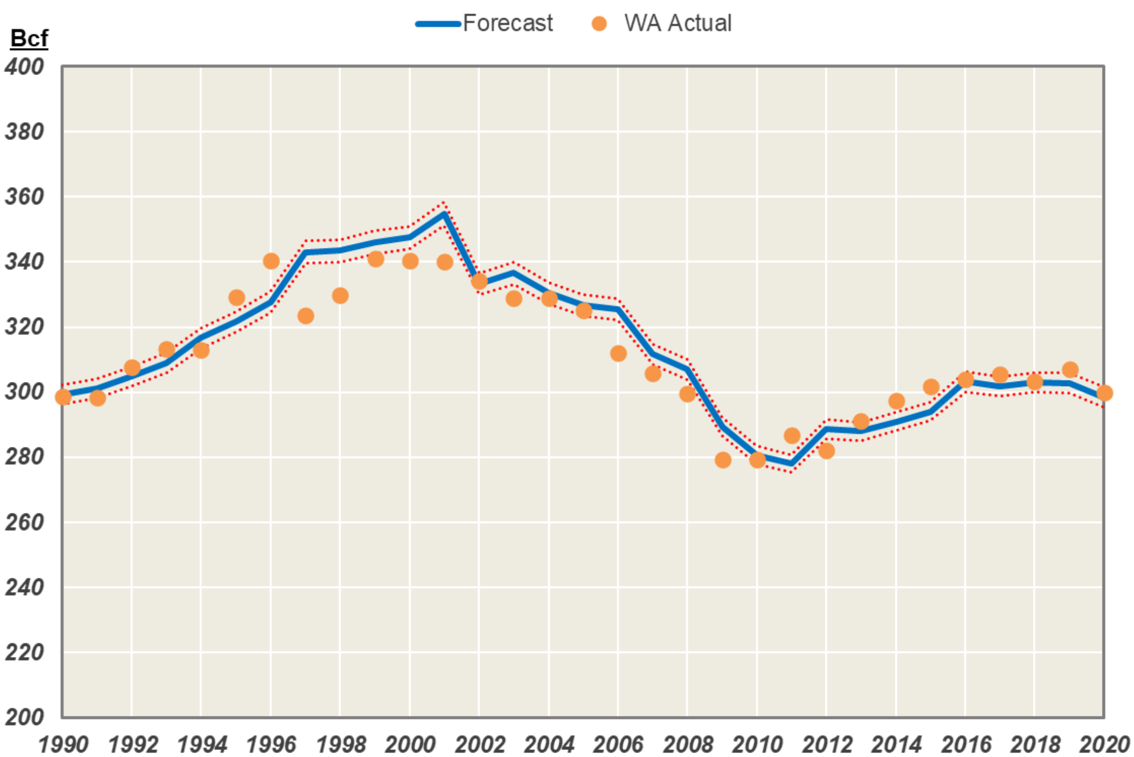
A. Both of these statistical tests are used to evaluate how well the models fit the historical data, and also provide a good indication of how well the models will perform in the forecast period. The R_a^2 measures the ability of the models to explain variations in the historical data. An R_a^2 of unity 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 2013 through 2020 is 4.5 Bcf and the MAPE is only 1.2%.



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

A. Total calendar deliveries are projected to grow from historic weather normal levels of 300 Bcf in 2020 through the test year. Over the next five years, total deliveries are projected to increase by 0.4% per annum to 308 Bcf by 2026. However, the growth or loss in gas deliveries is not symmetric across all classes. The total and class level gas delivery annual forecasts for 2022 through 2026 are provided in Exhibit A-15 (EJK-5), Schedule E-

1. Exhibit A-15 (EJK-6), Schedule E-2, provides the 12 months ending September 2023 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 2020 historical deliveries. The results of the allocation process is provided in Exhibit A-15 (EJK-7), Schedule E-3, and Exhibit A-15 (EJK-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 0.5% from 1,797,441 in 2020 to 1,823,704 in the 12 months ending September 2023 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 (EJK-9), Schedule E-5, and Exhibit A-15 (EJK-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 2020 historical customer count levels. The results of the allocation process is provided in Exhibit A-15 (EJK-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 72,000 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 (EJK-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 (EJK-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 (EJK-14), Schedule E-10, provides a summary of the change in revenue, customer levels, and gas deliveries from the 2020 historical year to the 12 months ending September 2023 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 distribution of natural gas and for other relief.	)))))	Case No. U-21148

DIRECT TESTIMONY

OF

DOUGLAS E. LAW, P.E.

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

Q. Please state your name and business address.

A. Douglas E. Law, 9255 Cadiz Road, Cambridge, Ohio 43725

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

A. Basic Systems, Inc., Cambridge, Ohio. My title is Sr. Project Manager. I am a Registered Professional mechanical engineer, licensed in Michigan and 13 other states. I manage a 26-person facility engineering group of civil, mechanical and electrical engineers and support staff.

Q. Can you please provide a brief overview of the services Basic Systems, Inc. provides?

A. Basic Systems, Inc. is a consulting engineering firm that offers project, process, mechanical, electrical, instrumentation, civil, structural and automation/systems control engineering as well as procurement, construction management and start-up services. Basic Systems specializes in natural gas transmission, production, storage, interconnects, Liquefied Natural Gas and Compressed Natural Gas/Natural Gas Vehicle facilities.

Since the firm's founding in 1982, our core business has been to design compressor stations for many of the nation's interstate gas transmission companies, including Consumers Energy Company ("Consumers Energy" or the "Company"). We are narrowly focused on natural gas facility design. We have provided engineering services for various Consumers Energy projects since the 1990s, including an expansion at Overisel Compressor Station, engineering procurement, and construction of the Huron Compressor Station, and electrical upgrades at Ray Compressor Station.

Q. What are your responsibilities as a Senior Project Manager at Basic Systems, Inc?

A. My responsibilities include conceptual through detailed engineering, oversight of engineering teams, and communication with clients on projects from concept through in-service.

Q. Would you please describe your work experience in the design and construction of Natural Gas systems?

A. Since 1990 I have participated in the design of hundreds of natural gas facility projects for gas production, transmission, and distribution companies. Roles in these projects began as a mechanical engineer, progressed to discipline lead, project manager and ultimately manager of a design group. I participate in the design of natural gas facilities and oversee design teams, especially the mechanical engineering discipline.

Q. Were you or Basic Systems, Inc. involved in the original design and construction of Consumers Energy's Ray Compressor Station? Specifically, Ray Plant 3 which was designed and constructed from 2010-2013?

A. No. Basic Systems, Inc. has provided engineering services for Ray in the past including engineering for the 6,000 HP unit C2-7 in Plant 2, electrical upgrade project, and numerous automation and control upgrades at the facility. However, Basic Systems, Inc. was not involved with design and construction of Plant 3 from 2010-2013.

Q. Based on your 31 years of experience in the design and construction of Natural Gas systems – are you familiar with Pipeline and Hazardous Materials Safety Administration and Michigan Gas Safety Standards? (ref specifically 49 CFR 192.167(a)(2))

A. Yes. The referenced CFR states that the emergency shutdown system "must discharge gas at a location where the gas will not create a hazard." It gives no guidance on how an owner or engineering staff would determine if a location will create a hazard.

Q. In your work experience, have you been responsible for the design of new or made changes to a natural gas facility? Specifically, have you been responsible for the design and siting of gas vents?

A. Yes, to both questions. Design and siting for gas vents is a typical part of our design projects.

Q. Prior to January 30, 2019, was there a standard industry design practice for siting these vents in a location that will not present a hazard?

A. No. In my experience, prior to January 30, 2019, engineering judgment and risk analysis were used on a project-by-project basis to determine safe spacing between vents and other facilities. There was no formal industry standard design practice.

Q. In your experience, how did professional engineering firms responsible for the design of gas compression facilities determine safe vent siting before January 30, 2019?

A. The most common approach was with the use of spacing tables that include minimum distance from gas vents to fired equipment (thermal oxidizers, glycol reboilers, line heaters, etc.), buildings, property lines, and roads. These tables were created based on historical industry data and experience. One large interstate gas transmission company, for example, has an engineering standard that recommends a vent be spaced 100 feet from: an "open flame device", warehouse/shop/office building, electrical building, auxiliary building, or compressor building. This is a recommendation, not a firm requirement. The director of engineering may accept a modification if the project needs it. Vent locations are generally established early in the design of a new facilities as the project is being laid out and discussed during early design reviews. The locations may be revisited during a Process Hazard Analysis later in the project, but since changing a vent location later in the project would drive numerous other changes, it would be difficult to make a late change and not likely to happen.

Q. In your experience, prior to January 30, 2019, were dispersion models commonly used as part of the hazard evaluation process to determine proper siting and distance from potential ignitions sources for emergency blowdown vents?

A. No.

Q. Are you familiar with the fire event that occurred at Ray Plant 3 in January of 2019?

A. Yes.

Q. How did you first learn about the Ray Plant 3 fire?

A. The event was mentioned in nearly every industry news source. As an engineer interested in learning how to prevent this type of risk in future designs, I followed the story as new information was released. A client at the time was in an industry group together with employees of Consumers Energy and was also learning the details of the incident from Consumers Energy. The details of Consumers Energy's experience at Ray Plant 3 became considerations as that project, an expansion of a gas storage compressor station, was being developed and equipment was sited.

Q. Have you reviewed the design details of Ray Plant 3's blowdown vents that the Michigan Public Service Commission Staff determined were the primary factor contributing to the significance of the January 30, 2019 fire at Consumers Energy's Ray compressor station?

A. Yes.

Q. Do you feel that the siting of Ray plant 3's blowdown vents met the industry standard per the spacing tables noted above?

A. Yes. Having worked with many gas industry clients, I believe siting a blowdown vent 130 feet from a thermal oxidizer exhaust, as Ray plant 3's blowdown vents were, would have been deemed acceptable under the pre-January 30, 2019 hazard identification processes recognized by any of my gas industry peers and clients at the time.

Q. In your professional opinion, have industry practices regarding the design of blowdown vents changed or been updated in the past 20 years? If so, what was the driver for these changes?

A. In the past 20 years the industry has changed to include the addition of silencers to gas vents. Earlier in my career, emergency shutdown vents were directed straight up, with no restriction. The gas stream would shoot hundreds of feet up before it mixed with enough air to be flammable, and the gas piping would vent down quickly. These vents were loud and alarming to neighbors near the stations. As such, over the last 20 years it has become more common to install silencers on the vents, which reduce the flow and velocity of the exiting gas. The gas exits a silencer more like a cloud than a stream. This, especially combined with a breeze in the wrong direction, makes the vent gas from a silenced vent much more likely to be ignited than from an unsilenced vent.

Q. Has there been a change to the standard industry design practice to accommodate the addition of silencers to gas vents? If so, what was the driver?

A. In my opinion, while silencers have become more common in the past 20 years, the industry had not identified or created an updated standard practice to identify or assess the potential hazard created by addition of silencers to gas vents. It is not my experience that other companies have incorporated actual written standards to accommodate the additional hazard created by silencing the gas vent. Dispersion modeling is a way to visualize where gas will go after it leaves the vent silencer and ensure no ignition sources are close, but this is not a common practice in the gas industry. The Ray incident was a wakeup call to better evaluate such an event during facility design.

Q. Is it your professional opinion that the 2019 Ray fire event and associated lessons learned communicated to the industry from Consumers Energy has changed the standard industry practice for siting blowdown vents?

A. All industry participants want to design and operate safe and reliable facilities, are eager to learn from the Ray incident, and will improve design practices to reduce the risk of such an incident. We appreciate Consumers Energy's openness. Some operating companies will incorporate these lessons learned into written design standards and Design for Safety documents. With no change to the current regulations, I don't think all or even many gas companies will run dispersion models on their gas vents. I think it more likely they will use engineering judgement and give more consideration to the location of the vents, location of ignition sources, the relative height of the vent vs. ignition sources and wind direction. This will be decided site-to-site and company-to-company in the absence of a rule requiring a dispersion model.

Q. Does this complete 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 distribution of natural gas and for other relief.	)))))	Case No. U-21148

DIRECT TESTIMONY

OF

STEVEN Q. MCLEAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

Q. Please state your name and business address.

A. My name is Steven Q. McLean, 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 the Director of Customer Regulatory and Compliance in the Customer Strategy and Data Analytics department.

Q. Please review your educational background.

A. I earned a Bachelor of Science in Political Science and Economics from Central Michigan University in May 2003. I earned a Master of Arts in Economics from Central Michigan University in December 2007.

Q. Please review your business experience.

A. In January 2006, I joined the Michigan Public Service Commission ("MPSC" or the "Commission") where I held various positions of increasing responsibility. In 2011, I was promoted to the Manager of the Rates and Tariffs section. The responsibilities of that section included, but were not limited to, analyzing utility reports, financial records, and rate case filings to determine the appropriate level of rates for regulated energy utilities utilizing laws, regulations, and Commission policies. In August of 2014, I was hired by SEMCO Energy Gas Company ("SEMCO") as the Rates and Regulatory Affairs Manager. In December of 2016, I was promoted to Director of Regulatory Affairs. As Director of Regulatory Affairs, I was responsible for all state and federal regulatory matters for SEMCO. In addition, I was responsible for SEMCO's Energy Waste Reduction ("EWR") Program. In September of 2019, I was hired by Consumers Energy as the Director of

Customer Experience Regulatory Strategy, Reporting and Quality within the Clean Energy Department, and in October 2021, I was promoted to Director of Customer Regulatory and Compliance.

Q. What are your responsibilities as the Director of Customer Regulatory and Compliance?

A. In this position, I am responsible for coordinating the regulatory filing and planning processes associated with the Company's EWR Plans, Renewable Energy Voluntary Green Pricing programs, and residential Demand Response ("DR") programs. In addition, I am responsible for corporate compliance within the Customer Experience and Customer Operations departements.

Q. Have you previously testified before the MPSC?

A. Yes. I testified in the Company's general rate cases, Case Nos. U-20650 and U-20697; the Company's 2019 and 2020 DR Reconciliations, Case Nos. U-20766 and U-21080, respectively; the Company's 2021 Integrated Resource Plan ("IRP"), Case No. U-21090: and the Company's 2021 EWR Plan filing, Case No. U-20875. Additionally, I have testified before the MPSC in numerous general rate cases, Gas Cost Recovery cases, EWR cases, and other miscellaneous proceedings on behalf of the MPSC Staff ("Staff") and SEMCO.

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

A. The purpose of my direct testimony is to propose a second phase (Phase II) to expand the Company's gas DR Pilot, which is a component of the Company's Natural Gas Delivery Plan. The pilot will continue to test the use of voluntary tools to understand and assess the potential to use DR to help balance the Company's available natural gas system capacity and load requirements.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-166 (SQM-1)	Projected O&M Expenditures - Phase II Gas DR Pilot; and
Exhibit A-116 (SQM-2)	Gas DR Phase II Pilot Expansion.

Q. Please describe Exhibit A-166 (SQM-1).

A. Exhibit A-166 (SQM-1), details the the operating and maintenance ("O&M") expenses related to work associated with the gas DR pilot expansion (Phase II) proposed in this case, which total $3,000,000.

Q. Please describe Exhibit A-116 (SQM-2).

A. Exhibit A-116 (SQM-2) details the criteria for the Company's proposed expanded gas DR pilot consistent with the format approved by the Commission in Case No. U-20645.

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

A. Yes.

Q. What recovery is the Company seeking forthe gas DR pilot in this case?

A. The Company is seeking recovery for $3 million in O&M related specifically to the proposed gas DR pilot Phase II expansion in the projected test year, marketed to customers as the gas Smart Thermostat Program ("STP"). As part of the Settlement Agreement in Case No. U-20650 the Company agreed to defer all of the gas DR pilot costs as a regulatory asset for recovery in a future procced. The Company is proposing to continue to defer and track the gas DR pilot O&M costs addressed in Case No. U-20650 to a future proceeding. In addition, the Company is requesting to track any under/over recovery of cost related to implementing the Phase II pilot expansion O&M costs as a regulatory asset or liabiltity to be included in a future proceeding. This includes costs prior to and after the test year in this proceeding. In addition to recovery of the O&M costs, and related regulatory accounting, the Company is requesting approval of capital expenditures related to the Commercial & Industrial ("C&I") Gas DR Pilot ("C&I Gas DR Pilot"). As described below the pilot was addressed in Case No. U-20650 and will begin with the 2021-2022 winter. The capital expenditues are for the installation of gas telemetry on customer cites and are necessary to effectively implement the pilot. The costs are included in Company witness Cullen M. Hale's Exhibit A-12 (CMH-1), Schedule B-5.7 and include $400,000 of expenditures for the bridge year and $150,000 of expenditures for the projected test year.

Q. Why is the Company requesting a second phase to expand the gas DR pilot originally addressed in Case No. U-20650?

A. As requested in the Statewide Energy Assessment, and as part of the Company's Natural Gas Delivery Plan, Consumers Energy launched two pilot programs for gas DR: (i) the Residential and small and medium business ("SMB") gas DR Pilot ("Residential and SMB Gas DR Pilot") and (ii) the C&I Gas DR Pilot. These pilots are designed to incentivize customers to reduce their gas consumption during times of peak system demand or abnormal system conditions. The pilots were intended to demonstrate whether or not gas DR could be a new reliability resource that can be called upon to balance the Company's available system capacity and customer load requirements, among other benefits.

The O&M recovery sought in the instant case pertains to the expansion of the Company's Residential and SMB Gas DR Pilot. During the initial pilot phase (Phase 1A), it was necessary to test whether customers would participate in such an arrangement in the first place. Having demonstrated they will not only participate but that they rate the program highly (as further discussed below), Consumers Energy will launch Phase II of the pilot to learn more as outlined in the pilot expansion application.

Phase II of the Residential and SMB Gas DR Pilot will test the potential for gas DR to bolster system reliability, defer or avoid capital investments, and support the Company's climate goals. Expanding the program to more participants will allow it to gauge whether certain customers are so located as to offer particular system benefit in certain areas, materially reduce the Company's carbon emissions, and more (further learning objectives are described below and in Exhibit 116 (SQM-2).

With an increase in the frequency of severe weather events, the Company's progress toward its climate goals, and its commitment customer affordabity, system reliability, resiliency and safety, gas DR presents a previously-unexplored possibility to partner with customers to realize system and customer benefits.

Q. Please describe the Company's gas DR pilots.

A. As part of the Settlement Agreement in Case No. U-20650, the Company agreed to conduct a stakeholder collaborative prior to launching its gas DR pilots. The collaborative took place in November 2020. As explained above, the Company has launched two gas DR pilots, one for C&I customers and one for residential and SMB customers. These pilots are described in more detail below.

<u>C&I Gas DR Pilot</u>

The C&I Gas DR Pilot will be executed during the 2021-2022 and 2022-2023 winter heating seasons. The Company is marketing the pilot to its 400 largest C&I gas transport and supply customers with the intent to enroll up to 20 participants for the period

November 1st through March 31st for the 2021-2022 and 2022-2023 winters. Originally targeted to begin in the 2020-2021 winter the pilot was delayed to the 2021-2020 to incorporate the input from stakeholders. In addition, the Company plans to continue operating the pilot for the 2022-2023 winter for additional testing. The scope and spending level will remain the same for the 2022-2023 winter and all costs will be tracked as a regulatory asset for future recovery. Participants will be asked to reduce gas use by at least 50 Mcf below the average daily consumption during the 10 days preceding the event day. The pilot will call five 24-hour events, and participants will be compensated at a rate of $200 per Mcf reduction up to 125 Mcf. The compensation will be provided by check at the conclusion of the pilot.

The learning objectives for the pilot include assessing customer interest and recording degree of participation among enrolled customers. At the conclusion of the pilot, the Company will measure the impact of the reduction and attempt to discern the number of customers and/or total volume of gas required to accrue system benefits. Findings from the pilot will be shared among the stakeholder collaborative members when available.

<u>Residential and SMB Gas DR Pilot</u>

The Residential and SMB Gas DR Pilot is a Bring Your Own Device ("BYOD") Smart Thermostat program. The initial phase of the pilot (Phase 1A) ran during the winter of 2020-2021 and initially targeted 3,000 customers who have a gas furnace and a Wi-Fi enabled smart thermostat. The program used cloud-based software deployed through the customer's Wi-Fi thermostat to reduce the heating load during DR events. The pilot was modeled after the electric DR programs currently offered to customers.

Q. Please discuss the learnings derived from Phase 1A of the Residential and SMB Gas DR Pilot.

A. The Company called 10 successful Energy Savings Events between January 20 and February 25, 2021 when the weather was less than 30 degrees Fahrenheit. The implementation contractor's event dispatch system and load control algorithms operated as planned which allows for remote control of customers' thermostats during the events.

The average number of participants across the 10 events were 3,609 residential and 352 SMB. There are randomized control groups of 1,500 enrolled customers for each event, and customers could choose to opt out of events by overriding their thermostat.

Load shift did occur during peak times when events were called. In total, residential customers delivered an average hourly load shift of 36 Mcf during the Consumers Energy system peak day DR event hours, and SMB customers delivered 5 Mcf. The pilot shifted customer consumption on the peak day DR event hours by 47% for residential customers and 31% for small business customers. After accounting for pre-conditioning, event setback, and post-event rebound impacts, there was about 5.3 cf of natural gas savings per residential participant which accumulated to 190.3 Mcf of energy savings across the 10 dispatched events.

Customers responded favorably in post program surveys. Residential customers had enough interest that they exceeded the original enrollment target for Phase 1A by almost double. The original enrollment target for residential was 3,000 customers and 5,647 were enrolled by the start of event season. A Net Promoter Score ("NPS") of +51 was measured for residential customers, and +83 for was measured for SMB participants. NPS measures how likely the customer is to recommend this product on a scale of -100 to +100, and the results for this pilot are rated in the "excellent" range. For comparison, the NPS of the electric STP program was +62. The Customer Experience Index ("CXi") scores from the first pilot phase were +81 for residential customers and +92 for SMB customers. CXi measures how successfully a company delivers customer experiences that create and sustain loyalty on a scale of -100 to +100.

The Company successfully tested whether customers would participate in gas DR events, and whether their satisfaction would be sufficiently high to determine this pilot has true market potential. Phase 1A of the pilot satisfactorily answered these questions in the affirmative, but these high level findings are merely the necessary foundation for further work to test the potential system and climate benefits for the Company and its customers through expanding the pilot to a larger participant pool.

Q. Please describe the proposed Phase II of the Residential and SMB Gas DR Pilot.

A. The Company is proposing a Phase II Residential and SMB Gas DR Pilot by expanding its gas STP for two additional years for both residential and SMB customers. Phase II of the pilot will scale from the current Phase I enrollment of 5,600 residential and 400 SMB participants to 20,000 residential and 3,000 SMB participants by the winter 2023-2024 DR season across Consumers Energy's gas and combination service territories, with up to two thermostats in each residence or business. The goal of expansion is to continue to accrue and evaluate the potential benefits of shifting enrolled customers' gas consumption during times of peak system demand or abnormal system conditions by controlling the temperature settings on their Wi-Fi enabled thermostat.

Q. What additional benefits does the Company plan to measure during Phase II?

A. Phase 1A of the pilot was successful in identifying and measuring customer load shift during events and Phase II of the pilot will begin to further measure and analyze both system and customer benefits. Expanding the pilot for two additional years will allow the Company to fully measure program benefits that would justify whether or not to commercialize into a fully operational program. Specifically, the Company plans to: continue measuring load reduction during scaled events to determine resiliency impacts; measure financial impacts for the Company and customers; determine the role of gas DR during emergency events; include evaluation of geo-targeting capabilities; measure avoidance of CO_2 Emissions; and continue to measure customer satifation with the program. Please see Exhibit A-116 (SQM-2) for addition details of the Company's proposed Phase II expansion of the gas DR pilot.

VI. SUMMARY

Q. Please summarize your direct testimony.

A. The Company requests approval of a Phase II expansion of the gas DR pilot originally addressed in Case No. U-20650. The second phase of the pilot is targeted at expanding enrollment in the Residential and SMB DR pilot and will measure additional DR benefits to help make a determination of the viability of a full scale gas DR program. As part of this proposal the Company is requesting $3 million in test year O&M expenses to support the expansion of the Residential & SMB Gas DR pilot. In addition, the Company is requesting to track any under/over recovery of O&M costs related to implementing the

Phase II pilot expansion as a regulatory asset or liabiltity to be included in a future proceeding for recovery. Exhibit A-166 (SQM-1) details the O&M expenses related to this work for the test year ending September 30, 2023. The Company is also requesting approval of capital expenditures related to the Gas DR Pilot addressed in Case No. U-20650. The costs are included in Company witness Hale's Exhibit A-12 (CMH-1), Schedule B-5.7 and include $400,000 of expenditures for the bridge year and $150,000 of expenditures for the projected test year. Additional detail regarding the Company's gas DR pilot is presented in Exhibit A-116 (SQM-2).

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-21148

DIRECT TESTIMONY

OF

KRISTINE A. PASCARELLO

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

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 the Manager Asset Strategy in Gas Engineering and Supply.

Q. What are your responsibilities as Manager Asset Strategy?

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 22 years. I have been a Manager of Asset Strategy 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 Manager of Asset Strategy, I spent 10 years on the Smart Energy Advanced Metering Infrastructure ("AMI") and Gas Automatic Meter Reading ("AMR") project teams where I was responsible for leading all 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, Security, etc., 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 33 years of experience with 29 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") and a member of the PMI Michigan Capital Area Chapter. 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 served on the American National Standards Institute ("ANSI") B109 working committee and was elected to serve as one of seven utility representatives on the committee in 2012.

Q. What is your formal educational experience?

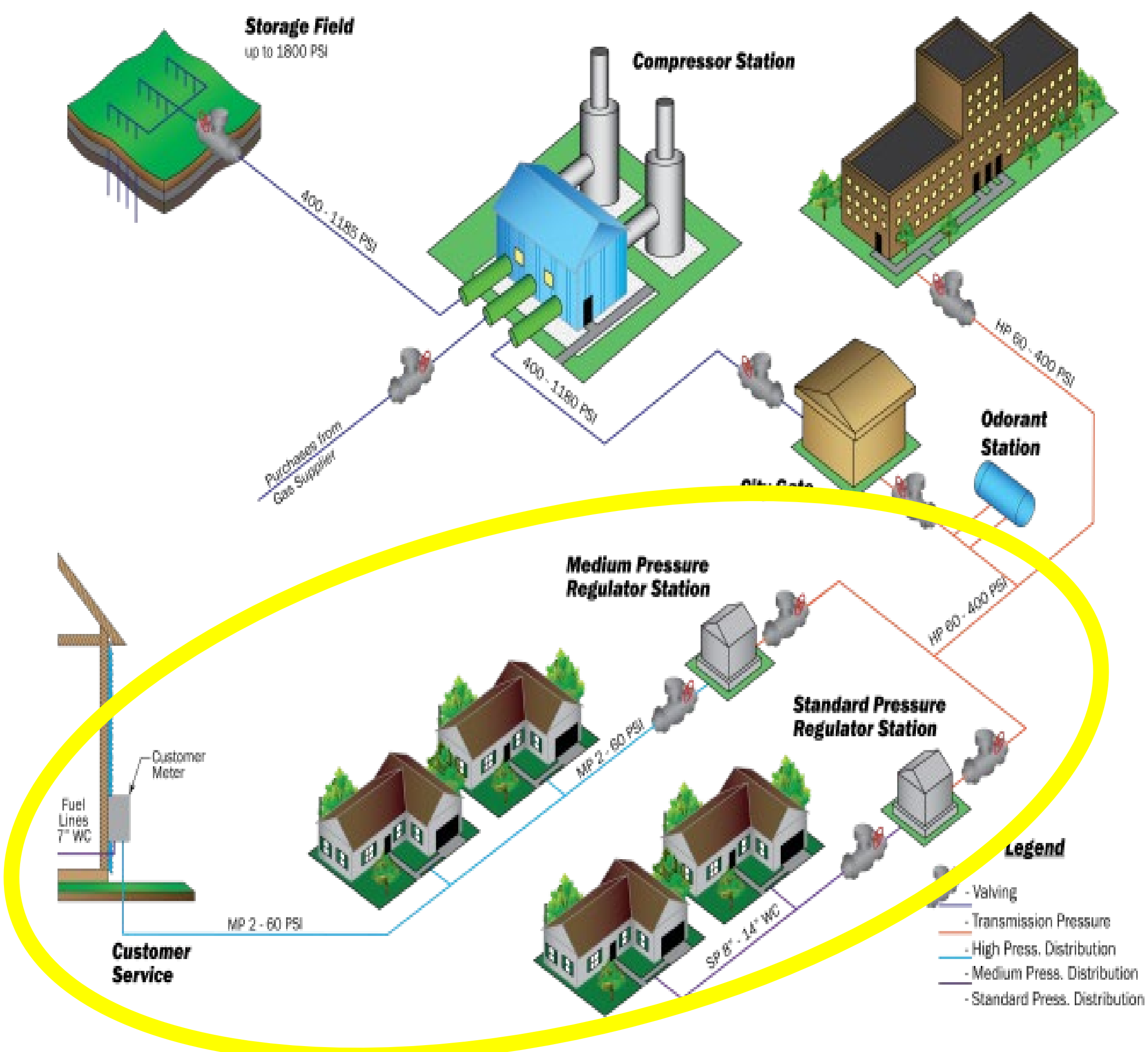
A. I graduated from Lake Superior State University with a Bachelor of Science degree in Electrical Engineering Technology. I graduated with an Associate degree in Electronics from Lansing Community College. I also hold Master and Associate Certificates in Project Management from George Washington University 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 No. U-20893.

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 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. 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 Gas Engineering and Supply department; and (ii) a description of the Company's gas distribution capital expenditures that I am sponsoring for

2020, 2021, the nine months ending September 30, 2022, and for the projected test year 12 months ending September 30, 2023.

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 Gas Engineering and Supply staff represented in my direct testimony consists of the individuals and teams 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-117 (KAP-1)		Summary of Actual & Projected O&M Expenses, Gas Engineering and Supply;
Exhibit A-118 (KAP-2)		Detailed Summary of Actual & Projected O&M Expenses, Gas Engineering and Supply;
Exhibit A-12 (KAP-3)	Schedule B-5.9	Projected Capital Expenditures, Distribution Plant, Summary of Actual & Projected Gas and Common Capital Expenditures;
Exhibit A-119 (KAP-4)		Actual & Projected Gas Capital Expenditures - New Business Program;

Exhibit A-120 (KAP-5)	Actual & Projected Gas Capital Expenditures - Asset Relocation Program;
Exhibit A-121 (KAP-6)	Actual & Projected Gas Capital Expenditures - Regulatory Compliance Program;
Exhibit A-122 (KAP-7)	Actual & Projected Gas Capital Expenditures - Material Condition Program;
Exhibit A-123 (KAP-8)	Actual & Projected Gas Capital Expenditures – Capacity/ Deliverability Program;
Exhibit A-124 (KAP-9)	Actual & Projected Gas & Common Capital Expenditures - Gas Operations Other Program; and
Exhibit A-125 (KAP-10)	Projected Capital Expenditures - Distribution Plant, 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 Gas Engineering and Supply Management department, which are described on Exhibit A-117 (KAP-1). The total O&M expenses for the years 2020, 2021, 2022 and for the projected test year 12 months ending September 30, 2023, are $10,705,000; $12,703,000; $17,737,000; and $20,342,000; as set forth on this exhibit on line 6, column (b); line 6, column (c) line 6, column (d); and line 6, column (e), respectively. These expenses are shown in the Table 1 below.

($000)	(a)	(b)	(c)	(d)	(e)
Line No.	Description	2020 Actual	2021 Projected	2022 Projected	Projected 12-Mos Ending Sep 30, 2023
1	Gas Project Management	699	1,550	1,256	1,307
2	Gas Asset Management	4,297	4,928	6,879	7,715
3	Gas Engineering Support	1,907	2,170	5,346	6,973
4	Planning - Generation	125	0	0	0
5	Gas Management Services	3,677	4,055	4,256	4,347
6	**Total Gas Engineering and Supply O&M Expenses**	**$ 10,705**	**$ 12,703**	**$ 17,737**	**$ 20,342**

My direct testimony also represents certain Gas Distribution capital investments through September 30, 2023, which are described on Exhibit A-12 (KAP-3), Schedule B-5.9. The total Gas Distribution capital expenditures represented by this direct testimony for the years 2020, 2021, the nine months ending September 30, 2022, and for the projected test year 12 months ending September 30, 2023, are $446,217,000; $515,483,000; $391,264,000; and $640,540,000; as set forth on this exhibit on line 7, column (b); line 7, column (c); line 7, column (d); and line 7, column (f), respectively. These expenditures are shown in the Table 2 below.

Table 2: Gas Distribution Capital Expenditures

($000)	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line No.	Program Description	12 Mos Ended 12/31/2020	12 Mos Ending 12/31/2021	9 Mos Ending 9/30/2022	21 Mos Ending 9/30/2022	12 mos. Ending 9/30/2023
1	New Business	87,021	63,656	44,622	108,279	65,394
2	Asset Relocation	83,973	85,121	72,955	158,076	88,840
3	Regulatory Compliance	31,691	37,565	17,324	54,888	21,867
4	Material Condition	234,350	297,461	243,838	541,299	437,779
5	Capacity/Deliverability	3,599	9,959	5,390	15,349	7,316
6	Gas Operations Other	5,583	21,722	7,135	28,856	19,344
7	**Total Capital**	**446,217**	**515,483**	**391,264**	**906,747**	**640,540**

Q. How has the Company projected its O&M expenses for 2021, 2022, and the test year 12 months ending September 30, 2023?

A. The Company has projected its O&M expenses for 2021, 2022, and the test year 12 months ending September 30, 2023, to the level that is reasonable and necessary to meet customer service and safety requirements. This projection is based upon multiple factors, including annual merit increases for the Gas Engineering and Supply department, a projection for added staff to support the NGDP, and projected O&M expenses for individual programs necessary to ensure customer safety, meet regulatory requirements, and provide reliable service to customers. First, for the O&M expenses representing the current Gas Engineering and Supply employee salaries and expenses, the Company projected the amount of the O&M expenses by applying either an inflation rate or a merit increase rate, or both to historical 2020 O&M expense. The test year salaries and expenses were projected to account for increasing staff levels to support the NGDP investments and are described within each respective section later in this direct testimony. 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 2021 through the 12 months ending September 30, 2023.

A. The projected capital expenditures for this period are based on projected costs for individual projects and programs necessary to ensure customer safety, meet regulatory requirements, and provide reliable service to customers. The projection methodologies vary among the different programs and are described within each respective section later in this direct testimony.

GAS ENGINEERING AND SUPPLY DEPARTMENTS O&M EXPENSES

Q. Please explain the source of the 2020 actual O&M expenses for the Gas Engineering and Supply department expenses shown on Exhibit A-117 (KAP-1), line 6.

A. The 2020 actual O&M expense amount of $10,705,000 for the Gas Engineering and Supply 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-118 (KAP-2), pages 1 through 3. The 2020 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 2020. The projected expenses for 2021 are $12,703,000, and for 2022 are $17,737,000, and for the test year 12 months ending September 30, 2023, are $20,342,000 as shown in Table 1 above and on

Exhibit A-117 (KAP-1), line 6, 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 Gas Engineering and Supply department O&M expenses for the test year as shown on Exhibit A-117 (KAP-1), line 6, column (e).

A. The Company has projected expenses for additional engineering and supply personnel to implement the increased investment in the gas system replacement as described in the NGDP. To support the increased investments, the Company is proposing an increase of 283 employees from the 2020 historic staffing level in the Gas Engineering and Supply organization. Each affected department within Gas Engineering and Supply analyzed the work activities and factored in productivity improvements to project the number of employees necessary to complete the work for the NGDP. 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, gas control, supply, transport and customer choice, and system and operations planning. The resulting projected costs for the 12 months ending September 30, 2023, are $20,342,000,000, and can be found on Exhibit A-118 (KAP-2), page 3, line 13, column (e). These expense levels for the Gas Engineering and Supply department's programs are reasonable, and allow the Company to meet customer service, deliverability, and safety requirements in the test year.

Q. Is it necessary to increase Gas Engineering and Supply staff to support the NGDP?

A. Yes. The Company's current staff is sized to support the Company's current level of investment. To increase that investment as outlined in the NGDP, the Company will need to hire and train more engineering staff to ensure the Company has thoroughly reviewed, planned, and coordinated all considerations in engineering design. This will ensure the Company's construction workforce can execute the work safely and efficiently. In response to the gas safety incident in Merrimack Valley, Massachusetts, the AGA issued a white paper titled "Skills and Experience for Effectively Designing Natural Gas Systems." In this white paper, the AGA describes the importance of training and the competencies required to produce engineering designs that allow for safely executing gas system construction projects. This paper outlines a three-tiered approach for development of entry and mid-level engineers and technicians. The first tier focuses on natural gas system fundamentals, the second tier on improving knowledge and operator-specific requirements, and the third tier focuses on building technical acumen and expertise. By providing the right level of engineering staff, the Company will ensure the technical staff performing the engineering work on all projects, including those for the NGDP, have the requisite skills and gas system knowledge for safe and efficient completion of the objectives outlined in the NGDP.

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 Gas Engineering and Supply, as listed on Exhibit A-118 (KAP-2).

A. Gas Engineering and Supply is described in eight major departments:

- Gas Project Management

- Gas Asset Management – Consists of the Gas Engineering & Asset Planning, System Integrity, which includes the Storage Integrity Management Program ("SIMP"), and Gas Compression Engineering departments
- Gas Engineering Support – Consists of Gas Strategy, Gas Regulatory and Compliance, Customer Energy Management, and Geospatial Management and Data Quality, which includes the Geospatial Inventory and Modeling Program
- Planning – Generation
- Gas Management Services

Q. Please briefly describe pages 4 through 6 of Exhibit A-118 (KAP-2).

A. Pages 4 through 6 of Exhibit A-118 (KAP-2) 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 amount 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-118 (KAP-2), pages 1 through 3. Therefore, column (i) represents the increase (or decrease) 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. Where column (i) indicates a significant difference between O&M expense increases that are due to inflation as opposed to due to some other factor, as I describe each department's expenses.

Q. Please describe the activities of the Gas Project Management department.

A. Gas Project Management provides project oversight and management for certain projects that are required by the business or directly for a customer. These projects are usually large or complex in nature and require project management methodology to achieve predictable results. The Gas Project Management team includes Company-employed and contract project managers who oversee large-scale gas projects, and ensure that each project meets the intended scope, schedule, and cost projection. The Gas Project Management line item, as shown on Exhibit A-118 (KAP-2), page 1, line 1, consists of the O&M portion of the salaries and expenses for project managers, and their Company-employed and contracted support staff(s). The majority of the expenses for this department are charged to capital either through direct charging or overhead allocations. 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.

Q. What is the basis for determining the $1,307,000 of projected O&M expenses in the test year 12 months ending September 30, 2023, for this program?

A. As shown in Table 3 below, Gas Project Management is increasing from $699,000 in the historical year 2020 to the test year amount of $1,307,000 due to the increased staffing needed to meet the targets set forth in the NGDP. The increased staffing of 13 full time equivalent ("FTE") employees includes project managers and analysts in this department. Gas Project Management oversees the planning and execution of a project, they help ensure the project's overall goals and its subsequent tasks and milestones are achieved. Not increasing headcount to the projected level will cause delays in completing the necessary scoping, cost projections, budgeting, and implementation of the distribution, transmission, compression, and storage engineering projects outlined in the NDGP, which would increase the risk of unpredictable outcomes due to lack of resources for proper oversight and control.

Table 3: Gas Project Management O&M Calculation

	Gas Project Management O&M Calculation		
	2020 Actual	2020 Adjusted	Test Yr 12ME 9/30/23
Labor	4,976,102	4,976,102	12,683,439
Capital Direct Charge Labor		5,946,409	
Total Labor	4,976,102	10,922,511	12,683,439
FTE	80	80	93
Labor $ Per FTE	61,873	135,812	136,935
O&M %	8%	8%	8%
O&M Labor	398,088	873,801	1,032,658
O&M Non-Labor	300,608	300,608	273,931
Total O&M	$ 698,696	$ 1,174,409	$ 1,306,589

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 three sub departments which I will describe more fully below. They are:

- Gas Engineering and Asset Planning
- System Integrity
- 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 Pipeline Integrity. 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 (i.e., cities, Michigan Department of Transportation ("DOT"), etc.) and for large new industrial customers. Gas Asset Management includes System Integrity, which implements the SIMP 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 non-labor expenses for the SIMP are represented on Exhibit A-118 (KAP-2), pages 1 and 2, lines 2 through 5.

Q. Please describe the activities of the Gas Engineering and Asset Planning department.

A. The Gas Engineering and Asset Planning team consists of three sub departments that I describe more fully below. They are:

- Gas Distribution Engineering
- Gas Transmission Engineering
- Gas Engineering Asset Planning

The Gas Distribution Engineering department consists of three sections. The Distribution Pipeline Engineering team is responsible for the design of all new and replacement gas mains across the Company's distribution system. This group is also responsible for service replacement design and any other design support needed for distribution piping facilities. The Gas System Engineering team is responsible for emergent engineering projects and operational support across the Company's distribution system. 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 to represent Distribution Engineering on internal projects and process development, and they own the contracts for any outside engineering services needed to support the Distribution Engineering team.

The Gas Transmission Engineering Department contains two sections. The Transmission 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, Deliverability Base Pipeline, Maximum Allowable Operating Pressure ("MAOP") Pipeline, MAOP Transmission and Transmission Enhancements for Deliverability & Integrity ("TED-I"). The Transmission Engineering employees have responsibility for improving the pipeline system, ensuring compliance with applicable regulations, and supporting the Company objectives of supplying safe, reliable, affordable, and clean energy to customers.

The second section is the Metering, Regulation & Controls Engineering ("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. The MR&C

Engineering employees support the above-mentioned programs, allowing them to deliver safe and reliable natural gas to our customers. My testimony covers the labor and expense costs for staffing of the Gas Transmission Engineering department. The capital programs described above are sponsored by Company witness Michael P. Griffin.

The 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 more 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. Finally, Gas Engineering Asset Planning is involved with research of new technologies including, but not limited to, renewable natural gas and hydrogen.

Q. What is the basis for determining the $2,930,000 of projected O&M expenses in the test year 12 months ending September 30, 2023, for the Gas Engineering and Asset Planning department?

A. As shown in Table 4 below, Gas Engineering and Asset Planning is increasing from $1,925,000 in the historical year 2020 to the test year amount of $2,930,000 due to the increased staffing needed to meet the targets set forth in the NGDP. To meet the design and planning needs of the NGDP, this department needs an increase in staffing of 142, which includes engineers, design technicians, and analysts.

For Gas Distribution Engineering and Gas Transmission Engineering, not increasing headcount to the projected level will cause delays in completing the necessary engineering design projects as needed to stay on schedule. This will affect permitting and construction activities as well as increase the potential for postponement of a portion of the distribution and transmission projects outlined in the NGDP. For example, in Gas Distribution Engineering, the EIRP Program is targeting 240 retired miles in 2023 compared to the 2020 target of 75 miles (165 additional miles or 220% increase). In Gas Transmission Engineering, the Remote Control Valve ("RCV") program is targeting 40 remote control valve installations in 2023 compared to the 2020 target of 15 installations (25 additional RCV installations or 166% increase).

For the Gas Engineering Asset Planning team, not increasing headcount to the projected level will cause delays in completing the necessary engineering planning and permitting of projects, impacting implementation of the projects outlined in the NDGP. For example, with the increase in distribution and transmission projects, a delay in permitting projects could result in missing the construction outage window for a project.

Table 4: Gas Engineering and Asset Planning O&M Calculation

Gas Engineering and Asset Planning O&M Calculation	2020 Actual	Projected 12-Mos Ending Sep 30, 2023
Headcount	173	315
Cost/FTE	104,056	117,041
Total Cost	18,001,745	36,867,904
O&M Percentage	8.7%	6.5%
O&M Base Cost	$ 1,562,371	$ 2,394,939
Odorant/Material Adjustments	363,000	535,184
Total O&M	$ 1,925,371	$ 2,930,123

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, Distribution Integrity Management Program, and SIMP. These programs ensure the integrity of our 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 program. The other System Integrity programs described above are sponsored by Company witness Timothy K. Joyce.

Q. What is the basis for determining the $2,324,000 of projected System Integrity O&M expenses in the test year 12 months ending September 30, 2023, for this department?

A. As shown in Table 5 below, System Integrity is increasing from $1,530,000 in the historical year 2020 to the test year amount of $2,324,000 due to the increased staffing needed to meet the targets set forth in the NGDP and the requirements of Pipeline and Hazardous Materials Safety Administration's ("PHMSA's") Safety of Gas Transmission and Gathering Pipelines rule (Part 1) published on October 1, 2019, the anticipated Safety of

Gas Transmission and Gathering Pipelines rule (Part 2) in 2022, the implementation of the Transmission and Storage Probabilistic Risk Models, and Storage Engineering and Storage Integrity Management. The increased staffing of 29 includes engineers, analysts, and technicians in this department. System Integrity oversees the Company's integrity management programs. Included in the total increased staffing numbers are nineteen employees in Transmission Integrity Management to provide oversight and meet targets related to the NGDP, including the corrosion control design reviews of capital projects (for example, storage lateral replacements, valve replacements, RCV's) and increased Direct Assessment work, Safety of Gas Transmission and Gathering Pipelines rule (Part 1), including MAOP Reconfirmation and Material Verification, and Safety of Gas Transmission and Gathering Pipelines rule (Part 2), including the enhancements to Corrosion Control requirements. Three of the staffing increases are related to risk modeling. This includes one dedicated engineer to the Distribution Risk Model and one additional engineer, each, for the Transmission and Storage Probabilistic Risk Model due to the data intensive nature of these new models. Six of the staffing increases are in the SIMP area to provide oversight and engineering related to the increase in new wells being drilled, surface equipment design (separators, tanks, etc.), the Riverside Disposition, and the analysis of data gathered from the storage SCADA projects. In the additional staffing, there is one engineer who is dedicated to the development of a Facilities Integrity Management Program. This engineer will be responsible for implementing an integrity management approach to facilities not currently part of the Company's Integrity Management Programs; examples include tanks, heaters, and separators, to ensure the integrity and safety of this equipment. Not increasing headcount to the projected level will impact implementation and cause challenges in meeting compliance requirements of the Company's integrity management programs that ensure the integrity of our Transmission, Distribution, and Storage Assets.

Table 5: System Integrity O&M Calculation

System Integrity O&M Calculation		
		Projected
	2020 Actual	**12-Mos Ending Sep 30, 2023**
Headcount	64	93
Cost/FTE	103,932	108,649
Total Cost	6,651,647	10,104,348
O&M Percentage	23%	23%
O&M Cost	$ 1,529,879	$ 2,324,000

In addition to the staffing requirements, the SIMP was created in response to a new PHMSA final rule issued on February 12, 2020. The SIMP line item is shown on Exhibit A-118 (KAP-2), page 2, line 5. The basis for this program funding is described below.

Q. What is the basis for determining the $916,000 SIMP O&M expenses in the test year 12 months ending September 30, 2023, 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 incorporated by reference in the consensus document American Petroleum Institute Recommended Practice 1171: Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs ("API RP 1171"). 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 SIMP has several O&M components necessary to execute the program. The O&M components address the expenses required for the Well Plugging program and for atmospheric corrosion protection (painting) of rehabilitated wells. The O&M costs for the SIMP in the test year total $916,000.

Q. Please describe the Well Plugging portion of the SIMP funding requirements.

A. To comply with PHMSA Regulation 192.12 and API 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 wells that are plugged as part of the Well Rehabilitation Program, and prior plugged wells within the Company's natural gas storage fields, the Company must further comply with new plugged well monitoring requirements. The O&M costs associated with the program are comprised of conducting research and engineering analysis of plugged wells and field monitoring criteria for all plugged wells. The engineering assessment characterizes the plugged wells and sets forth a monitoring frequency per the program criteria. The monitoring portion of the program requires visual and instrumented observation of the plugged well sites for any indication of methane leaks. The plugged well assessment and monitoring program was initiated in 2021 with engineering assessment of approximately 450 plugged wells and field monitoring of 14 plugged wells. The field monitoring will expand to include 129 plugged wells in the test year. The O&M costs associated with the Well Plugging portion of the SIMP in the test year total $741,000.

Q. Please describe the Well Rehabilitation atmospheric corrosion portion of the SIMP funding requirements.

A. The Well Rehabilitation Program is part of the SIMP which 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. The O&M costs associated with the Well Rehabilitation atmospheric corrosion portion of the SIMP for the projected test year totals $175,000.

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.

Q. What is the basis for determining the $1,545,000 of projected O&M expenses in the test year 12 months ending September 30, 2023, for this department?

A. As shown in Table 6 below, Gas Compression Engineering is increasing from $842,000 in the historical year 2020 to the test year amount of $1,545,000. This is due to three primary areas:

- Increased staffing needed to meet the targets set forth in the NDGP. This includes the decommissioning program as described by Company witness Joyce, Overisel Unitized Cooling, Muskegon River Jet Upgrade, as well as Renewable Natural Gas development. The increased staffing of ten includes engineers, analysts, and the establishment of a single civil engineering team.

Civil engineering support was previously provided solely via contracted engineering firms. This team will provide civil design, peer review and engineering analysis support to each area of the Gas Asset Management department. Creation of an in-house team will build a core technical competency in a critical field and provide a more cost-effective solution compared to outsourcing this work.

- The incorporation of lessons learned from the 2019 Ray Fire event, including system safety and resiliency improvements. This includes detailed hazard assessments, dispersion modeling and failure modes and effects analyses.
- The establishment of a specific allocation for O&M costs associated with capital investments. This includes alternative analysis, feasibility studies, etc. These costs have not previously been specifically identified for capital projects.

Not increasing the Gas Compression Engineering O&M expenses as described above will cause delays in the implementation of the projects and programs.

Table 6: Gas Compression Engineering O&M Calculation

Gas Compression Engineering O&M Calculation	2020 Actual	Projected 12-Mos Ending Sep 30, 2023
Headcount	29	39
Cost/FTE	145,172	145,172
Total Cost	4,210,000	5,661,724
O&M Percentage	20%	20%
O&M Base Cost	$ 842,000	$ 1,132,345
Adjustments		
Safety Risk Program		175,000
O&M Assoc. w/ Capital Projects		237,655
Total O&M	$ 842,000	$ 1,545,000

Q. What operating sections are included in Gas Engineering Support?

A. Gas Engineering Support consists of four departments which I will describe more fully below. They are:

- Gas Strategy
- Gas Regulatory and Compliance
- Customer Energy Management
- Geospatial Management and Data Quality

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 systems and the development of the NGDP. 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 salaries and expenses associated with the Gas Strategy department are represented on Exhibit A-118 (KAP-2), page 2, line 6.

Q. What is the basis for determining the $390,000 of projected O&M expenses in the test year 12 months ending September 30, 2023, for this department?

A. As shown in Table 7 below, Gas Strategy is decreasing from $473,000 in the historical year 2020 to the test year amount of $390,000 due to the increased staffing needed to meet the targets set forth in the NGDP offset by reduced contractor costs in System Decarbonization Strategy. The increased staffing of two includes one strategy manager and one gas asset consultant in this department. Gas Strategy ensures the overall goals and outcomes developed in the NGDP align with the Company's strategy. Not increasing headcount to the projected level will limit the financial analysis and business performance measurement necessary to ensure implementation of the NGDP as well as the long-term strategy development for the natural gas system.

The contractor costs are associated with the System Decarbonization Strategy. The projected costs include the Company's clean energy transformational strategy development and analysis needed to achieve the Company's 2030 net-zero methane goal, in support of Michigan's Healthy Climate Plan 2050 carbon neutrality goal, and continued participation in the Electric Power Research Institute ("EPRI") and Gas Technology Institute ("GTI") Low-Carbon Resources Initiative ("LCRI"). The LCRI is a five-year research, development, and demonstration ("RD&D") collaborative effort supported by major electric and gas utilities and is focused on low and zero carbon energy technologies options essential to a clean energy future.

Table 7: Gas Strategy O&M Calculation

Gas Strategy O&M Calculation		
		Projected
	2020	12-Mos Ending
	Actual	Sep 30, 2023
Total Cost Labor/Expenses	$ 1,483,446	$ 1,787,603
Headcount (FTE)	9	11
Cost/FTE	$ 164,827	$ 162,509
O&M Percentage	15.0%	13.5%
O&M Base Cost	$ 222,517	$ 241,326
System Decarbonization Strategy	$ 250,000	$ 148,750
Total O&M Cost	**$ 472,517**	**$ 390,076**

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, 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. The Gas Regulatory and Compliance department is also managing the Company's implementation of the American Petroleum Institute Recommended Practice 1173 – Pipeline Safety Management Systems which is the Company's Gas Safety Management System ("GSMS"). The Company's GSMS is sponsored by Company witness Stephanie V. Watson. The salaries and expenses associated with the Gas Regulatory and Compliance department are represented on Exhibit A-118 (KAP-2), page 2, line 7.

Q. What is the basis for determining the $666,000 of projected O&M expenses in the test year 12 months ending September 30, 2023, for this department?

A. As shown in Table 8 below, Gas Regulatory and Compliance is increasing from $393,000 in the historical year 2020 to the test year amount of $666,000 due to the increased staffing needed to meet the compliance workload and GSMS requirements. The increased staffing of nine includes engineers and analysts in this department. Not increasing headcount to the projected level will cause challenges in meeting compliance requirements and supporting the requirements of our GSMS.

Table 8: Gas Regulatory and Compliance O&M Calculation

Gas Regulatory & Compliance O&M Calculation		
		Projected
	2020	12-Mos Ending
	Actual	Sep 30, 2023
Headcount	16	25
Cost/FTE	136,331	148,000
Total Cost	2,181,296	3,700,000
O&M Percentage	18%	18%
O&M Cost	$ 392,633	$ 666,000

Q. Please describe the activities in the Customer Energy Management department.

A. The Customer Energy Management ("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. In 2020, this department coordinated the work on more than 67,000 customer requests. Within CEM there are three 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 was responsible for scoping and coordination of projects, enabling the expansion of 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. The salaries and expenses associated with the Customer Energy Management department are represented on Exhibit A-118 (KAP-2), page 2, line 8.

Q. What is the basis for determining the $631,000 of projected O&M expenses in the test year 12 months ending September 30, 2023, for this department?

A. As shown in Table 9 below, CEM is increasing from $488,000 in the historical year 2020 to the test year amount of $631,000 due to the increased staffing needed to meet customer requested work. The increased staffing of 49 includes design technicians and project coordinators in this department. Not increasing headcount to the projected level will cause delays in completing the necessary design projects and impact delivery of customer requested work.

Table 9: Customer Energy Management O&M Calculation

Customer Energy Management O&M Calculation		
	2020 Actual	Projected 12-Mos Ending Sep 30, 2023
Headcount	168	217
Cost/FTE	58,054	58,157
Total Cost	9,753,058	12,620,000
O&M Percentage	5%	5%
O&M Cost	$ 487,653	$ 631,000

Q. Please describe the activities of the Geospatial Management and Data Quality department.

A. The Geospatial Management and Data Quality department includes the employees responsible for the Geospatial Information Systems ("GIS") including gas maps and records. The team is responsible for creating and maintaining the GIS & Service Information Management System ("SIMS") databases for gas distribution, transmission, storage, service, measurement, and regulation systems and for supporting strategic and operating capacity planning, performance, asset management, and regulatory reporting requirements. The salaries and expenses associated with the Geospatial Management and Data Quality department are represented on Exhibit A-118 (KAP-2), page 3, line 9. This department is also responsible for the Geospatial Inventory and Modeling program, which includes the Gas Compliance Code Program - Service Information Mapping System project and the Utility Network implementation, which I cover further below. The O&M expenses for the Geospatial Inventory and Modeling Program within the Geospatial Management and Data Quality department are described on Exhibit A-118 (KAP-2), page 3, line 10.

Q. What is the basis for determining the $1,033,000 of projected O&M expenses in the test year 12 months ending September 30, 2023, for the Geospatial Management and Data Quality department?

A. As shown in Table 10 below, Geospatial Management and Data Quality is increasing from $554,130 in the historical year 2020 to the test year amount of $1,033,000 due to the increased staffing needed to support the increased asset records management workload driven by the NGDP and to ensure that Company records are compliant and current enabling employees and other end users to have comprehensive access to correct information in a timely and cost-effective manner, all contributing to increased pipeline safety. The increased staffing of 23 includes technicians, analysts, database administrator, and team lead in this department. Not increasing headcount to the projected level will cause challenges in meeting compliance requirements including the ability to provide current and accurate mapping.

Table 10: Geospatial Mgmt & Data Quality O&M Calculation

Geospatial Mgmt & Data Quality O&M Calculation		
	2020 Actual	Projected 12-Mos Ending Sep 30, 2023
Headcount	30	53
Cost/FTE	92,355	102,582
Total Cost	2,770,648	5,436,842
O&M Percentage	20%	19%
O&M Cost	$ 554,130	$ 1,033,000

Q. What is the basis for determining the $4,253,000 of projected O&M expenses in the test year 12 months ending September 30, 2023, for the Geospatial Inventory and Modeling Program?

A. The Geospatial Inventory and Modeling program includes the Gas Compliance Code Program - Service Information Mapping System project and the Utility Network project. This program was created to modernize and transform the Company's GIS records and systems. These projects have a capital and O&M component. I describe the capital costs in further detail in the Gas Operations Other program later in my testimony. There are two additional projects included in this program. The first is the Gas Compliance Code Program – IT Enhancements, which are updates to compliance software required to meet regulatory requirements. This project will require O&M funding in the amount of $133,500 in the test year 12 months ending September 30, 2023. Second is the GE&S Engineering Records Management project, which represents the change management costs associated with the Gas Distribution records projects. This project will require O&M funding in the amount of $48,000 in the test year 12 months ending September 30, 2023.

Q. Please describe the activities of the Planning - Generation department.

A. Planning – Generation was an allocation from an electric group within the Company that previously provided a small amount of support for Gas Compression Engineering. Starting in 2021, this department will no longer be supporting Gas Compression Engineering and has $000 as shown on Exhibit A-118 (KAP-2), page 3, line 11.

Q. The last department within the Gas Engineering and Supply group is Gas Management Services, as set forth on Exhibit A-118 (KAP-2), page 3, line 12. What operating sections are included in the Gas Management Services?

A. Gas Management Services is responsible for four major functions:

- Gas Control
- Gas System and Operations Planning
- Gas Supply
- Gas Transportation, Customer Choice and Measurement

The Gas Control department 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). Gas Control monitors scheduled third-party pipeline supply, dispatches compression, and storage assets to ensure customer supply is met within the Transmission system's design limits, and monitors portions of the Distribution system.

Gas System and Operations Planning is responsible for the following: 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 plan with the Company's operational plans; as well as administration of interconnect agreements with entities.

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. In addition to 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. It has responsibility for 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. This section is also responsible for 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.

Q. What is the basis for determining the $4,347,000 of projected O&M expenses in the test year 12 months ending September 30, 2023, for this department?

A. As shown in Table 11 below, Gas Management Services is increasing from $3,677,353 in the historical year 2020 to the test year amount of $4,347,000 due to the increased staffing needed to meet the targets set forth in the NDGP. The increased staffing of six includes engineers and gas control staff in this department. Not increasing headcount to the projected level will cause delays in outage coordination, scheduling, and system planning activities necessary to support the system control, and system analytics plans in the NGDP.

Table 11: Gas Management Services O&M Calculation

Gas Management Services O&M Calculation		
	2020 Actual	Projected 12-Mos Ending Sep 30, 2023
Headcount	37	43
Cost/FTE	129,075	134,791
Total Cost	4,775,783	5,796,000
O&M Percentage	77%	75%
O&M Cost	$ 3,677,353	$ 4,347,000

<u>**GAS DISTRIBUTION CAPITAL EXPENDITURES**</u>

Q. Please describe the Company's projections of capital expenditures for Gas Distribution.

A. As shown on Exhibit A-12 (KAP-3), Schedule B-5.9, the Gas Distribution capital expenditures I am sponsoring were $446,217,000 in 2020, and are projected to be $515,483,000 in 2021; $391,264,000 for the nine months ending September 30, 2022; and $640,540,000 for the 12 months ending September 30, 2023, as set forth on this exhibit on line 7, column (b); line 7, column (c); line 7, column (d); and line 7, column (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-5.9, are:

- New Business
- Asset Relocation

- Regulatory Compliance
- Material Condition
- Capacity/Deliverability
- 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 these programs. The direct testimony of Company witnesses Griffin, Paul M. Wolven, Dreisig, 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 is not any contingency costs included in the capital expenditures.

1. <u>New Business</u>

Q. Please describe the capital expenditures related to the New Business Program as shown on Exhibit A-12 (KAP-3), Schedule B-5.9, line 1.

A. The New Business Program consists of the capital costs of adding new commercial, industrial, and residential customers. 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. The Company calculates the projected construction and maintenance costs for the facilities required to serve the customer's request and applies the appropriate rate book tariffs to calculate the projected revenue due to the system expansion to calculate what portion of the project must be paid for by contribution from the customer. The Company's test year projection includes the expansion of service to additional residential, commercial, and industrial customers. The total New Business capital expenditures (net of customer contributions) that the Company experienced in 2020 were $87,021,000, and the Company's projections for the years 2021, the nine months ending September 30, 2022, and the 12 month test year ending September 30, 2023, are $63,656,000; $44,622,000; and $65,394,000, 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. These expenditures are also shown in Table 12 below.

Table 12: New Business Capital Expenditures

($000)	(a)	(b)	(c)	(d)	(e)	(f)
		New Business Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line No.	Program Description	12 Mos Ended 12/31/2020	12 Mos Ending 12/31/2021	9 Mos Ending 9/30/2022	21 Mos Ending 9/30/2022	12 mos. Ending 9/30/2023
1	Mains Services & Meter Stands - Dist	52,770	59,997	44,622	104,620	65,394
2	Large New Business Projects - Dist	33,440	2,825	-	2,825	-
3	Customer Attachment Program - Dist	811	834	-	834	-
4	**Total New Business Capital**	**87,021**	**63,656**	**44,622**	**108,279**	**65,394**

Exhibit A-119 (KAP-4) provides further details of the expenditures included in this program.

Q. Please explain the Company's gas new business connection projections.

A. The Company uses data from multiple sources to project and plan for new business growth. In alignment with the Michigan Home Builders Association's expected growth for 2022, and the increase growth of 46% the Company has seen in 2021, this data suggests that housing starts (new house build projects) will have moderate growth in 2022 and 2023. The Company believes that due to construction timing there is a delay between the housing start and the Company receiving a request for service. Therefore, current year housing starts will continue to materialize into the following year for the Company. As a result, the Company has projecting a conservative growth of 3% in 2022 and held growth in 2023.

The continued demand for new subdivision developments in 2021 will result in houses built, and services connected, over the upcoming years.

Q. How many new business connections are you projecting in this filing?

A. The New Business Program projects 8,400 new attachments in 2021, 8,568 in 2022, and 8,568 for the full year 2023. There were 7,083 connections in 2020. This projection includes connections under the CAP Program, which are expected to be minimal going forward, in addition to the new connections that come on the gas system outside of customers converting to natural gas. Some of these new connections will be along existing gas main facilities, while others will require some extension of the distribution main network.

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 collects the customer's location, requested hourly and annual 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 all work required to make the connection, including main installation, service installation, permit costs, etc. These costs will be offset by the customer's projected revenue, according to the Customer Attachment tariffs, as stated in Rule C8 of the Company's Rate Books.

Q. What is the status of the Company's CAP 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 Customer Attachment tariffs, as stated in Rule C8 of the Company's Rate Books, but the Company will no longer be proactively soliciting to scope and construct additional CAP main extensions under the CAP Program. New service connections to existing CAP Program mains will still be offered with the prorated monthly payment option until expiration of the CAP charges on that particular system.

Q. Please describe the projects in the Large New Business Program, represented on Exhibit A-119 (KAP-4), line 2.

A. The Large New Business Program includes new customer connection projects where the estimated infrastructure cost exceeds $500,000, and therefore may require special tracking and project management. As with the New Business Mains and Services Program, each project cost is governed by the application of tariff Rule C8 Customer Attachment Program from the Company's gas rate book to determine the Customer's contribution or if project costs will be fully offset by the projected revenue from the customer. For the timeframe represented in this proceeding, there are no new projects included in this program. In 2020, the Company continued construction on the Lansing Board of Water and Light Erickson Plant project, at an estimated total project construction cost of $52,000,000. Additionally, in 2020, the Company completed construction and restoration in conjunction with connecting two large agri-business customers in Saint Johns. The Company also connected a new agri-business customer in Reese under the Large New Business Program.

Additionally, the Company partnered with the Michigan Economic Development Corporation to help secure the expansion of a business in southwest Michigan, which required approximately 4000' of high-pressure gas main, a new service and a new meter to enable this customer's growth. This construction began in 2020, with the final meter installation taking place in 2021. In total, the 2020 large new business projects consisted of separate transmission taps, city gate, regulator station, distribution main, service, and meter stand installations to serve the Lansing Board of Water and Light, the agri-business customer in St Johns and Reese, and the industrial expansion in southwest Michigan.

For 2021, the Company has expenditures on Lansing Board of Water and Light project to perform permanent restoration of disturbed construction sites and to complete equipment installation at the Grand Ledge City Gate. The program also contained some carryover costs related to the completion of the St Johns agri-business customer installation. Additionally, in 2021, the Company completed the final meter installation on the southwest Michigan industrial customer expansion.

2. Asset Relocation

Q. Please describe the capital expenditures related to the Asset Relocation Program as shown on Exhibit A-12 (KAP-3), 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 13 below and Exhibit A-120 (KAP-5) provides further details of these expenditures.

Table 13: Asset Relocation Capital Expenditures

($000)	(a)	(b)	(c)	(d)	(e)	(f)
		Asset Relocation Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line No.	Program Description	12 Mos Ended 12/31/2020	12 Mos Ending 12/31/2021	9 Mos Ending 9/30/2022	21 Mos Ending 9/30/2022	12 mos. Ending 9/30/2023
1	Asset Relocation - Civic Improvement	**74,653**	74,723	63,015	137,738	75,769
2	Asset Relocation - Reimbursable	**9,320**	10,398	9,940	20,338	13,070
3	**Total Asset Relocation Capital**	**83,973**	**85,121**	**72,955**	**158,076**	**88,840**

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 located 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 upgrade, 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 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 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 final report of the Statewide Energy Assessment ("SEA") that was submitted on September 11, 2018 in Case No. U-20464.

Public infrastructure continues to be a significant topic of conversation at the state and local political levels. In their most recent report card from 2018, the American Society of Civil Engineers gave Michigan's overall infrastructure a D+ grade and downgraded that to a D- when specifically referencing roads and stormwater infrastructure.[1] According to the Michigan Transportation Asset Management Council, statewide expenditures on transportation assets have grown from just under $1.7 billion in 2013 to over $2.6 billion in 2019.[2] Governor Whitmer's 2020 fiscal year plan included a "Fixing Michigan's Roads Plan" that recognizes a need for an additional investment in roads of at least $1.5 billion annually.[3] These investments will continue to impact the Company's assets located in the road right-of-way, and any required replacement of those assets will be funded from the Asset Relocation – Civic Improvement Program.

The average Asset Relocation - Civic Improvement project size is approximately 1,512' based on the three-year average of 2019, 2020, 2021 and the majority of the projects involve replacement of metallic facilities with plastic pipe. However, each year the Company has historically been required to replace portions of high-pressure facilities within this program, which requires steel pipe to be installed, and this is more costly than plastic pipe installation. This trend has continued in 2020, with the relocation of high pressure gas piping in Buena Vista Twp. in Saginaw with the I-75 and M-46 Interchange Reconstruction. Additional high-pressure gas piping work will be required for facilities

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[1] https://www.infrastructurereportcard.org/asce-gives-michigan-infrastructure-a-d/

[2] http://www.mcgi.state.mi.us/mitrp/tamcDashboards/reports/finance/finance?year=2019&areaType=Statewide&area=All%20City%2FVillage%20%26%20County&reportType=financialExpenditures

[3] https://www.michigan.gov/documents/mdot/Fixing_Michigan_Roads_Plan_Summary_648340_7.pdf

along 9 Mile Road in 2021. 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 14: Asset Relocation – Civic Improvement Project Details

	2019	2020	2021 (Projected)	2022 (Projected)	2023 (Projected
Projects completed	203	125	183	185	185
Asset Relocation Feet of Distribution Main Installed	285,284	162,920	290,170	No Footage Projection	No Footage Projection
Asset Relocation Services Replaced	3,072	1,547	3,121	No Service Projection	No Service Projection

There are significant benefits to the capital investment 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 as a result of the ground impact of that construction. This enhances the safety of those working near these facilities, as well as the affected public. Additionally, 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.

As shown on Exhibit A-120 (KAP-5), line 1, the capital expenditures for the Asset Relocation – Civic Improvement Program were $74,653,000 in 2020, and are projected to be $74,723,000; $63,015,000; and $75,769,000 for the years 2021; the nine months ending September 30, 2022; and the test year ending September 30, 2023, 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. These projections are based upon recent history, projections of increased federal and state funding for infrastructure improvements, and on knowledge of specific projects planned for the next several years. The Company's projected test year expenditure amounts are required to meet the projected level of asset relocations associated with local and state government projects.

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. Despite not having a named council member, the Company has representatives that serve on subcommittees and contribute to the quarterly meetings. Additionally, the Company had three employees 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 on timing with the city to replace vintage mains and services that may leak from such type of construction. In addition, the Company works to coordinate project timelines with municipalities to align construction schedules to reduce the Company's 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 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, primarily gas mains. These negotiations reduce overall project scope, and therefore, reduce the costs to both the taxpayer and the Company's customers. While the team has been successful in negotiating out of, or limiting the scope of, many projects over the past few years, there still has been steady trend in the number of main and service replacements required in this program, as demonstrated in Table 14 above.

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.

The costs and projections for this program are reflected on Exhibit A-120 (KAP-5), line 2, and demonstrated in Table 13 above. The capital expenditures for this program were $9,320,000 in 2020, and are projected to be $10,398,000; $9,940,000; and $13,070,000 for the years 2021; the nine months ending September 30, 2022; and the test year ending September 30, 2023, 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.

3. <u>Regulatory Compliance</u>

Q. Please describe the capital expenditures relating to the Regulatory Compliance Program shown on Exhibit A-12 (KAP-3), 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 Program, and MAOP Distribution projects. The capital expenditures for this program were $31,691,000 in 2020, and are projected to be $37,565,000; $17,324,000; and $21,867,000 for the years 2021; the nine months ending September 30, 2022; and the test year ending September 30, 2023, as set forth on this exhibit on line 3, column (b); line 2, column (c); line 2, column (d); and line 2, column (f), respectively. A further breakdown of the Regulatory Compliance Program expenditures is shown on Exhibit A-121 (KAP-6). The Regulatory Compliance expenditures are shown in Table 15 below.

Table 15: Regulatory Compliance Capital Expenditures

($000)	(a)	(b)	(c)	(d)	(e)	(f)
		Regulatory Compliance Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line No.	Program Description	12 Mos Ended 12/31/2020	12 Mos Ending 12/31/2021	9 Mos Ending 9/30/2022	21 Mos Ending 9/30/2022	12 mos. Ending 9/30/2023
1	Regulatory Base Distribution	4,903	7,779	365	8,144	135
2	Meters	26,788	29,786	16,958	46,744	21,218
3	MAOP Distribution	-	-	-	-	515
4	**Total Regulatory Compliance Capital**	**31,691**	**37,565**	**17,324**	**54,888**	**21,867**

Q. Please describe the Regulatory Base Distribution Program.

A. This program funds the capital construction projects required to meet regulatory commitments. This is a five-year program that began in 2017 with an initial plan for 17 projects. When the Company committed to this program, it also made a commitment to continue to monitor the Supervisory Control and Data Acquisition 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 will replace sections of the standard pressure system with medium pressure plastic, which will remove 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 equipment. The scope of work for a typical project would involve replacing all vintage mains and services along with any other facilities not rated for the higher operating pressure. Those existing main and service facilities rated to operate at medium pressure would be converted without replacement. Each customer on either a replaced or upgraded section of the system gets a new meter and regulator to reduce the pressure before it enters the building. This will allow the Company to lower the maximum operating pressures of these standard pressure systems from 18" water column to 14" water column or less, per an agreement between the Company and the MPSC Safety Staff in 2017. The Company is on track with the plan for the completion of this five-year program, as shown in Table 16 below:

Table 16: Regulatory 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	2021 – Released for Construction
16132	Owosso	Ada St	2021 – Released for Construction
12085	Lansing	High St – Charlotte	Cancelled

While this program is intended to reduce the operating pressure on the standard pressure system, there are additional benefits from this work. The 17 projects involved will replace just over 10 miles of cast iron and other vintage mains and eliminate more than 200 vintage services. Existing plastic main in the standard pressure system will be converted or uprated to medium pressure wherever it is practical and possible, saving the cost of replacement for these segments, while still eliminating them from the standard pressure system.

The Regulatory Compliance Program will be completed in 2021, as agreed to with the MPSC Staff, but the above details are included in this testimony to describe costs incurred during the historical and bridge years of the case. The 2022 and 2023 expenditures detailed on Exhibit A-121 (KAP-6), line 1, included projected restoration costs from 2021 projects.

Q. Please describe the Meters Program within the Regulatory Compliance Program and the projections in this filing.

A. The meters purchased in the Regulatory Compliance Program are used in serving new business connections, the Routine Meter Exchange Program, VSRs, and for normal replacement of obsolete or broken meters. The Routine Meter Exchange Program involves replacing the customer's existing meter with a new or refurbished meter, then testing the old meter's accuracy, thereby checking that the equipment in the field is measuring properly to ensure meters meet the requirements of the MPSC regulations. The Meters Program also includes equipment purchased for customer-generated 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 replaced are regulated meters, rotary meters, and temperature compensating meters. The expenditures detailed on Exhibit A-121 (KAP-6), line 2, also include gas meter communication modules, gas corrector units, and testing equipment in 2020 and 2021. The 2022 and 2023 expenditures for gas meter communication modules and gas corrector units will be further discussed below.

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 August 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 VSRs, 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 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 is able to adjust the orders as material usage variations are observed. The actual and projected total number of meters purchased for the Meters Program for each period in this filing are shown in Table 17 below:

Table 17: Actual and Projected Meters Program Purchases by Year

	2020	**2021**	**2022**	**2023**	**2023 Test Yr**
Meter Units	58,997	51,459	45,664	47,461	47,012
Unit Cost	419	480	460	448	451
Total Meter Cost	24,742,799	24,678,694	21,020,278	21,264,847	21,217,705
Correctors	1,460	3,897			
Unit Cost	1,383	1,307			
Total Corrector Cost	2,018,812	5,094,704			
Comm Modules	200	100			
Unit Cost	131	127			
Total Comm Module Cost	26,166	12,665			
Total Cost	**26,787,777**	**29,786,063**	**21,020,278**	**21,264,847**	**21,217,705**

Q. What changes have impacted the costs of the Meters Program?

A. The costs in the Meters 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 AMI and AMR programs in 2019, all meters are purchased with a communication module ("GCM") installed on the meter by the meter manufacturers. While the AMI and AMR programs were being rolled out, these programs paid for the cost of these modules. With those programs now complete, the cost of the modules are included in the Meters Program. GCMs are meter manufacturer and meter type specific. When meters are returned from the field, if the meter is scrapped/retired, the GCM is either scrapped/retired or, in the case of meters that will be returned to service, recycled to be used as replacements for defective or damaged GCMs. This limits the purchase of new GCMs primarily to the units that come with new meter purchases.

Second, in late 2020, the sole-source provider of the regulated meters (meter with built-in regulator) announced the decision to discontinue production of diaphragm gas meters in mid-2021. From 2022 forward, the primary meter purchased will be the temperature compensating meter (the regulator is part of the meter stand). This will lower the unit cost of meters purchased in this program going forward. The cost of the in-stand regulator is not included in this program.

Third, historically, gas meter volume and temperature correctors and GCMs purchased as stand-alone units were purchased in this program. Company witness Christopher T. Fultz will represent these additional components in the Meter Technology and Management Systems Support Program in the future. The removal of these purchases is reflected in Table 17, above. All new meter purchases include the meter, the GCM, and where required, the temperature and volume correctors as a single unit and are procured 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 will be completed in 2021. In 2022, the Company will procure new gas regulator test equipment, with an estimated cost of $150,000. Additionally, the current spend plan in this program includes potential replacement of two gas meter accuracy test stations at a cost of $65,000 per unit. This expenditure will be realized if any of the existing units fail and needs to be replaced.

Q. Please describe the MAOP Distribution Program within the Regulatory Compliance Program and the projections included in this filing.

A. The MAOP Distribution program expenditures are used to fund projects on the gas distribution system where reconfirmation of the established Maximum Allowable Operating Pressure ("MAOP") is required due to new gas code language included in PHMSA 192.624, as well as discovery in our records requiring reconfirmation. In some specific cases, replacement of gas distribution assets is determined to be the most effective way of reconfirming the MAOP. This program is used to fund those replacement projects. There is one project included in this filing, known as the Line 1080 West project.

Line 1080 West is a single feed system that serves approximately 20,000 customers. It is comprised primarily of 6.5 miles of pre-1955 and 20 miles of 8" diameter high-pressure steel which operates at > 20% Specified Minimum Yield Strength ("SMYS"). 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. Consumers Energy intends to lower the MAOP of this line, install/replace high pressure pipe, and rebuild the M Avenue City Gate. The purpose of the Line 1080 West project is to maintain customer load commitments with consideration for moderate future growth, increase reliability, resiliency, safety, and replace vintage materials to reduce methane emissions. In 2022, Consumers Energy will begin preliminary engineering and land survey. Project design and real estate acquisition is planned to commence in 2023. These expenditures detailed on Exhibit A-121 (KAP-6), line 3.

4. Material Condition

Q. Please describe the capital expenditures relating to the Material Condition Program set forth on Exhibit A-12 (KAP-3), Schedule B-5.9, line 4.

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 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, which includes commercial and industrial meter replacement projects. The projects and expenditures for these four programs are described in more detail below. As shown on Exhibit A-12 (KAP-3), Schedule B-5.9, line 4, the capital expenditures for these four programs were $234,350,000 in 2020, and are projected to be $297,461,000; $243,838,000; and $437,779,000 for the years 2021; the nine months ending September 30, 2022; and the test year 12 months ending September 30, 2023, 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 expenditures for the Material Condition Program are shown in Table 18 below and further detailed on Exhibit A-122 (KAP-7).

Table 18: Material Condition Capital Expenditures

($000)	(a)	(b)	(c)	(d)	(e)	(f)
		Material Condition Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line No.	Program Description	12 Mos Ended 12/31/2020	12 Mos Ending 12/31/2021	9 Mos Ending 9/30/2022	21 Mos Ending 9/30/2022	12 mos. Ending 9/30/2023
1	EIRP - Distribution	118,547	179,455	168,575	348,029	332,588
2	Material Condition Non Modeled	36,892	56,930	24,963	81,893	36,398
3	Material Condition Renewals	36,093	24,484	31,236	55,720	38,242
4	Replace Vintage Services	42,818	36,591	19,065	55,657	30,550
5	**Total Material Condition Capital**	**234,350**	**297,461**	**243,838**	**541,299**	**437,779**

Q. Please describe the EIRP Distribution Program.

A. Beginning in 2012, the Company implemented the EIRP to ensure continued customer safety and reliable system operation as part of the Distribution Integrity Management Program. The EIRP was originally proposed to be a 25-year program that would replace the Company's lowest performing mains, including all cast iron, wrought iron, Threaded and Coupled ("T&C"), oxyacetylene welded, copper, and bare steel distribution main with lower maintenance plastic and steel main, and replace (in the case of older metallic materials) or tie-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 LFERW pipe in the Company's Transmission and Storage fields
- Included in the Company's NGDP is replacement of approximately 108 miles of pipe at Standard Pressure on the Company's gas system that is not covered in the vintage main miles. The Company intends to complete this work and include it as part of planned EIRP Program work going forward.

Q. Please describe the progress of the EIRP.

A. Since the EIRP began in 2012 through the calendar year ended 2020, the program has retired 499.3 miles of the vintage gas pipe identified for replacement. In addition to the EIRP, other programs, like Asset Relocation – Civic Improvement and Material Condition Non-Modeled, also eliminate these mains. 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 2020 the status for each of the main types is detailed in the following bullets:

- 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 180.4 of 580.0 miles by the EIRP through 12/31/2020
- Wrought iron main – Eliminated 4.7 of 21.6 miles by the EIRP through 12/31/2020
- Bare steel main (including oxyacetylene welded bare steel) – Eliminated 162.0 of 1033.4 miles by the EIRP through 12/31/2020
- T&C main – Eliminated 100.1 of 1061.7 miles by the EIRP through 12/31/2020

Per the Company's NGDP, the EIRP is currently planned to be completed by the end of 2030.

See Table 19 below for a summary of pipe replacement each year by the EIRP Program and the associated program capital spend.

Table 19: Miles of EIRP Classified Main Pipe Replaced by Year

MILES OF EIRP CLASSIFIED MAIN PIPE REPLACED BY YEAR

PIPE TYPE:	Miles of Pipe by Pipe Type in EIRP Program Scope	EIRP Actuals (2012 - 2017)[1]	EIRP 2018 Actuals[1]	EIRP 2019 Actuals[1]	EIRP 2020 Actuals[1]	Cumulative EIRP Retired as of 12/31/20[1]	Estimated Cumulative Retired by Other Programs as of 12/31/20	Est. Miles Remaining as of 12/31/20
TOTAL:	2869.2	358.1	43.4	35.3	62.5	499.3	200.9	2,169.0
Cast Iron	580	144.0	13.3	9.3	13.9	180.4	51.3	348.2
Bare Steel	1033.4	107.4	14.0	14.0	26.6	162.0	80.8	790.6
Threaded & Coupled	1061.7	59.5	11.2	9.6	19.8	100.1	66.7	895.0
Wrought Iron	21.6	4.7	0.0	0.0	0.0	4.7	1.1	15.8
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	1.0	(0.0)
Coated & Wrapped on Standard Pressure[4]	108	0.0	0.0	0.0	0.0	0.0		
TOD	100	4.8	3.6	1.6	2.3	12.2		
LFERW	70	36.2	1.4	0.8	0.0	38.4		
Additional Pipe Replacement:								
Plastic[2]		6.4	1.2	0.8	1.7	10.1		
Coated & Wrapped[2]		60.5	6.3	9.7	7.4	83.9		

EIRP CAPITAL SPEND BY YEAR ($ MILLIONS)[3]

	EIRP Actuals (2012 - 2017)	EIRP 2018	EIRP 2019	EIRP 2020	Cumulative		
EIRP Distribution	$365	$87	$78	$119	$648		
EIRP T&S	$80.8	$2.0	$2.6	$.004	$85		
Total	**$446**	**$89**	**$81**	**$119**	**$734**		

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) Capital spend from EIRP Annual Performance Reports
4) Coated & Wrapped steel pipe on standard pressure does qualify under ERIP while Coated & Wrapped steel pipe on medium pressure does not qualify under EIRP

From 2012 through 2020, the Company selected and scoped EIRP pipe replacement projects with a focus on targeted high-risk pipe segments, resulting in an average project size of 1.7 miles of main pipe replacement per project. This approach requires a high level of movement by construction crews to mobilize and de-mobilize to many small project locations and does not achieve the economies of scale and other benefits provided by the planning and construction of larger size projects. In 2020, the Company moved to a grid approach that plans for and constructs large scale EIRP projects (typically 15-25 miles). The Company plans to use this approach where it is able to, for 2021 and future EIRP Program project work.

Q. Please describe the grid approach?

A. The grid approach uses risk model data to identify the highest average risk pipe in a geographic area and scopes, designs, and plans for the construction of large scale EIRP replacement projects to replace all the EIRP pipe in that area. Typically, projects range from 15 miles to 25 miles of distribution main replacement and the associated gas service lines. This large project approach benefits from economies of scale and reduces impact to customers by completing the work for entire neighborhoods with one project in a single year, compared to a street-by-street replacement approach with segmented projects that often required returning to the same neighborhoods for multiple years. The grid project approach has also been beneficial to communication and collaboration with the local cities and permitting agencies the Company works with, allowing for improved advance coordination and consideration of public works projects in planning the timing of grid project work.

Q. What were the results of the 2020 EIRP projects?

A. In 2020, the Company constructed five EIRP projects using the grid approach. These projects were not to the full size and scale of the planned grid approach and ranged in size from 2.85 miles to 11.71 miles of gas distribution main replacement and the associated services. In 2020, the Company also used the segment project approach for 26 projects. The approach of using grids and segments for 2020 projects was described in the testimony of Company witness Jared J. Martin in MPSC Case No. U-20650. See Table 20 below for a summary of the scope of the 2020 EIRP grid and segment project work completed.

Table 20: 2020 EIRP Program Completed Project Work

Project Type	# Projects	Installed Pipe (miles)	Service Counts
Grid Projects	5	36.8	4,673
Segment Projects	26	30.2	3,841
Steel/TOD Projects	3	4.2	42
Total	**34**	**71.2**	**8,556**

The average cost per mile installed for the grid projects was $1.21 million, while the average cost per mile for the segment projects was $1.60 million. The result showed a 32% higher cost per mile for projects completed using the segment project approach. The grid approach resulted in a 29% higher production rate for pipe installation going from an average rate of 0.90 feet per hour installed for 2019 projects to a rate of 1.16 feet per hour installed on 2020 grid projects, as the grid approach allowed construction crews to reduce mobilization by completing work for a larger project over a longer duration, compared to the segment project approach requiring movement from small project to small project multiple times during a year. The grid approach has improved coordination with local communities on longer-term planning and communication on fewer and larger projects and improving coordination of local public works projects and plans. This allows the Company to explore cost savings opportunities with local municipal partners. The grid approach has also provided an improved customer experience with a focus on completing vintage materials replacements within a larger construction project minimizing repeated road-user disruptions, reducing the number of project mobilization/demobilization occurrences in the neighborhood, and maintain personnel working within the project allowing them to keep an open dialogue with impacted customers sharing updates, issues and receiving customer feedback. More details on the 2020 EIRP Program projects can be found in the Company's Gas Enhanced Infrastructure Replacement Program 2020 Performance Report filed under Case No. U-20650. The initial projected cost per mile of the grid approach projects filed in Case No. U-20650 was $0.951 million. It is important to note that this projection was developed prior to the actual completion of any projects using the grid approach and both the segment and grid approach projects completed in 2020 were impacted by cost related to the Covid-19 pandemic. This impact is described in more detail below in this testimony.

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
- 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 are 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. Table 21 below provides data on services worked on through the EIRP Program for 2018 through 2020 and a projection of 2021 sorted by location based on the EIRP workforce zones (SW-southwest/Bellevue HQ, NE-northeast/Birch Run HQ, and SE-southeast/Wixom HQ). The information in Table 21 below does not include pipe miles installed or services related to high pressure steel Transmission Operated in Distribution ("TOD") projects.

Table 21: Total Services per Mile

Year/ Location		SW	NE	SE	Total
2018	**Total**	**656**	**1,411**	**2,565**	**4,632**
	Renewals	543	1,184	2,245	**3,972**
	Tie-overs	113	148	309	**570**
	Retired	0	79	11	**90**
	Miles Main Installed	13.25	15.2	24.4	**52.9**
	Total Services/Mile	49	132	83	**88**
2019	**Total**	**643**	**1,087**	**3,221**	**4,951**
	Renewals	448	879	2,803	**4,130**
	Tie-overs	192	205	408	**805**
	Retired	3	3	10	**16**
	Miles Main Installed	8.86	11.3	30.6	**50.8**
	Total Services/Mile	73	178	66	**98**
2020	**Total**	**641**	**1,500**	**6,373**	**8,514**
	Renewals	449	976	4,774	**6,199**
	Tie-overs	192	429	1,595	**2,216**
	Retired	0	95	4	**99**
	Miles Main Installed	9.39	15.5	42.2	**67.1**
	Total Services/Mile	68	130	48	**127**

2021 Projected	**Total**	**2,643**	**3,931**	**7,326**	**13,900**
	Renewals	1,704	3,007	5,114	**9,825**
	Tie-overs	939	924	2,212	**4,075**
	Retired	0	0	0	**0**
	Miles Main Installed	36.00	37.9	74.1	**148.0**
	Total Services/Mile	73	53	27	**94**
TOTAL SERVICES		**4,583**	**7,929**	**19,485**	**31,997**
TOTAL MILES		**67.5**	**80.0**	**171.2**	**318.7**
TOTAL SERVICES/MILE		**68**	**99**	**114**	**100**

- Pipe type – High pressure steel (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 22 and 23 below provide data on the feet of pipe installed through the EIRP Program for the years 2018 through 2020 and a projection for 2021.

Table 22: EIRP Feet of Pipe Installed by Size, Type and Year:

Year/ Size	2"P	4"P	6"P	8"P	2-6"S	8"S	10"S	12"S	16"S	Total
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 Projected	681,372	40,031	52,785	7,649	2,274	340	32	21,979	0	**806,462**
TOTAL	**1,372,683**	**132,478**	**135,090**	**12,749**	**2,789**	**4,467**	**25,847**	**26,908**	**16,685**	**1,729,696**

Table 23: EIRP % of Pipe Installed by Size, Type and Year:

Year/ Size	2"P	4"P	6"P	8"P	2-6"S	8"S	10"S	12"S	16"S	Total
2018	70.1%	9.0%	11.1%	0.0%	0.0%		3.6%	0.2%	6.0%	**100%**
2019	71.9%	12.2%	12.1%	0.6%	0.1%		3.0%	0.0%		**100%**
2020	80.6%	9.2%	5.0%	0.9%		1.1%	2.0%	1.2%		**100%**
2021 Projected	84.5%	5.0%	6.5%	0.9%	0.3%	0.0%	0.0%	2.7%		**100%**
TOTAL	**79.4%**	**7.7%**	**7.8%**	**0.7%**	**0.2%**	**0.3%**	**1.5%**	**1.6%**	**1.0%**	**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 required 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.

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 damages such as crossbores and leaves customer sewers lines intact. Sewer locating services are contracted to third-party vendors for this work and were primarily performed for the location of sewer mains at the onset of the program. .
- Increasing permitting cost – Over time, municipalities have expanded the scope of permitting requirements within jurisdictions. This includes moving to more specific permitting (by address/premise) as opposed to "blanket permitting." In addition, permitting fees are increasing in general. The detailed requirements to obtain permits are also more stringent, leading to higher costs to meet these requirements.
- 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.

- Crossbore 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 crossbores, 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. Has the Company experienced new cost drivers and benefits on the EIRP Program since the filing of Case No. U-20650?

A. Yes, the Company has experienced increased costs related to the Covid-19 pandemic. On March 2, 2020, the Company's gas construction crews returned from the seasonal shutdown and began work on EIRP Program projects. During March of 2020, the Company experienced increasing numbers of positive Covid-19 cases among its employees. In response, the Company issued a stay-at-home requirement, and from March 27, 2020, through April 20, 2020, gas construction crews were in a stay home quarantine period. During this time the Company developed new work requirements (mask wearing, social distancing, hand washing/sanitizing, limit of one person per vehicle for transportation/commuting) and obtained supporting PPE that would allow for crews to return to project work. Covid-19 changes to working requirements also impacted the vendors and suppliers the Company uses to support the project work. The Company estimates that the impact related to Covid-19 added cost on the 2020 EIRP Program project work to be approximately $12.4 million. This included additional labor cost, increased support services costs, and increased costs of project allocations and overheads. In 2021, the Company has experienced similar cost impacts, as described in more detail below.

- Labor cost impacts - As a result of Covid-19, the Company has experienced a higher level of absences within our gas construction crews assigned to projects, as workers who contracted Covid-19 and those exposed on a project site are off work during a quarantine period. To complete the planned project work with the reduced labor availability, both increased overtime work by Company crews and additional support services are being used on projects. Productivity rates are also impacted differently based on the specific crew absences, as an absence by a crew member with a high level of qualification and training is more impactful to a projects production than an absence by a crew member with a lower level of qualifications and training.
- Support services cost impacts – the cost of support services provided by the contractors and vendors the Company uses for this project work is increasing for multiple reasons, including: Covid-19 impacts, availability of labor and increasing wage rates, increasing cost of materials used and higher fuel and transportation cost. These services include, but are not limited to: sewer location, hydrovac, traffic control, aggregates supply, restoration services, project site security, and porta johns.
- Material cost impacts - The cost of materials purchased for this project work, including pipe, valves, tees, meters, and other materials is increasing as manufacturers of these materials are increasing their prices. Manufacturers are also being impacted similar to the support services contractors and vendor's the

Company uses, including: Covid-19 impacts, availability of labor and increasing wage rates, increasing cost of materials used and higher fuel and transportation cost. Lead times on materials ordered have also increased significantly going from many materials being available in 3-4 weeks historically, to now taking 4-6 months for delivery from the order date for the same materials.

- Project allocations and overhead cost impacts – project allocations and overheads include cost related to fleet and equipment, project survey cost and certain restoration cost, materials costs for items not purchased in advance and that are purchased as needed during project construction, cost of crew mobilization and travel expenses, cost of project engineering and services, administrative and general cost and other corporate overhead cost. These cost allocations and overheads have also been affected by Covid-19 impacts, availability of labor and increasing wage rates, increasing cost of equipment and services used and higher fuel and transportation costs.
- Cost reduction benefits – through implementation of the grid approach the Company is also working on certain cost reduction opportunities. This includes increased production rates for pipe installation, resulting in less total labor hours required by gas construction crews to complete installation of the planned main distribution pipe for a project compared to the segment approach. In addition, with fewer and larger project locations, there is less time and cost for project mobilization and demobilization to move people and equipment compared to the segment approach. The Company was also able to reach agreement with

the City of Saginaw, on the two 2021 grid projects located in Saginaw, to use a process for road restoration known as "key holing." This process uses equipment to bore an 18" or 24" diameter area in the road and remove a core section. The exposed hole is then excavated to work on a gas main and service. Once the work is completed the hole is filled and the core section re-inserted and glued in place. The result provides a seamless and strong repair. This process is much faster and less costly than the traditional approach of cutting square sections from a road to expose the main and service, then excavating the hole, backfilling with aggregate and soil once the work is completed, and then restoring the cut section with new cement or asphalt. The estimated cost reduction from use of key holing on the two 2021 Saginaw grid projects compared to the traditional approach is approximately $2.5 million. This is from reduced restoration cost and reduced traffic control cost, given the faster speed of key holing allowing for shorter time periods for needed road closure and traffic control measures. It is important to note that key holing requires advance approval by local permitting agencies, and not all areas allow for use of this approach. In addition, key holing is not possible in all areas, as roads in poor condition do not provide the strength or stability to bore and obtain a strong core that can be re-inserted. The Company plans to continue pursuing the use of key holing in the future, where possible.

Q. What cost per mile is the Company currently projecting for the EIRP Program grid approach projects?

A. For 2021, 2022 and 2023, the Company is currently projecting per mile cost of pipe installed for grid projects of $1.294 million, $1.155 million, and $1.173 million respectively. The 2021 projects are still experiencing impacts due to Covid-19 as explained above for 2020 projects. The projected cost is based on project scope and schedule information for 2021, 2022 and 2023.

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 also is replacing high pressure steel pipe and TOD pipe as part of the EIRP, and that work is planned as segment projects. For the test year of October 1, 2022, through September 30, 2023, a significant amount of the planned project work to completed by the EIRP will be using the grid project approach and that is the basis for the Company's current test year cost projection. The need to have more segment projects and related costs will be presented in future rate cases. The maps in Figures 1 and 2 below show the Company's vintage main distribution pipe areas of concentration as shaded blue squares, and outlines areas where 2021-2025 project work is currently planned.

Figure 1: State Level Map View:

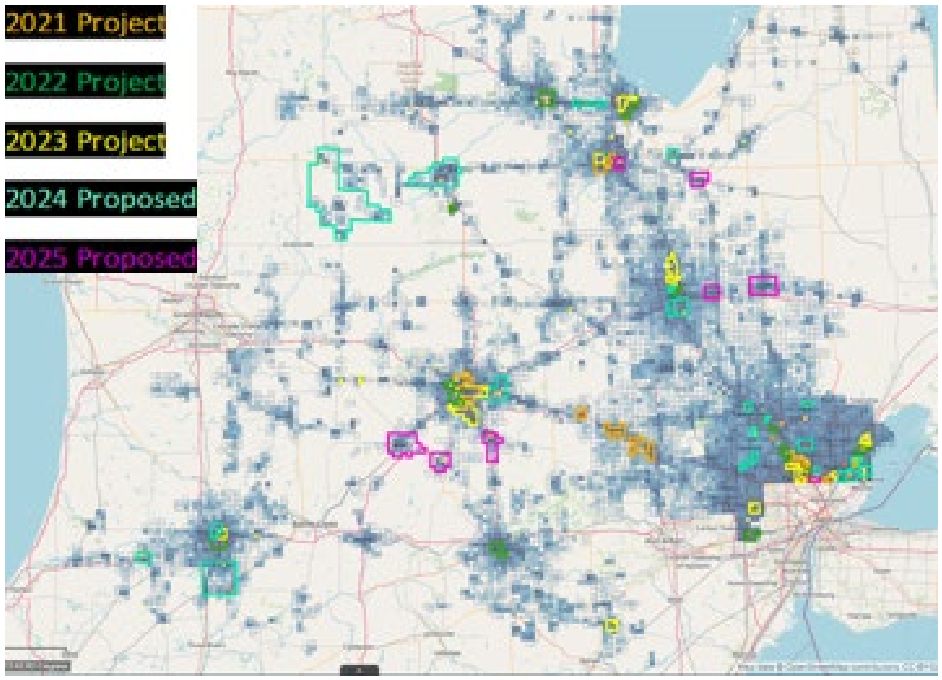
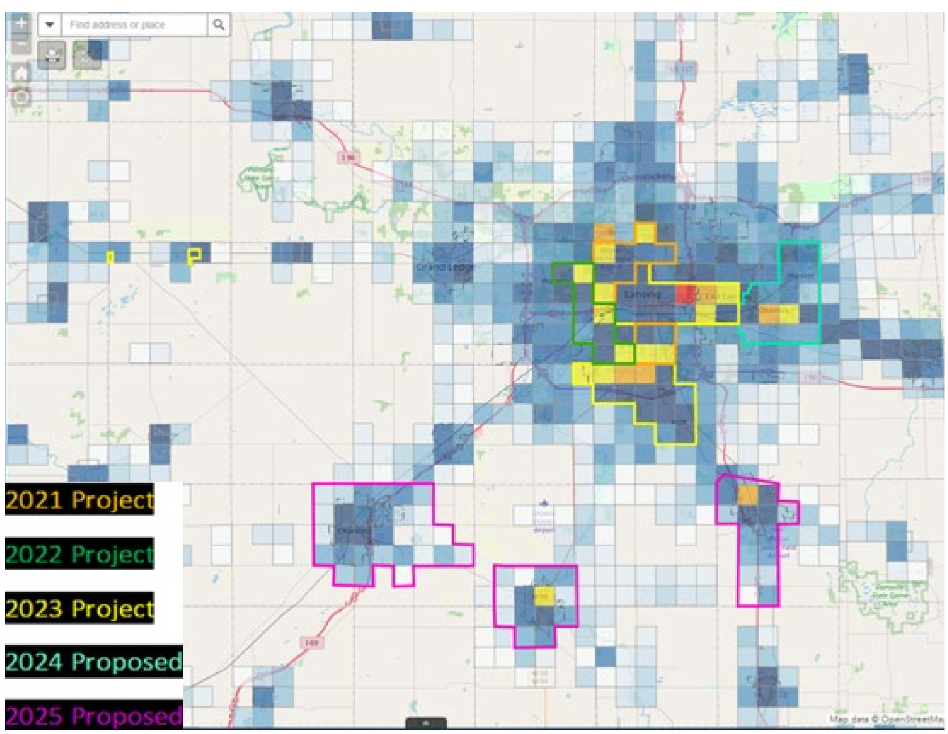


Figure 2: Local Level Map View (Lansing, MI area):



Q. Is the Company planning to complete other project work in addition to the grid projects within the EIRP Program?

A. Yes, The Company is also planning to complete high pressure steel and TOD steel pipe project work in 2021, 2022, and 2023. In 2021, this includes 6.7 miles of TOD steel pipe replacement with a projected cost of $21.3 million. In 2022, this includes 1.1 miles of high-pressure steel segment project work with a projected cost of $4.4 million. In 2023 this includes 4.7 miles of TOD and 4.1 miles of high-pressure steel segment project work with a projected cost of $40.6 million.

Q. What is the Company's projected EIRP cost for the projected test year?

A. The Company's projected spending for EIRP in the test year is $332.6 million. This spending amount is reasonable because of the increased scope of work to be completed in the test year compared to 2020 and 2021. As shown below in Table 24, the test year projects 260 installed miles compared to 71 and 155 miles in 2020 and 2021 respectively. The projected miles in the test year represent a 266% increase from the historical year installed miles.

Q. How many miles of distribution main and associated services does the Company plan to replace for the $332.6 million investment for the test year?

A. The Company prepares its estimates and projections based on calendar years running from January 1 through December 31. For the test year of October 1, 2022, through September 30, 2023, the Company combined a prorated projection for three months of 2022 and a prorated projection for the nine months of 2023. The computation of the test year projection is based on a proration of 25% (3/12th's) of the 2022 projection and 75% (9/12th's) of the 2023 projection.

- The Company's projection for the calendar year 2022 includes 186.6 miles of main installation and 18,776 associated services. This includes 1.1 miles of high-pressure steel pipe installation, 2 distribution pipe segment projects for 4.5 miles and 261 services, and 9 grid projects for 181.0 miles and 18,515 services.
- The Company's projection for the calendar year 2023 includes 284.4 miles of main installation and 26,660 associated services. This includes 8.8 miles of high-pressure steel pipe installation and 12 grid projects for 275.6 miles and 26,642 associated services.
- 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 260.0 miles of main installation and 24,689 associated services.
- Table 24 below provides a summary for the years 2020-2023 and the test year.

Table 24: EIRP 2020-2023 Scope and Cost

	Actual	**Projected**	**Projected**	**Projected**	**Projected**	**Projected**
Year	**2020**	**2021**	**2022**	**2023**	**9 months of 2022**	**Test Year 10/1/22 - 9/30/23**
Installed Pipe (Miles) [1]	**71.2**	**154.7**	**186.6**	**284.4**	**140.0**	**260.0**
Service Counts [1]	**8,556**	**13,991**	**18,776**	**26,660**	**14,082**	**24,689**
Capital Cost ($Millions) [2]	**$118.6**	**$179.5**	**$223.1**	**$368.0**	**$168.6**	**$332.6**

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 explain the increase in EIRP projected mileage in the test year?

A. The Company is projecting to increase installed miles for EIRP in the test year to 260 miles from 71 miles in the historic year. As shown in Table 24 above, EIRP has projected increases in mileage each year. The increase is reasonable for customer safety and reliability. Cast iron, wrought iron, and bare steel pipelines are among the oldest in the distribution system. Many of these pipelines were installed over 80 years ago and still deliver natural gas to customers today. The age and material of the pipelines makes them susceptible to corrosion and cracking due to the degradation of the iron alloys (i.e. pipes rust and get brittle with age). Given the pipeline incidents that have occurred around the country and the strong pipeline safety measures included in the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, it is necessary to accelerate investments in the Company's Distribution Integrity Management Program. An EIRP completion target of 2030 would reduce risk and help ensure the safety of customers and the public. To complete the remaining projected 2400 installed miles in EIRP by 2030 will require a yearly average installation of 270 miles. The projected installed miles will continue to ramp up until 2025 and then begin to ramp down as the EIRP nears completion in 2030. The projected EIRP retired miles per year can be found in Figure 35 of the NGDP.

Q. Please highlight the customer benefits of accelerating the vintage main distribution pipe and services replacement and using the grid project approach.

- Expected customer benefits of accelerating the EIRP using the grid approach include: Less disruption to customer property from reduced project mobilization and demobilization to the same or nearby locations

- Improved local coordination with municipalities to better align the timing of planned project work with public works projects
- Improved customer safety and reliability by more rapidly eliminating the higher-risk vintage main pipe and services from the system
- Improved system efficiency due to higher operating pressure and reduction of standard pressure on the system
- Lower gas losses and reduced emissions into the atmosphere
- Reduced O&M costs as described in the annually submitted EIRP performance reports
- Reduced risk of long-term cost inflation by completing the program work in a shorter time

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. 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, 2020, the Company has replaced 449 miles of high-risk distribution pipe through the EIRP, including 180 miles of cast iron and nearly 59,300 services replaced and retired through 2020 to improve reliability and customer safety.

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) Leak Mitigation (i.e., main or service replacements due to active gas main leaks or temporary leak 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);

(v) Projects based on operational improvements which may not be represented effectively in risk model results (and therefore are not EIRP projects); and

(vi) Customer meter stand replacements due to corrosion or obsolescence.

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 was $36,892,000 in 2020 and are projected to be $56,930,000; $24,963,000; and $36,398,000 for the years 2021; the nine months ending September 30, 2022; and the test year 12 months ending September 30, 2023. The costs for the Material Condition Non-Modeled Program are set forth on Exhibit A-122 (KAP-7), line 2, and are further detailed later in this direct testimony.

Q. What is the impact of the NGDP on the Material Condition Non-Modeled Program?

A. The acceleration of main replacement, as discussed in the NGDP, will have a significant impact on the Material Condition Non-Modeled Program, allowing the expenditures in this program to be reduced over time. However, the reduction in Material Condition Non-Modeled Program expenditures will take time as it is contingent on the accelerated replacement of main. Additionally, the objectives outlined in the NGDP will have moved the Company toward finalizing EIRP project areas earlier to complete design and align with affected municipalities and stakeholders. While this is beneficial overall, and will positively impact the Company's EIRP, it will reduce the number of projects selected by subject matter experts to deal with emergent issues on the system. Therefore, the Company is predicting an increase in Material Condition Non-Modeled for the early years of NGDP work, and then a decrease as the number of vintage mains and services are reduced through this accelerated replacement.

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 the 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.

As described above in the Regulatory Compliance Program, the Company is nearing completion of its program to ensure the cast iron and surrounding standard pressure systems operate at 14" water column or less. Standard pressure, also known as utilization pressure, systems do not have regulators at each meter, 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. This was a significant factor in the recent Merrimack Valley and Washington, PA incidents. There are several areas of the state where there are very few miles of cast iron main remaining. Replacing these small sections allows the operating pressure in that entire area to be increased, providing more reliable gas service to the customers in that area. 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 2019, the Company completed replacement of the entire cast iron system and eliminated standard pressure in the City of Ionia and the City of Saint Johns. In 2021, the Company plans to eliminate the standard pressure system in Mount Clemens and begin the phased replacement of the Pontiac standard pressure system.

Q. Please describe the two large standard pressure replacement projects in the Material Condition Non-Modeled Program for 2021.

A. The Company is undertaking two large standard pressure replacement projects in 2021**.** One of these projects is located within the City of Mount Clemens. Here, there is a total of 10.5 miles of standard pressure, of which 2.61 miles are cast iron installed between 1928 and 1952. While this pipe has some leak history and is definitely of a vintage worthy of replacement, it has not yet emerged on the distribution risk model ranking to become an EIRP project. Eliminating this standard pressure system will ensure a higher level of reliability for the customers in the area. During the coldest portions of the 2019 winter, the Company's crews spent a full week dealing with customer interruptions on this system due to low pressures. Replacing the cast iron and upgrading the system to tie in with the rest of the medium pressure network will eliminate these problems, resulting in increased reliability for customers, which is especially beneficial since these issues typically occur on the coldest days of the year. This also offers operational advantages to the Company of not having to stock fittings for standard pressure repairs or cast iron work, as well as not having to respond to the emergent work requests associated with these customer outages. The 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.

The second large standard pressure project is in the City of Pontiac. Here, there have been an increasing number of leaks and maintenance issues on the standard pressure system. This resulted in an emergent replacement project in 2019 – Project #17045: Portland Street - to replace approximately 1300' of cast iron main with plastic. This replacement was required because the condition of the gas main was so poor that repair was not feasible. Even with this replacement, the Company continues to be called out to respond to emergencies in this area. There are approximately 50 miles of standard pressure remaining in Pontiac, of which 30 miles are cast iron. The Company is currently replacing the first phase of this system in 2021, which consists of approximately six miles of cast iron main replacement and a total of 10 miles of the standard pressure system replaced. Phase I will also establish header mains that set the stage for the next phase of cast iron replacement. Additionally, this project will replace approximately 150 gas meters that are currently inside of customer homes and businesses with outside meters. Eliminating this standard pressure area through the Material Condition Non-Modeled Program will improve customer safety and alleviate the need for the continuous maintenance that has occurred in this area in recent history. 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. Yes, the Company has a small standard pressure system in the City of Plymouth. In Plymouth, there's just under a mile of cast iron remaining, and only about 1.25 miles of standard pressure total. The Company intends to replace this in 2023. Eliminating this system will have similar customer benefits as described for Pontiac and Mount Clemens in the earlier paragraphs of this testimony, namely improved reliability by eliminating sources of leaks and water infiltration and regulated meters at homes and businesses to protect against over pressure events.

Q. Please describe the Line 1008 and Line 1010 projects in the Material Condition Non-Modeled Program?

A. The Company plans to replace sections of Line 1008 and Line 1010 which will remove them from the Transmission Integrity Management Program ("TIMP") cycle. In 2022, 800' of 12" S-HP > 20% SMYS main will be replaced on Line 1008. The Company is replacing the pipeline rather than inspecting it with Direct Assessment due to the location. The area to be inspected is located under the Clinton River so it would cost more to dam the river or perform an inline inspection, than to replace the section of pipe. The projected cost to perform an inline inspection is $895,300. Although this is slightly less in cost than replacement, the pipe would have to be re-assessed every six years since this pipeline will continue to be > 20% SMYS. The projected cost to replace the pipeline is $988,400. The new section will not be > 20% SMYS main so it will not need to be inspected every six years.

Additionally, between 2021 and 2026, various segments of Line 1010, a line that was purchased from another utility, will be replaced or retired due to incomplete documentation of the MAOP. The various projects will retire approximately 79,000 feet of existing main. The Company plans to install approximately 21,200' of new 8" S-HP main. The Company will also convert three services from high pressure to medium pressure. The Company will also install a 200' bypass near the Coolidge City Gate.

Q. Please describe the expenditures within the Material Condition Non-Modeled Program for Commercial/Industrial Meters.

A. The Material Condition Non-Modeled Program also 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 for 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. In 2020, the Company completed six of these replacements, there are eight replacements in 2021, and the projection is to replace seven stands in 2022 and eight additional in 2023.

Q. Can you explain the purpose of the Material Condition Renewals Program?

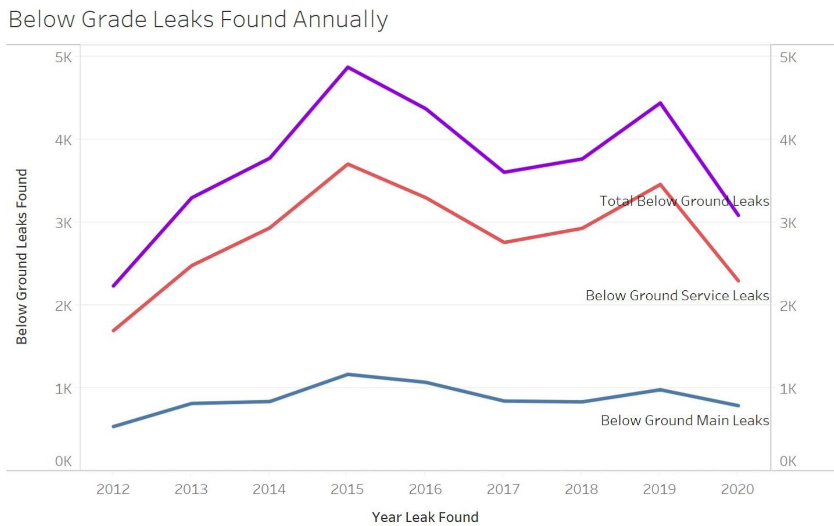
A. The Material Condition Renewals Program expenditures are part of a Company initiative to reduce actionable leaks through full-service replacement versus repair or reclassification of leaks. The distinction between the Material Condition Non-Modeled Program and the

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 database, and are directly related to active gas leaks on gas main and/or services. The capital expenditures for the Material Condition Renewals Program was $36,093,000 in 2020 and are projected to be $24,484,000; $31,236,000; and $38,242,000 for the years 2021; the nine months ending September 30, 2022; and the test year 12 months ending September 30, 2023. The historical and projected expenditures are detailed on Exhibit A-122 (KAP-7), line 3.

Q. Can you please explain the expenditures in the Material Condition Renewals Program?

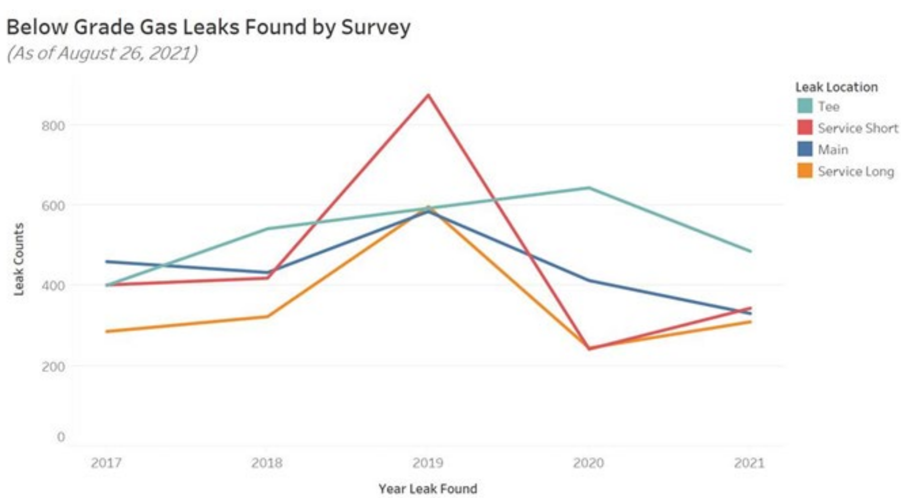
A. The Company has focused on many initiatives to reduce actionable leaks over the past few years. The graph below shows the below-grade leaks found from 2012 - 2020. While the Company did experience an uptick in leaks in 2018 and 2019, overall, Figure 3 demonstrates a general downward trend for below-grade leaks from the peak year in 2015.

Figure 3: Below Grade Leaks Found 2012 - 2020



The majority of new leaks are found during Leak Survey. Figure 4 below shows the breakdown of below grade leaks found on survey by location. The leak survey program is not yet completed for the year, so these counts could change as the program finishes for the year.

Figure 4: Below Grade Leaks Found by Survey

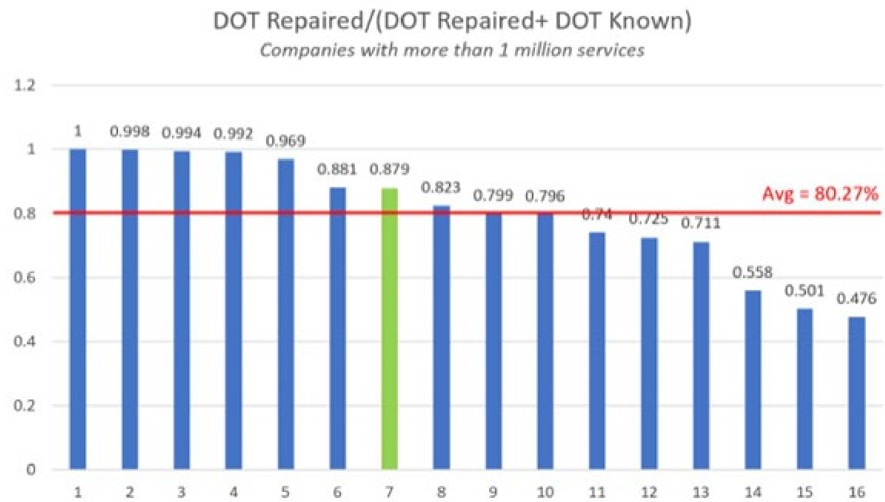


This demonstrates there is more work to be done on vintage facility replacement before a long-term, sustainable reduction in leaks is observed. As shown in Figure 5, the Company has also observed an increase in the number of leaks found by annual survey. In 2017, 6,775 leaks were found, compared to 9,646 in 2018, and 21,083 in 2019. 2020 was similar to 2018 with 10,913 leaks found during survey. 2021 is trending slightly higher than 2020. The increase of leaks found drives increased required main and service replacements.

Figure 5: Total Number of Leaks Found During Leak Survey

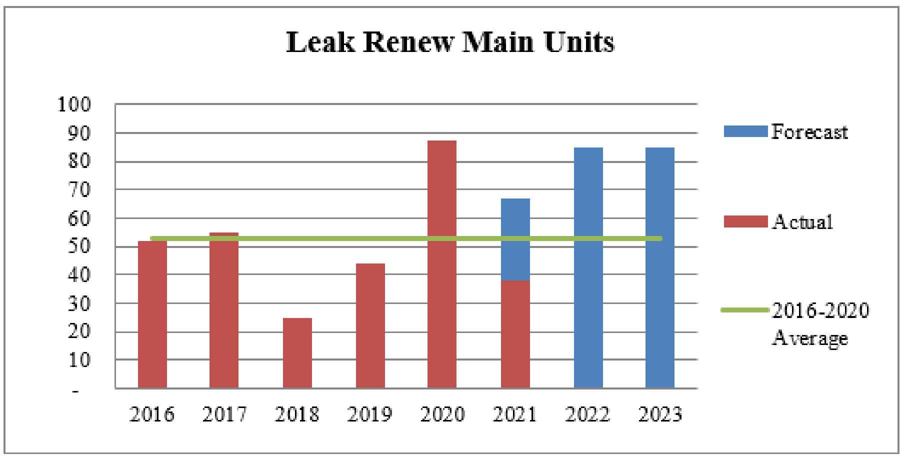
Additionally, Figure 6 below depicts a comparison of the percentage of leaks repaired for similarly sized gas companies - those with more than 1 million customers - and is based on the annual Federal DOT report information. This graph depicts the ratio of leaks repaired to the sum of leaks repaired and open leaks at year end for companies with vintage main as part of their system.

Figure 6: Industry Comparison of Leaks Repaired to Total Leaks



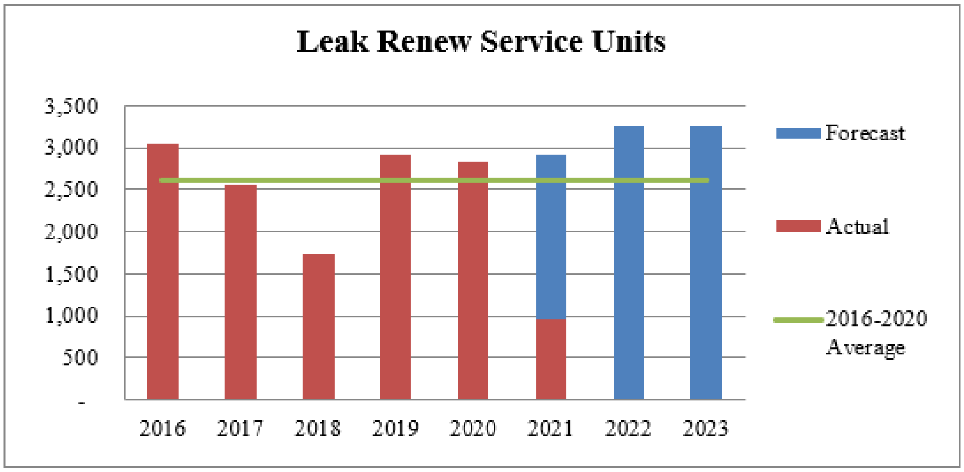
Consumers Energy is depicted in green (column 7) and was at 87.9% as of April 2021, which is above industry average. The Company seeks to improve in its leak reduction efforts in order to continue to ensure a safe and reliable gas system. One action to drive down the leak trend is to replace leaking metallic services and mains rather than repair them, which avoids the potential for future leaks on that same service or main. The Material Condition Renewals Program reflects an increase in expenditure to accomplish a significant number of replacements over the next two years. This replacement work will reduce the number of leaks being managed by the Company at any given point in time, as well as eliminate the possibility for a return trip to repair a service or main that has already leaked (at least) once in the past. The additional leak replacements planned for 2022 and 2023 will help the Company permanently replace a greater portion of the leaks and not continue to manage a list of open leaks. By reducing the number of open below- and above-grade leaks being tracked on the Company's gas system, the Company can enhance public safety and increase the integrity of its natural gas system. Figures 7, 8, and 9 below demonstrate the historical and projected unit counts for gas main, service and meter stand replacements under the Material Condition Renewals Program. It is important to note that the renewal units are showing a shift from meter stand replacements to main replacements. The Reasonable Expectancies for gas main replacement hours is much higher than that of gas meter stand replacements. As a result, despite declining unit counts in some of the other parts of the program, the costs associated to renew main leaks is driving up the total cost of the program.

Figure 7: Gas Main Renewal Projects



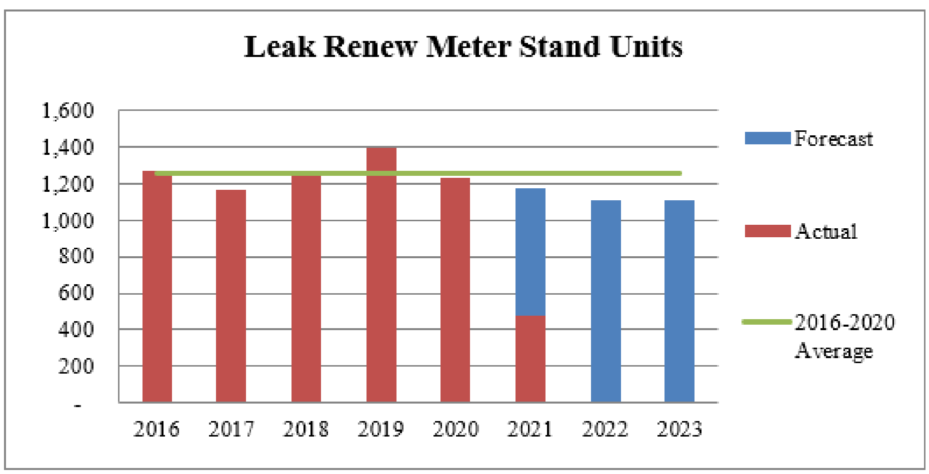
Leak Renew Main	2016	2017	2018	2019	2020	2021	2022	2023
Actual	52	55	25	44	87	38		
Forecast						29	85	85

Figure 8: Gas Service Renewal Projects



Leak Renew Service	2016	2017	2018	2019	2020	2021	2022	2023
Actual	3,043	2,571	1,740	2,918	2,824	968		
Forecast						1,945	3,257	3,257

Figure 9: Gas Meter Stand Renewal Projects



Leak Renew Mtr/Stand	2016	2017	2018	2019	2020	2021	2022	2023
Actual	1,274	1,163	1,246	1,393	1,231	476		
Forecast						701	1,107	1,107

This program also contains funding to replace obsolete Regulated Meter meter stands. As described earlier in this testimony in the Regulatory Compliance Meters Program, the Company received notification in 2020 that our sole sourced Regulated Meter residential gas meter was being discontinued. This meter style is the most prevalent meter on our gas system. As the Company's remaining Regulated Meter inventory reduces, meter stand replacements will be necessary to covert Regulated Meter meters stands to an industry standard meter stand with a temperature compensated top connect gas meter and separate pressure regulator. As described in Section IV, subsection D, part 7 of the NGDP, the two meter types have different connection methods which require an Regulated Meter meter stand to be rebuilt to accept a top connect meter. To meet meter exchange requirements and reduce extended customer outage risks related to emergent meter exchanges the Company will begin to convert meter stands starting in 2021. The projected cost of $7.7 million includes 10,000 units of single meter stand rebuilds at $3.36 million and 2,500 units of multiple meter set rebuilds at $3.36 million.

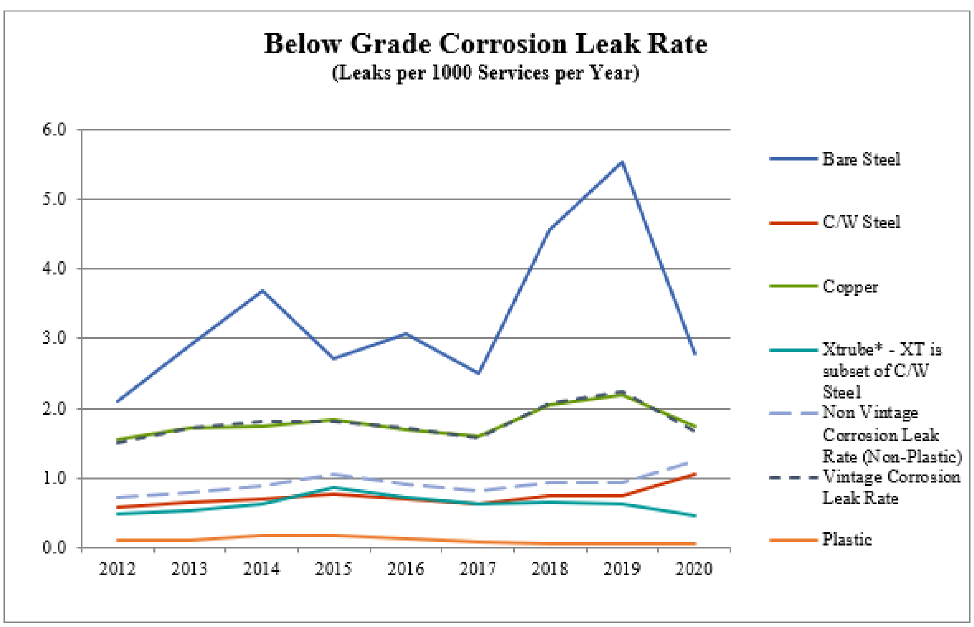
Q. What impact does the NGDP have on the Material Condition Renewals Program?

A. As outlined directly above, the Company is aggressively targeting the replacement of leaking facilities through the Material Condition Renewals Program. The Company believes that 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 when that area is prioritized under the grid approach. 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 of 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 of these service pipe types not replaced under the EIRP Distribution, Material Condition Renewals, Material Condition Non-Modeled, Compliance Base Distribution, and Asset Relocation programs. These vintage service materials have a higher corrosion leak rate than current materials. Figure 10 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 10: Below Grade Corrosion Leak Rate



Q. How does the Company determine the order in which services will be replaced?

A. The Company examines the leak rate of each distribution service material in order to prioritize replacement in accordance with the Company's Distribution Integrity Management Program. The data reveals that certain soil types lead to more corrosion leaks than other soil types on these vintage materials. There are many ways to define soil types, but the combination of factors most relevant to corrosion are soil corrosiveness factors, soil drainage, and the amount of frost action in that soil. Combining these three factors with material, age, and leak history yields additional insight into prioritization of VSRs.

Copper services make up approximately 88% of all vintage services and therefore are the largest drivers of leak data and risk ranking results. Reviewing leak history demonstrates that the average age of a copper service when it first develops a leak is 37 years. The average age of all non-leaking copper services is approximately 53 years, or 16 years beyond the average first-leak age. Examining the soil data mentioned above yields four soils where the combination of corrosiveness, drainage, and frost action, plus age of service, create the greatest risk for future leaks. Additionally, any vintage services connected to mains eligible for EIRP replacement will be skipped and eliminated when the gas main is replaced, which is the most efficient way to manage those services.

Q. Will the implementation of the grid approach for prioritizing EIRP work impact the selection process for vintage services?

A. The grid approach will include the replacement of all vintage services within the grid as well, allowing the Company to gain efficiency in the field. This approach will enable the Company to eliminate all vintage distribution facilities in a given area in one trip, which will also improve customer and municipal relationships. However, not all vintage services fall within a grid where there is vintage main, and thus the Company will still require a risk-based selection process to prioritize these services.

For 2021, the Company plans to replace at least 10,250 total vintage services. These services will be selected in the following manner:

- The Company will increase the number of miles completed in the EIRP, and therefore expects to achieve approximately 5,000 vintage services through replacing services associated with gas main replacement and other program work in 2021. The costs of these VSRs will be charged to each of these individual programs.
- Using the grid approach, the Company will also proactively replace vintage services within the grids targeted by the EIRP that are not connected to a vintage main pipeline. These grids will be selected for replacement based on the risk associated with the gas main in that grid, but once a grid is selected, all vintage facilities in that grid will be replaced. For 2021, the Company expects the selected grids to contain approximately 1,050 proactive vintage services. As these services are not connected to a vintage main, the costs for these VSRs will be charged to the VSR Program.
- For 2021, there are a total of 4,510 vintage services that do not fall within an EIRP grid, and therefore would not be prioritized in the grid approach. The costs for these VSRs will be charged to the VSR Program.

To achieve the annual replacement amount of 10,250 and to complete the program by 2030 as outlined in the NGDP, the Company will also need to proactively replace VSRs that are outside of the vintage main grids. As shown in Figure 10 above, bare steel and copper services have the highest leak rates per 1000 services. This figure also shows the vintage corrosion leak rate is higher than the non-vintage leak rate. Vintage materials are susceptible to corrosion which can lead to cracking and fluid infiltration. The fluid can migrate from the service into customer meters causing a gas interruption. This can cause risk to customers during the heating season. Eliminating the vintage materials will provide a safer and more reliable service to customers. The Company will utilize an engineering analysis to prioritize these proactive service replacements. The analysis will be performed annually and will consider soil conditions, pipe material and vintage, and leak history plus any additional factors the Company identifies that contribute to vintage service leaks. This analysis will be refreshed annually as part of the proactive VSR planning process. The Company continues to examine the leak rate of each distribution service material in order to prioritize replacement in accordance with the Company's Distribution Integrity Management Program. As discussed, the data reveals that certain soil types lead to more corrosion leaks than other soil types on these vintage materials. Combining soil type consideration with material, age, and leak history yields additional insight into prioritization of VSRs.

Q. How many services will be replaced under the VSR Program?

A. As of year-end 2020, there are approximately 135,000 vintage services remaining on the Consumers Energy gas system. The Company's VSR Program included the replacement of 5,456 proactive vintage services in 2020. Table 25 below outlines the vintage services replacement projections for 2021, 2022, and 2023.

Table 25: Vintage Services Projected Replacements

Year	VSR Program	EIRP/ Other Programs	Total Vintage Services Replaced
2021	5,250	5,000	10,250
2022	4,100	7,400	11,500
2023	5,000	8,000	13,000

The Company will continue to replace vintage services as part of EIRP Distribution, Material Condition Renewals, Material Condition Non-Modeled, Compliance Base Distribution, 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 general 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 Distribution Integrity Management Program plan, and per that plan, will be monitored regularly for effectiveness.

As shown in Exhibit A-122 (KAP-7), line 4, the historical VSR Program expenditures were $42,818,000 for the year 2020 and are projected to be $36,591,000 in 2021, $19,065,000 for the nine months ending September 30, 2020, and $30,550,000 in the 12 months ending September 30, 2021.

The projected costs are based on an estimated unit cost per VSR of $6,970 for 2021, $6,131 for 2022, and $6,455 for 2023. The 2020 actual unit cost per VSR was $7,848.

Table 26: Vintage Services Projected Unit Costs

Year	Actual 2020	Projected 2021	Projected 2022	Projected 2023
Unit Cost	$ 7,848	$ 6,970	$ 6,131	$ 6,455

During 2020, the Company experienced 9% increased costs related to the Covid-19 pandemic. This impacted the unit cost for the VSR Program. The Company developed new work requirements (mask wearing, social distancing, hand washing/sanitizing, limit of one person per vehicle for transportation/commuting) and obtained supporting personal protective equipment that would allow for crews to return to project work. Covid-19 changes to working requirements also impacted the vendors and suppliers the Company uses to support the project work. This increased labor hours and cost, increased support services costs, and increased costs of project allocations and overheads.

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 that have the potential for increased leak rates, the Company is reducing the future methane emissions into the atmosphere. Consumers Energy is one of nearly 40 natural gas providers from across the country in the United States Environmental Protection Agency's Natural Gas STAR Methane Challenge Program, intended to reduce methane (a greenhouse gas) emissions. The Company's commitment for this program is to reduce cast iron and unprotected steel distribution mains at a minimum rate of 3% per year by 2021, and to maintain that rate for at least 5 years. This is primarily accomplished through the Material Condition, Asset Relocation, and Regulatory Compliance programs. In addition to a safer, more reliable gas distribution system, these programs also contribute to a cleaner, more sustainable planet.

5. **Capacity/Deliverability**

Q. Please describe the capital expenditures relating to the Distribution Capacity and Deliverability Program as shown on Exhibit A-12 (KAP-3), Schedule B-5.9, line 5.

A. As shown on Exhibit A-12 (KAP-3), Schedule B-5.9, the capital expenditures the Company experienced in 2020, and is projecting for the years 2021, the nine months ending September 30, 2022, and the test year ending September 30, 2023, are $3,599,000; $9,959,000; $5,390,000; and $7,316,000; as set forth on this exhibit on line 5, column (b); line 5, column (c); line 5, column (d); and line 5, column (f), respectively. The expenditures in the Capacity/Deliverability Program are also shown in Table 27 below:

Table 27: Capacity/Deliverability Capital Expenditures

($000)	(a)	(b)	(c)	(d)	(e)	(f)
		Capacity/Deliverability Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line		12 Mos Ended	12 Mos Ending	9 Mos Ending	21 Mos Ending	12 mos. Ending
No.	Program Description	12/31/2020	12/31/2021	9/30/2022	9/30/2022	9/30/2023
1	Augment	3,599	9,959	5,390	15,349	7,316
2	Total Capacity/Deliverability Capital	3,599	9,959	5,390	15,349	7,316

Exhibit A-123 (KAP-8) 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 AFB. The Company also continued the augmentation of the medium pressure system in Caledonia in 2020. 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. Can you describe the Augment investments included in this filing?

A. The largest project for 2020 was the Caledonia MP Augment Project with a total cost of $1.7 million. 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 is the largest project for 2021. It involves replacement of undersized HP pipe with properly sized main allowing for the station to supply adequate amounts of gas to the local Macomb area with a projected cost of approximately $4 million. There are three large HP projects for 2022/2023 to reduce bottlenecks on the system. These are intended to provide capacity and resiliency outside the Galesburg, Climax, and Coleman-Beaverton City Gate stations. These projects will result in a projected total cost of $10 million.

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.

6. <u>Gas Operations Other</u>

Q. Please describe the capital expenditures relating to the Gas Operations Other Program as shown on Exhibit A-12 (KAP-3), Schedule B-5.9, line 6.

A. The Gas Operations Other Program includes computer and related equipment, software, and tools, certain Land and Right-of-Way expenditures, Enterprise Corrective Action Program and Advanced Methane Detection. Computer equipment would include printers, plotters, and other technical equipment. Desktop and laptop computers for existing employees are not included in this program as they are purchased by the Information Technology ("IT") department. Capital 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. The Gas Operations Other

Program includes costs associated with Land and Right-of-Way specialists supporting gas distribution projects, these are shown on line 3 of Exhibit A-124 (KAP-9). Additionally, Compliance and Controls projects, namely the Enterprise Corrective Action Program and Advanced Methane Detection contained within Gas Operations Other Program are described in the direct testimony of Company witness Sarah Hollis Bowers. These are shown on line 4 of Exhibit A-124 (KAP-9). Finally, this program includes capital expenditures for the Geospatial Inventory and Modeling Program. I will further describe this program below. These are shown on line 5 of Exhibit A-124 (KAP-9). Capital expenditures in the Gas Operations Other Program that the Company experienced in 2020; and is projecting for the year 2021; the nine months ending September 30, 2022; and the test year ending September 30, 2023, are $5,583,000; $21,722,000; $7,135,000; and $19,344,000 as set forth on Exhibit A-12 (KAP-3), Schedule B-5.9 on line 6, column (b); line 6, column (c); line 6, column (d); and line 6, column (f), respectively. The Gas Operations Other capital expenditures are also shown in Table 28 below.

Table 28: Gas Operations Other Capital Expenditures

($000)	(a)	(b)	(c)	(d)	(e)	(f)
		Gas Operations Other Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line		12 Mos Ended	12 Mos Ending	9 Mos Ending	21 Mos Ending	12 mos. Ending
No.	Program Description	12/31/2020	12/31/2021	9/30/2022	9/30/2022	9/30/2023
1	Routine Computer & Equipment	1,011	75	8	83	75
2	Tools	3,574	12,262	3,719	15,981	5,935
3	Land & ROW	999	716	600	1,315	891
4	Compliance & Controls Projects	-	8,429	2,474	10,903	9,322
5	Geospatial Inventory and Modeling Prog	-	240	333	573	3,122
6	**Total Gas Operations Other Capital**	5,583	21,722	7,135	28,856	19,344

Exhibit A-124 (KAP-9) provides further details of the expenditures included in this program.

Q. Please describe the Gas Compliance Code Program - Service Information Mapping System ("GCCP – SIMS") project funding requirements within the Geospatial Inventory and Modeling Program.

A. The Gas Compliance Code Program - Service Information Mapping System ("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. The existing gas service records data has no spatial data, and the database is limited in its ability to store all required service attributes, which create inaccuracies in 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 in order to get a complete picture of the distribution network which limits our ability for data analytics, creates operational complexities, adds risk to damage prevention efforts and increases response time during safety emergencies. The existing systems utilize 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; (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 the future asset maintenance requirements including but not limited to tracking and traceability of gas distribution assets and Global Positioning System ("GPS") tracking of leak survey routes to facilities. This project will require O&M funding of $2,300,000 in the test year 12 months ending September 30, 2023. This funding will be for the migration of current gas service asset data into the gas distribution GIS. These expenses are included in Exhibit A-118 (KAP-2), page 3, line 12. This project will also require capital funding in the amount of $240,000 in 2021, $333,000 in the nine months ending September 30, 2022 and $602,000 of the $3,122,000 in the test year 12 months ending September 30, 2023. These expenditures are included in Exhibit A-124 (KAP-9), page 1, line 5. Without this support, there is increased safety risk associated with inability to provide accurate and real-time data to end users as well as more accurate data analytics to support required compliance reports.

Q. Please describe the Utility Network project funding requirements within the Geospatial Inventory and Modeling Program.

A. The Utility Network project will transform the Company's current GIS platform to the Environmental Systems Research Institute ("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 as described in the direct testimony of Company witness Watson 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. 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 understandings 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) views the up to date network in a map or schematic diagram and be able to quickly toggle back and forth between them; and (10) enables archiving and historical moments 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 of Michigan. This project will require O&M funding of $1,772,000 in the test year 12 months ending September 30, 2023. This funding will support the activities required to enable and begin the migration to the Utility Network. These expenses are included in Exhibit A-118 (KAP-2), page 3, line 12. This project will also require capital funding in the amount of $000 in 2021, $000 in the nine months ending September 30, 2022, and $2,520,000 of the $3,122,000 in the test year 12 months ending September 30, 2023. These expenditures are included in Exhibit A-124 (KAP-9), page 1, line 5.

Q. Please describe Exhibit A-125 (KAP-10).

A. Exhibit A-125 (KAP-10), 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-20650.

Q. Can you explain why columns (c), (e), and (f) of Exhibit A-125 (KAP-10) do not contain any data with the exception of the EIRP?

A. Yes, with the exception of the EIRP, the information for column (c), the "Last Rate Case Approved Spending Plan Case No. U-20650," cannot be provided because Case No. U-20650 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.

Q. Can you explain why the EIRP exceeded the test year approved expenditure from Case No. U-20650 by more than 10%?

A. Yes, the EIRP exceeded the test year 12 months ending September 30, 2021 approved expenditure from Case No. U-20650 by 11% due to increased costs related to the Covid-19 pandemic. This included additional labor cost, increased support services costs, increasing materials cost, and increased costs of project allocations and overheads. This is more fully described in the EIRP section above.

<u>IT PROJECTS</u>

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 D. Duncan Paterson includes in his 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 Mr. Paterson. The projects for the areas which I am sponsoring are described below:

- The Gas Distribution ProjectWise project requires $213,750 in capital and $24,550 in O&M in the test year. ProjectWise is a suite of project collaboration software for engineering projects currently in use at the Company by gas transmission and generation engineering teams. It is capable of bundling, managing, and handling the versions of records and documents related to designs, proposals, contract resources and record-keeping. The Gas Distribution ProjectWise project will expand the implementation of the software to gas distribution and be used to facilitate a management of change process for gas engineering design and gas system configuration changes. SharePoint and a centralized Company data store are currently used as a data warehouse for gas distribution engineering design documentation. The current solution has limited ability to meet the functionality required for managing and approving the files and drawings that are unique to engineering design work. Gaps include: (1) inability to track design edits and document design change authorization approval; (2) inability to manage multiple outage windows and potential impact of planned projects; (3) inability to track gas system configuration changes, both temporary and permanent; (4) no current standardized structure of project documents for ease of viewing/editing; and (5) no current structure for tracking as-built/final record completion. In addition, the engineering teams lack an effective tool to centralize the management of change processes for gas engineering design and gas system configuration, leading to unapproved changes to projects without proper knowledge and authorization. Without the proper controls and versioning in place, the opportunity for rework is enhanced causing extended project time for completion, negative impacts on other projects and increased costs. Completion of this project will provide value to the Company through: (1) comprehensive documentation of all design review changes from key technical Subject Matter Expert (SME) groups, ensuring that the final design is inclusive of all approved changes; (2) end to end workflow tracking and approval sign-off from initial design and engineering through field operations and final sign-off, providing for a centralized historical record that is traceable and verifiable; (3) consistent gas technical records across project and asset lifecycles; (4) increasing public and employee safety and regulatory compliance with complete and accurate records that are readily accessible and easily searchable; (5) providing visibility to and improving tracking for system outage windows and/or temporary pressure changes/reductions providing the ability to align outage schedules with distribution construction schedules; (6) tracking temporary and permanent gas distribution system configuration changes in a centralized repository; (7) maintaining spatial relationships within drawings and documents such that all documents pertinent to a geographic location can be quickly accessed and maintained; (8) providing a universal system of record for complex operating procedures; (9) creating a universal system of record for all construction prints; (10) centralizing tracking of SCADA commissioning and decommissioning activities; (11) tracking project as-built and final project record completion; and (12) providing a centralized repository for document retention, archival and version tracking, resulting in records that are traceable and retrievable. Collectively, these items support the Company's implementation of the American Petroleum Institute (API) Recommended Practice 1173 Pipeline Safety and adherence to regulatory requirements. The project provides additional value by implementing a management of change tool with capabilities that can be replicated in other organizations, including gas engineering metering and regulation, gas system integrity, and gas transmission. The scope of this project encompasses implementation of

ProjectWise software modules for use by Gas Distribution Engineering. The project will: (1) configure the software modules within the application, and (2) design and develop integrations with other Company systems. Alternatives considered include: (1) Continue with current SharePoint and shared data store warehousing solution for versioning of Gas Engineering designs and system outage windows. This alternative was not selected because it does not resolve the identified problems. (2) Develop and implement an in-house solution. This alternative was not selected due to costs and lack of expertise in developing a custom solution. (3) Implement ProjectWise software. This alternative was selected for the following reasons: (1) ProjectWise is available in a Software as a Service (SaaS) solution with out of the box capabilities, and (2) ProjectWise aligns with the Company direction as it has been implemented and is in use in other areas of the Company including Generation and Gas Transmission.

Q. Please summarize your direct testimony.

A. My direct testimony describes the Gas Engineering and Supply staffing O&M expenses and capital investment requirements 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, 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 distribution of natural gas and for other relief.	)))))	Case No. U-21148

DIRECT TESTIMONY

OF

D. DUNCAN PATERSON III

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

Q. Please state your name and business address.

A. My name is D. Duncan Paterson III, 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 14 years. Throughout this time, I have worked entirely within the Information Technology ("IT") Department and have held various individual contributor and leadership positions. Prior positions have included IT Analyst, Application Developer/Architect, Application Development Team Lead, Application Development Manager, and IT Agile Transformation Lead. As the IT Agile Transformation Lead, I was the accountable leader for the overall Agile Transformation to increase the Company's effective use of Agile delivery methods as an enabler for its Digital Three-Year Plan ("Digital Plan"). I currently lead the Application Enterprise Services organization, reporting directly to the Executive Director of the IT Enterprise Platform Services department. In this capacity, I have departmental responsibility for the delivery and operations of IT shared application and integration platforms, data and analytics capabilities, and application development services that are used to enable and support technology and business capabilities across the Company.

Q. Would you please state your educational background?

A. I earned a Bachelor of Science degree from Western Michigan University in July of 2007 with a major in Computer Science and a minor in Mathematics.

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

A. No.

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

A. The purpose of my direct testimony is to describe the IT Department's Operating and Maintenance ("O&M") expenses and capital expenditures needed to maintain and secure existing IT systems and enable new capabilities, various types of programs (e.g. investment programs, customer programs) and services for the Company's customers. My testimony will also describe how the increasing use of technology correlates to an increase in the requested recovery and how the Company's digital investments are part of a larger Digital Plan. In addition, my testimony will demonstrate why it is important to achieve full recovery of the requested expenses and expenditures and the resulting positive impact to the Company's customers.

Q. Does the purpose of your direct testimony include the Security Department?

A. No. The Security Department is represented in the direct testimony of Company witness Audra L. Cumberworth. This is different than in prior rate cases where the IT and Security Departments' expenses and expenditures were represented under a single witness's direct testimony. This change, new to this Case No. U-21148, better delineates the departments' expenses and expenditures. The IT expenses and expenditures to meet security requirements that keep the Company's technology assets and customer information secure remain in my direct testimony.

Q. What is the biggest challenge the IT Department currently faces?

A. The biggest challenge the IT Department currently faces is the ability to operate its systems and networks within the given five-year historic average O&M budget constraint of previous rate case orders while adding new capabilities to support the Company's Natural Gas Delivery Plan ("NGDP"). As discussed later in my testimony, the use of a five-year historic average to project the Company's IT Operations O&M expenses puts the Company and service to its customers at risk. The projected cost to support and maintain the capital expenditures implemented on behalf of the Company's customers, combined with increased use of cloud computing, is greater than the five-year historic average for IT Operations O&M expense. To appropriately support the assets and keep them secure, the Company needs approval of the projected IT Operations O&M expense as requested in this case, so funds do not need to be diverted from approved investments in new technology capabilities.

Q. Why is the five-year historic average for Operations O&M an ever-increasing challenge for the Company?

A. The technology landscape at Consumers Energy has grown and changed significantly over the last five years, and that change continues to accelerate with each new year. The pace of technology change is increasing, cyber security regulation is expanding as threats continue to intensify, and there is a growing dependence on technology and new digital capabilities for the Company to deliver upon the NGDP's vision of providing safe, reliable, and affordable natural gas to customers while transforming the system to deliver cleaner fuels for a decarbonized future. These factors increase the complexity of the Company's technology landscape and consequently increase the operating expense needed to maintain and operate it securely and reliably. The importance of this maintenance is reflected in what the Company has spent in 2018, 2019, and 2020, respectively, 23%, 25%, and 14% higher Operational O&M to operate its systems as compared to the prior allowed five-year historic average of Operational O&M.

Q. What is the Company requesting to help with this challenge and support new capabilities for its customers?

A. The Company is seeking full recovery of projected expenses required to maintain safe, reliable technology assets, just like it maintains safe, reliable gas assets. At the same time, the Company is also seeking full recovery for expenditures and expenses planned for new digital capabilities and foundational technology required to realize the outcomes of the NGDP, as well as those that enable residential and business programs that engage customers and adapt with their needs and behaviors.

Q. Please summarize the main portions of this testimony.

A. My direct testimony discusses the following:

- Introduction of the Digital Plan;
- The importance of digital investments and the role of IT to build and support those investments;
- Support for adequate Operational O&M expense funding, including a thorough alternative projection method analysis;
- A description of the Investments O&M and capital needed to keep the Company's systems secure, current, stable, and to support new capabilities;
- Definition and rationale for the use of Rough Order of Magnitude ("ROM") estimates;
- Individual project synopses and requests to support gas and customer business drivers as described in the Digital Plan; and

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

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

Exhibit A-126 (DDP-1)		Consumers Energy Digital Three-Year Plan for the Years 2022 – 2024;
Exhibit A-127 (DDP-2)		Summary of Actual and Projected Information Technology Operations O&M Expense for the Years 2020, 2021, 2022 and Test Year 12 Months Ending September 30, 2023;
Exhibit A-128 (DDP-3)		IT Operations O&M Alternative Analysis - Source Data for the years 2011 through 2023;
Exhibit A-129 (DDP-4)		IT Operations O&M Alternative Analysis for the years 2018 through 2023;
Exhibit A-130 (DDP-5)		Summary of Actual and Projected Information Technology Investments O&M Expense for the Years 2020, 2021, 2022 and Test Year 12 Months Ending September 30, 2023;
Exhibit A-12 (DDP-6)	Schedule B-5.10	Projected Capital Expenditures Information Technology Summary of Actual and Projected Gas and Common Capital Expenditures;
Exhibit A-131 (DDP-7)		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 2020, 2021, 2022 through 12 Months Ending September 30, 2023;

Exhibit A-132 (DDP-8)	Historical and Projected 13-Month Average of IT Cloud Computing Prepaid Balance for the years 2020 - 13-month balance ending June 30, 2021, and for the projected years 2022 - 13 months balance ending September 30, 2023;
Exhibit A-133 (DDP-9)	Asset Refresh Programs Projected Gas and Common Capital Expenditures, For the Projected Year 2022 and Test Year and For the Historical Year 2020 and Projected Year 2021;
Confidential Exhibit A-134 (DDP-10)	Application Currency Programs Projected Gas and Common Capital and O&M Expenditures, for the Projected Year 2022 and Test Year; and
Exhibit A-135 (DDP-11)	Projected Versus Actual Enhancement Capital Expenditures and O&M Expense Summary and Analysis.

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

A. Yes.

DESCRIPTION OF THE IT DEPARTMENT

Q. Please describe the purpose of the IT Department.

A. The purpose of the IT Department is to provide and maintain reliable and secure IT solutions and services that support the delivery of excellent customer experiences and other business objectives, including execution of the Company's NGDP. The Company created the Digital Plan to guide its decisions for technology investments and operations. Digital, as the Company describes it, is connecting people, "smart" things, and information (data) to create better products, services, and ways of working. The Company's evolving and pragmatic approach to digital supports:

- Adaptable delivery practices (e.g. adopting Agile frameworks and product-centric operating model);
- Widespread building and use of digital skills and practices;
- A move to cloud solutions where and when appropriate;
- Treating data as an asset and deployment of analytics on a larger scale;
- Deployment of a consistent asset management system and framework;
- Deployment of integrated control systems for system automation;
- Continuous operational improvements via automation;
- A commitment to ensure digital investments do not introduce unnecessary risk to the Company or its customers and to protect sensitive data and critical infrastructure from cyber threats; and
- Evaluating current strategic platforms to ensure they are fully leveraged/optimized, and implementing enhancements as needed to provide new functionality for emergent business and customer value.

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 through the identification, delivery, operational support, and maintenance of both on-premise and cloud software solutions and computing and communications infrastructure. Included in the scope of the IT Department is Operational Technology ("OT"). OT is the set of real-time industrial control systems that monitor and control the Company's critical gas and electric infrastructure, such as the Gas Supervisory Control and Data Acquisition ("SCADA") system. The IT Department also provides the day-to-day operational support for each individual user of 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).

Q. Why did the Company develop the Digital Plan?

A. Digital capabilities delivered, supported, and operated by IT are key enablers for the Company's business plans, including the Natural Gas Delivery Plan, and Customer offerings and engagements. The effort to develop and maintain the Digital Plan was designed to provide a clear and inclusive view of IT's plans over the next three years and how they closely align with the Company's long-term business plans that go beyond the horizon of this filing. The spend corresponding to the investment and operations of digital capabilities are largely centralized under IT for visibility, control, and optimization of a growing asset base. The Digital Plan provides the Company a mechanism to share and demonstrate the logical relationship, strong dependency, and substantial impact that digital capabilities and decisions have in the Company's business plans, capabilities, and goals. Funding requests contained within my testimony are a pathway to enable the business capabilities and to help the Company achieve the outcomes of the Digital Plan.

Q. Is the Company providing the Digital Plan in this proceeding?

A. Yes. The Company's Digital Plan is my Exhibit A-126 (DDP-1). This exhibit represents the latest revision of the Digital Plan at the time of filing, and it has been updated from the version admitted in the Company's 2021 Electric Rate Case, Case No. U-20963. The Company will continue to update, refresh, and seek input of MPSC Staff on the Digital Plan beyond the duration of this case.

Q. How does technology support the Company's NGDP?

A. 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.

Q. Why is the Company moving to cloud solutions in some cases instead of on-premise solutions?

A. The Company is moving to cloud solutions for several reasons as cloud technology is becoming an increasingly important foundation in providing the digital capabilities required to support Company's business plans, including the NGDP. Cloud solutions can offer several advantages: the ability for the Company to start using services at a small scale, and increase the use of services over time; the ability to deploy and use advanced technology that would be cost-prohibitive to deploy in the data center, such as advanced analytics and Artificial Intelligence ("AI") services; the ability to quickly scale computer power to handle occasional or peak demand such as resource intensive data modeling; the ability to scale down application environments and services when not in use to reduce costs; reduced effort in managing and maintaining underlying or base technology, including patching and upgrades; advanced security capabilities which are continuously improving; built-in capabilities to deploy technology in an always-on or highly available fashion; easier automation and maintenance of the deployment and configuration of services and applications, resulting in increased speed and quality of deployment; lower costs for disaster recovery environments until they are used; the ability to take advantage of new services as they are released; and the opportunity to optimize the number of on-premise assets that reduce the scope and capital expenditures of server and storage asset refresh programs, which is described in later Q&A. Benefits of a Hybrid Cloud approach, where public cloud is combined with the Company's private cloud, are further detailed in the Business Drivers\Technology section and Cloud sub-section of Appendix A of Exhibit A-126 (DDP-1).

In addition to the advantages of cloud, some technology vendors are shifting away from on-premise offerings and forcing companies with their products to either run their aging software on-premise without support or migrate to the cloud. The Company's technology landscape is a complex group of interconnected systems working together with many technical dependencies as described in the Company's Digital Plan, and the use of cloud solutions helps the Company keep pace with the rapidly changing digital landscape.

However, the benefits of cloud solutions often come with an increase in cost to Operations O&M for scaling and subscriptions as described later in my testimony.

Q. How has the work required to meet cyber security regulation and requirements increased recently?

A. The current and emerging cyber attack trends are evolving and the number of threats are increasing in impact and sophistication as further described in the direct testimony of Company witness Cumberworth. Examples of the increasing threat include ransomware attacks and attacks on operational technologies controlling infrastructure. Today, ransomware is one of the greatest security risks an organization faces, with a recent example being the prominent ransomware attack on the Colonial Pipeline in June of 2021. The increasing threats and impactful events have resulted in additional regulation and security requirements for the Company. Following the Colonial Pipeline ransomware attack, the Transportation Security Administration ("TSA"), which regulates Gas pipelines as part of the Department of Transportation, issued two directives that have required immediate action by gas asset owners and operators. Included in the second directive are security requirements that resulted in the IT Department shifting priority and executing significant work efforts to comply.

Other recent regulation that has been driving security requirements and the associated IT/OT work includes the American Petroleum Institute ("API") 1164 Pipeline SCADA Security Standard. This was included in the Gas security standards as of 2020, with the objectives of modernizing and standardizing the gas SCADA networks at the gas compressor stations and control rooms, mitigating cyber security vulnerabilities in the gas SCADA networks, allowing the Company to fully comply with the Gas Security Standards, and fulfilling the Company's commitment to the MPSC to provide a secure gas system to meet customer needs. Compliance with the various Gas Security Standards requires incremental IT/OT resources to both implement the required systems and technology, and maintain those systems.

As Company witness Cumberworth notes in her direct testimony, the Company is expecting additional mandatory cyber security standards for gas in the next year. The Company expects this to include further cyber security requirements that will require additional work by the IT department to achieve. As the security industry best practices evolve, new regulations are issued, and security requirements change, the IT organization 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 patches to their products. Timely security patching has become a key control for any security program, and with the recent TSA directive, the required turnaround to apply patches to IT/OT systems is significantly quicker. According to a 2019 survey of 15 similar utilities, most patch at least monthly. From 2018 through the end of 2020, the use of the Company's emergency management protocols to respond to critical patching requirements more than doubled. The need for security patches also heightens the need to keep systems current. Vendors establish an end-of-life process for products/versions they no longer support and, at some point, will no longer provide security updates or patches for earlier versions. 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 fully expects this trend to continue indefinitely as more technology assets require the appropriate level of security to protect them.

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 approved in prior and current rate cases. 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 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, and software patching. The activities associated with the fixed and variable costs are required to keep the Company's digital and information assets protected and performing at sufficient levels. The Company's customers continue to benefit from the system stability and reliability that results from the activities funded by IT Operations O&M expense. Gaps in the recovery of Operations O&M cannot be recovered in future rate case filings, which is why any disallowance is so impactful to the Company's ability to maintain and secure its systems.

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

A. There is a variety of operational work required to keep IT and information assets protected from cyber threats. First, security tools must be kept functional on all relevant technology. These include software to collect logs, scan for vulnerabilities, detect intrusions, and provide antivirus and encryption services. Second, as described previously, systems must be patched on a regular basis in accordance with security requirements. Vendors regularly release security updates that then must be tested to ensure these updates do not introduce negative impacts to Company-specific configurations, and then deployed to associated technology assets. Third, 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. The Security department publishes and maintains enterprise security standards which include the technical requirements for IT to follow. The Security department regularly updates standards to maintain the appropriate posture with the Center for Internet Security framework in which the Company subscribes, as well as compliance with cyber security related regulation that is enacted.

Q. Please describe Exhibit A-127 (DDP-2).

A. Exhibit A-127 (DDP-2) is a Summary of Actual and Projected IT Operations O&M Expense for the Years 2020, 2021, 2022 and 12 months ending September 30, 2023. Page 1 provides a summary of 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 2020 historical Operations O&M expense as $24,476,000;

- Column (c) identifies the 2021 projected Operations O&M expense as $25,340,000;
- Column (d) identifies the 2022 projected Operations O&M expense as $24,695,000;
- Column (e) identifies the 3 months ending December 31, 2022 projected Operations O&M expense as $6,154,000;
- Column (f) identifies the 9 months ending September 30, 2023 projected Operations O&M expense as $20,458,000; and
- Column (g) identifies the 12 months Test Year projected Operations O&M expense as $26,612,000; and
- Column (h) identifies the 12 months ending December 31, 2023 projected Operations O&M expense as $27,270,000; and
- "Labor" line items include employee labor, and "Contracts" line items include hardware and software licenses and maintenance, staff augmentation, the Company's managed services contract, and other contracted services.

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

- Column (a) is a description of the categorical expense;
- Column (b) provides the historical O&M expense;
- Column (c) provides the historical amount that an inflation rate or merit increase rate was applied to;
- Columns (e) and (g) provide the amounts to which an inflation rate or merit increase rate were applied for each bridge period, respectively;
- Columns (d), (f), and (h) provide the merit and inflation increases for each respective period;
- 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 indicated in Exhibit A-127 (DDP-2), page 2.

A. IT does not apply inflation in all categorical spend projections for Operations O&M expense. Merit increases are the primary method for labor projections; however, the projection is adjusted by $36,000 for anticipated increases in headcount. Inflation is not used to project any other categorical spend projections for Operations O&M expense. Future contract expenses are projected based on annual increases for current commitments for contract expenses and the addition of new contracts as a result of ongoing and new project implementations before or during the test year period. Business Expense is projected based on historical spend and known adjustments for employee training needs, wireless plans, and supplies. The other adjustments for business expenses and material include projected decreases due to efficiencies gained from a new virtual working environment and revised business practices implemented as a result of COVID-19 that are expected to continue into 2022 and 2023.

Q. Please describe the projected IT Department Operations O&M expense for 2021 and 2022.

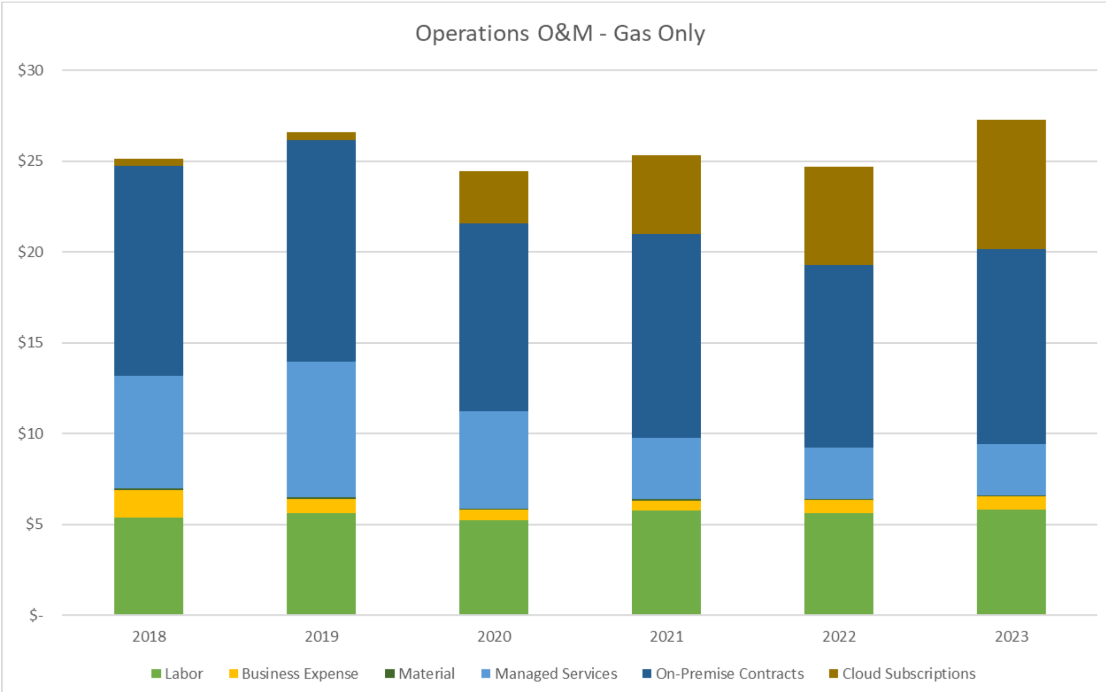
A. The Operations O&M expense in 2021 of $25,340,000 and 2022 of $24,695,000 is projected to be, respectively, 3.53% and 0.89% higher than 2020. The reason for the increase in 2021 and 2022 is continued investment in programs to sustain and improve the customer experience; to maintain, improve, and secure critical enterprise systems that support the Company's NGDP; and to prevent obsolescence and risk to business operations. Key drivers for the change from 2021 to 2022 include: (1) increase due to migration of Data Center computing to the cloud ($.4 million); (2) increase due to ransomware recovery capabilities ($.4 million); (3) increase in labor for merit increases and additional resources ($.4 million); (4) annual subscription increases related to existing cloud computing agreements ($.2 million); (5) increase for additional workplace collaboration tools and analytics ($.9 million); (6) increase for robotic process automation capabilities ($.1 million); (7) increase for value stream management capabilities ($.1 million); (8) decrease in Managed Services ($2.5 million); and (9) decrease in various license and maintenance agreements ($.3 million).

Q. Please describe the projected IT Department Operations O&M expense for 2023.

A. The Operations O&M expense in 2023 of $27,270,000 is projected to be 11.4% higher than 2022. The reason for the increase in 2023 is continued investment in programs to sustain and improve the customer experience; to maintain, improve, and secure critical enterprise systems that support the Company's NGDP; and to prevent obsolescence and risk to business operations. Key drivers for the change from 2022 to 2023 include: (1) continued migration of Data Center to the cloud ($1 million); (2) annual subscription increases related to existing subscription agreements ($.3 million); (3) increases related to existing license and maintenance agreements ($1 million); and (3) increase in labor for merit increases and additional resources ($0.2 million).

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

A. As described earlier, Operations O&M expense is made up of a number of components. As shown in the graph below, Operations O&M includes labor, business expenses, material costs, managed services support, and vendor licensing and maintenance contracts.



"Labor" includes operational and governance costs for the IT employees who perform activities such as: maintain and support capital assets; disaster recovery planning and testing; cyber security analysis and mitigation, such as security patching; and implement controls and measure performance to control IT costs and ensure compliance. These activities are variable and dependent on the outcome of risk analyses and other factors. These activities are also proportional to, and increase with, the Company's growing digital asset base.

"Business Expense" includes costs such as: employee training, wireless plans, and office supplies. These costs are variable and dependent on needs of the organization. Employee training activities center around data analytics, robotic process automation, and proliferating IT self-service across the Company through the use of low-code and no-code technology that can integrate with existing platforms.

"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.

"Managed Services" are costs to 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 Managed Services provides value by helping to control labor costs, offers up to 24/7/365 support, and provides certain types of expertise not resident at the Company.

Contracts which include "On-Premise Contracts" and "Cloud Subscriptions" are the Company's IT operations expenses that are committed in 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 further describe the make-up of "Cloud Subscriptions" within the Company's IT Operations O&M expenses.

A. "Cloud Subscriptions" contracts include costs for software, platform, and infrastructure as a service. The key items contributing to the increase in cloud subscriptions in 2021 are for: additional workplace collaboration tools and moving to higher level of licensing that provides field workers with the same collaboration tools as office workers, allowing the

Company to further automate processes and procedures with mobile access and additional analytic capabilities ($.7 million) and ransomware recovery capabilities (.4 million). There are several items contributing to the increase in cloud subscriptions in 2022, such as migration to the cloud ($0.4 million), which is described further in the Digital – Hybrid Cloud and Data Center Migration portion of my testimony; annual subscription increases related to existing cloud computing agreements ($.2 million); additional workplace collaboration tools and analytics ($.1 million); robotic process automation capabilities ($.1 million); and value stream management capabilities ($.1 million). The cloud subscriptions increase in 2023 is related to the continued migration to the cloud ($1 million) and annual subscription increases related to existing subscription agreements ($.3 million).

Q. Please describe Exhibit A-132 (DDP-8).

A. Exhibit A-132 (DDP-8) is the Historical 13-month Average of IT Cloud Computing Prepaid Balance for Gas and Common for the actual 13-month balance ending June 30, 2021, and projected 13 months ending September 30, 2023. 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-132 (DDP-8).

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. This working capital adjustment is provided by Company witness Heather L. Rayl on Exhibit A-12 (HLR-35), Schedule B-4a.

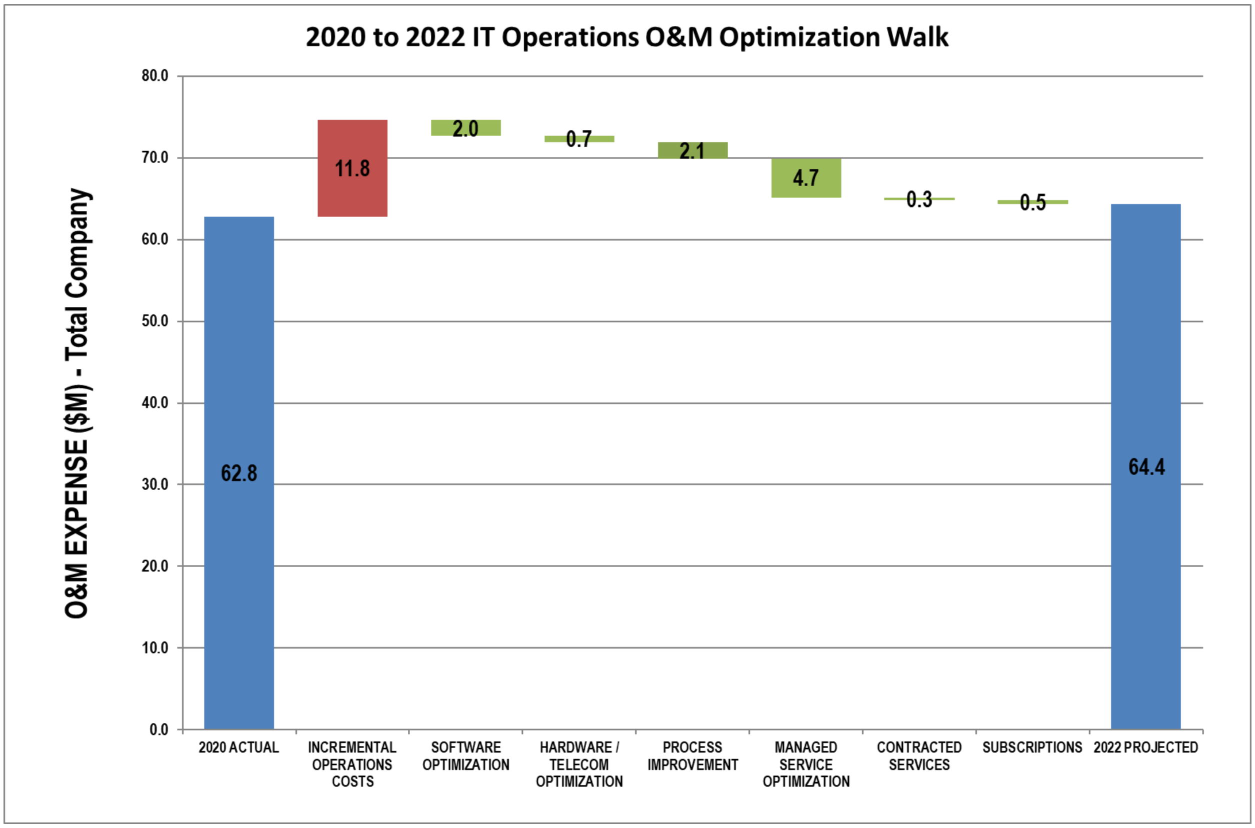
Q. Please further describe the make-up of "On-Premise Contracts" within the Company's IT Operations O&M expenses.

A. Not only do vendors and their products make up a significant portion of the Company's IT Operations O&M expenses, they are a part of all critical processes at the Company. The top 25 on-premise contracts account on average over 55% or $5.3 million in 2022 and $5.5 million in 2023 of on-premise contracts cost. These contracts are the primary contracts that support the Company's infrastructure, which is the essential foundation for all systems, including safety, emergency response, and high financial impact applications. The remaining roughly 150 on-premise contracts account for $4.1 million in 2023.

Q. How has the IT Department controlled the rate of increase in Operations O&M expenses?

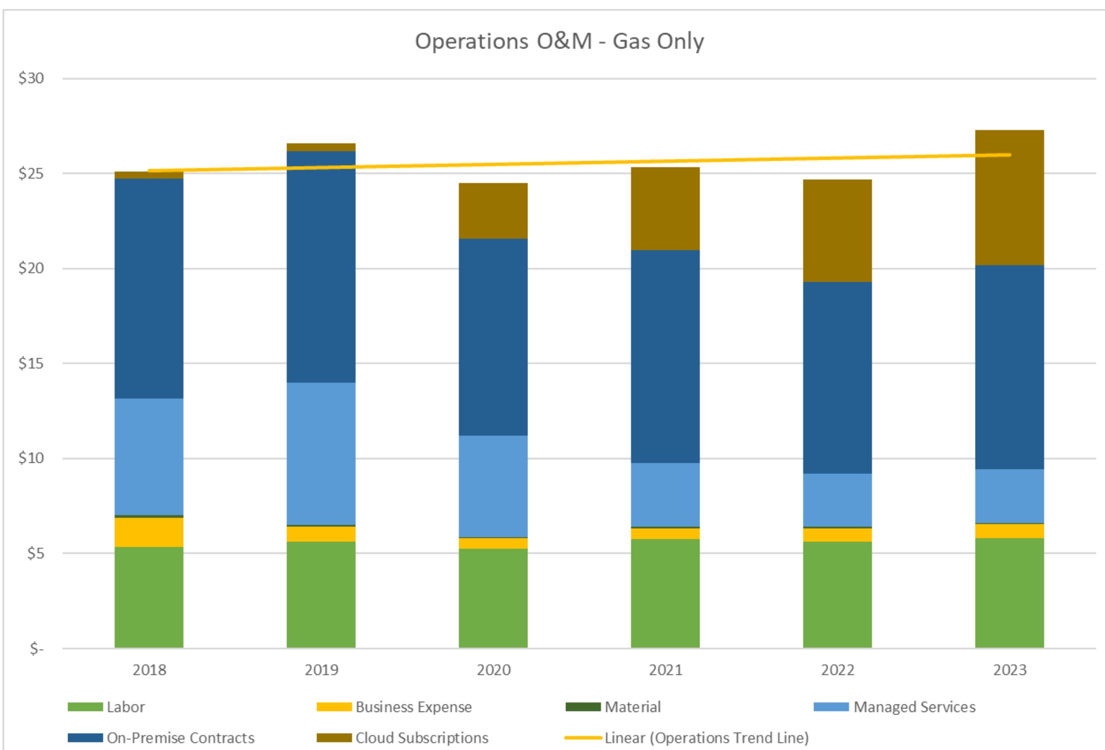
A. The IT Department continues to optimize total Operations O&M expense required to maintain the Company's technology assets. From 2017 through 2020, investments in technology would have increased the total operational costs by $19.1 million, but through continuous optimization efforts, costs only increased by $2.3 million, saving $16.8 million. In addition, as shown in the graph below, IT offset $11.8 million in projected O&M increases with an additional $10.3 million in cost reductions through 2022. The substantial work done to reduce operational costs over the last four years resulted in on-going savings.

However, the opportunities to find additional savings are decreasing and the Company does not anticipate cost optimization reductions at the same level going forward.



Q. What is the trend for the Company's IT Operations O&M expenses?

A. The Company is steadily increasing its use of technology. As described above, the number of OT assets in the Company's compressor stations will increase in complying with standard API 1164. In addition, each Remote Control Valve ("RCV") on the gas system represents an OT asset to support. The NGDP describes roughly a doubling of RCVs between 2020 and 2023 (109 to 226). This increases to 336 RCVs by 2026. These represent a portion of the increasing number of Company devices requiring maintenance and security updates. All technology is vulnerable to cyber attack if not properly maintained and updated. Increasing cyber threats require the Company to keep pace with industry security requirements. These rapidly changing security requirements increase the operational costs of keeping the Company's technology assets and customer data secure. The increased use of technology also includes cloud adoption, which requires a corresponding and proportional Operations O&M increase to leverage the benefits described earlier in my testimony. Implementing cloud technologies also shifts the cost model from capital investment to Operations O&M. The Company also performs an evaluation of cloud-based solutions during the planning stage of an IT project as specified in the settlement agreement in Case No. U-18424. In making these moves to the cloud, the evaluation and ongoing cloud O&M expenses must be recovered. The graph below reflects the upward trend in the Operations O&M required to keep new and existing capital investments secure and reliable and support an increasing number of cloud-based solutions. These increases would have been higher without cost-reduction efforts undertaken by the Company.



Q. Please describe Exhibit A-128 (DDP-3).

A. Exhibit A-128 (DDP-3) is the IT Operations O&M Alternative Analysis – Source Data that provides the source for the data that supports the IT Operations O&M Alternative Analysis. Specifically:

- Column (a) identifies the gas case where the projected or actual amounts were provided;
- Column (b) identifies the exhibit number, line number, and column where the project or actual amounts were provided; and
- Columns (c) through (o) identify the projected or actual amounts for each year.

Q. Please describe Exhibit A-129 (DDP-4).

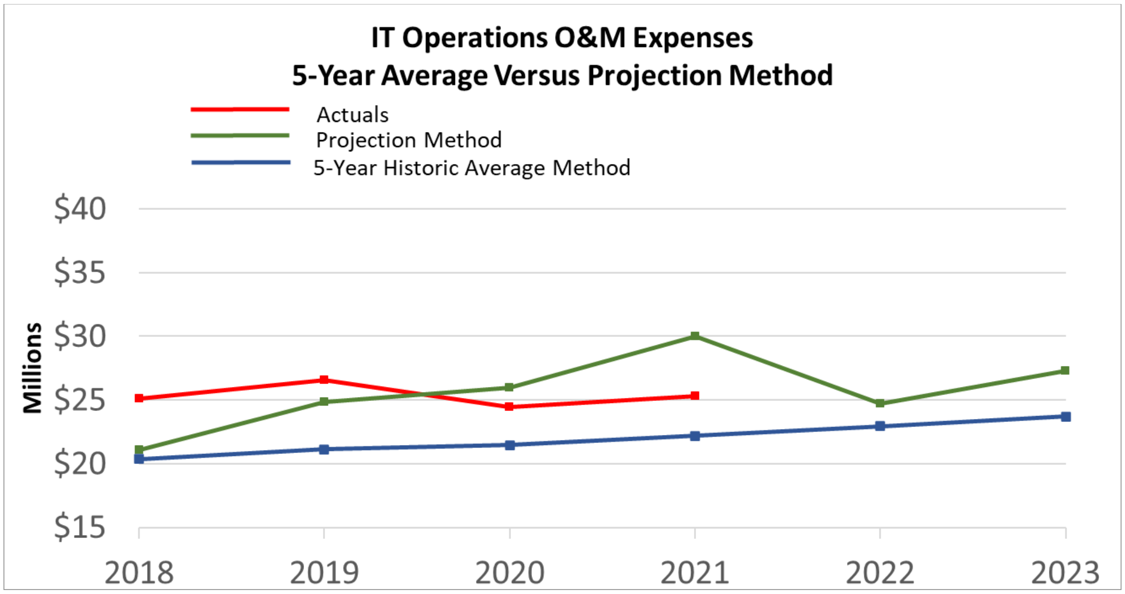
A. Exhibit A-129 (DDP-4) is the IT Operations O&M Alternative Analysis that provides the data that supports the IT Operations O&M Alternative Analysis graph. Specifically:

- Column (a) identifies the year to which the amounts refer;
- Column (b) identifies the projected amount for each test year;
- Column (c) identifies the Five-Year Historical Average based on the most recent five years actual for the test year indicated in column (a);
- Column (d) identifies the difference between the projected amount and the five-year historical average;
- Column (e) identifies the actual or projected amount for each year;
- Column (f) identifies the Recent Year Actual or Projected amount, if the Projected amount is greater than the Recent Year Actual amount;
- Column (g) is the historical year actuals plus projected salary increase on labor and inflation increase on non-labor costs;
- Column (h) is the difference between column (c) (Five-Year Historical Average) less column (e) (Actual/Projected);
- Column (i) is the cumulative average difference of column (h) (difference Five-Year Hist Avg vs. Actuals);

- Column (j) is the Five-Year Average Difference Recovery method calculation, which is column (c) (Five-Year Average) less column (i) (Average Difference Five-Year Hist Avg vs. Actuals);
- Column (k) identifies the timeframe that is the basis for the Five-Year Historical Average;
- Column (l) identifies the Five-Year Historical Average (same as column (c));
- Column (m) identifies the timeframe that is the basis for the Projected Five-Year Average;
- Column (n) identifies the Five-Year Historical Average based on historical and projected expenses through the test year; and
- Column (o) identifies the difference between the Projected amount and the Projected Five-Year Average.

Q. Is the use of a five-year historical average an accurate method to project the Company's IT Operations O&M expenses?

A. No. According to the historical data in Exhibit A-129 (DDP-4), the use of a five-year historical average falls short an average of over $4.1 million per year for the last four years and does not provide sufficient recovery in the projected test year to maintain the Company's systems. The Company places a high priority on system stability and safety, and when there are Operations O&M shortfalls, funding is redirected from new investments to operations. This approach keeps the most critical systems updated at the expense of less critical systems that are on average 3.6 versions behind, and at the expense of building and offering new capabilities. As shown in the graph below, the five-year historical average is plotted with actual and projected Operations O&M expenses. The five-year historic average is consistently less than the required expenses. As a result of this continued gap, the Company evaluated alternatives to project IT Operations O&M expenses.



Q. What additional alternatives has the Company evaluated that would more accurately project IT Operations O&M Expense than a five-year historic average?

A. In addition to the Five-Year Historic Average Method, which assumes projected costs can be ascertained by looking back over the previous five years and applying the average of actual expenses to forecast future years, the Company evaluated three alternative methods to project Operations O&M expenses. These alternatives, including graphs, are shown in A-129 (DDP-4).

1) Recent Years Actual Method: This method compares the previous year's actual expenses to the projected expenses and applies the lower of the two. (Graph 2)

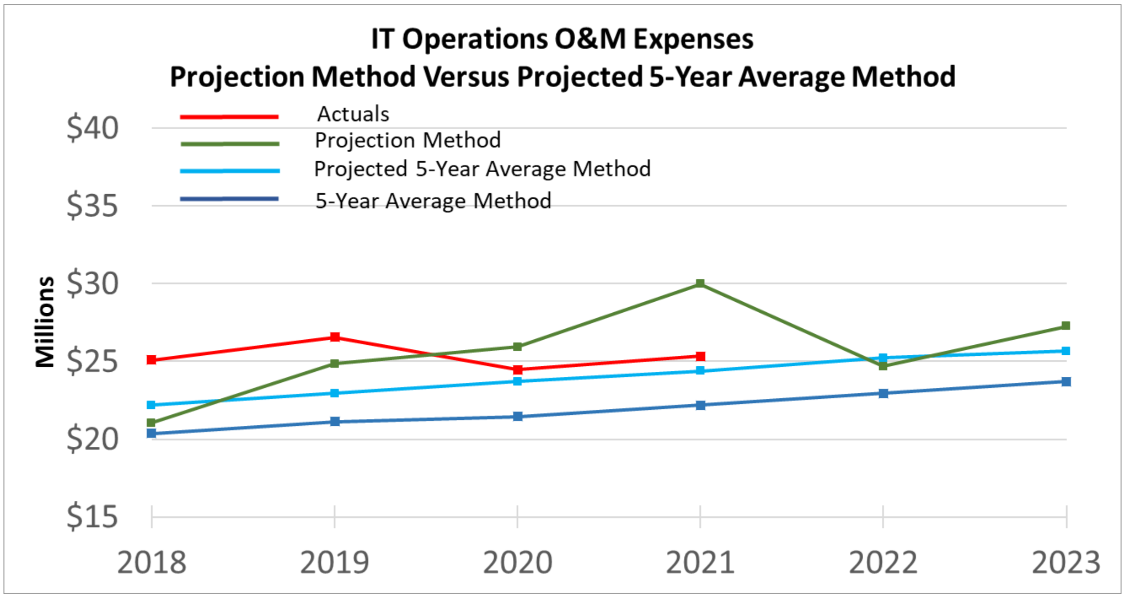
2) Inflation Method: This method uses the most recent year of actual expense plus inflation. (Graph 2)

3) Five-Year Average Difference Method: This method utilizes the five-year historical average and accounts for the difference between the five-year

historical average and the Company's actual expenses by adding the average difference over time. (Graph 3)

Q. Are there any adjustments that can be made to the five-year historic average method that would make it more accurate?

A. Yes. Referencing the Commission's December 17, 2020 Order in Case No. U-20697, it states the following on pages 196 through 197: "The Commission finds that a projection based on a five-year historical average is appropriate at this time considering that Consumers' presentation lacked a specific, detailed plan for the future; however, the Commission is flexible on the time frame employed for projections in future filings if a supportable, concrete IT plan accompanies the projection and a different timeframe appears to be warranted." The Company's Digital Plan provides a clear and inclusive view of IT's plans over the next three years, and proposes that the Commission approve the Company's projected IT Operations O&M Expense, as shown in Exhibit A-127 (DDP-2). If the Commission is inclined to continue using an average to approve this expense, along with the Digital Plan and the Commission's flexible timeframe, the Company proposes that the five-year average timeframe shifts to include the projected O&M costs through the test year as the ending point of the five-year period used to calculate the average. The Projected Five-Year Average Method is plotted below, and the calculations are included in Exhibit A-129 (DDP-4). The Projected Five-Year Average maintains a stable increase that is closer to the actual costs than the Five-Year Historic Average.



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-127 (DDP-2) is the most accurate method and is recommended over the use of a five-year historic average and the alternatives described above. While the Five-Year Average Difference Method is a more accurate alternative method than the use of a five-year historic average, the Company's approach, referred to above as the "Projection Method," 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 capabilities outlined in the Digital Plan, 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.

INVESTMENTS O&M EXPENSES—MAINTAIN ADEQUATE SYSTEM CURRENCY 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 to provide new capabilities for internal business units, as well as customers.

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

A. Upgrading applications, operating systems, and database management systems is essential to delivering safe, reliable, affordable and increasingly clean natural gas to the Company's customers. Implementing current versions of technology enables the Company to maintain vendor support, remediate security vulnerabilities, address defects that impair stability and functionality, and address version interdependencies and compatibility between systems.

Q. What could happen if the Company did not keep its systems upgraded?

A. Technologies that are not upgraded are often no longer supported by vendors, which increases security 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 and services to its customers.

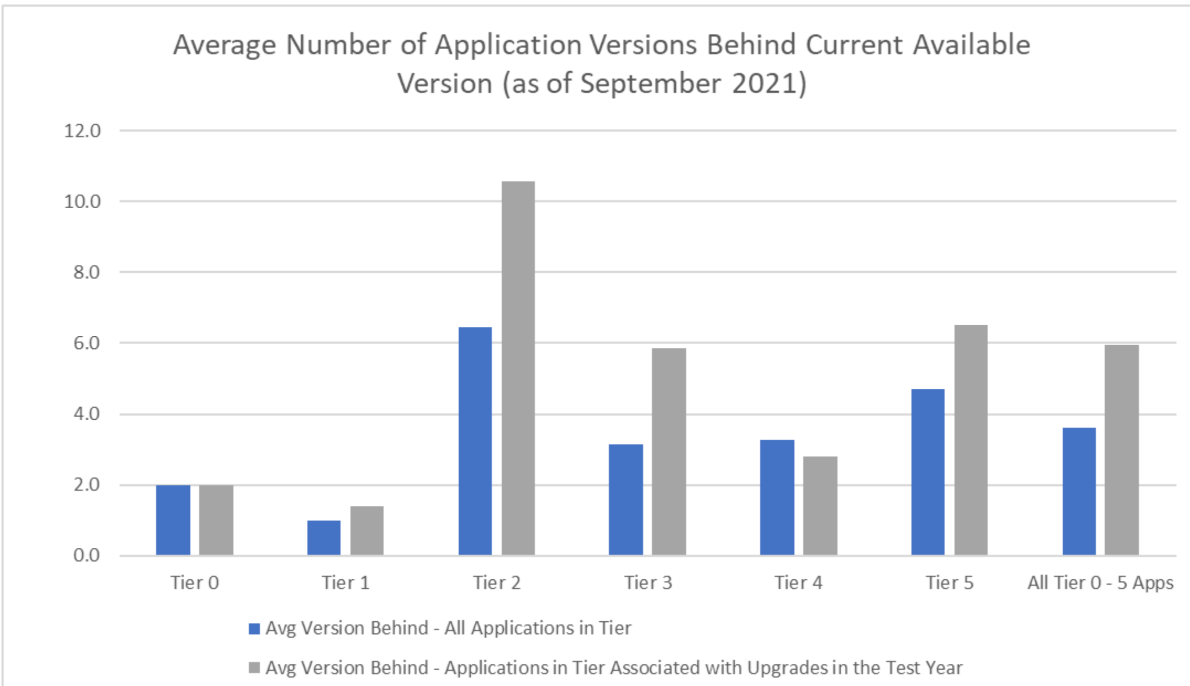
Q. How does the Company determine which systems need to be upgraded?

A. While the Company would prefer to maintain an upgrade strategy of staying, 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, 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.

Historically, the Company has not been authorized the full O&M needed in rates to maintain and keep systems current. Technical obsolescence continues to increase, and the Company is in a position of playing catch-up, adding risk that a significant cyber security or technical issue could not be remediated or mitigated, causing direct impact to Company operations, its customers, or both. The Company prioritizes systems and is currently in a situation where important systems cannot be kept current within recovered rates without impacts to approved investments. The Company prioritizes operational support over new investments when resources are limited, thus putting the NGDP and enabling Digital Plan at risk.

Q. Please describe the risk level of the Company's IT systems based on software versions.

A. The Company has 8 tiers (designated "0" through "7") to categorize application importance and priority in the event of a disaster. Tier designation is based on the criticality of the application to business operations as defined for disaster recovery and business continuity purposes, with Tier 0 as the first priority to restore in the event of a disaster. Using the top 6 priority application tiers (0 through 5) of the total 8, the graph below shows the average number of versions that the Company is behind from the vendors' most current versions for applications in that tier. For example, the applications in Tier 2, which are applications associated with emergency response and have high financial impact when unavailable, are an average of 6.4 versions behind the vendors' most current versions. The graph also shows the same version information for applications that have associated upgrades planned in the test year in this case. For example, Tier 2 applications with associated upgrade projects in this case are an average of 10.6 versions behind the vendors' current version. The application currency projects presented in this case address applications that require upgrades.



Generally, applications that are further behind the vendors' current available version are at higher risk of not having vendor support or require higher costs for extended support, which includes the ability to obtain and apply security patches for the applications. The graph demonstrates the Company's focus on investing first in upgrading those applications at greatest risk of obsolescence and support issues. The version variances shown in the graph are certain to widen as vendors release new software versions before the test year begins, increasing the risk level for the Company. While applications in Tiers

0 through 5 are considered the most important, there are many other applications outside of these tiers that need to be upgraded on a regular basis for security and reliability, including underlying platforms, such as infrastructure, desktop operating systems, and databases.

Q. Please describe Exhibit A-130 (DDP-5).

A. Exhibit A-130 (DDP-5) is a Summary of Actual and Projected IT Investments O&M Expenses for the Years 2020, 2021, 2022, and 12 months ending September 30, 2023. 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 2020 historical Investments O&M expense as $4,125,000;
- Column (c) identifies the 2021 projected Investments O&M expense as $7,870,000;
- Column (d) identifies the 2022 projected Investments O&M expense as $8,464,000;
- Column (e) identifies the 3 months ending December 31, 2022 projected Investments O&M expense as $2,116,000;
- Column (f) identifies the 9 months ending September 30, 2023 projected Investments O&M expense as $6,105,000;
- Column (g) identifies the Test Year projected Investments O&M expense as $8,221,000;
- Column (h) identifies the 12 months ending December 31, 2023 projected Investments O&M expense as $8,139,000;
- 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, and "Overhead and Others" line items include overheads and business expenses.

Page 2 presents the amounts of the projected Investments O&M expenses that were developed by applying either an inflation rate or a merit increase 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 to which an inflation rate or merit increase rate was applied;
- Columns (e) and (g) provide the amounts to which an inflation rate or merit increase rate was applied for each bridge period, respectively;
- Columns (d), (f), and (h) provide the merit and inflation increases for each respective period;
- 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-130 (DDP-5), page 2.

A. IT does not apply inflation for categorical spend projections for Investments Planning expense. The investments planning labor projection is adjusted by $305,000 for anticipated increases in the test year for investments planning activities that directly support business case development and cost estimate refinement for projects that support the Digital Plan, 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 are based solely on expected project costs for the test year as compared to the historical period, as detailed in Exhibit A-131 (DDP-7).

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 functionality of the system, 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. 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 project. 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. It is in the best interest of the Company's customers that the Company perform these investment planning activities to ensure the investment idea provides sufficient value to justify the expense. The Company considers many ideas, but not all are feasible or even warrant investment planning. Only those with the highest expected value even reach the planning phase. The work required by the MPSC for technology investment planning is both reasonable and prudent, and does have associated costs. The Company should receive recovery for this required expense.

Q. Would it be more accurate to use a historical average 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. Typically, the Company has received final rulings approving most of the IT capital expenditures requested in previous rate cases. 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 at reasonable levels of currency and security, 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, versus a backward-looking average. A historic average, which would be lower than the requested amount in this case, would not allow the Company to make the necessary and prudent capital expenditures to achieve the outcomes of the NGDP, improve customer service, and keep its systems current for security and reliability. Additionally, the Company projects an increase in cloud solutions, which often have a higher level of Investments O&M than projects in earlier years.

INVESTMENTS CAPITAL EXPENDITURES

Q. Please describe the capital expenditures shown on Exhibit A-12 (DDP-6), Schedule B-5.10.

A. Exhibit A-12 (DDP-6), Schedule B-5.10, 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 program designation for the capital expenditures, using programs that have been used historically to categorize IT projects:
  - Upgrades and replacements (enterprise);
  - Upgrades and replacements (business partner);
  - IT service delivery;
  - Enhancements;
  - Business partner functionality; and
  - Architecture;
- Page 1 of 2

  - Column (b) identifies the 2020 historical capital expenditures as $20,753,000;
  - Column (c) identifies the 2021 projected bridge year capital expenditures as $28,709,000;
  - Column (d) identifies the 9 months ending September 30, 2022 projected bridge year capital expenditures as $19,061,000;
  - Column (e) identifies the 21 months ending September 30, 2022 projected bridge year capital expenditures as $47,771,000; and
  - Column (f) identifies the 12 months ending September 30, 2023 projected test year capital expenditures of $24,074,000;

- Page 2 of 2
  - Column (b) identifies the 9 months ending September 30, 2021 capital expenditures as $20,817,000;
  - Column (c) identifies the 12 months ending September 30, 2022 capital expenditures as $26,953,000;
  - Column (d) identifies the 12 months ending September 30, 2023 projected bridge year capital expenditures as $24,074,000; and
  - Column (e) identifies the 33 months ending September 30, 2023 projected bridge year capital expenditures as $71,845,000;

- 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 Costs" line items include staff augmentation, managed services, and other contracted services, and "Overhead and Others" line items include overheads and business expenses.

Q. Please explain Exhibit A-131 (DDP-7).

A. Exhibit A-131 (DDP-7) 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 IT program category;
- Column (d) identifies the Federal Energy Regulatory Commission ("FERC") category relative to the line item project's asset type;
- Column (e) identifies the Business Category of the project which aligns with the financial categorization in the Digital Plan;
- Column (f) provides a synopsis of the project, including the project description and information on project scope, functionality, and benefits;
- Column (g) identifies the project's implementation date;
- Column (h) provides the project's cost/benefit ratio;
- Column (i) provides the project's gas portion total capital expenditure for the applicable year;
- Columns (j) through (n) 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 (j);
  - Material costs (k);
  - Labor costs (l);
  - Contractor costs (m); and
  - Overhead and other costs (n);
- Column (o) provides the project's gas portion total O&M spend for the applicable year; and
- Columns (p) through (t) 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 (p);

- Material costs (q);
- Labor costs (r);
- Contractor costs (s); and
- Overhead and other costs (t).

Q. Please explain the difference between Exhibits A-12 (DDP-6), Schedule B-5.10, and A-131 (DDP-7).

A. Exhibit A-12 (DDP-6), Schedule B-5.10, and A-131 (DDP-7) 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 (DDP-6), Schedule B-5.10, is a high-level summary of capital expenditures by year, by program, and by categorical spend; and
- Exhibit A-131 (DDP-7) is an all-inclusive exhibit displaying every detail of each project over the four-year time periods of 2020, 2021, 2022, and 2023.

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 an opportunity to implement technology to meet the requirements of the Company's customers, including technology that customers interact with directly, and technology that sustains and improves business operations 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 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 alignment with 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 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 as 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 actual costs for similar projects. The crux 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, which makes up over 60% of releases delivered by IT in 2020, 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, 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 all of 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. Most projects in the test year have been through up-front planning activities where the start dates for the Plan, Define, Execute, and Close phases and Go-Live dates have been projected. When a project begins the Plan phase, the project manager 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.

<u>INVESTMENT PROJECTS</u>

Q. Please provide a description of the various IT investment project areas to be highlighted in testimony.

A. Costs, descriptions, benefits, alternatives, and other relevant project information for each individual project can be found in Exhibit A-131 (DDP-7). The IT investment projects are grouped into the following areas for explanation in this testimony:

- **NGDP** projects 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 increasingly clean natural gas;

- **Customer Experience and Operations** ("CX&O") projects that enable the Company to comply with regulatory billing changes, improve billing functionality, improve customer satisfaction, increase the Company's ability to serve customers within the channel of their choice, and improve the experience of customers in completing self-service transactions within that channel;

- **Corporate and Enterprise** projects that support internal departments of the Company crucial to running an efficient business for customers such as Treasury; Tax; Legal; Human Resources ("HR") (recently changed to People & Culture); Governmental, Regulatory and Public Affairs; and Finance;

- **Operations Support** projects that enhance the capabilities of the Company's supply chain function;

- **Asset Refresh Program** ("ARP") projects implemented to maintain the currency, reliability, and security of the Company's IT infrastructure that is core to all Company operations, including customer service, and maintaining a safe, reliable, affordable, and clean gas system;

- **Upgrades and Application Currency** projects implemented to maintain the currency, reliability, and security of the Company's IT applications and enterprise software supporting all Company operations, including customer service, and maintaining a safe, reliable, affordable, and clean gas system;

- **Enhancements** projects implemented to improve and change business processes resulting from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas; and

- **Digital Foundations and Capabilities** projects to create the technology platforms, tools, processes, and frameworks that enable NGDP and customer service outcomes.

Q. Please explain the projects enabling the NGDP.

A. Below are the projects enabling the NGDP. As described in Exhibit A-126 (DDP-1), in the Business Drivers\Natural Gas and Business Drivers\Work Management Common to Gas and Electric sections, the investment in digital capabilities are essential to achieving the Company's NGDP. A synopsis of each project with its value is included in the testimony of Company witnesses, as indicated below.

Project	Capital	O&M	Witness
Gas Construction Operations Enablement	$272,860	$45,560	C. Fultz
Field Contractor Work Management Technology Enablement	$153,794	$4,100	C. Fultz
Gas Measurement, Regulation, Pipeline, and Storage Field Work Management Enablement	$301,081	$2,738	C. Fultz
Field Mapping and Graphics	$43,361	$4,930	C. Fultz
Work Management Scheduling Analytics and Reporting	$255,251	$27,006	C. Fultz
Gas Distribution ProjectWise	$213,750	$24,550	K. Pascarello
Gas SCADA Software Solution	$1,884,469	$320,410	M. Griffin
Gas Transmission Probabilistic Risk Model	$147,500	$54,650	P. Wolven
Gas Storage Probabilistic Risk Model	$1,174,250	$239,313	T. Joyce
Generation Operations and Compression Digital Work Management	$402,690	$13,741	T. Joyce

Q. Please explain the projects included in the CX&O area.

A. Below are the projects included within the CX&O area. A synopsis of each project with its value is included in the testimony of Company witness Cullen M. Hale. In Exhibit A-126 (DDP-1), the Business Drivers\Customer section describes how digital investments can support lower cost of customer service while increasing customer satisfaction.

Project	Capital	O&M
Customer Self-Service Online Work Scheduling	$17,328	$16,958
Flexible and Advanced Payment Options	$161,304	$42,615
Bill Design and Delivery Transformation	$2,211,267	$679,995

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

A. Below are short descriptions for the projects included within the Corporate area. In Exhibit A-126 (DDP-1), the Business Drivers\Corporate section provides the areas of core shared services and key capabilities needed to operate the utility and how the use of digital solutions can optimize and even transform these foundational services. A synopsis of each project with its value is included in the testimony of Company witnesses, as indicated below.

Project	Capital	O&M	Witness
Career and Reward Framework	$99,108	$44,388	K. Gaston
EHS Compliance	$27,009	$5,243	K. Gaston
Expense Reporting Improvements	$128,743	$38,070	K. Gaston
Labor Relations Management Software	$7,127	$0	K. Gaston
Legal Case Management	$82,152	$28,485	K. Gaston
Rates Case Implementation	$0	$105,104	K. Gaston
Supplier Portal for Invoice Management	$27,009	$73,440	K. Gaston
Talent Management Enablement	$243,081	$49,410	K. Gaston
Facilities Work Management	$356,518	$5,620	Q. Guinn

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

A. The Company's ARP projects replace technology assets in line with industry 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 8-years based on Company data related to historical failure rates. Refreshing hardware at the recommended refresh 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 software to support their work.

Below are links to some industry standards the Company has reviewed to determine its hardware refresh time periods:

- Michigan.gov, Information Technology Equipment Life Cycle. https://www.michigan.gov/documents/dtmb/Sec._829_IT_Lifecycle_Report_2018_619021_7.pdf
- International Data Corporation ("IDC"), Why Upgrade Your Server Infrastructure Now? (IDC is a global provider of market intelligence, advisory services, and events for the information technology, telecommunications, and consumer technology markets.) https://www.dell.com/learn/us/en/12/shared-content~data-sheets~en/documents~dell_why_upgrade_incl_link_to_dell.pdf

Q. Please describe how the investment in cloud services impacts Asset Refresh Projects included in the test year.

A. By investing in cloud services as part of the Digital – Hybrid Cloud and Data Center Migration project, the number of on-premise assets that are scoped to be replaced through the ARP – Server and Storage project is substantially less. This enables the Company to reduce total company capital expenditures of the ARP – Server and Storage project from $8.8 million to $5.6 million in the test year. This adjustment is already reflected in the costs of the ARP – Server and Storage project. If the Digital – Hybrid Cloud and Data Center Migration project's capital and O&M are not approved as requested, the Company will pursue an alternative - replace all assets slated for replacement through the ARP – Server and Storage project. In this scenario, the Company will need $8.8 million in capital and $0.623 million of O&M to fund the full scope of the ARP – Server and Storage project.

Q. Please describe Exhibit A-133 (DDP-9).

A. Exhibit A-133 (DDP-9) shows the detailed projected and actual capital expenditures of each ARP.

- 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; and
- Columns (g) through (h) provide gas allocation of capital expenditures for the specified year.

Q. Please explain the ARP and infrastructure projects.

A. The following are the ARP and infrastructure projects:

- The **ARP-Collaboration** project requires $350,334 in capital and $175,986 in O&M in the test year. This project will replace the Company's collaborative tools and equipment. When Collaboration Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they are not only more expensive to support, but also 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. This project creates value by: (1) ensuring that the Company's audio, visual, telephony, and other communications systems are stable and reliable; and (2) beginning the foundational retirement of the legacy enterprise Avaya telephone systems that have reached end of mainstream manufacturer support. The project scope consists of: (1) annually replacing aging collaboration assets; and (2) installing new collaboration assets to account for organic growth requirements. The following options 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-Field Device Asset Management** project requires $758,442 in capital and $1,800 in O&M in the test year. 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. 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 can be very difficult to 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. 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 field workers to complete their job tasks. The project scope consists of replacing field device assets according to the four-year refresh cycle. 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. 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.

- The **ARP-Local Area Network** project requires $188,456 in capital and $5,769 in O&M in the test year. This project will upgrade the Company's entire Local Area Network (LAN) and a significant portion of the Wireless LAN (WLAN). 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. 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 phones, Internet of Things, and field devices. 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. The alternative considered was to continue operating on the existing platform past the vendor's 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 a lack 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 $524,751 in capital in the test year. The ARP —OT Support Gas project will replace dated and obsolete servers and workstations. When OT 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. This project creates value by maintaining the currency of the Company's IT infrastructure and core enterprise software that are utilized to support the operation of the Company's critical gas infrastructure. The program scope consists of: (1) the annual replacement of compute hardware under the program; and (2) installing additional new compute capacity to account for organic growth requirements. Extending maintenance is not a viable alternative as current systems do not provide sufficient capacity for new gas system support capabilities.

- The **ARP-Printer Asset Management** project requires $220,740 in capital and $1,800 in O&M in the test year. This project will replace and install select printers, plotters, and multi-function printing devices according to a five-year refresh cycle. When Printer Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and more difficult to 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. 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. The project scope consists of the annual replacement of printer assets according to a five-year refresh cycle. 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 result in additional, unneeded expense for replacement of assets that were still in peak operating condition, and anything greater than five years, including running the asset to failure, would result in additional expenses for maintenance of the equipment and downtime, negatively affecting employee productivity.

- The **ARP-Radio** project requires $641,875 in capital and $18,761 in O&M in the test year. This project will refresh hardware to include: 800Mhz Radios, 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 and 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. 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 customers' 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 best-in-class 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. This project creates value for 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 staying in compliance with MPSC regulatory requirements by maintaining critical radio infrastructure. The project scope consists of: (1) scheduled replacement of radios, modems, and consoles; and (2) installing additional radios, modems, and console assets to satisfy growth requirements. 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 1 was not selected because it requires replacement of existing management systems which are vendor specific and would need to also be replaced if the Company were to move to different equipment. This would result in a significantly higher investment. Option 2 was selected as this has the least disruption to radio and mobile data system users and deliver the highest value and lowest cost solution to meet the objectives of this Business Case.

- The **ARP-Server and Storage** project requires $1,672,683 in capital and $188,278 in O&M in the test year. The ARP — Server and Storage will replace or augment server and storage infrastructure for the Company. 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 if it does not adhere to a regular five- to seven-year refresh cycle. 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. 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 organic growth requirements. The alternative considered was to purchase extended maintenance. This solution was not selected because full support would not be offered after seven years and maintenance costs would increase. The Company continues to refresh these critical technologies based on a five- to seven-year refresh cycle to mitigate the risk of failure.

- The **ARP-Workstation Asset Management** project requires $2,497,454 in capital and $37,020 in O&M in the test year. 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. 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 can be very difficult to 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. 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. The project scope consists of: (1) replacing workstation assets; and (2) installing new units for new resources. 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. 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. What are Upgrades and Application Currency projects?

A. Upgrades and Application Currency projects are projects that address the need to upgrade 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 and when. Upgrade projects are created for larger and more complex application and platform upgrades that require increased oversight and project management. Smaller upgrades are aggregated by IT portfolio and spend type in the Application Currency projects.

Q. Please explain the Upgrades projects.

A. The following are the Upgrades projects:

- The **800 MHZ Modernization** project requires $295,321 in capital and $154,896 in O&M in the test year. The 800Mhz Modernization project will replace the core Company radio system infrastructure that is a regulatory requirement for field dispatch communications. The existing Company radio system was installed in 1994, and reached the end of its serviceable life in 2017, creating significant reliability and safety risks. This project creates value for the Company by: (1) creating a reliable and stable radio network by migrating the Company to core production and dispatch equipment with vendor support; (2) ensuring customer and employee safety by maintaining a radio network that provides real-time communication and emergency response to electric outages, wire downs, and gas leaks; and (3) staying in compliance with regulatory requirements from the MPSC by maintaining critical radio network infrastructure. The scope of the project includes the design, configuration, and implementation of a new, standards-based digital mobile radio infrastructure designed for use by utilities and public safety organizations to communicate using 800MHz radios in North America. This project includes replacing current hardware with Project 25 ("P25") system infrastructure hardware for head ends, tower sites, dispatch consoles, and subscriber equipment. P25 radio is a standard that defines a form of interoperable digital two-way wireless communications suited to public safety and first responders. The alternatives considered were: (1) upgrade the current system with existing manufacturer; (2) replace and migrate to a new manufacturer and architecture; and (3) upgrade and subscribe to a Public Communications as a Service ("PCSaaS") with the Michigan Public Safety Communications System. Although Option 1 and 2 both support new digital P25 Standards, neither option was selected because the Company would be required to support a private statewide communications system in the lower peninsula, creating significantly higher costs over a ten-year timeline. Option 3 was selected because it meets new digital P25 standards, offers better geographical coverage, is more reliable, and the PCSaaS – Michigan Public Safety Communications System provides a much lower cost over a 10-year timeline.

- The **Asset Accounting Upgrade** project requires $192,439 in capital and $27,000 in O&M in the test year. The project will upgrade the Company's current accounting asset management software to the latest version as required by the vendor and implement additional new features, ensuring continued support of a critical financial application and providing new functionality. In 2022, 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. The current monthly allocation process has limited visibility to Company financial performance, and the upgrade provides functionality that allows more frequent allocation processes. Additionally, implementing the vendor's regulatory module eliminates the time-consuming and labor-intensive process of manual data extracts for regulatory analysis used for Cost of Service modeling. 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) eliminating the labor intensive and time-consuming process of pulling data for regulatory analysis used for Cost of Service; (3) automating manual tasks; and (4) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support. The project scope includes: (1) upgrading the vendor software from the current version to the newer version;

(2) implementing new functionality that includes features for the regulatory Cost of Service analysis, additional reporting, job scheduling, and centralized error processing; and (3) populating the data lake with data from the asset accounting system for improved reporting. Alternatives considered include: (1) Upgrade to the newest, cloud version of PowerPlan. 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; (2) 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 likely be more complex, cost more, and may not provide all the required features; and (3) Evaluate other software options. This option will introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements.

- The **AxWay Secure Transport 2022 Upgrade** project requires $25,449 in O&M in the test year. Axway SecureTransport is the official CE multi-protocol Managed File Transfer gateway for securing, managing, and tracking data file flow for business partners and external vendors. Files impacting billing, HR, Supply Chain, Finance, Alternate Energy Programs, Front Office, Back Office, Device Management, Outage Management, and Business Reporting functions utilize these services. This upgrade project will modernize the Axway Secure Transport platform; enabling new cost saving operational enhancements while retaining data security and platform supportability. As Axway Secure Transport is the public-facing managed file transfer gateway, maintaining platform version integrity is critical to ensuring it remains secure and supportable in the event of a cyber attack, outage or other critical incident. A prolonged outage or incident, for any reason, compromises the ability of Consumers Energy to perform mission-critical business transactions in finance, operations, and direct customer support. Upgrading this application also gives Consumers Energy the opportunity to properly scale Axway SecureTransport and take advantage of the growing demand for additional, cost-savings features of the tool, such as managing internal Electronic Data Interchange (“EDI”) transactions. The value this project brings Consumers Energy, its customers, and business partners includes: (1) Addresses known problems and limitations of the current software platforms; (2) Ensures continued secure, scalable, and critical data transmission services running through Axway SecureTransport remain smoothly functioning; (3) Creating the capacity to methodically merge/streamline internal and external data file transfer services to eliminate waste; and (4) Reduces cyber attack vectors and creates a better, more easily maintained and monitored security model. The scope of this project includes: (1) Upgrading the application and database to the current released and supported versions; (2) Enable and test expanded EDI functionality; and (3) After successful testing, process new, compatible, Consumers Energy EDI requests with Axway SecureTransport platform. Alternatives considered include: (1) deferring the upgrade. This alternative was not selected because the Axway SecureTransport platform handles critical Company financial, HR, and operational transactions--the risk associated with problems stemming from an outdated and unsupported version is too high. Nor would the waste elimination benefits of using the upgraded Axway SecureTransport platform to start consolidating EDI for Consumers Energy be realized; (2) Replacing the platform. The estimated project costs and timetable for replacing the business functions currently performed by the existing Axway SecureTransport platform would be extensive, and operationally, it is not well suited for a cloud or hybrid cloud solution. In addition to significant platform, application, implementation, and functional testing costs, replacing it would require extensive coordination and testing with all of the internal and external account holders, taking upwards of one calendar year; and (3) Upgrading the platform. This provides Consumers Energy the best, most cost-effective alternative, balancing costs, known risks, and growing business capacity and productivity.

- The **BizTalk 2022 Upgrade** project requires $21,439 in O&M in the test year. The Microsoft BizTalk application transfers data from one location to another with internal and external software systems and assists with securely communicating sensitive financial data. The project will upgrade the BizTalk software to ensure continuing application stability, reliability, and security. BizTalk consists of more than 1,200 integrations that transport data files to internal business partners, internal Company applications, and external business partners. This software interacts with most core parts of the business, including Billing, HR, Supply Chain, Finance, Alternate Energy Programs, Front Office, Back Office, Device Management, Outage Management, and Business Reporting. Because of the business criticality and Information Security information classification of the various data streams, it is essential to upgrade the BizTalk application to ensure the stability, scalability, and security of the data and platform. Failure to upgrade the application and remain current with a version supported by the vendor would put the Company at risk of losing support for an application responsible for handling payments, billing, and purchase orders. This project creates and maintains value for the Company and its customers by: (1) Keeping the BizTalk platform, the Company EDI solution, reliable, stable, and scalable; this is critical for supporting accurate financial transaction data exchanges between the Company and external partners; (2) Ensures current and future compliance with Information Security critical and sensitive data initiatives, such as patching, data encryption, and authentication requirements; and (3) Guarantees 7x24x365 vendor support is available to the Company during significant outages by remaining on a version supported by the vendor. The scope of the project includes: (1) installing the new BizTalk version; (2) database data migration; (3) application testing; and (4) training and transition to support activities. Alternatives considered include: (1) Deferring the upgrade. This alternative was not selected because the BizTalk platform manages critical Company financial, HR, and operational transactions—the risk associated with compatibility or security issues stemming from an outdated and unsupported version is too high; (2) Replacing the platform. The project costs and timetable for replacing the business functions currently performed by the existing BizTalk platform would be extensive regardless if the new solution was hosted on site, in the cloud, or was part of a hybrid solution; and (3) Upgrading the platform. This alternative was selected because it meets the business needs as the most cost-effective and timely option, while significantly reducing regulatory and operational risks that include Health Insurance Portability and Accountability Act, North American Electric Reliability Corporation/FERC, Sarbanes-Oxley, and MPSC regulations.

- The **Consumers Affordable Resource for Energy ("CARE") Annual Updates** project requires $120,519 in O&M in the test year. The CARE Annual Updates project will implement software changes to offer energy assistance to low income customers and streamline the process for the assistance agencies who use the application. This is accomplished though improved user interfaces and updates to SAP to process various CARE requests. Upcoming modifications will be identified following an annual review of requests to prioritize the list of changes. Each grant year, Department of Health and Human Services and Michigan Agency for Energy ("MAE") 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 benefits through bill credits and arrears forgiveness. The criteria changes significantly each year, therefore the CARE 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 electric bills, thereby increasing the customer's risk of shutoff for non-payment. 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 the bill credits and arrears forgiveness; and (2) improve the data within the assistance agencies portal, thereby making it easier to assist customers in need of LIHEAP funding. The project scope includes: (1) updating the enrollment and status process; (2) allowing for flexible bill credits; (3) improving reporting; (4) updating the arrears forgiveness plan; and (5) satisfying additional regulatory requirements for the annual grant rule changes required by the Department of Health and Human Services and MAE. 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. All the changes are internal to SAP and Agency Portal related, 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 2023-2024 Upgrade** project requires $8,203 in O&M in the test year. This project will upgrade and migrate the Business Works developer application to the next version. Newer Enterprise Service Bus ("ESB") software versions offer improved integration with cloud-based services and applications. As the Company increasingly migrates to cloud-based Infrastructure, Platform- and Software-as-a-Service solutions, it is critical that this vital data tool or pathway, be more scalable, secure, and capable of working in a cloud-based environment. In addition, the messaging and event modules within the ESB are currently outside of their standard support windows. While it's possible to continue to get extended support by paying an estimated annual premium of $40,000, this is just temporary coverage and serves only to delay the need for an upgrade. The value this project provides the Company includes: (1) accelerated productivity; (2) continuous delivery and integration; (3) an open ecosystem for improved operational visibility; (4) real-time integration with web, mobile apps, and application programming interfaces; and (5) improved administrative and operational efficiencies. The project scope includes: (1) implementing new versions of all applications that are part of the Tibco ESB software suite – BusinessWorks, Enterprise Messaging Service, BusinessEvents, and Hawk; and (2) a server refresh. The new products will be implemented on the latest version of the SUSE Enterprise Edition operating system. Alternatives considered included: (1) Absorb the annual $40,000 maintenance cost and lose supportability. 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 meters. The current implementation of the ESB platform was built with five years of growth in mind. This alternative was not chosen for these reasons, and the additional expense; (2) Replace the platform by moving it to cloud. Migrating the ESB to the cloud would be too early in the Company's plan for cloud adoption, which may cause issues with operational stability and incur additional expenditure. A cloud migration would also take longer to plan, which would put the Company at risk of falling outside of the the current vendor support window for the product's current version; and (3) Upgrade the existing application. This option was selected because it best suits customer and Company needs for the near future by restoring vendor support for hot fixes and patches, and enables product scalability to the measure required of business capabilities.

- The **HR Support Pack and Business Software Inc Upgrade** project requires $377,226 in O&M in the test year. The HR Support Pack and Business Software Inc upgrade will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes. 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. 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. The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information by the Company. 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 **Itron Enterprise Edition ("IEE") 2023 Upgrade** project requires $138,014 in O&M in the test year. This project will upgrade IEE, which collects the reads from meters to ensure accurate and non-estimated bills are provided to customers. IEE is the Company's keystone application of the Advanced Metering Infrastructure, enabling Time Of Use billing. If this application does not stay current, the Company increases the risk business operations could be interrupted or compromised. Keeping updates current will also assist the Company in maintaining system capacity, stability, and security obligations with the IEE platform. This project creates value for the Company by: (1) ensuring the features and functionality needed to meet business requirements are available to business partners and IT; (2) meeting Information Security's requirement to keep applications patched and protected from cyber attack; and (3) allowing for validation, estimation, and editing functions for all data collected to ensure accurate billing. The scope of this project includes: (1) upgrading the IEE applications to the next appropriate versions; and (2) migrating the database to the next version required by the application. Alternatives considered included: (1) Defer the upgrade. This alternative was not selected because it would add application stability, security, and dependency risks to the meter data management ("MDM") utility, possibly negatively impacting critical customer electric and gas billing operations. It would also likely de-couple IEE and MDM from the Itron security infrastructure that other business critical Itron applications use, creating more expense and complexity in the technology environment; (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; and (3) Perform the upgrade. This option best suits customer and Company needs as it restores vendor support for hot fixes and patches as well as keeping IEE integrated into the Itron Security infrastructure with the other Itron software products in use at the Company, like Itron Field Collection Systems ("FCS").

- The **Itron Field Collection Systems (FCS) 2022 Upgrade** project requires $94,262 in O&M in the test year. The Itron FCS Upgrade project will upgrade the Itron FCS and Meter Collection System ("MCS") software to the latest version available. Upgrading the FCS software ensures continued integration with Itron Security Manager as well as conforms to the current stability, performance, and security standards. The project adds value by: (1) collecting accurate and timely gas meter reads; and (2) maintaining alignment for security requirements with FCS and other Company-owned Itron applications, including IEE, FDM, and OpenWay, instead of creating a standalone solution. Included in the implementation are: (1) upgrading the Itron FCS and MCS applications to the next appropriate versions; and (2) migrating the database to the next version required by the application. Alternatives considered included: (1) Defer the upgrade. This alternative was not selected because it would add application stability, security, and dependency risks to gas meter reading data collection and critical customer billing operations. It would also risk de-coupling Itron FCS 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. 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; and (3) Complete the upgrade. This option best suits customer and Company needs as it restores vendor support for hot fixes and patches and keeps FCS integrated into the Itron Security infrastructure and with the other Itron software products in use at the Company.

- The **Oracle Server Database Upgrade** project requires $20,761 in capital and $184,486 in O&M in the test year. This project will upgrade Oracle server databases to the next version to support all business portfolios. The Company is currently managing Oracle server databases that run on multiple versions of Oracle: 8i, 9i, 11g, and 12c; all of which are currently unsupported as of 12/31/2020. Version 12c recently lost vendor support in July of 2019 and is eligible for extended support. Relying on extended support for Version 12c increases operational costs. Extended support is not available for version 11g and older. Without vendor support, the databases no longer receive security patches, bug fixes, or functionality support which creates security, stability, and reliability risks. This project will create value for the Company and its customers by: (1) reducing the risk of system failure and the resulting impacts to business partners and customers; and (2) ensuring that systems are secure, supported, and have the latest features and functionality. The scope of this project includes upgrading to the next version of Oracle across all impacted business systems. Systems that cannot support Oracle 19, will be upgraded to the highest supported version. Alternatives considered were: (1) delay database upgrades. This option was not chosen becasuse, as stated, it would introduce significant security, stability, and reliabity risks; and (2) Upgrade only to Version 12c and pay extended support. This option was not chosen, where possible, to avoid increased operational costs. The alternative chosen is to upgrade to the next version of Oracle and where systems do not support Oracle 19 or above, upgrade to Version 12c and pay extended support until those systems are upgraded.

- The **OSIsoft Plant Information ("PI") Historian Upgrade** project requires $109,277 in capital and $298,805 in O&M in the test year. The OSIsoft PI Historian Upgrade project will maintain application and hardware platform currency for the OSIsoft PI system. Not performing periodic upgrades of the

OSIsoft PI Historian software application and hardware puts system accessibility, supportability, and sustainability at risk, and this could impact business operations. To mitigate this risk, the Company plans to upgrade the software every two years, and the hardware every four. The project will create value for the Company and its customers by: (1) reducing security vulnerability; (2) improving system performance and increasing synergies between environments; and (3) enabling business partners to leverage new features that the vendor includes with major releases. The project scope includes the upgrade of: (1) OSIsoft Meter Operational Data Management; (2) OSIsoft Electric Distribution Historian – Analytics instance; (3) OSIsoft Generation; (4) OSIsoft Low Voltage Distribution/High Voltage Distribution – Operational instances; (5) OSIsoft Gas Automated Meter Read; and (6) data archiving for analytics purposes. Alternatives considered were to: (1) delay the software and hardware upgrade until a future year. This option was not selected, as continuing to delay the upgrade puts the system at risk for system accessibility, supportability, sustainability, and vulnerability risk which could impact business operations; and (2) Consider replacing the OSIsoft software platform with another solution. This option was not selected since the Company has a longstanding enterprise agreement with the vendor that is leveraged to optimize costs associated with the historian requirements. A new vendor would introduce significant additional costs. The Company chose the option to upgrade the software every two years and the hardware every four years. Periodically maintaining the software and hardware mitigates the risk of the system accessibility, supportability, and sustainability, thus avoiding potential impact to business operations.

- The **Redwood Cronacle 2022 Upgrade** project requires $33,008 in O&M in the test year. This project will upgrade the Redwood Cronacle batch job scheduling software. Redwood Cronacle is a real-time event-driven scheduling and process automation software. It streamlines, automates, and manages the end-to-end business and IT processes across the enterprise. Redwood Cronacle is critical to performing critical business functions: (1) accounts payable, accounts receivable, payroll, and other financial processes; (2) providing customer relationship management team with data needed to support customers; (3) updating data requested by customers using consumersenergy.com; (4) gas and electric meter configuration, syncing and reads; and (5) gas and electric field operations. If this application does not stay current, the Company increases the risk business operations could be interrupted or compromised. This project will create value for the Company and its customers by maintaining a secure, stable, and supported platform, integral to achieving customer satisfaction, safety, and efficiency key performance indicators. This project also helps the Company avoid costs associated when critical business functions fail or are compromised, which would create financial, reputational, and regulatory concerns. The scope of this project includes upgrading Redwood Cronacle and the associated database to the latest release of the software. Alternatives considered included: (1) Deferring the upgrade. This alternative was not selected because the Redwood

Cronacle platform enables critical Company financial, customer relationship, energy operations, energy infrastructure projects, and data analytics transactions. Applying all application, operating system, infrastructure patches, and hot fixes to sustain these key business processes is predicated on platform support and currency. Significant financial, reputational, and regulatory costs would accrue within hours of a significant Redwood outage or major incident; (2) Replacing Redwood Cronacle. This option was not chosen because the complexity and cost of moving all the necessary application configuration and code to a different application and/or platform would be prohibitive. Since many of the transactions are SAP related, changing job schedulers would kick off an entirely new capital project on the level of previous SAP upgrade projects; and (3) Upgrading Redwood Cronacle platform. This was chosen as the most cost-effective. It avoids costs associated when critical business functions fail or are compromised, which would create financial, reputational, and regulatory concerns.

- The **S4 HANA Assessment** project requires $49,216 in O&M in the test year. The S4 HANA Platform Assessment project will review options for moving to the new platform before the current SAP Platform is no longer supported in 2030. Once an option is selected, the SAP S4 implementation program will perform the migration. As such the Company must find an alternative solution to the current platform or risk no longer having SAP support of the platform in use. By not having the proper support, the Company risks having issues with maintaining the system stability or face increased cost to assure support of the existing platform. The value of the project is to: (1) devise the best option to migrate to a new platform at the least cost; and (2) ensure that the Company is prepared to move to the new platform by projected 2030 end of SAP Support, and that all alternatives have been explored so the best option is implemented. The scope of the project includes: (1) reviewing SAP options for migrating to a new platform; (2) reviewing alternative platform options that the Company could use in place of S4 HANA; (3) reviewing support options for the existing SAP Platform past 2030; and (4) providing cost and alternative options so that the Company can develop a project for the best option to address the SAP Platform. Three alternatives were explored and determined non-viable for the project: (1) Complete the assessment as the initial phase of the implementation project. This option was not considered since it would limit the amount of options considered and make assumptions about cost needed to stand up the project; (2) Delay the assessment beyond 2023. This option was not considered since it would not give the Company enough time to prepare for the implementation; and (3) Complete an assessment that had a scope limited only to migrating to the new SAP platform. This option was not considered in that it may result in the Company accepting a sub-optimal solution. After evaluating the lack of change in market condition, the option selected is to delay the assessment beyond 2023 of pursuing a separate assessment project, which gives the Company the best opportunity to look at all viable options with enough lead time for an appropriate transition to the targeted solution.

- The **SAP Data Archiving** project requires $84,028 in capital and $82,800 in O&M in the test year. This project will move outdated data from an online database to offline storage. The SAP Enterprise Resource Planning Central Component database is 38 terabytes in size and growing at a rate of 0.3 terabytes to 0.5 terabytes per month. If the database is not archived, then SAP system performance will degrade, and this will affect customers and employees who are completing tasks within the system. This project will create value for the Company by: (1) increasing system stability by controlling online data storage levels; and (2) controlling maintenance costs associated with data storage. The project scope includes: (1) archiving data based on the fastest growing and largest archiving objects in SAP (an archiving object defines the structure and context of the data in the SAP database from an archiving perspective); (2) building and archiving solutions that allow retrieval of archived data in the required form; and (3) setting up a solution that meets compliance standards. Three alternatives were explored and determined non-viable for the project: (1) allow the database to continue to grow, which puts system performance at risk and results in prohibitive storage costs; (2) decrease the overall scope and archive fewer objects, which would result in minimal positive impact to system growth and significant storage-related costs; and (3) increase the scope and archive more objects in a shorter timeframe, which would result in a significant cost increase over shorter time period. After considering each of these options, it was determined that the current scope of the project was the best strategy to address the problem while balancing annual spending.

- The **SAP Support Pack Upgrade** project requires $498,822 in O&M in the test year. 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 business partners. In the past, the SAP enhancement packs were applied to Company systems to ensure these problems were addressed in a timely manner. However, SAP is no longer releasing enhancement packs. 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. 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. The scope of this project includes routine support pack upgrades to all SAP applications, which include: Enterprise Core Component, Customer Relationship Manager, Enterprise Portal, Process Orchestration, Business Warehouse, Business Objects, Data Services, Governance, Risk and Compliance, Solution Manager, Data Quality Manager, Graphical User Interface, Single Sign On, System Landscape

Directory and other related SAP applications. 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 S4 HANA. This option was not selected at this time because it is part of the long-term digital plan and requires substantial planning and investment; and (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, maximizing the value derived from the effort.

- The **Service Suite Upgrade** project requires $425,488 in capital and $36,657 in O&M in the test year. The project will: (1) implement a new version of Service Suite Work Management that allows for easier distribution of work orders to the field; and (2) maintain a current version on a vendor supported platform for this critical enterprise application used across Operations and Engineering. The Service Suite Application is the mission critical work management software delivering work orders for customers. The current solution lacks an integrated view of traffic and a readable dispatch work schedule. The upgrade will improve application deployment and keep the application current to maintain vendor support. The project will add value by: (1) implementing a new version that provides the appropriate level of vendor support for this 24x7 critical solution that provides over 100,000 work orders to the field weekly; (2) implementing Service Suite Workforce Management and migrating to cloud-based configurations that will simplify support and speed deployment of future changes; (3) providing the new feature of live traffic display on the Dispatch Application which will allow for better dispatch decision making; and (4) improving the readability and usability of the Dispatch Application schedule view, which will allow for a better understanding of employees' work schedule. The scope of the project includes: (1) implementing the new version of Service Suite Workforce Management; and (2) integrating to a mobile mapping and driving directions application with Service Suite for mobile mapping on the field device to improve safety, response, usability, and supportability of the system. The alternatives considered included: (1) remaining on the current Service Suite version, which requires additional manual steps in the emergency response and work assignment; (2) creating a custom-developed solution, which increases waste and inefficiency, without the same level of Enterprise Resource Planning integration; or (3) changing the current vendor—which was not selected due to the increased complexity of migration and organizational change management. Upgrading Service Suite Field Service Management was chosen because it allows the Company to stay on the supported and familiar platform already being used in the field and provides additional business value and benefits to operations.

- The **SharePoint 2016 and K2 4.7 Replacement** project requires $87,929 in capital and $186,480 in O&M in the test year. The project will upgrade

SharePoint 2016 to SharePoint Online and replace the K2 4.7 platform with the Microsoft Power Apps Platform. The SharePoint K2 platform is a tool for building and running automated business processes that include forms, workflows, data, and reports, and is widely used across the Company. More than 7,000 Company employees and approximately 3,000 Company internal sites use SharePoint for collaboration and information sharing, documentation, business processes and forms, or reporting, among other business functions. The SharePoint 2016 platform loses standard vendor support in July 2021. K2 4.7 support is end of life and not available after 2021. Lack of vendor support results in the inability to receive and install security patches, leading to security vulnerabilities. In addition, vendor support will not be available for incident and defect resolution, which can lead to stability and performance issues. The project adds value to the Company by migrating from the on-premise version of SharePoint 2016 to SharePoint Online and from K2 to the Power Apps Platform, including Microsoft 365 Cloud-based hosting, which extends and enhances the existing SharePoint 2016 platform by providing additional functionalities and an enhanced user experience. By moving to the Power Apps Platform for reporting and workflows, the Company can eliminate K2 vendor support, saving license, maintenance, and support costs. The project scope includes: (1) rewriting 37 customized applications written on the K2 4.7 platform to the Microsoft Power Apps Platform; and (2) migrating all data in the existing SharePoint 2016 environment to SharePoint Online. Alternatives considered include: (1) Continue to use SharePoint 2016/K2 without vendor support. This alternative was not selected because of the inability to receive and install security patches which leads to unacceptable security vulnerabilities. (2) Continue to use SharePoint 2016/K2 and pay extended support. This alternative was not selected because extended maintenance costs for SharePoint are cost prohibitive and vendor support is not available for K2 after 2021; and (3) Migrate all business content to OpenText. This alternative was not selected because SharePoint Online is the Company standard for all business content, the application does not allow for flexibility and user experience needed to perform many business processes, and should only be used for very specific requirements the preferred solution cannot satisfy. The alternative to upgrade to SharePoint Online and Power Apps Platform was selected because it builds on the Company plan of moving to cloud and uses existing licensing agreement investment with Microsoft for both SharePoint Online and the Power Apps Platform.

- The **SiteCore Upgrade 2022** project requires $39,383 in capital and $73,468 in O&M in the test year. The SiteCore Upgrade 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 consumersenergy.com website, a channel many customers use for accessing account information and bill payment. The application requires regular upgrades to ensure system reliability, take advantage of new application features, and improve the customer's website experience. The Sitecore upgrade provides these four benefits: (1) maintains currency with the web hosting application version; (2) allows business users to make use of new features and functionality; (3) neutralizes continually evolving cyber threats; and (4) continuously improves customer experience using consumersenergy.com. 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; (2) upgrading the Coveo software, which will allow for more intuitive search results, increase search performance, and provide suggestions or recommendations based on the customers search text; and (3) upgrading the Mongo database, which provides the analytics functionality within Sitecore. Alternatives considered included: (1) implement a two-year upgrade cycle, which was not chosen due to the rapidly changing feature set being developed by the vendor, as well as not being able to position the Company to keep up with constantly changing cyber threats; (2) purchase an existing cloud solution, which was not chosen as the cost/benefit analysis revealed this option is not viable at the time of filing; and (3) annually upgrade the existing Sitecore platform, which was chosen as it provides the functionality and stability needed, is cost effective compared to alternatives, and mitigates cyber security risks.

- The **SiteCore Upgrade 2023** project requires $105,815 in O&M in the test year. The SiteCore Upgrade 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 consumersenergy.com website, a channel many customers use for accessing account information and bill payment. The application requires regular upgrades to ensure system reliability, take advantage of new application features, and improve the customer's website experience. The Sitecore upgrade provides these four benefits: (1) maintains currency with the web hosting application version; (2) allows business users to make use of new features and functionality; (3) neutralizes continually evolving cyber threats; and (4) continuously improves customer experience using consumersenergy.com. 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; (2) upgrading the Coveo software, which will allow for more intuitive search results, increase search performance, and provide suggestions or recommendations based on the customers search text; and (3) upgrading the Mongo database, which provides the analytics functionality within Sitecore. Alternatives considered included: (1) Implement a two-year upgrade cycle. This alternative was not chosen due to the rapidly changing feature set being developed by the vendor, as well as not being able to position the Company to keep up with constantly changing cyber threats; (2) Purchase an existing cloud solution. The cloud solution was not chosen as the cost/benefit analysis revealed this option is viable at the time of filing; and (3) Annually upgrade the existing Sitecore platform. This alternative was chosen as it provides the functionality and stability needed, is cost effective compared to alternatives, and mitigates cyber security risks.

- The **Software Platform Refresh** project requires $249,339 in O&M in the test year. The Software Platform Refresh project will upgrade server operating systems, hypervisors (virtual machine monitors), and databases to retain low-cost, unlimited vendor support. The Company has systems that are within three years of normal manufacturer support ending. At the end of three years, there will be increased support and maintenance fees. 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. 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. The project scope includes: (1) upgrading operating systems and databases on servers that are within three years of end of support; and (2) maintaining hypervisors at the current version for stability and performance. 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; and (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.

- The **SQL Server Database Upgrade** project requires $22,892 in capital and $58,320 in O&M in the test year. This project supports critical applications such as the meter read collection systems and the customer contact center applications, and will upgrade all SQL Server 2000–2014 instances to the latest version. The Company is currently managing SQL server databases that run on multiple legacy versions of SQL Server: 2000, 2005, 2008, 2012, 2014, and 2016. Extended vendor support for 2016 ends in July of 2026. All other versions are beyond their end-of-support dates, and extended support is not available from the vendor. Without vendor support, the databases no longer receive security patches, bug fixes, or functionality support from the vendor, which creates security, stability, and reliability risk. Microsoft continues to release new major versions every two years, on average, requiring the Company to upgrade more frequently to keep pace with new releases and remain in support. This project will create value for the Company and its customers by: (1) reducing the risk of system failure and the resulting impact to business partners and customers; and (2) ensuring that systems are secure, supported, and have the latest features and functionality. Project scope includes: (1) upgrades to all SQL Server 2000–2014 instances currently in use and not identified as part of another portfolio upgrade project, legal hold, or pending system retirement (approximately 400 instances); (2) installation and/or distribution of new SQL Server Client Tool software packages to affected workstations and application servers; (3) new Nimbus virtual machine templates for the new SQL Server release; and (4) technical database support to IT portfolios, business partners, and vendors during all project phases. The alternative considered was to migrate to Azure Cloud. As part of this option, the organization would obtain three years of extended support through Microsoft on SQL Server versions 2005–2008. This option was not selected because it did not address SQL Server versions beyond 2008 that are nearing end of Premier Support. In addition, the organization would not reap the benefits of new features offered through a version upgrade. The Company decided in favor of the upgrade to avoid these issues and ensure system stability.

- The **Website Redesign** project requires $2,517,518 in capital and $464,738 in O&M in the test year. The Website Redesign project will implement an updated online experience through changes to the customer self-service platform. The project will address known and reported customer issues with the existing experience, update the site to modern and secure architectures, leading to improved overall customer satisfaction and reliability. The new features will help to achieve a five to seven point increase in Customer Experience Index ("CXi") goals through improved website features. The outdated technical components increases the risk of cyber attacks and incidents which impact the reliability of the self-service portal. Additionally, in order to deliver an effective customer experience, the customer self-service portal needs to be optimized to deliver world class experiences in key customer transactions, ensuring the technical foundation can support future expansions. Without a thoughtful redesign that can aid in delivering a faster, more user-friendly and engaging interface, the Company will not be able to meet customer expectations for self-service capabilities, reduce cyber risk, and ensure site reliability. The Company and its customers will gain value from this project through: (1) improved technology footprint supporting the website increasing reliability and limiting cyber risk, (2)improved self-service capabilities on the customer portal supporting desktop and mobile web users, (3) simplified processes for online transactions increasing success rate which reduces calls to contact centers, (4) improved ease of use and enjoyment of the website experience improving customer satisfaction and CXi scores, and (5) enhanced user interface personalized to the customers usage profile which increases enrollment and engagement in clean energy solutions. The project scope encompasses: (1) improving website technology platforms to support an upgraded architecture improving reliability and security, (2) implementing new designs within the digital platform by partnering with a third-party firm for a better customer journey, (3) implementing ease of use capabilities to better support customer needs, and (4) continuing integration with existing systems to maintain functionality that supports customer self-service. Alternatives considered include: (1) Migrate the website to the cloud without redesigning the current solution. This alternative was not selected due to the complexity in migrating the solution to an external provider, financial implications, and the minimal value that it would add to the solution; (2) Modify the website visuals and delay the underlying foundation upgrade. The Company chose to avoid this alternative as it only addresses the customer experience aspect of the problem. The existing self-service portal requires an upgrade to meet current technology standards; delaying this upgrade creates a security and reliability risk along with limiting ease of use features; and (3) Complete a redesign of the website to an improved and modern infrastructure. This alternative was selected because it addresses key customer pain points and provides the necessary technical upgrades to ensure customers can continue to utilize the website as their channel of choice.

Q. Please describe Confidential Exhibit A-134 (DDP-10).

A. Exhibit A-134 (DDP-10) 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 2021 capital expenditures;
- Column (d) provides total projected 2021 O&M expense;
- Column (e) provides total projected 2022 capital expenditures;
- Column (f) provides total projected 2022 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-134 (DDP-10) is not inclusive of all applications that may be included 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
- The timing for 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 are the Application Currency projects:

- The **Application Currency - Capital** and **Application Currency - O&M** 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. 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. 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. 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. 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-134 (DDP-10).

Project	Capital	O&M
Application Currency-Customer Experience & Operations (CX&O)-Capital	$72,024	$78,840
Application Currency- Customer Experience & Operations (CX&O)-O&M	$0	$71,090
Application Currency-Corporate Services-Capital	$58,520	$12,510
Application Currency-Corporate Services-O&M	$0	$154,323
Application Currency-Enterprise Products and Services (EPS)-O&M	$0	$185,774
Application Currency-Operational Technology-Capital	$4,775	$1,539
Application Currency-Operational Technology-O&M	$0	$19,020
Application Currency-Operations-Capital	$132,682	$68,945
Application Currency-Operations-O&M	$0	$76,195
Application Currency-Product Transformation and Quality (PTAQ)-Capital	$49,156	$24,476
Application Currency-Transformation, Engineering & Operations Support (TEOS)-O&M	$0	$64,403

Q. Please describe Exhibit A-135 (DDP-11).

A. Exhibit A-135 (DDP-11) 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 2015 through 2023. 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 (l) identify the projected or actual capital amounts for each year; and

- Columns (m) through (r) identify the projected or actual O&M amounts for each year.

Page 2 provides an analysis of total projected and actual 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 (j) identify the projected or actual amounts by year; and
- Column (k) identifies the projected amounts for the test year.

Total Projected and Actual amounts are derived from Exhibit A-135 (DDP-11), page 1, which are the source for the figures indicated. Total Company incremental annual worklist 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 annual demand is defined as the total fulfilled and unfulfilled enhancement demand for the year, calculated by the sum of total Projected/Actual 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. Enhancement requests often increase in areas where the Company is actively investing in technology and new capabilities as the opportunity to optimize those investments is greater. Enhancements benefit customers and the Company through cost savings, cost avoidance, productivity improvements, safety improvements, efficiencies, mandated regulatory changes, and improved customer experience.

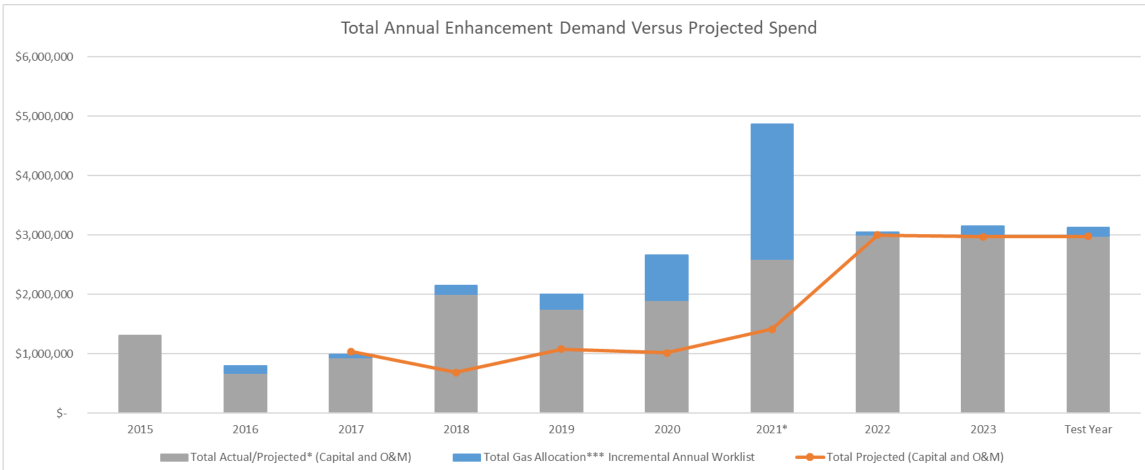
Q. How does the Company track and manage enhancements?

A. The Company actively maintains a worklist of enhancements. Each enhancement is tracked in detail from idea to completion including steps for value justification, estimation, prioritization, final funding approval, execution, and closure. In order for an enhancement to seek funding approval, it must be qualified with a cost estimate to ensure the enhancement is ready for execution. Once approved for funding, the enhancement is scheduled. When the enhancement begins execution, the status for enhancement records are updated by enhancement request coordinators on a weekly basis 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 increased an average of 36.2% over the past three years as a result of increased automation efforts, focus on waste elimination and cost optimization, additional functionality requests to optimize aging applications, and enhanced functionality requests for newly implemented technology. In fact, the Company outspent projected capital and O&M in 2020 by 88% and is on track to exceed projected spend levels again in 2021, as reflected in the summary for Exhibit A-135 (DDP-11). In addition, as of October 2021, the Company has a growing worklist of 517 requests

Company-wide to improve multiple applications and systems. This known worklist demonstrates the high level of demand for smaller technology efforts. Despite exceeding the projected spend, the Company is unable to keep up with the growing demand for enhancements, as shown on Exhibit A-135 (DDP-11), page 2, and in the following graph.

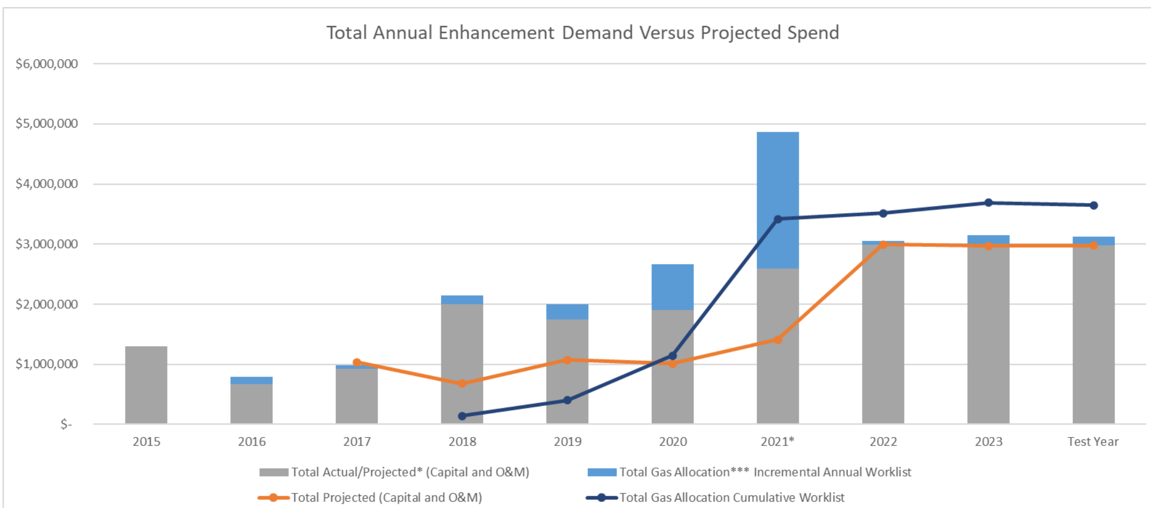


To recognize this increasing demand and better project Enhancement costs, the Company is projecting these costs by determining incremental enhancement demand for 2022 and 2023 based on a known worklist, plus applying a combination of historical demand and historical spend. The projected level of demand still outpaces projected spend, as indicated above.

Q. What method is the Company using for projected enhancement demand expenditures and expenses in the test year?

A. For the test year, the worklist provides a basis for total enhancement demand. In order to provide a consistent and stable projection approach, the Company analyzed historical averaging methods to smooth projected enhancement expenditures and expenses. The Company determined the average annual increases based on a three-year historical average of actual spend for the historical 2019-2021 period, added incremental increases for new programs like the Enhancements-CX&O-Capital, Digital - Foundational Enhancements, and Enhancements - Cloud Automation as defined and explained in my testimony and driven by the Digital Plan, and added these projections to the planned worklist to total the $2,975,191 test year ask.

Projections for the total cumulative worklist in 2022 and 2023 are based on the three-year average annual increase to enhancement demand. As indicated, enhancement requests grew at an average annual rate of 36.2% over the past three years. As a result, the cumulative worklist for enhancements continues to grow year over year, as depicted on Exhibit A-135 (DDP-11), page 2, Chart 2, and in the following graph.



By basing the projected Enhancement spending on a known worklist and a three-year historical average of actual spend, plus known incremental increases, the Company's test year projected spend is still 18% or $670,431 less than the expected cumulative worklist.

Q. Please explain the Enhancements projects.

A. The following are the Enhancements projects:

- The **Enhancements-Cloud Automation** project requires $147,936 in capital and $97,982 in O&M in the test year. The Enhancements - Cloud Automation project provides funding for small changes and improvements to existing software to address requests needed due to changing business requirements. The Company's existing cloud automation platform consists of a number of scripts that automate the build of infrastructure such as servers, operating systems, databases, and application installations in minutes or hours. These scripts include security hardening and application of the latest patches. This project will maintain and improve these scripts to ensure they meet the latest security policy and requirements, and any changes to the way the operating systems, databases, or applications are configured. The value of this enhancement project is the implementation of small changes and functionality improvements to existing IT software application investments for Cloud Automation to realize hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. The scope of the enhancement includes requests that will be fulfilled to provide functionality for areas such as IT Infrastructure provisioning. The alternative would be to continue as is with existing scripts; however, this introduces security risks and additional manual steps to build infrastructure, which in turn, will lead to increased costs and risk of manual errors.

- The **Digital-Foundation Enhancements** project requires $117,639 in capital and $114,840 in O&M in the test year. The Digital Foundation Enhancements initiative will use both Capital and O&M funding to make enhancements to existing technology and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort technology changes. Failure to make these changes or update aging applications can have a direct negative impact on key business processes, increase support costs, and limit the Company's ability to consistently meet objectives. While these small-work software efforts are neither projects nor operational work, funding for resources is still required and the annual budget cycle should ensure it is provided so that the Company may leverage the value of existing IT investments and safeguard business processes. The value of regular upgrades and enhancements to foundational applications in the digital space lies in: (1) lessening the number of incidents; (2) increasing application stability, leading to fewer incidents; and (3) allowing the Company to leverage new functionality. The project will add value by: (1) enabling advanced and new functionality; (2) increasing the reliability and resiliency of Company applications; and (3) ensuring flexible, configurable platforms to scale and adapt with an evolving business landscape and customer expectations. The Company's digital foundation consists of platforms that provide capabilities for: (1) advanced analytics; (2) electronic content management; and (3) Agile and DevOps, among others. These capabilities are the underlying foundation for digital systems needed to help achieve the Company's goals for clean energy, gas system reliability and safety, and the products, services, and experience customers expect. This project ensures that the Company keeps these foundational platforms updated with the latest software releases to keep the platforms secure while adding features like newer advanced analytics capabilities or new bundled and improved cloud service offerings. In the near future, it is expected that more smart devices will exist on the grid and pipelines and in customer's homes. The ability to communicate securely and in a timely manner in order to manage the electric and gas systems effectively will require upgrading underlying platforms to conform with the latest security and communication requirements. The alternative considered was not providing the funding for foundational enhancements. However, this limits the Company's ability to meet customer expectations, reduce security risks, and maintain an optimal balance between keeping the application current and risking failure. This alternative could result in: (1) an increased number of incidents; (2) paying increased support costs; and (3) preventing employees from performing their daily tasks. Historically, specific budget was not allocated for enhancements work requiring efforts to identify funding for each request. As part of the review process the alternative considered was to not provide funding for the enhancements. However, this limits the Company's ability to make software changes to support process improvements, regulatory changes, and to meet legally required system changes.

- The **Enhancements - Capital** and **Enhancements - O&M** 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. 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. 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. 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. 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 portfolio Enhancement project are indicated in the table below.

Project	Capital	O&M
Enhancements-Corporate Services-Capital	$255,085	$30,600
Enhancements-Corporate Services-O&M	$0	$21,819
Enhancements-CX&O-Capital	$1,125,009	$47,160
Enhancements-CX&O-O&M	$0	$82,027
Enhancements-IT-Capital	$202,568	$0
Enhancements-IT-O&M	$0	$94,714
Enhancements-Operations-Capital	$280,872	$23,652
Enhancements-Operations-O&M	$0	$74,628
Enhancements-TEOS-Capital	$194,290	$0
Enhancements-TEOS-O&M	$0	$64,371

Q. Please explain the Digital Foundations and Capabilities projects.

A. These are the Digital Foundations and Capabilities projects:

- The **Cloud Automation Phase 6** project requires $108,075 in capital and $21,948 in O&M in the test year. The Cloud Automation Phase 6 project will add additional features and enhancements to the Company's cloud automation platform, improving the efficiency, quality, and speed to market of customer-facing and internal IT services. Provisioning IT infrastructure and cloud services is often a manual and tedious process requiring specialized skills, numerous steps, and hand-offs between teams, with varying levels of quality and security. This complexity delays the delivery of IT services to projects, affecting speed to market and resource, project, and finance budgets and costs. Ultimately, this affects Consumers Energy's ability to deliver and innovate using modern technology. This project provides value to the Company by: (1) extending the ability to deploy, use, and decommission public and private cloud services in an automated, on-demand, and secure fashion; (2) increasing the agility of IT; (3) lowering risk in running applications in the cloud, keeping systems and customer data available and safe; and (4) improving the efficiency, quality, and speed to market of customer-facing and internal IT services. The scope of this project includes adding between three and six features to the Company's cloud automation platform including: (1) support of deployment of lower tier (more critical) applications in the public cloud; (2) support of container (an application and its dependencies) deployment in the hybrid cloud; (3) data lake cloud storage automation; (4) automation of Machine Learning ("ML") and AI services; (5) additional lifecycle and governance tooling; and (6) Disaster Recovery ("DR") as a Service ("DRaaS") automation. Alternatives considered include: (1) deploying all critical applications only in the on premises and co-location data centers; (2) manually deploying containers; (3) avoiding container technology; (4) manually deploying data lake storage in the cloud; (5) deploying storage only in the on-premises or co-location data centers; (6) deploying services similar to the available public cloud ML and AI services in the on-premises and co-location data centers; (7) manually deploying ML and AI cloud services; (8) avoiding ML and AI services; (9) manually managing the lifecycle and governance of cloud services; (10) continuing with existing on-premises DR solutions; and (11) manually managing cloud DRaaS offerings. These options were not chosen as they would require significant investment in hardware and staff augmentation to perform the work. Further, the quality of manual deployment is inconsistent, often requires rework, and could expose Company data by accident, incurring further costs and delaying deployment. The complexity and effort involved in manually managing these technologies at scale is not practical, and severely limits the Company's ability to innovate by leveraging the technologies available in cloud services. The option of enhancing the Company's cloud automation platform was chosen for its potential to improve the efficiency, quality, and speed to market of customer-facing and internal IT cloud services.

- The **Core Applications Always On for Business** project requires $352,565 in capital and $63,316 in O&M in the test year. The project will implement 'always on' capabilities for core applications across data centers. 'Always on' implies zero or near zero planned downtime without performance degradation. The average duration of planned IT maintenance outages in 2019 was 11 hours. At a minimum, it takes 4.5 hours simply to shut down and re-start SAP. Other maintenance activities increase the duration of the outage, such as operating system patching, database patching, HR Support Pack upgrades, and infrastructure changes. Lengthy planned outages have a negative impact on: CXi scores when customers cannot pay bills, check on power outages, or perform other online transactions. The Advanced Distribution Management System requires a significantly reduced SAP outage duration in order to function effectively. In addition, lengthy planned maintenance outages are more challenging to schedule given the impact to core business applications that support critical business operations, especially during storms. The project will add value to the Company and its customers by reducing the duration and frequency of the planned IT maintenance outages through the development of 'always on' capability for core applications. Implementing an 'always on' capability will: (1) increase availability of the website; (2) reduce planned interruptions to critical business operations; (3) reduce planned downtime for customer contact centers; and (4) increase business partner productivity and eliminate workarounds. The scope of this project includes enabling 'always on' capability for several core applications including SAP, Outage Management System, Service Suite, ESB, and Sitecore. Alternatives considered included: (1) Breaking the scope into separate projects to be completed individually. This alternative was not selected because the efforts are interrelated and completing them separately could lead to duplication of work efforts, and therefore potentially higher costs; (2) Move all core applications to the cloud. This alternative was not selected because it does not allow for flexibility in solution design based on the unique requirements of each core application and will not optimize performance and costs; and (3) Combining the work efforts for each of the core applications into a single project, albeit in separate work streams or tracks, and allowing for flexibility in solution design. This alternative was selected because it provided the best balance between achieving the project objectives and controlling the cost.

- The **Digital-Application Programming Interface Fabric** project requires \$324,408 in capital and \$86,960 in O&M in the test year. This project provides foundational capabilities (a fabric) for Application Programming Interfaces ("API"), which are a set of technologies used to integrate applications within the Company and with external third-party applications. In short, APIs allow two applications to communicate with each other. This is a key technical capability necessary to enable multiple IT projects related to the Company's strategy for clean energy including: Electric Interconnection Billing and Payments; MISO Market User Interface Changes; Utility Analytics Mis-Phasing/Power Quality/Outage; Field Contractor Work Management Technology Enablement; Work Management Scheduling, Analytics and Reporting; and Distributed Energy Resources Management. The API capability this project deploys will also enable customer-focused projects including: Business Customer Interval Web Portal, Bring Your Own Thermostat Pilot, Customer Relationship Management Product Suite, and Large Customer Rate Tool. Consumers Energy currently has an on-premise API platform which provides basic API capabilities. However, the current solution lacks several key functionalities, including API cataloging and discovery, monitoring, logging, throttling, and important security features, that are part of a modern API fabric. The current environment is also insufficient to handle API management at-scale. As Consumers Energy's use of cloud-based applications increases, the Company requires robust, developer-friendly, API-based services for cloud-based integrations. The project will add value by: (1) implementing functionality to perform API services at-scale; (2) allowing partners to integrate with the Company's on-premises and cloud-based applications; (3) providing the ability to reuse integrations; (4) enabling monitoring of API traffic; (5) implementing functionality to perform API throttling (i.e., traffic management); (6) visualizing API traffic and analytics through key performance indicators; (7) enabling faster prototyping, testing, and deployment of integrations; and (8) providing operational tools for monitoring, incident management, and resolution. The project scope includes: (1) executing API on-boarding for several external partners without scalability constraints; and (2) configuring and deploying API services with out-of-the-box operations to achieve faster speed to market. Alternatives considered included: (1) remain on the current Tibco API Exchange Gateway product. This alternative was not selected because it does not meet the needs of the Company as detailed above; and (2) implementing an API fabric over a longer period, which would prevent the Company from being able to create integrations at the speed at which they are required, and with the security they demand.

- The **Digital-Data and Analytics in the Cloud** project requires $340,018 in capital and $51,008 in O&M in the test year. This project will extend the Company's current data and analytics environment into a cloud environment, which will enable data and analytics at-scale and enable the delivery of outcomes for the NGDP, Electric Grid Integration, customer programs, and other business needs. The Company currently has an on-premise data and analytics platform, "Data Lake," that houses multiple data attributes ranging from customer, grid, and operations. As the Company requires more predictive and prescriptive analytical use case outcomes, the current environment is insufficient to handle the data analytics at-scale for multiple use cases. Also, the current solution lacks the libraries of advanced ML, AI tools, and Industry-Standard Big Data Ingestion tools, which are standard offerings as part of Cloud environments, such as Amazon Web Services, Azure, or Google Cloud Platforms. The project will add value by: (1) providing the ability to perform data analytics at-scale; (2) allowing the ability to leverage the leading ML and AI tools to enable predictive and prescriptive analytics at-scale; (3) providing the ability to provision infrastructure at-scale rapidly; (4) enabling pay for use; (5) empowering faster prototyping, testing, and deployment of analytics solutions; (6) reducing total cost of ownership; and (7) providing operational tools for monitoring, incident management, and resolution. The project scope includes: (1) the execution of data analytics without scalability constraints; (2) flexible transitioning with technology platforms as they evolve; (3) the use of out-of-the-box ML and AI tools provided by cloud vendors; (4) new services and innovations on the cloud platform; (5) capacity pay per use; and (6) the foundation for future cloud migration and maintenance. The alternative considered to a cloud solution is to expand the on-premise infrastructure and purchase multiple tools to solve individual capability gaps. The Company did not choose this alternative because it is more costly than cloud due to higher infrastructure costs and a larger workforce required for implementation.

- The **Digital-Data Governance** project requires $193,040 in capital and $59,330 in O&M in the test year. This project will be used to establish data governance roles and responsibilities, processes, and the purchase of a tool to support best practices across the enterprise. Current operational processes result in poor data quality across various systems of record making it difficult to effectively report on and produce more advanced analytics to help the

Company achieve its goals relative to Electric Grid Integration, Gas Delivery, and Customer Experience. Individuals interacting with data today do not have a way of understanding the semantic definition associated with the data that they are using, posing a risk of misinterpretation or poor decision making. The project will add value by: (1) increasing productivity of data analysts across the Company by reducing time spent cleaning data; (2) improving business planning; (3) maximizing the use of data to make decisions; and (4) discovering where data lives and the definition of data elements. The project scope includes: (1) initializing key data domains and ownership across the Company through the creation of an overarching data governance process; (2) establishing processes and cadence for introducing new data elements into their domains; and (3) implementing technology through the selection of a data cleansing, data quality, data extract, and transformation tool, including enterprise-wide semantic definition. Alternatives considered included: (1) not implementing a data governance solution, potentially limiting the Company's productivity due to data quality and accessibility; (2) developing an internal tool to help manage the Company's data footprint. This option was not selected since developing this type of tool internally would cost far more than purchasing a third-party tool; or (3) purchasing a third-party solution. Purchasing a third-party solution was selected because the skillsets required to internally develop such tools are not available, and it would take a larger investment to upskill or hire individuals with this experience.

- The **Digital-Hybrid Cloud and Data Center Migration** project requires $1,042,734 in capital and $204,408 in O&M in the test year. 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. 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. 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 Parnall 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 managed service operational support costs; and (8) enable the use of a vast array of cloud services to support Company applications. The project scope includes: (1) promoting the robust Grand Rapids Main co-location data center to become the primary data center for on-premises IT services; (2) demoting the Company's Parnall data center to the disaster recovery data center for on-premises IT services; (3) analyzing applications for migration to cloud or retirement; (4) migrating applications from on-premises to cloud; (5) transforming applications to use cost-effective cloud services; (6) altering network architecture and deploying base infrastructure to allow each location (on-premises or in cloud) to function independently; (7) deploying cloud and on-premises 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 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. 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.

Q. What cost savings does the Company expect as a result of the implementation of the Digital–Hybrid Cloud and Data Center Migration project?

A. The Company expects the following annual total Company savings and gas allocation Capital and O&M cost savings for capital hardware, colocation data center lease costs, hardware and software maintenance, managed service provider, and ARP – Server and Storage O&M costs once the project is complete.

Projected Total Company Savings - Annual					
Capital	**Investments O&M**	**Operations O&M**			
Hardware	ARP -Server and Storage	Colocation Lease	Hardware/Software Maintenance	Managed Service Provider Support	Total Operations O&M
$5,060,984	$641,685	$809,503	$1,744,844	$846,003	$3,400,350
Projected Gas Allocation Savings - Annual					
Capital	**Investments O&M**	**Operations O&M**			
Hardware	ARP -Server and Storage	Colocation Lease	Hardware/Software Maintenance	Managed Service Provider Support	Total Operations O&M
$1,518,801	$231,007	$311,464	$672,664	$325,508	$1,309,636

- The **Digital-Work Automation** project requires $213,596 in capital and $118,890 in O&M in the test year. The Digital - Work Automation Project will implement and enhance Robotic Process Automation ("RPA"), ML, and AI platforms and develop automation tools. Many work processes are completed manually, leading to errors, and wasted time and resources. RPA, ML, and AI technology have advanced significantly, and can now automate complicated processes, eliminating errors and freeing up employees to complete other work. The project adds value to the Company by providing the platforms that will allow business areas to automate key processes. Each automation created on these platforms will reduce errors and improve overall productivity. The scope of the project will be to extend and leverage existing platforms, and enable new platforms to provide RPA, ML, and AI functionality, and to develop the automation tools, necessary to automate several key business processes. The alternative considered was to continue with existing manual processes, which prevents the business areas from reducing the risk of manual errors or improving productivity through automation. Providing foundational automation platforms and creating the automation allows the Company to maximize the benefits of automation in support of customers and employees.

Q. Are the expenses and expenditures identified here 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 more 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, support for its operational O&M requirements, and the inability to sustain with O&M funding based on a five-year historic average.

The digital investments presented in this case will enable the NGDP through increased visibility, monitoring, and control of the gas system; improved asset and work management capabilities; and advanced analytics. Continuing to base O&M funding on a five-year historic average requires the Company to prioritize dollars on operating, maintaining, and securing existing technology, and does not enable it to make important digital investments for the future. The Company's technology versions have fallen behind reasonable levels, and funding based on a five-year historic average does not enable the Company to patch and upgrade its systems to reasonable levels of version currency, putting systems at risk of growing cyber security threats and increasing performance risks to systems that customers depend on.

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-21148
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

HANNAH L. PATTON

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

Q. Please state your name and business address.

A. My name is Hannah L. Patton, 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 at Consumers Energy?

A. I am a Senior Accounting Analyst III in the Electric and Gas Revenue and Fuel Reconciliation section of the General Accounting Department.

Q. Please state your educational background and work experience.

A. I graduated from Albion College in May 2009 with a Bachelor of Arts degree in Economics and Management. I began working for the Company in January 2012 in the Electric Revenue and Fuel Reconciliation section of the General Accounting Department. I was an external auditor employed by Rehmann Robson from December 2007 through December 2011. I obtained my Certified Public Accountant license in February 2011.

Q. What are your responsibilities in your present position?

A. My primary responsibilities include the accounting for cost of gas, the analysis of gas revenues and costs, and the associated gas cost over- or under-recoveries. Additionally, I am responsible for accounting of the Company's Renewable Energy ("RE") Plan and voluntary RE programs, as well as the analysis of electric revenue and gross margin.

Q. Have you previously filed testimony with the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I filed testimony in the following cases:

- MPSC Case No. U-17631, the Company's 2013 RE Reconciliation Case;

- MPSC Case No. U-17803, the Company's 2014 RE Reconciliation Case;
- MPSC Case No. U-18081, the Company's 2015 RE Reconciliation Case;
- MPSC Case No. U-18241, the Company's 2016 RE Reconciliation Case;
- MPSC Case No. U-17918-R, the Company's 2016 Power Supply Cost Recovery ("PSCR") Reconciliation Case;
- MPSC Case No. U-20068, the Company's 2017 PSCR Reconciliation Case;
- MPSC Case No. U-20202, the Company's 2018 PSCR Reconciliation Case;
- MPSC Case No. U-20220, the Company's 2019 PSCR Reconciliation Case;
- MPSC Case No. U-20802, the Company's 2021 PSCR Plan Case;
- MPSC Case No. U-20542, the Company's Gas Cost Recovery ("GCR") Reconciliation Case; and
- MPSC Case No. U-21141, Carbon Offset Program.

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

A. The purpose of my direct testimony is to describe the accounting for the Company's renewable natural gas ("RNG") production facility.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-136 (HLP-1)	Sample Journal Entries – Renewable Natural Gas Facility.

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

A. Yes.

Q. Please describe the accounting for the RNG facility.

A. New general ledger accounts or unique identifiers in the Company's general ledger will be created to track all capital costs and other expenses related to the facility such as the feedstock, operational, and maintenance expenses. As described by Company witness

Kevin J. Watkins, the Company plans to record RNG assets as Products Extraction. Any operation or maintenance expense will also be recorded as products extraction in Federal Energy Regulatory Commission ("FERC") Accounts 770 through 791.

Q. How will the Company record the gas produced by the RNG facility and the related feedstock expenses?

A. The cost of feedstock will not be included in the GCR case. The gas produced from the RNG facility will be considered as used by the Company for internal use and it will not be sold to end-use customers. The feedstock expenses will be recorded first through FERC Account 773, Fuel, with an equal offsetting amount being recorded through FERC Account 811, Gas Use for Products Extraction, resulting in these feedstock expenses ultimately being recorded in FERC Account 819, Compressor Station Fuel.

Q. Will any costs be included in the GCR?

A. No, there will not be any costs related to the RNG facility reflected or included in the GCR case.

Q. How will the sale of the environmental attributes be recorded?

A. The sale of the environmental attributes will be recorded as Other Gas Revenues Account 495 and will offset the revenue requirement of the RNG facility as described in more detail by Company witness Neal P. Dreisig.

Q. Does this conclude your direct testimony in this proceeding?

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	)	Case No. U-21148
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

HEATHER M. PRENTICE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

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 and Laboratory Services 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 over 20 years and includes a variety of technical and managerial responsibilities as an environmental consultant.

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.

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, and U-20650.

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 Karen M. Gaston.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-137 (HMP-1)	Manufactured Gas Plant Sites Information; and
Exhibit A-138 (HMP-2)	MGP Environmental Response Cash Outflows - January 2020 to December 2021 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 $13.3 million that will be deferred (amortized) over 10 years, and approximately $935,500 in non-deferred (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.

<u>SECTION I – Information on MGP Sites</u>

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-137 (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 our customers. Predecessor companies were either acquired by Consumers Energy or no longer exist.

Q. Please describe Exhibit A-137 (HMP-1).

A. Exhibit A-137 (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.

<u>SECTION II – Need for Environmental Investigation and Remediation</u>

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 our 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-137 (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 16,699 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 Operation and Maintenance ("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.

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 – 2021
- Royal Oak - 2021

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 2020.

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.

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.

SECTION III – Costs and Prudence

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 2020 through December 2021 totals approximately $13.3 million in deferred (amortized) dollars, and $935,300 in non-deferred dollars for the period of October 1, 2022 through September 30, 2023.

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-138 (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-138 (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 to 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. Is a change being made to recover additional items as non-deferred (O&M) expenses?

A. Yes.

Q. Please explain.

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 is beginning with the test year for this case which is October 1, 2022 through September 30, 2023. These costs are in addition to the direct management or other O&M costs previously discussed.

Q. What is the amount of the additional non-deferred MGP expenditures?

A. The additional amount of non-deferred MGP expenditures is $935,500. These expenses are covered in Company Witness Karen M. Gaston's Exhibit A-56 (KMG-5).

Q. Were MGP environmental response activity costs incurred prior to January 2020?

A. Yes. Costs for environmental response activities for periods prior to January 2020 were reviewed and audited by Staff in Case No. U-20650 and earlier cases; therefore, these costs have not been included on Exhibit A-138 (HMP-2) in the current case.

Q. At how many of the sites will Consumers Energy incur costs during the period January 2020 through December 2021?

A. Costs will be incurred at 21 sites.

Q. Why were costs not incurred at two 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-138 (HMP-2).

A. Exhibit A-138 (HMP-2) shows the cash outflows for environmental investigation and remediation during the period January 2020 through December 2021 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-138 (HMP-2) includes projected costs. Costs for January through December 2020 are actual costs expended. Costs for January through December 2021 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 2020 through December 2021. The Company is also seeking approval of non-deferred (O&M) recovery of MGP expenditures for the test year that covers October 1, 2022 through September 30, 2023.

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 we serve. 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 main 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 selected six main consultants for the 23 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-138 (HMP-2) are for remedial actions. Remedial action costs were incurred at 19 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 was further divided into pre-NFA and post-NFA. Pre-NFA tasks included EGLE negotiations, preparation of NFA reports, property surveys, and recording use restrictions, etc. Post-NFA 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; and
6. NFA – pre- and post.

Q. Please briefly describe each of these activities.

A. **Site Investigation:** 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.

Remedial Investigation: 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.

Interim Response Activities: 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 activities associated with NFA can be further classified as pre-NFA activities and post-NFA activities. The pre-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 Pre-NFA activities. Post-NFA activities may include routine monitoring data collection, due-care activities, O&M, and reporting. The post-NFA activities may be required indefinitely.

Q. What is the current status of the 23 sites?

A. As requested in rate case, Case No. U-20650, the Company has added the current site status to Exhibit A-137 (HMP-1).

Q. What are some examples of environmental response activities that have either been completed during the January 2020 through December 2021 timeframe or are currently underway?

A. Examples of projects that have been completed or are underway include the following:

- Flint Court MGP site – A sediment investigation was completed in June 2020 to evaluate the preliminary nature and extent of sediment impacts observed by EGLE in Gilkey Creek downstream of the site's storm sewer outfall. A memorandum of the observations was provided to EGLE and no additional investigation or sampling activities in the creek are planned at this time. A video inspection of onsite and offsite storm sewers was also completed in June 2020 to document storm sewer conditions and to determine the relevance of the indirect GSI pathway. A draft NFA for the onsite portion of the MGP is currently being developed in consultation with EGLE.

- Kalamazoo MGP site – Based on feedback from EGLE, two nested pairs of groundwater monitoring wells were installed at the upgradient edge of the groundwater contamination plume. Results indicated that the upgradient plume is defined. Quarterly sampling of the new wells, and select other wells, was conducted, in addition to the annual sampling of nearly all project monitoring wells. DNAPL bail-down tests were conducted to assess the transmissivity and recoverability of DNAPL. Also based on EGLE feedback, several soil borings were drilled within the Pitcher Street right-of-way to assess the potential for shallow groundwater to intersect the storm sewer within Pitcher Street. Monthly observations of the Pitcher Street storm sewer have also been performed.

- Jackson MGP site - Bedrock investigations were performed in May 2020 and May 2021 to delineate the extent of deeper groundwater impacts. The investigations were performed in accordance with EGLE-approved Response Activity Plans. The results indicate that deeper groundwater impacts are delineated. Sub-slab soil gas sampling points were installed in the eastern Jackson Glass Works building and sampled in the 2nd quarter of 2020. Due to COVID, access for subsequent sampling was postponed by Jackson Glass Works. Access was granted in 2021 and sampling was performed in 1st and 3rd quarters, with the 4th quarter sampling pending. Results to date confirm no vapor intrusion is occurring at the Jackson Glass Works. Semi-annual groundwater sampling continued in 2020 and 2021, as well as periodic observations of the storm sewer in the area.

- Manistee MGP site (ongoing) – Completed sediment dredging in the Manistee River adjacent to and downstream of the former MGP site according to a EGLE and USACE approved work plans and permits. Work that was conducted between April and November 2020 included mechanical dredging approximately 21,945 cubic yards (CY) and hydraulic dredging approximately 125 CY of sediment; removal of a limited amount of instream in-situ solidification (ISS) material along the bank of the former MGP to allow for proper slope restoration; installation of backfill aggregate instream to stabilize the riverbanks as necessary; and, restoration of the disturbed bank and work areas on the Operational Site and former Relief Holder. Submitted a draft NFA to EGLE for the Operational Site in July 2021. Continue to evaluate groundwater concentrations to determine if the existing groundwater treatment system can be decommissioned at the former Relief Holder site or if it needs to operate for a short period of time to assist with remaining groundwater impacts following the stabilization project in 2019. The system is currently off and there are no plans to operate unless necessary.

- Owosso – A soil investigation delineated remaining NAPL present west of the former MGP property. The investigation also included installation of five (5) groundwater monitoring wells to refine the horizontal and vertical extent of impacted groundwater west of the site and installation of fourteen (14) soil vapor monitoring points (four around each of the three residential houses west of the site and two around Consumers' regulator building onsite). Four (4) quarters of groundwater and soil vapor samples were obtained between 2020 and 2021. The results indicate that groundwater impacts are delineated and vapor instruction is currently not a concern (with all results below applicable screening levels).

- Pontiac MGP site – Borings were completed and monitoring wells installed on offsite properties to delineate the extent of DNAPL on vacant, city-owned parcels and demonstrate that the vapor inhalation pathway was not complete in the vicinity of an addition to a church property. A geophysical survey was completed on accessible portions of the vacant, city-owned parcels to identify the presence of buried metallic anomalies. No significant anomalies were identified. Quarterly and annual groundwater monitoring confirmed that the extent of groundwater impacts has been delineated and that GSI and VI exposure pathways are not complete. In addition, Consumers Energy partnered with EGLE and the City of Pontiac to begin drafting a local groundwater use ordinance that will prohibit the installation of water wells on the MGP and adjoining, impacted parcels.

- St. Johns MGP site – Quarterly sampling of sub-slab soil gas sampling points within a residential portion of the former FC Mason manufacturing building redevelopment was performed. Additionally, monthly storm sewer sampling has been undertaken, which has included an upgradient manhole location, two down-gradient manhole locations, and the outfall to the County drain. Dye testing to confirm the discharge location was also performed prior to initiating outfall sampling.

Additionally, investigations, routine monitoring, reporting, and pre- and post-NFA 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. Yes. For the period of January 1, 2020 through August 30, 2021, Consumers Energy obtained formal written approvals from EGLE for the following sites:

- Alpena MGP site – Limited Residential NFA Status Report was approved by EGLE on January 12, 2021.
- Jackson MGP site – Response Activity Plan approvals from EGLE for bedrock investigation and vapor intrusion assessment in 2020.
- Manistee MGP site – Sediment Dredging Response Activity Plan was approved by EGLE in March 2020.
- Mt. Clemens MGP site – NFA Status Report was approved by EGLE on August 23, 2021.
- Royal Oak MGP site – NFA Status Report was administratively approved in August 2021.
- Sault Saint Marie MGP site – Certificate of Completion Report was approved by EGLE in March 2021.

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 the EGLE. Inclusion of additional parameters or other requests suggested by the 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 are no active soil and groundwater remediation systems at the MGP sites.

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 ("LNAPL") 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 was shut down to evaluate the mobility of the remaining LNAPL and impacts on groundwater constituent concentrations.

Prior to the shut-down, the system had successfully performed the following:

- Removal of 437 gallons of LNAPL, approximately 3,000 lbs. of dissolved contaminants via 29 million gallons of contaminated groundwater extraction and treatment, and approximately 197 lbs. of contaminant mass via vapor extraction and treatment;
- Based on carbon dioxide monitoring, about 57,000 lbs. of contaminants have been degraded via biological processes;
- Reducing the maximum contaminant concentration within the groundwater plume by up to 100% for polynuclear aromatic hydrocarbons at certain locations; and
- Providing hydraulic control to minimize further exacerbation and or migration.

The Company is currently evaluating whether to maintain or decommission the Jackson MGP multiphase extraction system based on the groundwater concentrations and findings from off-site assessments.

The Cross Street site remediation system at Manistee was shut down to evaluate the impacts on the groundwater constituent concentrations. An evaluation of whether the system needs to be restarted as a polishing step for a period of time following the in-situ soil stabilization in the area of the former holder is necessary, in addition to an evaluation of whether the system should be decommissioned.

Q. Were there any 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	)	Case No. U-21148
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

HEATHER L. RAYL

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

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 Rate Analyst III in the Revenue Requirement and Analysis 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's Program in Professional Accounting 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 was employed as a Staff/Senior Auditor at Ernst & Young, LLP – Detroit. My responsibilities included the planning, execution, and completion of financial statements and compliance audits for a variety of health care and financial services clients. In 1995 through 1999, I joined M-CARE, a non-profit Health Maintenance Organization and a wholly owned subsidiary of the University of Michigan, as a Senior Financial Analyst in the Finance Department. My main responsibilities included financial statement preparation and analysis, general ledger analysis, and preparation and analysis of M-CARE's statutory annual reports.

From 2004 to 2005, 2009 to 2013, and 2018 to 2020, I worked for Consumers Energy as a Senior Accounting Analyst in Accounting Research and External Financial Reporting. My responsibilities included the research and documentation of numerous technical accounting topics for departmental clients, including United States Generally Accepted Accounting Principles ("GAAP") issues, United States Securities and Exchange Commission ("SEC") issues, utility/regulatory issues, and the preparation and documentation of numerous disclosures in the Company's Forms 10-K and 10-Q, with a primary focus in regulatory matters and business outlook.

In 2005, I joined FinCor Holdings, Inc. ("FinCor"), a medical malpractice insurance company, as a Senior Financial Analyst. My primary responsibilities included the management and coordination of the monthly close process and the preparation of GAAP and statutory financial statements and disclosures, including Regulation S-X compliant financials and Management's Discussion and Analysis of Financial Condition and Results of Operations. In 2007, I was promoted to External Financial Reporting Manager where my primary responsibility was the preparation of FinCor's Form S-1.

In 2013, I joined Consumers Energy's Rates and Regulation Department. During my tenure, I have held positions in Revenue Requirements and Analysis and Pricing and Rate Design sections of the Rates and Regulation Department as a Senior Rate Analyst II. I was promoted to the position of Senior Rate Analyst III in the Revenue Requirements and Analysis section of the Rates and Regulation Department in May 2020.

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.

Q. Please state the proceedings in which you have provided testimony.

A. I have filed testimony in Gas Rate Case Nos. U-18124 and U-18424; Gas Cost Recovery ("GCR") Plan Case Nos. U-17334, U-17693, U-17943, and U-18151; 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 July 31, 2017 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 two sections. Section I includes the supporting testimony and exhibits for the historical year results. Section II includes supporting testimony and exhibits for the projected test year revenue requirement calculation.

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 in order 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.

I. <u>HISTORICAL YEAR</u>

Q. What is the historical year used in your exhibits and supporting direct testimony?

A. Calendar year 2020 was chosen for the historical year.

Q. Please identify the exhibits that you are sponsoring to comply with the Commission's Filing Requirements for the historical year.

A. The following exhibits are being submitted to satisfy the historical year Filing Requirements:

Exhibit A-1 (HLR-1)	Schedule A-1	Revenue Deficiency (Sufficiency) for the Historical Year Ended December 31, 2020;
Exhibit A-1 (HLR-2)	Schedule A-2	Historical Financial Metrics - Gas Results Only;
Exhibit A-2 (HLR-3)	Schedule B-1	Rate Base for the Historical Year Ended December 31, 2020;
Exhibit A-2 (HLR-4)	Schedule B-2	Total Utility Plant for the Historical Year Ended December 31, 2020;
Exhibit A-2 (HLR-5)	Schedule B-3	Depreciation Reserve and Other Deductions for the Historical Year Ended December 31, 2020;
Exhibit A-2 (HLR-6)	Schedule B-4	Working Capital for the Historical Year Ended December 31, 2020;

Exhibit A-2 (HLR-7)	Schedule B-5	13-Month Average Balance Sheet Summary for the Historical Year Ended December 31, 2020;
Exhibit A-2 (HLR-8)	Schedule B-6	Point in Time Balance Sheet Summary for the Historical Year Ended December 31, 2020;
Exhibit A-3 (HLR-9)	Schedule C-1	Adjusted Net Operating Income for the Historical Year Ended December 31, 2020;
Exhibit A-3 (HLR-10)	Schedule C-2	Calculation of the Revenue Conversion Factor for the Historical Year Ended December 31, 2020;
Exhibit A-3 (HLR-11)	Schedule C-3	Operating Revenues for the Historical Year Ended December 31, 2020;
Exhibit A-3 (HLR-12)	Schedule C-4	Cost of Gas Sold for the Historical Year Ended December 31, 2020;
Exhibit A-3 (HLR-13)	Schedule C-5	Other Operation and Maintenance Expenses for the Historical Year Ended December 31, 2020;
Exhibit A-3 (HLR-14)	Schedule C-6	Depreciation and Amortization Expenses for the Historical Year Ended December 31, 2020;
Exhibit A-3 (HLR-15)	Schedule C-7	General Taxes for the Historical Year Ended December 31, 2020;
Exhibit A-3 (HLR-16)	Schedule C-8	Federal Income Taxes for the Historical Year Ended December 31, 2020;
Exhibit A-3 (HLR-17)	Schedule C-9	State Income Taxes for the Historical Year Ended December 31, 2020;
Exhibit A-3 (HLR-18)	Schedule C-10	Other (or Local) Taxes for the Historical Year Ended December 31, 2020;
Exhibit A-3 (HLR-19)	Schedule C-11	Allowance for Funds Used During Construction for the Historical Year Ended December 31, 2020;

Exhibit A-3 (HLR-20)	Schedule C-12	Pro Forma Interest Adjustment for the Historical Year Ended December 31, 2020;
Exhibit A-3 (HLR-21)	Schedule C-13	Interest Synchronization Adjustment for the Historical Year Ended December 31, 2020;
Exhibit A-4 (HLR-22)	Schedule D-1	Overall Rate of Return Summary for the Historical Year Ended December 31, 2020;
Exhibit A-4 (HLR-23)	Schedule D-2	Cost of Long-Term Debt for the Historical Year Ended December 31, 2020;
Exhibit A-4 (HLR-24)	Schedule D-3	Cost of Short-Term Debt for the Historical Year Ended December 31, 2020;
Exhibit A-4 (HLR-25)	Schedule D-4	Cost of Preferred Stock for the Historical Year Ended December 31, 2020; and
Exhibit A-4 (HLR-26)	Schedule D-5	Cost of Common Equity for the Historical Year Ended December 31, 2020.

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

A. Yes.

Q. How are these exhibits organized?

A. The exhibits are organized into schedules that present the development of the revenue deficiency (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 and Schedule F exhibits?

A. The historical year Schedule E exhibits are sponsored by Company witness Eric J. Keaton. The historical year Schedule F exhibits are sponsored by Company witness Alex M. Gast.

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 gas revenue requirement for the year ended December 31, 2020. 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 2016 through 2020. The calculation of the gas 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 ended December 31, 2020. The average rate base of $6.8 billion is disclosed on line 7. This amount 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 average 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 ended December 31, 2020. Adjusted NOI of $402.7 million is disclosed on line 33. This amount 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-21), Schedule C-13, support the development of the various components of adjusted NOI. Schedule C data for the historical year are generally sourced to the Company's 2020 Form P-522 Annual Report to the MPSC. In addition, Exhibit A-3 (HLR-13), Schedule C-5, reconciles the historical year other operating and maintenance ("O&M") expense by account, by witness with the other O&M expense amounts filed in the Company's 2020 Form P-522 Annual Report.

Q. Please describe the Schedule D exhibits for the historical year.

A. Exhibit A-4 (HLR-22), Schedule D-1, presents the overall rate of return summary for the historical year ended December 31, 2020. The total weighted cost of capital is shown on line 13, column (g), and is carried forward to Exhibit A-1 (HLR-1), Schedule A-1, line 4. Exhibit A-4 (HLR-23), Schedule D-2, through Exhibit A-4 (HLR-26), 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 $29 million for the historical year ended December 31, 2020.

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, 2020 are as follows:

		($ In Thousands)
Rate Base	$	6,807,907
Adjusted NOI	$	402,666
Overall Rate of Return		5.91%
Required Rate of Return		5.60%
Income Required	$	381,009
Income Sufficiency	$	(21,657)
Revenue Conversion Factor		1.3391
Revenue Sufficiency	$	(29,000)

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 adjustments and normalizations in Section II of my direct testimony, which covers the projected test year.

II. <u>PROJECTED TEST YEAR</u>

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 September 30, 2023 in this proceeding.

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-27)	Schedule A-1	Revenue Deficiency (Sufficiency) for the Projected 12-Month Period Ending September 30, 2023;
Exhibit A-11 (HLR-28)	Schedule A-2	Financial Metrics – Ratemaking Basis – Gas Results Only;
Exhibit A-11 (HLR-29)	Schedule A-3	Comparison of the Historical and Projected Revenue Requirement for the Projected 12-Month Period Ending September 30, 2023;
Exhibit A-12 (HLR-30)	Schedule B-1	Rate Base for the Projected 12-Month Period Ending September 30, 2023;
Exhibit A-12 (HLR-31)	Schedule B-1a	Development of Rate Base for the Projected 12-Month Period Ending September 30, 2023;
Exhibit A-12 (HLR-32)	Schedule B-2	Total Utility Plant for the Projected 12-Month Period Ending September 30, 2023;
Exhibit A-12 (HLR-33)	Schedule B-3	Depreciation Reserve for the Projected 12-Month Period Ending September 30, 2023;
Exhibit A-12 (HLR-34)	Schedule B-4	Working Capital for the Projected 12-Month Period Ending September 30, 2023;
Exhibit A-12 (HLR-35)	Schedule B-4a	Development of Working Capital for the Projected 12-Month Period Ending September 30, 2023;
Exhibit A-12 (HLR-36)	Schedule B-5	Capital Spending for the Projected 12-Month Period Ending September 30, 2023;

Exhibit A-13 (HLR-37)	Schedule C-1	Adjusted Net Operating Income for the Projected 12-Month Period Ending September 30, 2023;
Exhibit A-13 (HLR-38)	Schedule C-2	Calculation of the Revenue Conversion Factor for the Projected 12-Month Period Ending September 30, 2023;
Exhibit A-13 (HLR-39)	Schedule C-3	Operating Revenues for the Projected 12-Month Period Ending September 30, 2023;
Exhibit A-13 (HLR-40)	Schedule C-4	Cost of Gas Sold for the Projected 12-Month Period Ending September 30, 2023;
Exhibit A-13 (HLR-41)	Schedule C-5	Other Operation and Maintenance Expenses for the Projected 12-Month Period Ending September 30, 2023;
Exhibit A-13 (HLR-42)	Schedule C-5a	Summary of Inflation and Merit Increases Included in Other Operation and Maintenance Expenses for the Projected 12-Month Period Ending September 30, 2023;
Exhibit A-13 (HLR-43)	Schedule C-6	Depreciation and Amortization Expenses for the Projected 12-Month Period Ending September 30, 2023;
Exhibit A-13 (HLR-44)	Schedule C-7	General Taxes for the Projected 12-Month Period Ending September 30, 2023;
Exhibit A-13 (HLR-45)	Schedule C-8	Federal Income Taxes for the Projected 12-Month Period Ending September 30, 2023;
Exhibit A-13 (HLR-46)	Schedule C-9	State Income Taxes for the Projected 12-Month Period Ending September 30, 2023;
Exhibit A-13 (HLR-47)	Schedule C-10	Other (or Local) Taxes for the Projected 12-Month Period Ending September 30, 2023;

Exhibit A-13 (HLR-48)	Schedule C-11	Allowance for Funds Used During Construction for the Projected 12-Month Period Ending September 30, 2023;
Exhibit A-13 (HLR-49)	Schedule C-12	Pro Forma Interest Adjustment for the Projected 12-Month Period Ending September 30, 2023;
Exhibit A-13 (HLR-50)	Schedule C-13	Interest Synchronization Adjustment for the Projected 12-Month Period Ending September 30, 2023; and
Exhibit A-13 (HLR-51)	Schedule C-14	Development of Adjusted Net Operating Income for the Projected 12-Month Period Ending September 30, 2023.

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

A. Yes.

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 Keaton is sponsoring sales, load, and customer data (Schedules E) exhibits. Company witnesses Gast and Shawn C. Hurd are sponsoring cost-of-service allocation, present and proposed revenue, and proposed tariff sheets (Schedule F) exhibits.

Q. Please summarize the key findings for the projected test year exhibits.

A. As presented on Exhibit A-11 (HLR-27), Schedule A-1, the key findings from the exhibits for the projected 12-month period ending September 30, 2023 are as follows:

	($ In Thousands)
Rate Base	$ 9,308,109
Adjusted NOI	$ 346,663
Overall Rate of Return	3.72%
Required Rate of Return	5.96%
Income Required	$ 554,583
Income Deficiency	$ 207,921
Revenue Conversion Factor	1.3391
Revenue Deficiency	$ 278,421

Q. What inflation factors is the Company using in its presentation?

A. The Company is using an inflation factor of 3.3% for 2021, 2.1% for 2022, and an inflation factor of 2.0% for 2023, as forecast by IHS Markit and reported in the June 2021 edition of their publication *U.S. Economic Outlook.* IHS Markit is a leader in economic and financial analysis, forecasting, and market intelligence.

Q. Has the Company provided a summary of where these inflation factors have been used in the case?

A. Yes. Exhibit A-13 (HLR-42), Schedule C-5a provides a summary of the inflation 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-29), Schedule A-3; (ii) Exhibit A-12 (HLR-31), Schedule B-1a;

(iii) Exhibit A-12 (HLR-34), Schedule B-4; (iv) Exhibit A-13 (HLR-41), Schedule C-5; and (v) Exhibit A-13 (HLR-51), Schedule C-14.

Q. Please explain Exhibit A-11 (HLR-28), 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-29), Schedule A-3.

A. This exhibit presents the projected test year revenue deficiency for Consumers Energy of $278.4 million (line 10, column (f)). 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 12-month period ending September 30, 2023.

Q. What are the major differences between the historical year and the projected test year results shown on Exhibit A-11 (HLR-29), Schedule A-3?

A. The comparison of historical and projected results in Exhibit A-11 (HLR-29), Schedule A-3, shows that rate base increases by approximately $2.5 billion (line 4) and the rate of return increases from 5.60% to 5.96% (line 5). In addition, adjusted NOI (line 7) decreases by approximately $56 million from the historical year to the projected test year.

Q. Please describe Exhibit A-12 (HLR-30), Schedule B-1.

A. Exhibit A-12 (HLR-30), Schedule B-1, is a summary presentation of the projected test year average rate base. The average rate base for the 12 months ending September 30, 2023 is $9.3 billion as disclosed on line 8.

Q. Please describe Exhibit A-12 (HLR-31), Schedule B-1a.

A. Exhibit A-12 (HLR-31), Schedule B 1a, is a summary presentation of the development of the projected test year average rate base from Exhibit A-12 (HLR-30), Schedule B-1. Line 4 shows the average rate base for the historical year. Lines 5 through 7 show the adjustments to the historical year rate base necessary to develop the projected test year rate base. The adjustments to historical net utility plant (line 5) are the result of projected capital expenditures for 2021 through September 30, 2023, as provided by Company witnesses Adam S. Carveth, Audra L. Cumberworth, Neal P. Dreisig, Karen M. Gaston, Michael P. Griffin, Quentin A. Guinn, Cullen M. Hale, Timothy K. Joyce, Kristine A. Pascarello, D. Duncan Paterson, and Paul M. Wolven. These capital expenditures are summarized on Exhibit A-12 (HLR-36), Schedule B-5. The adjustment to historical net unamortized manufactured gas plant (line 6) reflects the projected test year amount supplied by Company witness Gaston. Working capital (line 7) is adjusted to reflect June 2021 balances along with certain other adjustments as shown on Exhibit A-12 (HLR-34), Schedule B-4. The projected test year rate base of $9.3 billion is disclosed on line 9.

Q. Please describe how the projected test year average plant and related amounts were developed.

A. Average gas plant and reserve balances for the projected test year were developed by taking the average of the balances at September 30, 2022 and September 30, 2023. Actual calendar year 2020 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 2021, calendar year 2022, and for the 9 months ending September 30, 2023; 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-32), Schedule B-2.

A. Exhibit A-12 (HLR-32), Schedule B-2, shows the total utility plant for the projected test year that was developed as described above. The total on line 9 is carried forward to line 1 on Exhibit A-12 (HLR-30), Schedule B-1.

Q. Please describe Exhibit A-12 (HLR-33), Schedule B-3.

A. Exhibit A-12 (HLR-33), Schedule B-3, presents the accumulated provision for depreciation for the projected test year by functional group. The total on line 19 is carried forward to line 2 on Exhibit A 12 (HLR-30), Schedule B-1. The increase in the projected accumulated provision for depreciation incorporates 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 2020 historical working capital (column (b)), which is first adjusted to reflect the 13-month average June 2021 ending balances shown in column (d), the most current study practical for inclusion at the time of assembling the case. The June 2021 average balances are then adjusted to reflect changes to: (i) gas stored underground as sponsored by Company witness Joyce; (ii) pension and other post-employment benefits ("OPEB") balances based on projections sponsored by Company witness Lora B. Christopher; (iii) prepaid cloud computing balances sponsored by Company witness Paterson; (iv) accrued tax balances; (v) deferred debits for a Standardization Engineering Analysis adjustment sponsored by Company witness Griffin; and (vi) cash balances sponsored by Company witness Bleckman. Details for the adjustments made to calculate the projected test year working capital are shown on Exhibit A-12 (HLR-35), Schedule B-4a.

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-36), Schedule B-5?

A. Exhibit A-12 (HLR-36), Schedule-B-5, provides a summary of capital spending as supported by Company witnesses Carveth, Cumberworth, Dreisig, Gaston, Griffin, Guinn, Hale, Joyce, Pascarello, Paterson, and Wolven. This exhibit provides capital spending for the bridge years and the projected test year as well as the approved and projected test year capital spending in Case No. U-20650.

Q. Please describe Exhibit A-13 (HLR-37), Schedule C-1.

A. Exhibit A-13 (HLR-37), Schedule C-1, presents the calculation of adjusted NOI for the projected test year of $346.7 million as shown on line 21. Total operating revenues (line 4) are netted against total operating expenses (line 15) to arrive at net operating income on line 16. Further adjustments are made on lines 17 through 20, which utilize normal ratemaking practices to arrive at adjusted NOI on line 21.

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 Federal Income Tax ("FIT") rate is 21.00%, the Michigan Corporate Income Tax ("MCIT") rate is 5.31%, and the City Income Tax ("CIT") rate is 0.16%, which results in a revenue conversion factor of 1.3391.

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. Lines 1 and 2 of the exhibit present the sales and transportation revenue supported by Company witness Keaton. The total on line 4 is carried forward to the Company's projected adjusted NOI presentation on Exhibit A-13 (HLR-37), 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 Keaton. This total is carried forward to line 5 of the Company's projected adjusted NOI presentation on Exhibit A-13 (HLR-37), 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 and line 28 were provided by Company witnesses Christopher, Amy M. Conrad, Cumberworth, Christopher T. Fultz, Gaston, Griffin, Guinn, Hale, Joyce, Pascarello, Paterson, and Wolven and are supported in their direct testimony and exhibits. Lost and unaccounted for ("LAUF") gas (line 7), company use gas (line 8), and total O&M expense (line 32) are carried forward to lines 6, 7, and 8, respectively, of the Company's projected adjusted NOI presentation on Exhibit A-13 (HLR-37), Schedule C-1.

Q. Please explain Exhibit A-13 (HLR-43), Schedule C-6.

A. Exhibit A-13 (HLR-43), Schedule C-6, presents depreciation and amortization expenses by functional grouping for the projected test year. The total on line 21 is carried forward to line 9 of the Company's projected adjusted NOI presentation on Exhibit A-13 (HLR-37), Schedule C-1. The calculated depreciation expense and associated accumulated provision for depreciation presented uses the book depreciation rates approved by the Commission in the Settlement Agreement in Case No. U-17653 dated May 14, 2015 and in its March 28, 2017 Order in Case No. U-18127. The book depreciation rate for the renewable natural gas production facility is supported by

Company witness Kevin J. Watkins. 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. Yes. The Company's electric and common plant depreciation case, Case No. U-20849, is currently pending before the Commission. If a final order in Case No. U-20849 is issued before a final order is issued in this proceeding, the Company proposes to utilize the depreciation rates approved in Case No. U-20849 and adjust depreciation expense included in this instant case accordingly. The total revenue deficiency in this proceeding would increase by $0.8 million if the rates proposed in Case No. U-20849 are approved as filed.

Q. Are there any concerns you would like to address regarding depreciation expense?

A. Yes. There has been discussion in past rate cases specific to fleet vehicles and the difference between the calculation of depreciation under GAAP and the methodology utilized by Utilimarc[1].

Q. Can you please explain the depreciation methodology under GAAP?

A. Yes. GAAP uses straight-line depreciation which methodically distributes costs over the approximate lives of assets and assigns a depreciation value evenly over several years (i.e. straight line) until the asset is fully depreciated. Accounting Standards Codification (ASC) 360-10-35-4 states:

[1]Utilimarc is an independent, third-party vendor for utility fleet analytics. Please refer to the testimony of Company witnesses Carveth and Christopher Schaffer for additional information regarding Utilimarc.

> Generally accepted accounting principles (GAAP) require that this cost be spread over the expected useful life of the facility in such a way as to allocate it as equitably as possible to the periods during which services are obtained from the use of the facility. This procedure is known as depreciation accounting, a system of accounting which aims to distribute the costs or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation.

Q. Does the Company have an option to deviate from utilizing the straight-line depreciation methodology in its accounting practices?

A. No.

Q. Are you familiar with the Utilimarc methodology for valuing (depreciating or devaluing) fleet vehicles?

A. I understand that Utilimarc uses an economic analysis and other methodologies to determine how fleet vehicles lose value for purposes of replacement.

Q. Does it concern you that Utilimarc uses a methodology different than straight-line depreciation for arriving at vehicle value?

A. No. Straight-line depreciation of fleet vehicles, while required by GAAP accounting standards, is a method of allocating costs of assets in a systematic and rational manner over the estimated useful lives of those assets. It is a process of allocation, not of valuation. It is my understanding that the Utilimarc study is a more precise analysis of the value of utility fleet vehicles and is meant to demonstrate a real-life value-based analysis of the loss of value of fleet vehicles over the life of those vehicles. While each of the depreciation or devaluation methods (i.e. GAAP straight-line depreciation and the Utilimarc methodology for devaluation) may "depreciate" the value of fleet vehicles in different ways, both methodologies are expected to reach the same or very similar end-of-life values.

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-37), 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 change in FITs.

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.

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 exhibits are part of the Filing Requirements. 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.

Q. Please explain Exhibit A-13 (HLR-51), Schedule C-14.

A. Exhibit A-13 (HLR-51), Schedule C-14, 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 (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 14, and projected test year adjustments on lines 16 through 29. Total adjusted NOI for the projected test year is shown on line 30. In general, the revenue and expense adjustments are shown with their accompanying tax impacts to arrive at adjusted NOI. The historic year NOI of $370.5 million on line 1, column (s), ties to the historic NOI on line 18 of Exhibit A-3 (HLR-9), Schedule C-1.

Q. Please explain the adjustments on Exhibit A-13 (HLR-51), Schedule C-14.

A. The adjustments on lines 2 through 14 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-51), Schedule C-14, line 15, column (s), of $402.7 million ties to the adjusted NOI on Exhibit A-3 (HLR-9), Schedule C-1, line 33.

Q. How were the projected test year adjustments on Exhibit A-13 (HLR-51), Schedule C-14, developed?

A. These adjustments represent the movement from the historical year adjusted NOI to the projected test year adjusted NOI. The adjustments on lines 16 through 29 are developed from my exhibits and supporting workpapers and from the exhibits of Company witnesses Christopher, Conrad, Cumberworth, Fultz, Gaston, Griffin, Guinn, Hale, Joyce, Keaton, Pascarello, Paterson, Brian J. VanBlarcum, and Wolven. The projected test year adjusted NOI on line 30 is the result of netting the projected test year adjustments on lines 16 through 29 against the historical year adjusted NOI on line 15. The projected test year adjusted NOI of $346.7 million on line 30, column (s), ties to the projected test year adjusted NOI on Exhibit A-13 (HLR-37), Schedule C 1, line 21.

Q. Please explain the projected test year adjustments on Exhibit A-13 (HLR-51), Schedule C-14.

A. Lines 16 through 19 represent the changes in gross margin from the adjusted historical year to the projected test year and are supported by Company witness Keaton. The change in projected other gas revenue from the adjusted historical year to the projected test year is supported by my workpapers.

Lines 20 and 21 represent the change in LAUF and company use gas, respectively, and are supported by Company witness Joyce.

Line 22 represents the change in other O&M expenses from the adjusted historical year to the projected test year and are supported by Company witnesses Christopher, Conrad, Cumberworth, Fultz, Gaston, Griffin, Guinn, Hale, Joyce, Pascarello, Paterson, and Wolven. The adjustments on lines 20 through 22 are summarized on Exhibit A-13 (HLR-41), Schedule C-5.

Line 23 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, the renewable natural gas production facility depreciation rate supported by Company witness Watkins, along with the projected capital expenditures and assumed plant retirements in the determination of the depreciation expense adjustment necessary to arrive at an appropriate level of book depreciation expense. The adjustment on line 23 increases depreciation expense for the projected test year due to significant new investment.

Line 24 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 25 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 2 and 3.

Line 26 represents the impact of CIT. The projected test year CIT expense is shown on Exhibit A-13 (HLR-47), Schedule C-10.

Line 27 reflects the impact of MCIT. The projected test year MCIT expense is shown on Exhibit A-13 (HLR-46), Schedule C-9.

Line 28 represents the FIT adjustments which result from the other changes in revenues and expenses in the projected test year. Line 28 also reflects the differences between the FIT expense calculated at the current federal statutory rate and the actual total income tax expense.

Line 29 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. This adjustment increases AFUDC because AFUDC is expected to be more in the projected test year than in the historical year.

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-21148

DIRECT TESTIMONY

OF

CHRISTOPHER SHAFFER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

Q. Please state your name and business address.

A. My name is Christopher Shaffer, and my business address is 1660 South Hwy 100, Suite 319, St Louis Park, Minnesota 55416.

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

A. I am employed by Utilimarc as President and CEO.

Q. What are your responsibilities as President and CEO of Utilimarc?

A. I am responsible for overall business strategy development and execution, which includes providing leadership company wide and making high-level decisions about policy and strategy; developing and implementing operational policies and strategic plans; acting as the primary spokesperson for the company; developing the company's culture and overall company vision; creating an environment that promotes great performance and positive morale; overseeing the company's fiscal activity, including budgeting, reporting, and auditing; working with senior stakeholders, CFO, CIO, and other executives; building alliances and partnerships with other organizations; overseeing day-to-day operation of the company, including review of Utilimarc reports; and working closely with department directors to ensure great hiring.

Q. What is your formal educational experience?

A. In 1994, I earned a Bachelor of Science degree in Sociology from the University of Wisconsin – Lacrosse.

Q. Would you please describe your work experience?

A. In 1994, after graduating from the University of Wisconsin – Lacrosse, I worked as a customer service and sales associate for United Van Lines, a transportation and moving company located in Eagan, Minnesota. In 1995, I left United Van Lines to become a sales associate for Lessors Incorporated, a full service refrigerated motor carrier trucking company also located in Eagan, Minnesota. Thereafter, in 1996, I was hired as the Vice President of Sales at Fil-Mor, Trucking and Logistics Company, located in Cannon Falls, Minnesota. Then, in 1998, I joined Professional Logistics Incorporated ("PLI") as their Vice President of Sales. PLI served as a consulting firm that provided fleet consulting to utilities and companies within a large fleet industry. Finally, in 2001, I co-founded Utilimarc and have served as its President and CEO since that time. I have worked with the Investor-Owned Utility industry from the inception of our legacy benchmark product to our evolution to a Business Intelligence platform for fleets, including a telematics offering.

Q. Are you a member of any professional societies or trade associations?

A. I am a member of the Electric Utility Fleet Managers Conference, National Association of Fleet Administrators, Midwest Energy Association, and the Western Energy Institute.

Q. Have you previously provided testimony before the Michigan Public Service Commission?

A. Yes. I provided written testimony on behalf of Consumers Energy Company ("Consumers Energy" or the "Company") in Case No. U-20963 (Consumers Energy's 2021 Electric Rate Case).

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

A. The purpose of my direct testimony is to present, describe, and support the outcomes of the recent study performed by Utilimarc for Consumers Energy. To that end I will:

- Describe Utilimarc and explain its work with utility fleets;
- Describe and support the 2021 Consumers Lifecycle Report prepared by Utilimarc; and

- Describe and support the findings set forth in the 2021 Consumers Lifecycle Report.

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

A. Yes. I am sponsoring the following exhibit:

Exhibit A-102 (CS-1)	2021 Consumers Lifecycle Report

Q. Was this exhibit prepared by you or under your direction and supervision?

A. Yes.

Q. Please briefly describe the exhibit you are sponsoring.

A. Exhibit A-139 (CS-1), the 2021 Consumers Lifecycle Report ("Utilimarc Report"), is a report prepared by Utilimarc for Consumers Energy. The Utilimarc Report presents the results of a study of the Company's existing fleet and future fleet needs, including findings related to investment necessary to achieve and maintain a fleet replacement strategy for the Company at a lower overall cost to customers.

<u>Utilimarc and the Utilimarc Report</u>

Q. What is Utilimarc?

A. Utilimarc is an independent, third-party vendor and industry leader for utility fleet analytics. Utilimarc began as a benchmarking company for businesses with fleets, such as Consumers Energy, and provided information to those businesses to help them understand their fleet ranking among peers related to matters such as age of fleet assets, mix of fleet assets, lifecycle of assets, and maintenance costs of assets. Utilimarc has since evolved to now also serve as a strategic partner with businesses to assist in maximizing the value of their fleets through the use of data analytics, statistical analysis, and real-world industry experience.

Q. What kinds of services does Utilimarc provide to various utilities?

A. Utilimarc's services include benchmarking of the utility's fleet; analytics of the utility's fleet using Telematics and operational data; dashboards which compile certain data sets to produce a toolset that assists the utility with executing on optimization of its fleet; Key Performance Indicator ("KPI") development; lifecycle development; and capital budget forecasting, staffing forecasting, and telematics.

Q. Please explain the benchmarking services Utilimarc provides to its utility clients.

A. Utilimarc's benchmarking application sheds light on the cost competitiveness of the utility's fleet and how that utility's fleet compares to other fleets industrywide. The Utilimarc benchmarking application standardizes the utility's data for use as consideration in operational decisions, which allows the utility to clearly set data-driven goals and objectives that aid in the optimization of that utility's fleet. As a result of Utilimarc's benchmarking services, the utility will receive vehicle class-specific queries, which include exceptions reporting for high cost, low performing vehicle classes; a utilization query; operating cost trends; mean time between service ratio; an aging query; staffing ratios; mechanic productivity analysis; a financial overview of the fleet; a fleet portfolio to show what percentage of a utility's fleet is a certain vehicle class compared to peer utilities; average miles per gallon by vehicle class; and average mechanic labor hours by vehicle class.

Q. Please explain the analytics services Utilimarc provides to its utility clients as it relates to Telematics, operational data, and KPI development.

A. Utilimarc's fleet analytics application provides a wealth of knowledge to its utility clients and becomes an important source of data when considering operational decisions. The analytics application integrates and connects multiple data sources into visual dashboards, updated on a daily basis, to empower our utility clients with performance insights across their entire fleet's operation. Data sources integrated within the application include Telematics, fuel cards, Fleet Management Companies ("FMC"), and fleet management system data. Our fleet analytics application provides utility managers with important fleet data that can be considered on a daily basis when determining operational decisions. With the application's unified platform and team of data analysts, Utilimarc can assist utilities with executing operational goals and objectives using quality data and insights, thereby resulting in smarter business decisions.

Q. Please explain the lifecycle development services, including the capital budget forecasting, staffing forecasting, and Telematics services, that Utilimarc provides to its utility clients.

A. Customers receive garage-level analysis providing utilization and replacement insights in order to determine the number of technicians to assign to each garage for maintenance purposes, which fleet assets to replace and when at each garage, and specific cases for capital forecasts based on the units and equipment remaining at each garage location.

Q. How many years has Utilimarc been assisting utility fleets?

A. Utilimarc has been assisting utility fleets for 20 years.

Q. How many utility fleets has Utilimarc assisted in the past 10 years and in what capacity?

A. Utilimarc has worked with 150 fleets in the past 10 years, providing 1 or more of our analytical services or products discussed above.

Q. How many of those 150 fleets have been located in the Midwest region of the United States?

A. Approximately 20 fleets have been in the Midwest region. Notable utilities include American Electric Power, Xcel Energy, Commonwealth Edison, Nisource, Nicor, Centerpoint Energy, DTE Energy, Ameren, and Kansas City Power and Light.

Q. How have Utilimarc's services evolved over the years as it has worked with public utilities?

A. Utilimarc started with a benchmarking service that compared like vehicles performing like work. The benchmarking was focused on utility vehicles and equipment. Since its origination, Utilimarc has evolved its services to now analyze additional data streams that are associated with large enterprise fleets - such as Telematics, Enterprise Resource Planning, Fleet Management Information Systems, FMC, and Fuel - as part of our Business Intelligence platform. The additional data streams allow Utilimarc to remove data silos and perform advanced analytics, including lifecycle development and fleet right-sizing and utilization metrics.

Q. What is Utilimarc's experience with Consumers Energy?

A. The Company has utilized Utilimarc for more than eight years for purposes of analyzing and benchmarking the Company's fleet and fleet performance against other utilities. The analytical and benchmarking type services previously explained in my testimony are the same services that Utilimarc has provided to the Company over the years. As part of those services, Utilimarc previously performed lifecycle studies and reports to assist Consumers Energy with its fleet replacement strategy. As described in my testimony, Utilimarc has since updated the Company's lifecycle study and report, which is reflected in the Utilimarc Report – Exhibit A-139 (CS-1).

Q. Please explain Exhibit A-139 (CS-1).

A. Exhibit A-139 (CS-1) is the Utilimarc Report. This report was generated in November 2021 to review and update what the appropriate lifecycle replacement plan should be for the Company's Fleet. The Utilimarc Report utilizes Utilimarc's Vehicle Replacement Module ("VRM"), which mathematically determines when Consumers Energy should replace its fleet assets. The VRM uses the Company's historic practices to predict future ownership and maintenance cost, ultimately determining what lifecycle will provide for the lowest total cost over the life of the fleet asset. Pages 2 through 5 of the report provide a summary of the lifecycle recommendations of the Company's top vehicle classes, as well as three capital funding replacement scenarios for the Company to consider. Pages 6 through 12 of the report provide an overview of the methodologies used by Utilimarc in its study. Further, pages 13 through 42 of the report provide the results of Utilimarc's study for each individual vehicle class of the Company.

Q. What were the Company's stated goals when engaging Utilimarc to prepare the Utilimarc Report?

A. Consumers Energy was looking to understand the economics of their Fleet Lifecycle Policy to determine the effect of capital spending on fleet performance, including ownership cost, operating cost, fleet age, and units out of lifecycle.

Q. Was Utilimarc able to perform an analysis supporting those stated goals?

A. Yes.

Q. What method was used to perform this analysis for Consumers Energy?

A. Utilimarc has developed a Lifecycle Model that calculates the economic lifecycle of each vehicle class and which also demonstrates the long-term effects on those vehicle classes based upon different levels of capital funding a utility might apply to those individual vehicle classes. This model is a tried and tested model, used for more than 20 gas and electric utility companies over the past eight years, and was applied for purposes of analyzing the Company's fleet in the Utilimarc Report for this proceeding. Using this model, based specifically on Consumers Energy's fleet and the Company's historic and recent lifecycle replacement expenditures, Utilimarc was able to demonstrate the long-term impact of different replacement scenarios on a variety of fleet variables for the Company, as shown in Exhibit A-139 (CS-1), pages 4 through 5.

Q. Please explain how the Lifecyle Model works.

A. The Lifecyle Model analyzes a fleet in two phases: (i) Lifecycle Analysis, and (ii) Capital Budget Analysis.

Q. What is the Lifecycle Analysis?

A. The Lifecycle Analysis calculates the economic lifecycle for Consumers Energy's largest vehicle classes (such as sedans, pickup trucks, service trucks, bucket trucks, and digger derricks), incorporating historic purchasing, sales, maintenance, and utilization data to determine what lifecycle leads to the lowest total cost over the life of the asset. In general, lifecycle means the age at which a unit is designated for replacement. Loosely put, the analysis identifies the point where it starts to become more expensive to continue to maintain an asset versus purchasing a new unit. This analysis uses the Mean Annual Cost Equivalent methodology by calculating the cradle-to-grave expense for each vehicle class for all possible lifecycles and determines which lifecycle provides the lowest mean annual cost.

Q. What was the result of the Lifecyle Analysis when applied to Consumers Energy's fleet?

A. The result is the class-specific set of lifecycles set forth on page 3 of the Utilimarc Report. The models for each class can also be found in the Utilimarc Report on pages 13 through 42, along with a more detailed description of this methodology on pages 6 through 12.

In general, the analysis identifies lifecycles of 9 to12 years for light-duty vehicles (Class 3 and under) and 12 to18 years for heavy-duty vehicles (Class 4 and above). Again, these are the points at which it becomes more expensive to continue to maintain an asset versus purchasing a new unit.

Q. What data was utilized to perform the Lifecycle Analysis?

A. The Lifecycle Analysis used five years of historic maintenance and utilization information from Consumers Energy's Fleet Management System to model future maintenance costs and three years of historic auction data to model future ownership costs.

Q. What was included in maintenance costs?

A. Historic maintenance costs include the cost of parts and labor for a repair handled by an internal garage or an outside vendor. A linear regression model is applied to historic maintenance values in order to predict future maintenance cost as equipment ages. If information was not available to model the maintenance of a specific class, a class average maintenance cost is used instead.

Q. Was the information available from Consumers Energy to model the maintenance of specific classes of units, or was a class average maintenance cost used in the preparation of the Utilimarc Report?

A. The classes that were modeled account for 75% of Consumers Energy's annual spend. The remaining classes are primarily off-road equipment (i.e. trailers, backhoes, trenchers) or vehicles that have too little information available for modeling. Class average maintenance cost is used for these classes in the Capital Budget Analysis. There is the potential that this will skew information, particularly in low funding scenarios, because the maintenance cost of these assets does not increase as they get older.

Q. What was included in ownership costs?

A. Ownership costs are calculated as the change in value of the asset overtime. This is determined by an exponential decay model applied to historic purchase prices and auction proceeds for each equipment class. Each asset loses, based on its class, 16% to 26% of its current value every year as a cost of ownership. For purposes of these studies, this will be called the Devaluation Rate. The Devaluation Rates for each class can be found on pages 13 to 42 of the Utilimarc Report. If information was not available for a specific class, the Devaluation Rate was assumed to be 18%.

Q. What is "Devaluation"?

A. Devaluation is a calculation of the cost of owning an asset. It is the difference between what the Company would receive if the vehicle was sold last year and what the Company would receive if the vehicle was sold this year. Mathematically, it is a decay model, where a fixed percentage of the vehicle's book value is lost each year. The percentage lost each year is a fixed rate based on the Company's historic purchase prices, how long they've held onto assets, and what they received at auction for assets. This percentage is typically between 16% and 26%.

Q. Does the Company use "devaluation" with regard to its fleet?

A. No. The Company applies a straight-line depreciation method, which applies a constant cost each year until the vehicle is fully depreciated.

Q. Please explain how the devaluation approach used by Utilimarc in its Utilimarc Report is different from the Company's straight-line depreciation method.

A. Devaluation takes a constant percentage of the vehicles value, rather than a constant cost. This means that devaluation cost is higher when the vehicle is young and lower when the vehicle is old, when compared to a straight-line depreciation method. Further, Generally Accepted Accounting Principles accounting straight-line depreciation is meant to approximate the lives of assets and evenly attributes loss of value over a number of years and doesn't reflect the actual way that vehicles lose value.

Q. Why is it important for Utilimarc to have used the devaluation in its report for purposes of determining an appropriate fleet lifecycle as opposed to a straight-line depreciation method?

A. Devaluation reflects the value of the asset seen in the marketplace and allows us to better incorporate the salvage value of the asset into the life-cycle model. We know that vehicles lose the most value when they're driven off the lot, but a straight-line calculation ignores this, implying that depreciation of a 1-year-old vehicle is the same as a 9-year-old vehicle. The vehicle is also never fully depreciated under the devaluation calculation. The vehicle is always worth something, even if it is only sold for parts, and this salvage value is incorporated into the calculation whereas straight-line depreciation does not. Finally, a straight-line approach creates computational difficulties in situations where the ideal economic life cycle may be shorter than the Company's historic depreciation cycle.

Q. Is the devaluation methodology utilized by Utilimarc a more accurate, economic analysis of the manner in which a fleet vehicle, specifically a utility vehicle, loses value?

A. Yes, because it recognizes that vehicles lose a lot of value up front and then more slowly over the years.

Q. What is the Capital Budget Analysis?

A. The Capital Budget Analysis shows what effect it would have on Consumers Energy's fleet if the Company provided different levels of capital funding over the next ten years. The analysis simulates the replacement of vehicles and equipment and estimates the effect of these replacements on ownership cost, maintenance cost, labor hours, average age, and units out of lifecycle.

Equipment is chosen for replacement in the following manner. Each equipment class is assigned a lifecycle value. For classes modeled in the Lifecycle Analysis, this value is set as the lifecycle that provides the lowest total cost over the life of the asset. For classes not modeled in the Lifecycle Analysis, this value was chosen by Consumers Energy based on historic policy. Equipment is chosen for replacement when it exceeds this lifecycle, subject to other restrictions set by each scenario.

Q. When is a class not modeled?

A. A class is not modeled when there are too few units in the class to meet the strict data requirements for the Lifecycle Analysis or does not track utilization information. This typically includes trailers, forklifts, backhoes, and other off-road equipment.

Q. How was the Capital Budget Analysis performed for the Utilimarc Report?

A. Three scenarios were run in the Utilimarc Report: (i) Even Replacement; (ii) Out-of-Life Replacement ("OoL Replacement"); and (iii) Approved Replacement. The results of each scenario can be found on page 4 of the Utilimarc Report.

Q. What do Even Replacement, OoL Replacement, and Approved Replacement signify in the Projections set forth on page 4 of the Utilimarc Report?

A. The Even Replacement scenario is one where Consumers Energy would replace vehicles that have exceeded their lifecycles; however, a cap is placed on the number of vehicles scheduled for replacement in a given year. Utilimarc typically recommends that companies, including utility companies such as Consumers Energy, purchase a consistent number of vehicles each year. Based on that approach, if a company owns 100 pickup trucks with a 10-year lifecycle, Utilimarc recommends replacing 10 vehicles each year. Mathematically, this cap is determined by taking the total number of vehicles owned by Consumers Energy in that class and dividing that number by the class lifecycle (rounded up). The goal of consistent replacement is to avoid unpredictable spikes in capital requests, maintenance cost, and vehicle availability which occur when a large portion of fleet is concentrated in a few vintages, called a "replacement bubble." This also protects fleet if there is a problem with a specific model year of truck. As demonstrated on page 4 of the Utilimarc Report, this scenario requires a capital commitment of $19.9 million in 2022 and approximately $18.9 million for the following four years. This capital commitment is somewhat atypical due to recent replacements.

The OoL Replacement scenario is one where Consumers Energy would replace vehicles that have exceeded their lifecycles, with no cap on the number of units replaced each year. Unlike the Even Replacement scenario, this scenario creates a large "bubble" due to a large portion of fleet already currently out of lifecycle. As demonstrated on page 4 of the Utilimarc Report, the capital commitment for this scenario is approximately $40.6 million in the first year but averages out to $29.7 million over the next four years.

The Approved Replacement scenario follows the Even Replacement scenario, but also puts a rough cap on capital spend to reflect the amount of gas lifecycle replacement expenditures previously approved by the Michigan Public Service Commission. As demonstrated on page 4 of the Utilimarc Report, while the capital commitment for this scenario is static at the amount of approximately $8.9 million, the average ages of the fleet units steadily rise over the years with a corresponding increase in maintenance expense for those progressively aging out-of-lifecycle vehicles. The Approved Replacement scenario sees additional maintenance costs compared to the Even Replacement scenario. Assuming consistent overtime and outsourcing practices, Consumers Energy would need to hire additional technicians to cover the increase in maintenance and plan for additional downtime based on the increase in labor hours needed to maintain the older fleet.

Q. Is Utilimarc recommending a certain course of spending for Consumers Energy?

A. No. Utilimarc is only providing the results of its analyses. The Capital Budget Analysis demonstrates the consequences of each replacement scenario so that stakeholders can determine the best course of action for their organization. There are other variables that stakeholders should consider in their discernment that are not included in this analysis, such as customer (driver) satisfaction, reliability, environmental impact, safety, and obsolescence.

Q. How should the results of each scenario be interpreted?

A. Each scenario calls for very different levels of capital commitment, but the total cost between the three scenarios is comparatively similar. What does change is where fleet dollars are being spent. The Even Replacement scenario spends more on ownership cost and less on maintenance cost as compared to the Approved Replacement. The Approved Replacement scenario sees an increase in the age of fleet, a pattern that will continue to increase at this level of funding. If this scenario is chosen, the Company needs to prepare for the increased labor hour demand of this older fleet. The Company would also need to plan for additional downtime based on this increase in labor hours, but many of the consequences of underfunding have been avoided in the short term by higher than approved replacement in the past two years.

Q. What assumptions are made in the Lifecycle Model?

A. The Lifecycle Model makes the following assumptions:

- 2% Inflation is added to all costs in future years;
- Annual utilization is assumed to be consistent for all vehicles within a class. No adjustments are made based on the age of the equipment;
- All units are replaced like for like and no increases or decreases in fleet size has been accounted for;
- A significant number of units were retained in 2020 to provide additional vehicles related to COVID safety measures. These vehicles are not included in this analysis; and
- Vehicle replacement is instantaneous at the start of each year.

Q. Has Utilimarc been engaged by other utilities to perform similar analyses?

A. Yes, more than 20 gas and electric utilities have used our Lifecycle Model over the last eight years to assist in their capital planning process.

Q. Are all reports performed for utilities the same?

A. No. The analysis for each utility is based on each company's specific inventory, maintenance, purchasing, and utilization data. No two reports are the same, and the same company will have different results if the model is run in different years due to changes in investment, inventory, maintenance, and other behaviors.

Q. Does the Utilimarc Report utilize Company data?

A. Yes. The Utilimarc Report, Exhibit A-139 (CS-1), utilizes the Company's data to determine the economic lifecycle for the Fleet.

Q. Was the Company's Fleet analyzed as a whole or was it broken down by different types of fleet assets?

A. The analysis is run at the class specific level. Each piece of equipment is assigned to one of 150 class codes based on its make, model, and typical job duties. Results of the class-specific analysis are then rolled up to the fleet level.

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 distribution of natural gas and for other relief.	)))))	Case No. U-21148

DIRECT TESTIMONY

OF

R. MICHAEL STUART

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

Q. Please state your name and business address.

A. My name is R. Michael Stuart, 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 Metrics and Strategic Planning.

Q. Please review your educational and business experience.

A. I graduated from Michigan State University in December of 1985 with a Bachelor of Arts Degree in Business Administration. Since joining Consumers Energy in June 2000, I have held various positions in the Supply Chain, Electric Meter Operations, Business Technology Support, Strategy Mobilization and Integration, and Quality Lean Office Departments.

Q. What are your responsibilities as Director of Metrics and Strategic Planning?

A. In the Director of Metrics and Strategic Planning 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. Have you previously filed testimony with the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I filed testimony in Case No. U-17643 and testified in Case Nos. U-17735, U-17882, U-17990, U-18124, U-18332, U-20650, U-20697, and U-20963.

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. Specifically, I will discuss Consumers Energy's EICP operational performance goals and how the EICP goals provide customer-related benefits.

Q. Are you sponsoring any exhibits?

A. No.

Q. Please explain the process for designing the Company's EICP goals.

A. Each year, the Company identifies key operational and financial goals to focus on for the next year. A list of these goals is provided in Exhibit A-35 (AMC-1). The EICP operational goals are key goals that focus on continuously evaluating work and delivery processes for opportunities to improve (e.g., waste elimination, first time quality, etc.) and enhance productivity and customer value, fulfilling the Company's purpose to provide world class performance delivering home-town service.

Q. Is there a direct tie between the design of the current operational incentive plan and desirable benefits for customers?

A. Yes. There is a direct tie between the current design of the operational incentive plans and desirable benefits for customers. The operational incentive plan focuses on safety, reliability, productivity, and customer value, which are all desirable benefits for customers. The Commission should permit recovery of these costs in the current case.

Q. Do you believe that benefits to customers from the EICPs 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 showing 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 quantitative benefits. The design of the EICP clearly leads to lower costs and improved service which benefit customers.

Q. Has the Company quantified customer benefits that are tied to its EICP?

A. Yes. Although specific quantification of the costs of the program and the benefits is not easy to perform for every metric included in the program, the Company has evaluated direct quantitative benefits of two key metrics of the program and has assessed indirect and/or qualitative benefits associated with the other metrics.

Q. What are the results of the direct quantitative benefits evaluations?

A. The benefits associated with just these two metrics confirm the Company's conclusion that there are substantial benefits that accrue to the customer. The first of those metrics is employee safety. Employee safety incidents decreased by 80% from 2006 through 2020. The resulting reduction in lost work days and medical expenses approximates $4.8 million of annual direct savings, and $8.4 million of annual average total savings that accrue to the benefit of the customer. The second metric that can be translated to cost avoidance for customers is in the area of electric distribution reliability. Using cost per outage minute estimates from Berkeley Labs,[1] the 5.3 minute annual average reduction in outage minutes from 2006 to 2020 results in annual economic benefits to customers in excess of $15.9 million.

Q. What are the results of the indirect and/or qualitative benefits assessments?

A. Each of the other metrics provides significant value to the customer. First, the Customer Experience Index goal focuses on ensuring that when customers contact Consumers

[1] https://www.osti.gov/servlets/purl/963320

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., reduces the number and duration of customer calls, which benefits the Company and the customer) and customer value (e.g., quick, easy, and enjoyable solutions for customer experiences). Second, the electric Generation Customer Value ("CVr") goal focuses on optimizing the use of the Company's electric generation fleet to maximize customer value. CVr measures the value customers realize from the Company's biggest seven fossil generators (D.E. Karn Units 1&2, J.H. Campbell Units 1, 2, & 3, Zeeland Combined Cycle, and Jackson Combined Cycle). The Company uses this metric to make sure we are maintaining reliability, planning outages effectively, and offering its units to the market correctly. It is ultimately a comparison between the production costs from these seven units to the cost of purchasing energy from the market. Third, the Employee Empowerment Index goal focuses on improving the employee experience and their 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.[2] Fourth, is Clean Energy where the Company prioritizes engaging with customers to enroll in electric demand response and Energy Waste Reduction programs to meet the framework of the Company's Integrated Resource Plan. Successfully completing this goal encourages customers to become engaged in actively controlling their energy costs. Reducing overall demand provides benefits for customers related to avoided capacity investments, reduced

[2] https://www.gallup.com/workplace/285674/improve-employee-engagement-workplace.aspx#ite-285704

emissions and better utilization of Company generation assets through an improved ability to balance and synchronize supply and demand.

Next are two goals that are generally associated with gas operations: (i) Methane Emission Reduction and (ii) Gas Flow Deliverability. Methane Emission Reduction measures the reduction in fugitive methane emission associated with natural gas distribution through the replacement of vintage and other materials. Gas Flow Deliverability measures the Company's ability to properly maintain natural gas distribution systems while maintaining overall station capability as compared to planned peak day capability. Both deliver customer benefits by improving safety for combination (electric and natural gas) and natural gas only customers and reducing the Company risk profile, which yields more favorable Company credit ratings and financing terms. Finally, are the benefits resulting from the Company's focus on its Cyber Safety goal related to minimizing phishing email click rates. There are a multitude of reasons to focus on phishing click rates. First, according to the 2016 Enterprise Phishing Susceptibility and Resiliency Report[3], 91% of cyber-attacks and the resulting data breach begin with a phishing email, phishing campaigns are up 55%, ransomware attacks are up 400%, and Business Email Compromise losses are up 1,300%. Second, the Company sees phishing attacks daily, including over 1,000 a month whose goal is to deliver ransomware. Ransomware continues to grow in its likelihood and impact with recent ransom payments reaching $30-70 million. The industry and Consumers Energy continue to see attacks by nation state attackers attempting to gain access to electric grid and natural gas infrastructure. Costs of such

[3]https://cofense.com/project/2016-phishing-susceptibility-report/

attacks would be in the millions and have a significant impact on Consumers Energy's customers.

Q. Has there been an attempt to quantify these indirect and/or qualitative benefits?

A. Yes. To quantify the benefit to customers of productivity and customer value metrics such as these, we can look at the Company's actual Operating and Maintenance ("O&M") costs versus what they would have been had they instead grown at the United States Consumer Price Index ("CPI") inflation rate. Since the Company began its deliberate focus on productivity and customer value EICP metrics, the Company's O&M costs have remained practically flat on average when compared against the 2006 performance baseline, while the United States CPI inflation rate grew by an average of 1.9% per year. The average annual savings during this time period is $279.6 million, which benefits customers.

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, productivity, and customer value helps keep employees focused on the importance of safety, reliability, productivity, and customer value for both the electric and natural gas operations. The quantified benefits of employee safety and O&M costs versus inflation show that benefits to gas customers clearly exceed the gas 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 customers.

Q. What portion of the indirect and/or qualitative benefits that you have quantified above do you conclude benefit gas customers?

A. A portion of the quantified benefits in the areas of employee safety, productivity, and customer value benefit gas customers. Utilizing an allocation of 34% for gas customers, this equates to annual savings for gas customers of $97.9 million, far exceeding the total costs of the EICP allocated to gas customers.

Q. Why did you use a 34% allocation to evaluate benefits to gas customers?

A. The 34% allocation is based on the total number of gas employees as a percentage of total number of Consumers Energy employees. Using the percentage of total employees is a reasonable allocation methodology to use to allocate the employee safety, productivity, and customer value 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 helps to highlight certain important elements of utility service and to emphasize to employees that they should pay attention to achieving these targets. Making it clear to employees that a portion of their total compensation depends upon their collective ability to meet these targets, communicates clearly to employees the importance of serving customers and encourages them to deliver their best performance. Because the EICP has been designed so that the incentive payments simply bring employee compensation to a competitive market-rate level, I think a better way to describe this program is that employees are penalized if the targets are not achieved.

Q. Do you believe that the EICP is the reason that the above benefits have been realized?

A. 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. By placing a portion of employees' market-based compensation at-risk, they are incentivized to deliver on the EICP goals related to safety, reliability, productivity, and customer value.

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, productivity, and customer value that results in broad customer benefits.

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-21148
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

BRIAN J. VANBLARCUM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

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, and
- Electric Rate Case No. U-20697.

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 September 30, 2023) 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. Finally, my testimony supports a request of the Commission to adjust the excess deferred tax balance ordered for refund in Case No. U-20309 based on an error discovered in the Company's original filing.

Q. Have you prepared any exhibits to accompany your direct testimony?

A. Yes. I am sponsoring:

Exhibit A-140 (BJV-1)	Development of the Property Tax Rate for the Test Year; and
Exhibit A-141 (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-140 (BJV-1), page 1, line 16, the Property Tax Rate for the test year is 0.014017112.

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 (Exhibit A-140 (BJV-1), page 1, line 10, divided by the total of the 2022 estimated year-end plant-in-service (Exhibit A-140 (BJV-1), page 1, line 11, plus one-half of the estimated 2022 Construction Work in Progress (Exhibit A-140 (BJV-1)), page 1, line 14.

Q. What is included in the Gas Property Taxes Paid – 2022 Estimate on Exhibit A-140 (BJV-1), page 1, line 1?

A. The Consumers Energy 2022 taxes paid of $157.4 million on behalf of the gas portion of the business represents estimated property taxes to be paid in 2022.

Q. What is included in the Gas Property Taxes on 2022 Plant Investment on Exhibit A-140 (BJV-1), page 1, line 2?

A. The $21.0 million increase is the estimated property taxes on the 2022 net additions that will be included in the 2023 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 50.2034 to obtain the estimated tax amount. This calculation is shown on Exhibit A-140 (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-140 (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 2023, the Company's property tax model assumes a CPI rate of 2.1%. This calculation is shown on Exhibit A-140 (BJV-1), page 3.

Q. What is the result of including the Gas Property Taxes on 2022 Plant Investment and the Gas Property Taxes on Real Property Taxable Value Increase on the estimated 2023 property tax amount paid by the gas business?

A. The result of including these additional items is an estimated 2023 property tax amount to be paid for the gas business of $178.5 million as shown on Exhibit A-140 (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, 49.7% of the 2022 estimated gas property tax payments for Consumers Energy is added to the 2023 estimated gas payments since that amount will be expensed in 2023, while subtracting 49.7% of the 2023 estimated gas payments that will be expensed in 2024, arriving at a total 2023 property tax expense of $168.0 million as shown on Exhibit A-140 (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 October 1, 2022 through September 30, 2023 using a monthly budgeted sales percentage applied to the 2022 and 2023 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 $161.7 million. The Prorated Property Tax Expense for the test year is divided by the 2022 estimated year-end plant-in-service plus one-half of 2022 Estimated Construction Work in Progress to arrive at an average tax rate of 0.014017112.

Amortization of Excess Deferred Federal Income Taxes for the Test Year

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 Calcualtion C Case No. U-20309 authorized the amount and time period under which the 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%. 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-141 (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 will have 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 refund to customers in this case?

A. As shown on Exhibit A-141 (BJV-2), page 1, line 22, the Company has proposed to refund an additional $653,000 of excess deferred taxes ($876,000 of regulatory liability after gross-up for taxes) in this case. This amount represents the Company's regulatory liability recorded as of year-end 2019 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 $876,000 regulatory balance, is included as Exhibit A-141 (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-141 (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 $4.772 million to reflect the amortization periods and amounts discussed above. This amount is shown on Company witness Heather L. Rayl's Exhibit A-3 (HLR-16), 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 31st of each year.

Q. What additional request is the Company seeking of the Commission related to the September 26, 2019 Order in Case No. U-20309?

A. In the process of preparing the Company's March 31, 2021 report to the Case No. U-20309 docket, included as Exhibit A-141 (BJV-2), page 3, it was determined the Company inadvertently included in its unprotected plant balance a remeasurement of excess deferred taxes associated with Allowance for Funds Used During Construction ("AFUDC") Equity timing differences. Inclusion of this timing difference overstated the Company's net TCJA regulatory liability by $4,174,259. I am requesting the Commission authorize a change to the beginning balance as shown on Exhibit A-141 (BJV-2), page 3. Upon approval, the Company will incorporate the change into a new 44-year amortization schedule for Other Plant Differences, as shown in Exhibit A-141 (BJV-2), page 2, column (c).

Q. Why is this adjustment necessary based on prior Commission approval?

A. In Case No. U-15986, the Company sought and the Commission granted accounting approval to charge the income tax effect of AFUDC Equity as a FAS 109 (now ASC 740) regulatory asset, rather than deferred income tax expense. This creates equal and offsetting regulatory asset and deferred income tax liability balances that reverse over the life of the assets for which the AFUDC Equity is included. The regulatory asset and the deferred income tax liability were both remeasured to reflect the lower income tax rate associated with TCJA. The remeasurement of the regulatory tax asset was not included in the TCJA net regulatory liability while the remeasurement of the deferred income tax liability was.

If the impacts of the deferred income tax liability are not removed, amounts will be refunded to customers that are intended to offset the reversal of the regulatory asset as provided for in Case No. U-15986.

Q. Did the Company respond to audit requests that discussed the inclusion of AFUDC Equity in its TCJA remeasurement?

A. Yes, in the Company's responses to 20309-HSC-CE-11 and 20309-HSC-CE 15, Company witness Scott B. McIntosh described the excess deferred taxes for "Net Capitalized Interest" as the cumulative timing difference between financing costs capitalized for regulatory purposes, AFUDC, and the interest capitalization required under Section 263A of the Internal Revenue Code. The Company's remeasurement for Net Capitalized Interest included the inadvertent remeasurement of this item.

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-21148

DIRECT TESTIMONY

OF

KEVIN J. WATKINS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

Q. Please state your name and business address.

A. My name is Kevin J. Watkins, and my business address is One Energy Plaza, Jackson, Michigan.

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 Accounting Analyst III in the Corporate Property Accounting Department.

Q. Please describe your educational background.

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

Q. Do you hold any professional certifications?

A. Yes. I became a Certified Depreciation Professional in 2012.

Q. What are your responsibilities as a Senior Accounting Analyst III?

A. My primary responsibilities are to support the Company's depreciation, regulatory and rates filings and to account for book depreciation and asset retirement obligations. I also supervise the monthly close process of the Property Accounting system.

Q. Please summarize your prior professional experience at Consumers Energy before taking your current position.

A. I began my career with Consumers Energy in 1999 as an Accounting Analyst in the Financial Forecasting Department. In 2001, I accepted a position of General Accounting Analyst in the Corporate Property Accounting Department. Over the years, I have accepted increasing responsibilities and was promoted to Senior Accounting Analyst III.

Q. Have you testified previously before the Michigan Public Service Commisssion ("MPSC" or the "Commission")?

A. Yes. I previously submitted testimony in Case No. U-16536 (Depreciation for Other Production – Wind Plant), Case No. U-16055 (Depreciation for Ludington Pumped Storage), Case No. U-16938 (Depreciation for Gas Utility Plant), Case No. U-17653 (Depreciation for Electric and Common Utility Plant), Case No. U-18127 (Depreciation for Gas Utility Plant), Case No. U-20849 (Depreciation for Electric and Common Utility Plant), and Case No. U-21090 (Integrated Resource Plan).

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

A. The purpose of my testimony is to present the plant accounts and related deprecation rates associated with the renewable natural gas ("RNG") production facility that the Company is proposing to construct, which is discussed by Company witness Neal P. Dreisig.

Q. Why are you presenting this information?

A. Since the Company does not currently own any RNG production facilities, depreciation rates have not yet been established in a depreciation filing for the utility plant accounts being proposed with the Commission. Therefore, I am supporting the depreciation rates that the Company has used in the property model for this filing.

Q. Are any other witnesses using the information provided in this analysis?

A. Yes, Company witness Heather L. Rayl uses the depreciation rates.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring:

Exhibit A-142 (KJW-1) Proposed RNG Depreciation Rates.

Q. Was this exhibit prepared by you or under your direction or supervision?

A. Yes.

UTILITY PLANT ACCOUNTS

Q. What utility plant accounts is the Company planning to use to record the RNG production facility assets?

A. The Company plans to record the RNG assets in the following accounts: 303 Miscellaneous Intangible Plant, 340.0 Land and Land Rights, 341 Structures and Improvements, 342 Extraction and Refining Equipment, 344 Extracted Product Storage Equipment, 345 Compressor Equipment, and 346 Gas Measuring and Regulating Equipment.

Q. How did you determine which utility plant accounts should be used?

A. The Company's engineers provided descriptions of the types of assets that would be included in the proposed RNG production facility. Based on these descriptions, the utility plant accounts were identified based on the FERC Code of Federal Regulations. Additionally, the Company reached out to Dane Watson from Alliance Consulting Group, who prepares the Company's depreciation studies, for review of the selected accounts..

PROPOSED DEPRECIATION RATES

Q. What depreciation rate is being used for the RNG production facility assets in the property model?

A. The depreciation rate for the RNG production facility asset is 3.90%. As shown in Exhibit A-142 (KJW-1), the 3.90% depreciation rate is a weighted average of the proposed depreciation rates for the utility plant accounts identified.

Q. How did you calculate the depreciation rates for each of the utility plant accounts?

A. Each of the accounts were looked at separately to determine the best way to calculate the depreciation rate. If the Company had similar assets in other existing utility plant accounts, I calculated the average of the approved depreciation rates for the corresponding accounts from the Company's last gas depreciation proceeding, Case No. U-18127. For the accounts where the Company did not have similar assets in existing utility plant accounts, the depreciation rates were calculated based on the estimated average service lives provided by owner's engineers and Alliance Consulting Group. Additionally, an estimated net salvage percent is also factored into the calculations of depreciation rates.

Q. What is net salvage and how is it factored into the calculation of depreciation rates?

A. Net salvage is equal to gross salvage less cost of removal and is expressed as a percentage of the gross plant in service. Basically, the gross salvage decreases the amount of plant investment to be depreciated, while cost of removal increases the amount of plant investment to be depreciated. The formula to calculate the depreciation rate is (1-net salvage)/average service life.

Q. What is the depreciation rate for Account 303 Miscellaneous Intangible Plant, and how was it calculated?

A. As shown in Exhibit A-142 (KJW-1), the depreciation rate for Account 303 is 4.00%. This rate is calculated using an average service life of 25 years and a net salvage of 0%.

Q. What is the depreciation rate for Account 341 Structures and Improvements, and how was it calculated?

A. As shown in Exhibit A-142 (KJW-1), the depreciation rate for Account 341 is 2.21%. This rate is the average of the approved depreciation rates for Accounts 351.2, 366, and 375, from Case No. U-18127.

Q. What is the depreciation rate for Account 342 Extraction and Refining Equipment, and how was it calculated?

A. As shown in Exhibit A-142 (KJW-1), the depreciation rate for Account 342 is 5.04%. This rate is calculated using an average service life of 25 years and a net salvage of -26%. The average service life is based on information provided by the owner's engineers and input from the Alliance Consulting Group. The net salvage percentage is an average of the net salvage percentages for Accounts 345 and 346.

Q. What is the depreciation rate for Account 344 Extracted Product Storage Equipment, and how was it calculated?

A. As shown in Exhibit A-142 (KJW-1), the depreciation rate for Account 344 is 5.04%. This rate is calculated using an average service life of 25 years and a net salvage of -26%. The average service life is based on information provided by the owner's engineers and input from the Alliance Consulting Group. The net salvage percentage is an average of the net salvage percentages for Accounts 345 and 346.

Q. What is the depreciation rate for Account 345 Compressor Equipment, and how was it calculated?

A. As shown in Exhibit A-142 (KJW-1), the depreciation rate for Account 345 is 2.28%. This rate is the average of the approved depreciation rates for Accounts 354 and 368, from Case No. U-18127.

Q. What is the depreciation rate for Account 346 Measuring & Regulating Equipment, and how was it calculated?

A. As shown in Exhibit A-142 (KJW-1), the depreciation rate for Account 346 is 3.22%. This rate is the average of the approved depreciation rates for Accounts 355, 369, and 378, from Case No. U-18127.

CONCLUSION

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-21148

DIRECT TESTIMONY

OF

STEPHANIE V. WATSON

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

Q. Please state your name and business address.

A. My name is Stephanie V. Watson, Ph.D. and my business address is 11801 Farmington Road, Livonia, Michigan 48150.

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 Engineer and serve as the the Gas Safety Management System ("GSMS") Program Manager for the Company.

Q. Please describe your educational background and work experience.

A. I graduated from Lawrence Technological University with a Bachelor of Science in Civil Engineering. I received my Master of Science and Ph.D. in Civil Engineering from the University of Alabama at Birmingham. I have been employed at Consumers Energy for 11 years.

Q. What are your responsibilities as GSMS Program Manager?

A. As GSMS Program Manager, I am responsible for oversight of the implementation of the GSMS, leading plan development, and routine program evaluation.

Q. Are you a member of any professional societies or trade associations?

A. I am a member and represent the Company on the Operations Section Regulatory Action Committee of the American Gas Association ("AGA").

Q. What is the purpose of your direct testimony?

A. My direct testimony explains the Company's GSMS, which is being implemented in response to the Commission's September 26, 2019 Order in MPSC Case No. U-20322, in which the Commission stated that it expected Consumers Energy to develop and implement a Pipeline Safety Management System ("PSMS") in accordance with American Petroleum Institute Recommended Practice 1173 ("API RP 1173").

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

A. Yes. I am sponsoring the following exhibit:

Exhibit A- 143 (SVW-1)	Summary of Company Witnesses Sponsoring Gas Safety Management System Expenses and Expenditures.

Q. Please describe Exhibit A-143 (SVW-1)?

A. Because GSMS involves initiatives that impact so many different parts of the Company's gas utility business, it is not practical to address the spending necessary to implement the GSMS program in only one witness's testimony. Exhibit A-143 (SVW-1) provides a summary overview of the O&M expenses and capital expenditures sponsored by various Company witnesses that are essential for the Company to implement the GSMS. This exhibit should serve as a key to help the Commission identify aspects of the GSMS throughout the case, with my testimony presenting the big-picture explanation about how these various initiatives serve the larger program objectives.

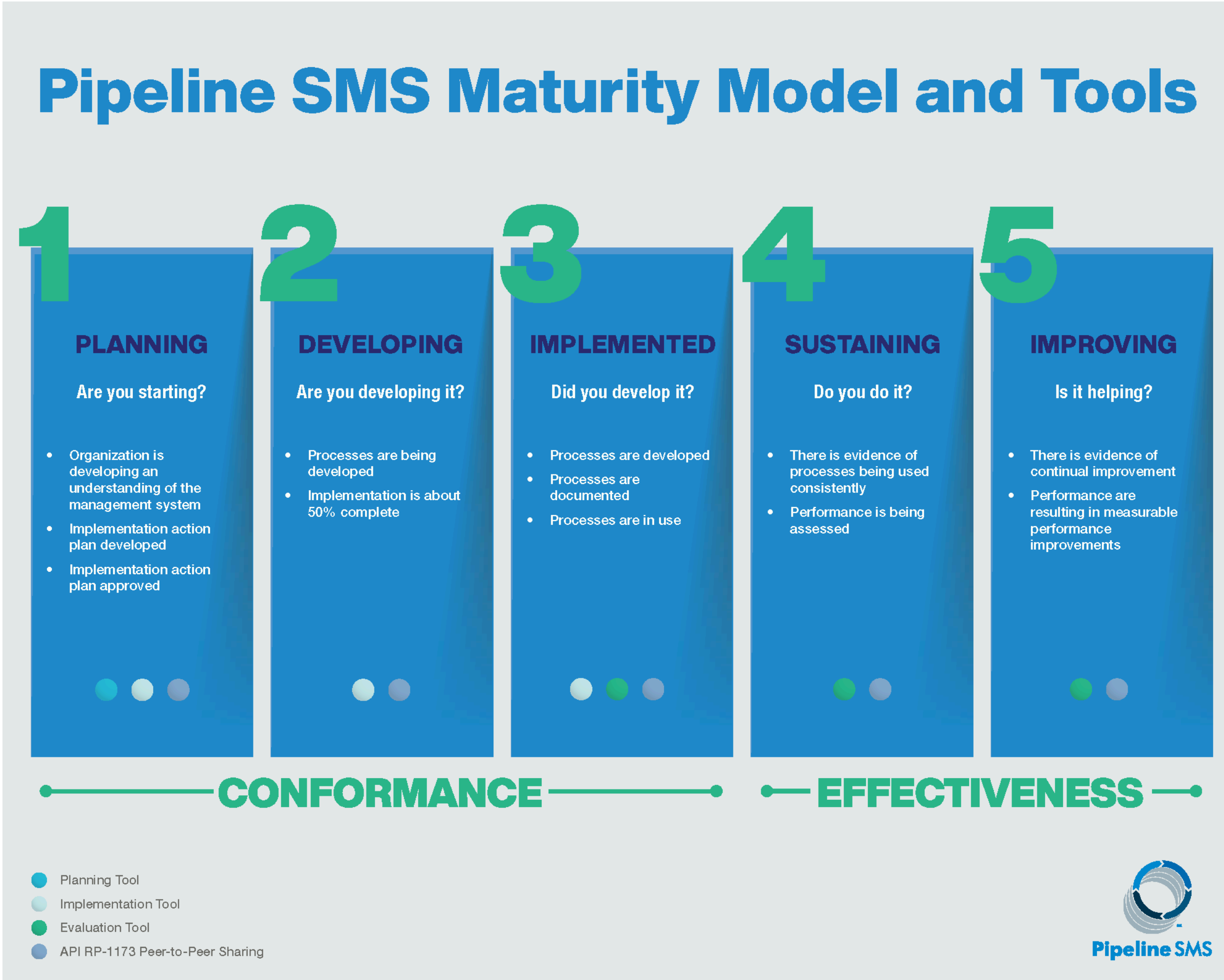
Q. Does the Natural Gas Delivery Plan ("NGDP") discuss the Company's GSMS?

A. Yes, it does. The Company's GSMS is discussed in Section V.B.3. of the Company's NGDP which is sponsored by Company witness Neal P. Dreisig as Exhibit A-45 (NPD-1).

Q. Please describe the Company's GSMS.

A. The implementation and sustainment of the GSMS is necessary to assure enhanced safety of pipeline activities and provide greater certainty that the natural gas system will perform as expected. GSMS is the Company's holistic approach to pipeline safety through enhanced practices for the identification, prevention, prioritization, and remediation of identified gas system risks. The Company adopted API RP 1173, a continuous improvement process which follows the "Plan-Do-Check-Act" cycle. Core to the Company's GSMS are essential elements identified in API RP 1173, which include Leadership & Management Commitment, Stakeholder Engagement, Risk Management, Operational Controls, Incident Investigation, Evaluation & Lessons Learned, Safety Assurance, Management Review & Continuous Improvement, Emergency Preparedness & Response, Competence, Awareness & Training, and Documentation & Record Keeping. The Company elected to include an additional element, Prioritization, Resources & Unit Cost. The Company has many programs in place and is implementing additional initiatives that support the requirements of the essential elements of the GSMS. In 2019, using internal resources, the Company completed a gap assessment of current processes against the requirements of API RP 1173. The Company developed an implementation plan to address gaps identified from the internal assessments and made a commitment to achieve Level 3 maturity. As validation that Level 3 maturity was achieved, the Company committed to having a third-party assessment of the GSMS in 2022. API assessors will complete an audit of the Company's GSMS for conformance and effectiveness as compared to the requirements included in API RP 1173. The target is Level 4 maturity or greater by 2028 as noted in the Company's NGDP, sponsored by Company witness Dreisig. Maturity levels are defined by the SMS Maturity Model developed by API and included as Figure 1.

Figure 1 Pipeline SMS Maturity Model



Q. Please describe the elements included in the Company's GSMS.

A. The elements of the Company's GSMS as shown in the Company's NGDP which is included in Company witness Dreisig' s Exhibit A-45 (NPD-1), Section V.B.3. include:

1. Leadership and Management Commitment – Demonstrated commitment to development, implementation, evaluation, and continuous improvement of gas system safety. This will be accomplished through continued enhancements to employee safety culture and resource planning.

2. Stakeholder Engagement – Executed processes for two-way internal and external stakeholder communication encouraging continual communication of risks and sharing safety performance.

3. Risk Management – Risk identification, assessment, prevention, mitigation, and periodic analysis of gas system assets and processes including a review of

analyses by top management. This is accomplished through continual enhancements to asset risk assessment tools and continued review of risk results with management.

4. Operational Controls – Operating, design, and construction procedures established to ensure the gas system performs as expected. This will be accomplished through enhancements to gas system standard work, implementation of the Enterprise Corrective Action Program, and enhancements to Management of Change processes.

5. Incident Investigation, Evaluation, and Lessons Learned – Investigation of gas system incidents with communication of lessons learned. The Company will continue to enhance processes for learning from and communicating incident causes.

6. Safety Assurance – Assessment of the effectiveness of risk management through audits and evaluations. This will be accomplished through an advanced audit & assessment program including risk-based assessments and field compliance assessments further described by Company witness Sarah H. Bowers.

7. Management Review and Continuous Improvement – Routine top management review of the management system effectiveness against defined key performance indicators. This is accomplished through routine, proceduralized gas system and operations performance reviews by gas leadership.

8. Emergency Preparedness and Response – Maintain emergency response procedures including communication plans, lessons learned communications, and improvement processes through the continued enhancement of the Company's Incident Command System.

9. Competence, Awareness, and Training – Competency based training of employees and contractors on the operational activities and elements of a safety management system to support gas system safety. This will be accomplished through enhancements to gas competency-based training curriculum.

10. Documentation and Recordkeeping – Maintain processes and procedures for control of documents and control of gas system records ("chain of custody" for required records). This is accomplished through enhancements to the gas information management network.

11. Prioritization, Resources & Unit Cost – Maintain processes and procedures for cost and resource allocation in line with the risks identified through asset and other corporate risk processes accomplished through the NGDP process.

Q. Please describe industry and regulatory support for GSMS?

A. The National Transportation Safety Board ("NTSB"), Pipeline and Hazardous Materials Safety Administration ("PHMSA"), and AGA have encouraged natural gas operators to implement API RP 1173. The Commission stated that it expected Consumers Energy to develop and implement a PSMS in accordance with API RP 1173 in Case No. U-20322. The Company is participating in the SMS Industry Collaborative, sharing lessons learned and best practices with 14 other gas utilities across the United States.

Q. Please describe the Company's long-term plan for gas safety enhancements.

A. The Company considers that a large part of the work management transformation will focus on the implementation and sustainment of the GSMS to achieve enhanced pipeline safety and, pursuing the industry-wide goal of zero incidents. The GSMS encompasses initiatives that will continue to meet this focus including Operational Compliance & Controls programs, Utility Network, and Competency Based Training.

Q. Please describe how the Operational Compliance & Controls programs support the GSMS.

A. Operational Compliance & Controls initiatives include five programs: (i) the Enterprise Corrective Action Program ("ECAP"), (ii) the Risk Based Assessments ("RBA") and Field Compliance Program, (iii) the Remote Inspection Program, (iv) the Advanced Methane Detection Program, and (v) the B31Q Implementation Program. ECAP is a key component of a management system, allowing transparency in reporting issues, identifying trends, and closing compliance and safety gaps through corrective actions and controls, based upon associated risk thresholds. RBA and Field Compliance supports continued maturity of the Risk Management, Operational Controls, and Safety Assurance elements of GSMS by identifying and addressing risk associated with operations, maintenance, engineering, and construction activities and assessing adherence to written procedures. The Advanced Methane Detection Program advances maturity of the Risk Management and Operational Controls elements of GSMS by enabling the Company to find and prioritize the higher risk leaks to improve public safety. B31Q Implementation advances maturity of the Competence, Awareness, and Training elements of GSMS by implementing the ASME B31Q Standard to minimize the impact on safety and integrity of the pipeline due to human error that may result from an individual's lack of knowledge, skills, or abilities during the performance of certain activities. Company witness Bowers further describes the Company's Operational Compliance & Controls initiatives.

Q. Please describe how the Utility Network supports the GSMS.

A. The Utility Network will support sustainment and continuous improvement for data gathering processes governed by the Risk Management element by enabling detailed asset management and location-based analytics to bring clearer understandings around the assets. The Utility Network initiative is further described by Company witness Kristine A. Pascarello.

Q. Please describe how the Competency Based Training supports the GSMS.

A. Competency based training builds on the Competence, Awareness, and Training elements of GSMS and supports continued safe and reliable operation of the Company's natural gas system. To enhance competency-based training, the Company will build the Gas City Facility and develop supporting training curriculum. Company witness Karen M. Gaston further describes the Company's Competency Based Training Development initiative and

Company witnesses Quentin A. Guinn and Christopher T. Fultz further describe the Company's Gas City Facility.

Q. Is the Company seeking recovery of costs related to GSMS?

A. Yes, to realize the safety benefits of an implemented management system it is essential for the Company to fully recover the costs associates with the initiatives and programs described in this testimony. The costs associated with the initiatives, witnesses sponsoring, and programs are summarized in Exhibit A-143 (SVW-1).

Q. Can you summarize your direct testimony?

A. Yes. The implementation and sustainment of the GSMS is necessary to assure enhanced safety of pipeline activities and provide greater certainty that the natural gas system will perform as expected and align with the requirements within API RP 1173. The initiatives outlined are essential to realize the safety benefits of GSMS.

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 distribution of natural gas and for other relief.	)))))	Case No. U-21148

DIRECT TESTIMONY

OF

TODD A. WEHNER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

Q. Please state your name and business address.

A. My name is Todd A. Wehner, 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 Assistant Treasurer.

Q. What are your current responsibilities?

A. I am responsible for planning and raising the financial capital required by the Company including revolving credit facilities, short-term and long-term debt capital, and equity capital. As part of my role, I work with my treasury colleagues to manage corporate liquidity, financing, and treasury operations, and maintain relationships with the banking community, rating agencies, investors, and research analysts. In order to carry out my responsibilities, I interact with commercial banks, investment banks, credit rating agencies, equity and fixed income analysts, and equity and fixed income investors. I also play a key role in the Company's strategic planning process and in developing the Company's financial plan that fulfills its strategic goals.

Q. What is your educational background?

A. I received Bachelor of Science degrees in Electrical Engineering and Mechanical Engineering from Michigan Technological University in 2002. I received a Master of Business Administration degree ("MBA") from the Ross School of Business at the University of Michigan in 2012, where I focused on finance and strategy. Concurrently, I completed a Master of Science degree from the School of Natural Resources at the University of Michigan.

Q. What positions did you hold prior to your present position?

A. I began my career in 2002 as an Acquisitions and Maintenance Officer in the United States Air Force where I worked with intelligence units through 2006. I was an Electrical Test Engineer with Nissan from 2007 to 2009. After completing my MBA in 2012, I joined Barclays Capital in the Investment Banking Division. In this role, I developed financial models to value both public and private companies, executed merger and acquisition transactions, and executed financing transactions for companies across a number of markets including equity, investment grade debt, and high yield debt. I developed cost of capital analyses, rating agency materials, and strategic review materials for management and boards. In 2014, I joined Morgan Stanley within the Investment Banking Division, focused solely on the power and utilities sector. In early 2016, I joined Consumers Energy as the Director of Corporate Finance.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I provided cost of equity testimony in Case No. U-20963, the Company's most recent electric rate case, as well as Case No. U-20697 the Company's 2020 electric rate case before the Commission. I provided testimony in Case No. U-20889, the Company's 2020 Securitization case; Case No. U-20165, the Company's 2018 Integrated Resource Plan case; and in Case No. U-18250, the Company's 2017 Securitization case. In addition, I have also provided support for both Venkat D. Rao and Srikanth Maddipati who have served as the Company witnesses covering capital structure and cost of capital in each of the electric and natural gas rate cases before the Commission since joining the Company, including Case No. U-20650, the Company's 2019 gas rate case.

PURPOSE

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present my recommendation regarding the Return on Equity ("ROE") which should be used in computing the overall rate of return for Consumers Energy's natural gas business, as well as provide clarification regarding the financial incentives in the Company's Employee Incentive Compensation Plan ("EICP") Program.

Q. How is the remainder of your direct testimony organized?

A. My direct testimony is organized as follows:

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring:

Exhibit A-14 (TAW-1)	Schedule D-5	Cost of Common Shareholders' Equity;

Exhibit A-144 (TAW-2)	JD Power Report;
Exhibit A-145 (TAW-3)	ROE and Equity Relationship;
Exhibit A-146 (TAW-4)	John D. Quackenbush Testimony before FERC;
Exhibit A-147 (TAW-5)	PPUC Decision;
Exhibit A-148 (TAW-6)	UBS Regulatory Report;
Exhibit A-149 (TAW-7)	Fama and French: *"The Cross-Section of Expected Stock Returns"*;
Exhibit A-150 (TAW-8)	Fama and French: *"The CAPM is Wanted, Dead or Alive"*;
Exhibit A-151 (TAW-9)	Financial Times: *"The time has come for the CAPM to RIP"*;
Exhibit A-152 (TAW-10)	Chartoff, Mayo, and Smith: "*The Case Against the Use of the Capital Asset Pricing Model in Public Utility Ratemaking"*;
Exhibit A-153 (TAW-11)	Chretien and Coggins: "*Cost of Equity for Energy Utilities: Beyond the CAPM"*;
Exhibit A-154 (TAW-12)	FERC Opinion No. 531-B;
Exhibit A-155 (TAW-13)	Federal Reserve: "*The Equity Risk Premium: A Review of Models"*;
Exhibit A-156 (TAW-14)	Brattle Group: "*Estimating the Cost of Equity for Regulated Companies*";
Exhibit A-157 (TAW-15)	Mississippi Public Service Commission Rate Schedule (Mississippi Power);
Exhibit A-158 (TAW-16)	Alberta Utility Commission, Decision 20622-D01-2016 (Extract);
Exhibit A-159 (TAW-17)	Value Line: "*Using Beta*";
Exhibit A-160 (TAW-18)	Gordon and Shapiro: "*Capital Equipment Analysis*";

Exhibit A-161 (TAW-19)	Moody's Investors Service Report – April 17, 2020; and
Exhibit A-162 (TAW-20)	Additional Cost of Common Shareholders' Equity Analyses.

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

A. Exhibits A-14 (TAW-1), Schedule D-5; A-145 (TAW-3); and A-162 (TAW-20) were prepared under my direction and supervision. The remaining exhibits were gathered from numerous sources commonly relied upon by finance professionals in the course of their work.

I. SUMMARY OF ROE RECOMMENDATIONS

Q. What ROE is the Company recommending for Consumers Energy's natural gas business?

A. Based on the qualitative and quantitative analyses performed by the Company, a reasonable ROE range for Consumers Energy's natural gas business is 10.0% to 11.0%. While the analyses support a higher recommendation, the Commission has a preference for adjustments to be limited to reasonable movements, and given the recommended equity ratio of 52.0% provided by Company witness Marc R. Bleckman, the Company recommends the Commission approve an ROE of 10.5% at this time, which is the mid-point of the recommended range. This recommendation arises out of the consideration of numerous factors including: (i) the current state of the economy and capital markets; (ii) the need to continue to attract capital and maintain financial strength as the Company undertakes a large capital expenditure program designed to improve safety, reliability, and customer value; (iii) the risk profile of Consumers Energy's natural gas business compared to the proxy group; (iv) established principles for setting a fair ROE, including ensuring the financial soundness and credit of the utility; and (v) results of various economic models used to calculate the cost of equity, all of which are described in detail in Section II.

Q. How does the Company's recommended ROE compare to its current authorized ROE?

A. The current ROE authorized by the Commission for Consumers Energy's natural gas business is 9.9%, which was established in the Commission's September 10, 2020 Order approving settlement agreement in Case No. U-20650, and is below the recommended reasonable range of 10.0% to 11.0%. Given the capital structure recommended by Company witness Bleckman, an ROE of at least 10.5% is recommended, which is 60 basis points higher than the current authorized 9.9% ROE.

Q. Discuss why the Commission should increase the ROE.

A. As will be outlined in this testimony, ROEs and equity ratios are linked and must be viewed together to balance credit supportive financial metrics. As discussed by Mr. Bleckman in his direct testimony, the average equity ratio for the Company's peer group is 55.8% (see Exhibit A-26 (MRB-10)), which is meaningfully higher than the 52.0% being recommended by the Company in this case. If the Commission does not desire to raise the ROE to 10.5% given its preference for gradualism, the Commission could alternatively maintain an ROE of 9.9%. In that case, however, the Company would propose an equity ratio higher than the 52.0% recommended by Company witness Bleckman and would request approval of an equity ratio of 53.1%. This demonstrates that the level of an approved ROE requires a corresponding equity ratio that maintains credit supportive financial metrics.

This direct testimony and supporting analysis, along with that of Company witness Bleckman, provide justification for the 10.5% or higher ROE recommendation; however, in the event the Commission believes that a more modest increase in ROE is reasonable, such an outcome could be partially mitigated with a corresponding increase in the authorized equity ratio.

II. <u>DEVELOPMENT OF ROE RECOMMENDATION</u>

A. <u>Importance of ROE and Financial Strength</u>

Q. Discuss the importance of financial strength for a utility, including Consumers Energy.

A. The Company's 1.8 million natural gas customers count on reliable natural gas to heat their homes, businesses, schools, and communities. Additionally, Consumers Energy's services play a key role in the economic development of Michigan by attracting industries that create jobs and invigorate communities. A strong, financially healthy utility is critical for providing this essential service.

As a regulated utility, Consumers Energy is obligated to serve all customers in its service territory. Doing so requires significant capital for both planned and unplanned investments in property, plant, and equipment. Customers and the state of Michigan are not well served if the Company's ability to meet these obligations is either subject to uncertainty or contingent on the instant state of the capital markets.

Q. Why is reliance on temporary markets a concern when evaluating the financial strength of a utility such as Consumers Energy?

A. Temporary market conditions can be disjointed from long-term patterns and, as such, it would not be in the best interest of customers to be heavily reliant upon them. While it is tempting to assume that markets will remain robust and capital will always remain accessible, markets can deteriorate and have rapidly deteriorated at times throughout the past. There are numerous historic examples to look back upon as evidence. Just a few examples include the Great Recession, the Taper Tantrum of 2013, and the September 2019 example when short-term interest rates spiked to nearly 10%, requiring the Federal Reserve to inject significant liquidity into the markets in order to help return interest rate levels back to moderate ranges. The onset of the COVID-19 pandemic can now be added to the growing list, as MPSC Staff ("Staff") witness Kirk D. Megginson noted in Case No. U-20650 that the ongoing global pandemic created a radical change in underlying economic conditions:

> The global market disruption due to the COVID-19 pandemic is testament to the scale of economic volatility and disruption an unforeseen event can cause. [Direct testimony of Staff witness Megginson, MPSC Case No. U-20650, page 31.]

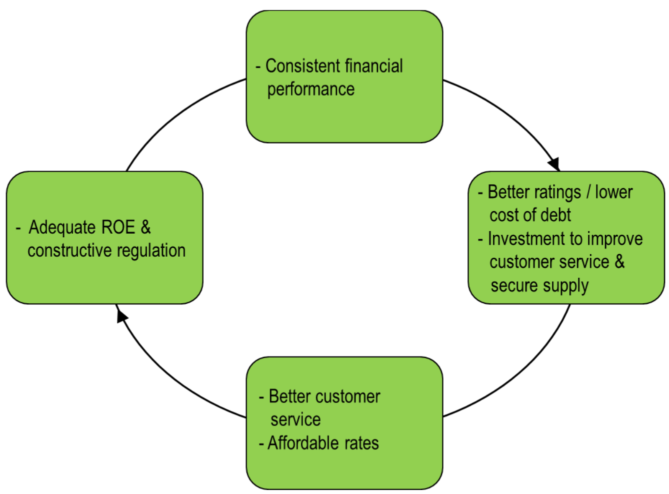
When markets deteriorate, there can be an upward surge in interest rates and a corresponding increase in the cost of borrowing, if market liquidity is not completely seized up altogether. Higher costs of borrowing for a utility means higher costs for making capital investments in property, plant, and equipment, fewer funds available for necessary projects, or both.

Q. What is the practical effect of avoiding this type of volatility in the market?

A. A financially strong utility that is not reliant upon temporary market conditions has a higher likelihood of maintaining access to capital at reasonable terms throughout the spectrum of possible capital market conditions, all the way from robust to more capital constrained conditions. For businesses faced with financing and investing decisions that are not regulated and lack an obligation to serve, it is not uncommon for major investments to be deferred or canceled in response to tightening market conditions or shifts in economic cycles. Consumers Energy's customers, however, would not be well served by such a strategy, particularly market conditions resulting in the need to adjust or delay work on major infrastructure projects that are geared toward maintaining or improving customer service and secure and reliable energy supply at affordable rates.

Q. Describe how utility regulation and ROE impact the financial strength of the utility.

A. The consistency, predictability, and promptness of regulatory outcomes, coupled with a constructive and supportive authorized ROE, are important parameters to enable a financially healthy utility. The following model demonstrates the benefits enabled by an attractive ROE and constructive regulation.



This "virtuous cycle," which is enabled by constructive and supportive regulation and attractive ROEs, is important for the Company to continue investing in its natural gas infrastructure. As the chart demonstrates, attractive ROEs are important and, in part, contribute to delivering consistent financial performance. Consistent financial performance contributes to better credit ratings and increased investment interest, thereby lowering borrowing costs. The investment provided by utility shareowners, and the return allowed on that equity, provide the financial resources and capital to: (i) support the debt financing raised by the utility; (ii) procure contracts with suppliers; and (iii) fund unplanned or unexpected expenses.

Q. Do more attractive ROEs have other benefits?

A. Yes. The virtuous cycle starting with attractive ROEs continues with lowered costs of borrowing and enables affordable customer rates. Higher ROEs are also associated with higher customer satisfaction. The J.D. Power report, *How Customer Satisfaction Drives Return on Equity for Regulated Electric Utilities*, included as Exhibit A-144 (TAW-2) demonstrated that utilities with customer satisfaction in the top quartile have ROEs that are 50 basis points higher than those in the bottom quartile, demonstrating that a reasonable ROE is not only important for investors, but reciprocally delivers value to customers as well. This reinforces the point illustrated above - the positive feedback of the "virtuous cycle," where a cycle of good regulation, together with a supportive ROE, enables a utility to attract capital and make investments that drive better service and maintain affordable rates.

Q. Discuss the role ROE has in capital allocation.

A. Simply put, capital is finite. As such, not all projects or investments can be funded, and a utility management team must decide which investments are most beneficial to customers and investors and should, therefore, be funded. While an attractive ROE enables the utility to maintain access to capital at a reasonable cost, access to capital is not the sole criteria used by a company to make an investment decision. Instead, both external and internal considerations must be weighed. Externally, private capital investment in the utility needs to be weighed against all other potential investments competing for capital. Internally, the management team, as fiduciaries, must weigh whether the Company's investment in the utility provides sufficient risk-adjusted returns relative to other options including gas utility investments, investments in other jurisdictions, non-regulated investments, or simply returning capital to shareowners in the form of dividends and/or share repurchases. While the investment community generally views the regulatory environment in Michigan as constructive and supportive, concerns over declining ROEs, or regulatory outcomes becoming less predictable, may cause a reassessment and deterioration of that view.

Q. Does the Company's ROE recommendation place an undue burden on ratepayers?

A. No. ROE is not the primary driver of customer bills and represents only approximately 20% of total costs. The recommended ROE would have a gross impact on the average residential customer bill increasing it by $0.58 per month. Impact on a "gross" basis is emphasized because this ROE impact may be partially offset by lower debt costs and improved access to capital markets given the aforementioned benefits of the "virtuous cycle."

Q. How does the Company view the needs of the customers versus the needs of the investors?

A. The Company recognizes and agrees with the need to balance customer and investor interests. Given the significant importance ROE plays in attracting cost-efficient capital and maintaining the financial health of the utility, however, an ROE and equity ratio consistent with the recommendation set forth herein ensures the continuation of the "virtuous cycle" and, as discussed above, is in the best interest of the customers Consumers Energy serves.

B. General Principles

Q. What are the general principles in setting a fair rate of return and return on common equity?

A. For regulated companies, the landmark *Hope* and *Bluefield* Supreme Court decisions have established the framework upon which a company's fair rate of return may be determined. In *Bluefield Water Works and Improvement Company v Public Service Commission of West Virginia*, 262 US 679 (1923), the United States Supreme Court stated that equity investors are entitled to a return commensurate with investments of comparable risk, that earnings must be sufficient to assure confidence in the financial soundness of the utility, and that a utility must be able to earn a return sufficient to support its credit and raise required capital. In *Federal Power Commission v Hope Natural Gas Company*, 320 US 591 (1944), the Court again stated that the return for common equity investors should be set at a level that is commensurate with returns on investments having corresponding risks. The Court also reiterated that the return should be sufficient to assure confidence in the financial integrity of the utility such that it is able to attract capital and maintain its credit. These principles are reflected in the ROE analyses provided and discussed in this direct testimony.

Q. How are ROE and rate of return related?

A. ROE is a measure of how much return a company is able to generate with each dollar of shareholder equity (investment) it receives. As discussed above, comparing the ROE of similar companies can help investors decide which constitute the most attractive investment choices. ROE is a significant part of a company's overall rate of return, which is the amount of return a utility earns, over and above its expenses.

Q. To support the principles reflected in *Hope* and *Bluefield,* what methodology was employed for setting a fair ROE?

A. Several analyses were performed to determine a reasonable ROE. Additionally, an analysis of the ROE and equity ratio that would support the Company's long-term Funds from Operations ("FFO") to Debt and credit was also performed. Finally, several quantitative models were employed to determine an appropriate return for investments having commensurate risk.

Q. Why were multiple methodologies and analyses employed to determine the requested ROE for this case?

A. As discussed above, an ROE and corresponding equity ratio may support the Company's credit but may not be commensurate with investments of similar risk and vice versa; therefore, the analyses performed look at both the impact of the proposed ROE on the Company's credit as well as a comparison to similar investments.

Q. Is the determination of an appropriate ROE a precise calculation?

A. No. While the determination of ROE should be set at a level that is commensurate with returns on investments having corresponding risks, this calculation is not an exact science, and any methodology utilized is based on assumptions and inputs that may be less than certain. As a result, multiple methodologies were utilized because: (i) each of these methods, individually, will often produce a range of values that should be considered in relation to each other, as illustrated by Exhibit A-14 (TAW-1), Schedule D-5, page 12; and (ii) the results of these quantitative models can often make assumptions that do not necessarily fully reflect the returns that investors require, given current economic and financial conditions. As such, the application of multiple methods, an understanding of model assumptions, in combination with an overall qualitative assessment of the marketplace, provides a more comprehensive evaluation of cost of capital and is most appropriate in evaluating the required cost rate for common equity capital.

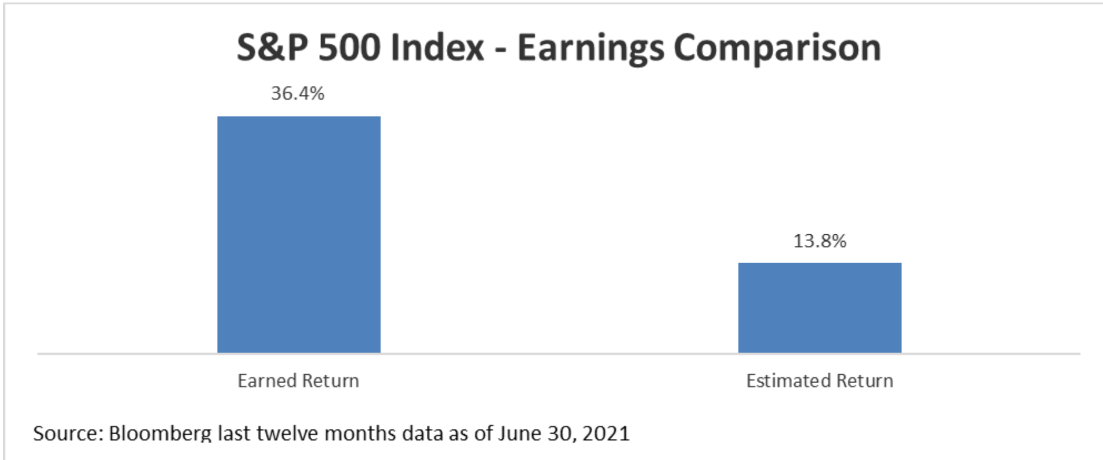
Q. Please explain.

A. Each of the historically customary quantitative models assumes that economic conditions are relatively stable and that current market inputs are reflective of their long-term outlook. That assumption may not be true in current market conditions, mainly because of the unprecedented amount of central bank intervention, along with the impacts of the Tax Cuts and Jobs Act of 2017 ("TCJA") and the COVID-19 pandemic on the economy and credit quality of utilities observed during the last several years.

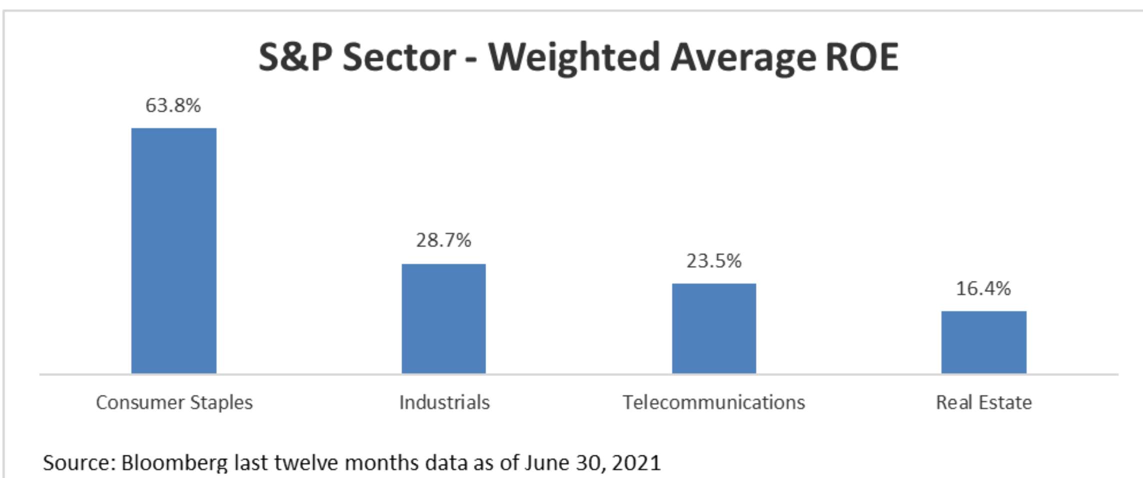
Q. What are the estimates produced by quantitative models representing?

A. Each of the quantitative models deployed produces an estimate of the required rate of return for an investor. If the expected return on investment is below the required rate of return, the management of a company will often cease making new investments and potentially seek to return capital unless returns are higher. If a company were to earn exactly the required rate of return, investors would be indifferent between new investment and the return of capital. In order to encourage investment, an ROE must therefore be greater than the required rate of return. This point is best illustrated by considering the average earned return of the Standard and Poor's ("S&P") 500 index.[1] In the last 12 months, the market earned an ROE that is a full 22.6% higher than that implied by standard model estimates.

[1] Data provided by Bloomberg, as of June 30, 2021. See workpapers for support data and summary.



While the returns for the broader market are not necessarily the same risk as the utility sector, it is informative to look at other industries that are considered stable or lower risk. The chart below shows four S&P sectors and the earned return of each. It clearly demonstrates that investors are able to realize competitive or superior returns from other investments with commensurate risk, and the utility sector is absolutely competing with each of them for investment dollars.



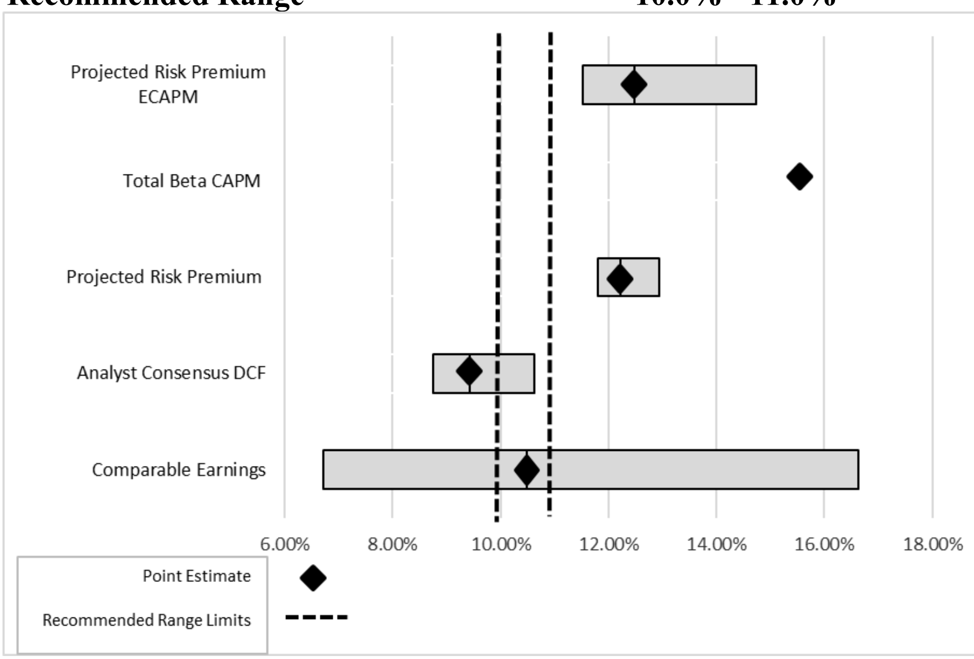
C. Summary of ROE Results

Q. Can you summarize the results of Consumers Energy's cost of common equity analyses?

A. The results of the analyses are summarized and graphically represented in the table and chart below.

Summary of ROE Estimates

Projected Risk Premium ECAPM	11.52% - 14.74%
CAPM	15.72%
Projected Risk Premium	11.81% - 12.96%
Analyst Consensus DCF	8.76% - 10.63%
Comparable Earnings	6.72% - 16.62%
Recommended Range	**10.0% - 11.0%**



Based on analyses and consideration of the factors discussed below, an appropriate ROE range for Consumers Energy's natural gas business for the test year is 10.0% to

11.0%. The significant need to update the Company's and the state's energy infrastructure would suggest an ROE in the upper half of the recommended range. The recommended ROE of 10.5%, however, is at the center of the reasonable ROE range.

Q. Is a 60 basis point increase in the proposed ROE appropriate?

A. Yes. While the Commission may view an increase of 60 basis points to be significant, in order to maintain the credit health of the Company as it pursues significant and necessary infrastructure and reliability improvements, this proposed ROE, in conjunction with the recommended equity ratio proposed by Mr. Bleckman, should be carefully considered. If the Commission believes a 60 basis point ROE increase is too sizeable, then a higher-than-requested equity ratio would be a reasonable compromise.

D. Qualitative Equity Cost Rate Considerations

1. Investor and Rating Agency Expectations and View of Regulatory Environment

Q. How do investors view the current regulatory environment in Michigan?

A. Investors have generally viewed the regulatory environment in Michigan as supportive; however, this perspective can change since their interests and expectations are predicated on expected future outcomes. Utility investors continually weigh the relative risk of investing in a utility relative to other investments and, inherent in that decision, is an assessment of both the status and direction of the regulatory environment in which a utility operates. As fiduciaries, the management teams of utilities will also have a similar perspective, which dictates their capital allocation decisions on behalf of investors. As a result, if the investor view of the Michigan regulatory environment becomes less certain or less predictable, then they will be less inclined to invest further capital into Michigan utilities, which would lead to higher funding costs and would be detrimental to customers.

Q. Do investors and rating agencies make assumptions regarding the ROE for Consumers Energy?

A. Yes. The ROE authorized by the Commission and the ability of Consumers Energy to earn the authorized return are important factors considered by investors and rating agencies. In fact, a utility's authorized ROE and a consistent, constructive track record in this regard are key components in credit ratings assessments.

Q. Do you have examples of these assessments?

A. Yes. The June 23, 2017 *Regulated Electric and Gas Utilities Rating Methodology* for Moody's Investors Service ("Moody's"), for example, includes the following factors:

- Legislative & Judicial Underpinnings;
- Consistency & Predictability; and
- Sufficiency of Rates & Returns.

Similarly, S&P, in its *Key Credit Factors For The Regulated Utilities Industry,* reports the importance of earning a timely return:

> We base our assessment of the regulatory framework's relative credit supportiveness on our view of how regulatory stability, efficiency of tariff setting procedures, financial stability, and regulatory independence protect a utility's credit quality and its ability to recover its costs and earn a timely return. [S&P, November 19, 2013. (Emphasis added.)]

In fact, S&P calls the ability to earn a timely return one of its "four pillars" in the "foundation of a utility's regulatory support."[2] These credit rating assessments provide confirmation that the authorized ROE and rates sufficient to earn the authorized ROE in this case are important signals that the Commission sends to the investment community.

[2] S&P report, "Key Credit Factors For The Regulated Utilities Industry", November 19, 2013. See page 6.

Q. What has been your recent experience with investors and rating agencies as it relates to ROEs and risk?

A. As part of my role within the Company, I have had many conversations with investors and rating agencies. They recognize the historical strength of Michigan's regulatory construct and legislative framework, but while they still believe Michigan to be a fairly strong regulatory environment, in recent years several have expressed concerns regarding authorized ROEs and a perceived deterioration in Michigan's regulatory environment from the premium spot it once held. While one case or decision may not instantly shift investor views, a pattern of cases over time can create disappointment among investors. Analysts have noted the Commission's lower ROEs in the Company's several recent successive general rate cases as a concern, with one analyst highlighting "ROE creep" as an area of ongoing concern in multiple Company cases. ROE creep refers to progressively lower authorized ROEs in successive rate cases. This concern was realized by the Commission's September 26, 2019 Order in the Company's gas rate case, Case No. U-20322. After the Commission's Order was issued in Case No. U-20322, Wolfe Research observed,

> The final order is a slight disappointment, as Michigan has finally fallen below the magic 10.0% allowed ROE threshold. [Wolfe Research, September 27, 2019.]

This comment is a direct reference to continued analyst concerns about ROE creep. Further, following the Commission's December 17, 2020 Order in the Company's previous electric rate case (Case No. U-20697) one analyst described the authorized ROE in the following manner:

> the sub-10% headline ROE is mildly disappointing at the margin… [Vertical Research Partners, December 17, 2020.]

Q. How will investors view the Company's proposed ROE?

A. Investors are likely to consider an authorized ROE of 10.5% together with an equity ratio of 52.0%; the legislative impacts of 2008 PA 286 ("PA 286"), 2016 PA 341 ("PA 341"), and 2012 PA 342 ("PA 342"); and other regulatory adjustments proposed by the Company, to be commensurate with the risks involved in investing in Consumers Energy.

Q. Has the Company considered the impacts of PA 286, PA 341, and PA 342 on investor risk perceptions?

A. Yes. Prior to PA 286, Michigan utilities faced long and uncertain processing times for rate cases compared to other states. By requiring a final rate order within 12 months of filing, PA 286 brought Michigan more in-line with other states. From an investor standpoint, while PA 286 reduced regulatory lag of case duration, it did not put Michigan in a more favorable competitive position than other states, as some other states require regulatory approval in less than 12 months. PA 341 reduced the overall time required for finalizing a rate case from 12 months to 10 months, but it did so while also eliminating the utilities' right to self-implement. Despite the shorter time period for receiving final rate relief, the Company will still only be allowed to request rate increases every 12 months. While the duration of the cases themselves will only be 10 months, the removal of the 180-day self-implementation included in the legislation introduced an additional source of regulatory lag. PA 341 actually <u>increases,</u> by four months, the time between filing a rate case and implementation of any rate increases. Overall, this aspect of the legislation does not reduce the risk faced by equity investors in the utility.

Q. Have the rating agencies commented on the Company's credit?

A. Yes. As discussed in Mr. Bleckman's testimony, on May 3, 2021 Moody's downgraded the Company's credit rating while pointing to recent rate case outcomes and their negative impact on weakened credit metrics.

S&P's summary of the final Order in Case No. U-20697 stated the following:

> Although we view resolving the effects of tax reform through this rate case as favorable, if lower ROEs and a lower equity ratio persist, credit quality could weaken. [S&P, January 27, 2021.]

Further, they went on to state their view that the lower equity ratio and ROE in the case are not supportive of credit quality.

Q. Have the rating agencies commented on any other Michigan utilities?

A. Yes. On July 22, 2019 Moody's downgraded DTE Gas Company's long-term issuer credit rating from A2 to A3. The ratings rationale of the press release specifically cites TCJA impacts saying:

> [t]he robust investment program of DTE Gas, combined with the negative cash flow effect of federal tax reform, continue to put pressure on its financial metrics, weakening its overall credit profile… [Moody's, July 22, 2019.]

It is noteworthy that this action was taken *despite* recognition of a credit supportive regulatory environment and *despite* an authorized ROE of 10.0% and a 52.0% equity ratio. As suggested by the credit rating agencies, public service commissions sending a clear message of support for increased ROEs and equity ratios will go far in signaling a cooperative regulatory environment and serve to solidify the Company's currently favorable credit.

Q. Discuss the relationship between the Company's ROE, its equity ratio, and the Company's credit metrics.

A. A key metric that is used to identify the credit worthiness of a company, including Consumers Energy, is the ratio of FFO to Debt. As discussed in Company witness Bleckman's testimony, 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. A higher FFO-to-Debt ratio, which reflects a cash flow from operating activities that is at a level viewed as favorable to offset or otherwise reduce the risk associated with the Company's ability to pay its debts, is indicative of a lower financial risk and a resulting higher credit rating. A higher credit rating, in turn, results in lower financing rates.

Two key factors that help determine this ratio are the Company's ROE and equity ratio. Exhibit A-145 (TAW-3) provides a mathematical development of how ROE and equity ratio determine a company's FFO-to-Debt ratio over the long term, assuming steady state conditions, and is in-line with Moody's ratings methodology. The final equation that is mathematically derived is shown below:

Equation 1:

$$\frac{\boldsymbol{FFO}}{\boldsymbol{Debt}} = \frac{\boldsymbol{ROE\ x\ Equity}}{\boldsymbol{Debt}} + \boldsymbol{Depreciation\ Rate\ x}\left(\mathbf{1} + \frac{\boldsymbol{Equity}}{\boldsymbol{Debt}}\right)$$

As Equation 1 illustrates, reducing either ROE or equity ratio on a stand-alone basis results in a corresponding deterioration of the FFO-to-Debt ratio. Applying the Company's depreciation rate[3] along with the Company's currently authorized ROE and equity ratio, Equation 1 results in a long-term FFO to Debt of only 18.9% as demonstrated below:

Equation 2:

$$\frac{FFO}{Debt} = \frac{9.9\%\ x\ 52.05\%}{(1 - 52.05\%)} + 3.9\%\ x\left(1 + \frac{52.05\%}{(1 - 52.05\%)}\right) = 18.9\%$$

Clearly this level of FFO to Debt would not maintain the Company's current credit ratings. Further, applying the Company's recommended equity ratio of 52.0% as described in Company witness Bleckman's direct testimony and my recommended ROE of 10.5%, Equation 1 results in a long-term FFO to Debt of only 19.5% as demonstrated below:

Equation 3:

$$\frac{FFO}{Debt} = \frac{10.5\%\ x\ 52.0\%}{(1-52.0\%)} + 3.9\%\ x\left(1 + \frac{52.0\%}{(1-52.0\%)}\right) = 19.5\%$$

Q. Will the requested ROE/equity ratio pair of 10.5%/52.0% fully support the Company's current credit rating?

A. No. This methodology that I have demonstrated most closely aligns with Moody's methodology and, as the Company has noted in prior cases, an FFO-to-Debt ratio of approximately 20% is the minimum level that would be supportive of the Company's current credit rating over time. However, in further recognition that the Commission may be hesitant to reverse course and raise the ROE by 60 basis points in this instant case, if the Commission believes an ROE of 9.9% is more appropriate, then a higher equity ratio would be warranted. In such a case, a minimum equity ratio of 53.1% would be required

[3] Page 141 of the Company's 2020 10-K reports depreciation rates for the Electric and Gas Utility Property as 3.9% and 2.9%, respectively. This example applies the electric rate of 3.9% which results in a higher FFO to Debt for a given equity ratio and ROE combination. While credit rating agencies look at credit metrics on a company-wide basis instead of segment by segment, subsequent versions of this analysis may need to be revised to reflect more accurately the lower depreciation rates and the implied lower FFO-to-Debt ratio.

to maintain credit neutrality with the Company request in this case, but the Commission could approve an equity ratio of 53.9% to remain supportive of the necessary long-term FFO-to-Debt ratio of 20%.

Equation 4:

$$\frac{\boldsymbol{FFO}}{\boldsymbol{Debt}} = \frac{\mathbf{9.9\%}\ \boldsymbol{x}\ \mathbf{53.9\%}}{(\mathbf{1} - \mathbf{53.9\%})} + \mathbf{3.9\%}\ \boldsymbol{x}\left(\mathbf{1} + \frac{\mathbf{53.9\%}}{(\mathbf{1} - \mathbf{53.9\%})}\right) = \mathbf{20\%}$$

Q. Do the rating agencies support the analysis and mathematical relationship you captured in Equation 1?

A. Yes. As stated earlier, the mathematical expression most closely aligns with Moody's ratings methodology. In fact, Moody's published a U.S. regulated electric and natural gas utilities sector report on April 17, 2020, included as Exhibit A-161 (TAW-19), which addresses this question. Please see the discussion on page 5 and Exhibit 5 of the report titled, "Changes in ROE and equity capital both affect key financial markets: Four scenarios illustrating how authorized return on equity and equity thickness affect CFO/debt ratio". While the formula used in the Moody's model is not stated explicitly, using Moody's four scenario inputs into Equation 1 above will precisely replicate the same published results as the Moody's model.

Q. Please summarize the Company's conclusions regarding investor and credit rating agency expectations.

A. Based on interactions with investors and the rating agencies and their publications, it is clear that they view the authorized ROE as a critical metric which serves as the key barometer of the regulatory environment in Michigan. As such, a reduction to the authorized ROE will affect their perception of the credit quality of Consumers Energy and, thus, reduce their willingness to invest in Consumers Energy and, ultimately, in Michigan.

While investors currently view Michigan's regulatory environment as fairly constructive, their assumptions are based on returned stability in regulatory outcomes. If investors and the credit rating agencies were to perceive the regulatory environment as further deteriorating, this would quickly undercut the view that they currently hold.

2. Interest Rates

Q. What role do interest rates play in cost of capital determinations?

A. Interest rates clearly play an integral role in cost of debt determinations and, because debt comprises a large portion of a utility's capital structure, interest rates also play a large role in determining a utility's overall cost of capital. Both short-term and long-term interest rates influence cost of capital, but the impact can vary depending on a company's capital structure. This is most clearly evidenced by Mr. Bleckman's Exhibit A-14 (MRB-1), Schedule D-1, which outlines the Company's overall rate of return and highlights the Company's capital structure both on a permanent capital and total capital basis. As seen in the exhibit, long-term interest rates are considered in the permanent capital structure as the cost rate of the long-term debt of the Company. Because most of the Company's outstanding long-term debt is of a fixed interest rate structure, long-term interest rates affect the planned financings of the Company. Short-term interest rates also affect a company's expenses, but it does not get considered in the permanent capital structure of the Company. The effects of long-term and short-term interest rates are differentiated, but both impact the Company's cost of equity analysis as will be discussed below.

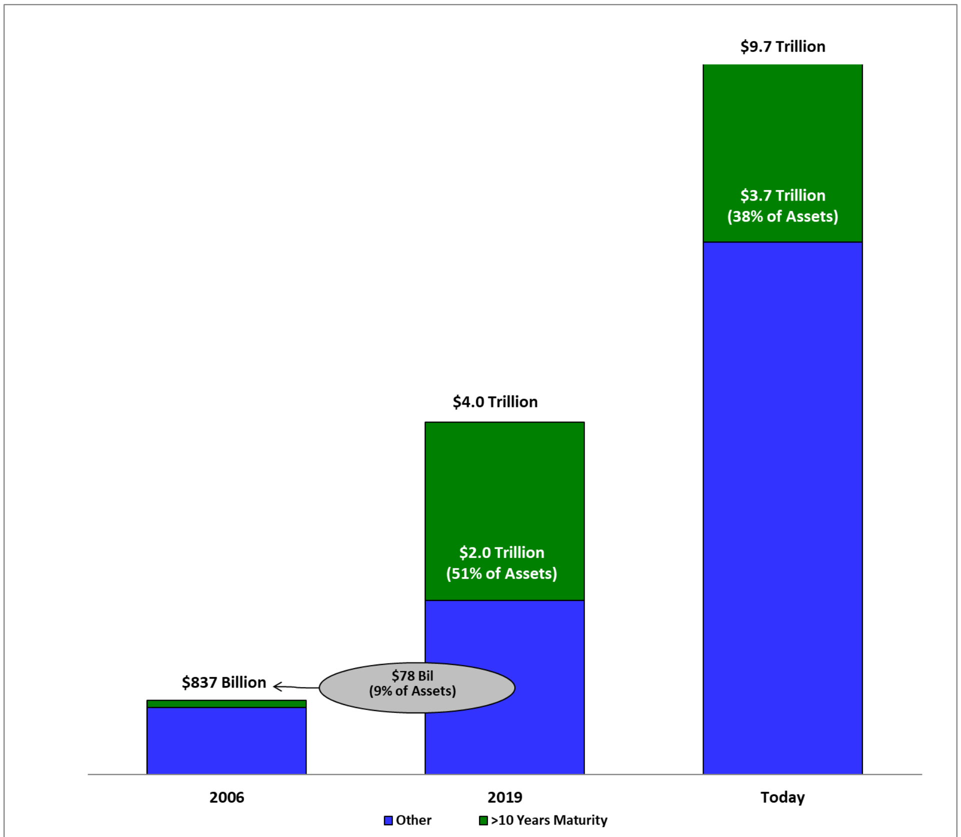
a. <u>Long-Term Interest Rates</u>

Q. What is the Company's assessment of current long-term interest rates?

A. Long-term interest rates have been, and continue to be, held artificially low by the Federal Reserve as a response to anemic domestic and global economic growth. This policy of maintaining low long-term interest rates has been replicated by central banks around the world and is perhaps one of the single largest considerations influencing cost of capital for interest sensitive assets and, in particular, utilities.

Q. Is there evidence the Federal Reserve is actually carrying out this policy?

A. Yes. The Federal Reserve has kept long-term interest rates low through the unprecedented growth in their balance sheet and similar growth in the monetary supply in the country. The size of the assets owned by the Federal Reserve has grown, and with the size of the Federal Reserve's balance sheet increasing, the duration of the assets being held have also grown dramatically. This combination of increasing balance sheet and purchasing longer-dated securities has had the effect of decreasing the supply of long-dated bonds and, therefore, <u>lowering long-term interest rates per the Federal Reserve's policy</u>. While the Federal Reserve's 2019 balance sheet was impressively large, the pace of growth of this dynamic has only been accelerated since then, as the Federal Reserve's balance sheet has more than doubled since and in less than two years' time.



Source: Federal Reserve, Schedule H.4.1 as of September 30, 2021.

Q. How have the actions of central banks outside of the United States impacted long-term Treasury rates?

A. Central banks outside of the United States have also largely kept interest rates artificially low as developed countries continue to experience tepid growth. As demonstrated in several of the Company's last rate cases, a substantial portion of all developed country sovereign debt, 31% or over $14 trillion, having negative yields.[4] Furthermore, 93% of all developed sovereign debt has a yield below that of the 30-year United States Treasury (a staggering $45 trillion of a total $48 trillion). These historic actions by central banks have made the rates offered by long-term United States Treasuries appear attractive on a relative

[4] Data provided by Bloomberg, as of October 29, 2021. See workpapers for support data and summary.[5] IPL's Emery Generating Station. See Alliant Energy's November 2020 Investor Fact Book.

basis, which has inflated the relative demand. However, as mentioned earlier, the supply of long-term treasuries has been drastically reduced by the Federal Reserve, which has increased the size of its balance sheet through purchases of long-dated securities. This combination of low global yield and Federal Reserve intervention has affected both sides of the supply/demand relationship in favor of lower rates, and these market dynamics have resulted in long-term rates being artificially suppressed.

Q. How do the actions by the Federal Reserve and other central banks to keep long-term rates low influence the cost of capital analysis for utilities?

A. One of the key components in many of the quantitative models is the interest rate on long-term government bonds as a benchmark; however, in an environment where the Federal Reserve is purposefully keeping long-term interest rates artificially low, these unadjusted models become less reliable, which is well documented not only by the Federal Reserve but also by academics and market practitioners alike. While unadjusted models would indicate diminished expected investor returns as a result of suppressed long-term government bonds, such a conclusion is erroneous. In fact, investors' expectations for investment returns do not simply decrease because of extraordinary intervention by central banks to lower rates.

Q. Has Staff commented on the assertion that the Federal Reserve actions have artificially suppressed interest rates?

A. Yes. Staff has been critical of this assertion in the past, calling it stale and incorrect. The criticism, however, has focused on short-term interest rate hikes that have been imposed and has ignored the continued state of long-term interest rates. However, a belief that multiple years of significant Federal Reserve intervention in the market should suddenly be considered normal compared to generations in which current market forces have been absent is simply neither reasonable nor sound. Even if these macroeconomic conditions are now the "new normal," Staff, along with the Commission, should agree that the new normal years certainly cannot be reasonably compared directly to the previous generations of data for which there were no such accommodative policies altering macroeconomic market forces. The Company has considered this dynamic and taken it into account in the analyses.

Q. Does the current interest rate environment result in customer savings?

A. Yes, lower long-term interest rates lead to a lower cost of debt which decreases the overall cost of capital, and this benefit is passed on to customers.

Q. What has been the cost of debt for the Company in recent years?

A. Refer to Company witness Bleckman's Exhibit A-14 (MRB-4), Schedule D-2, which reflects the Company's debt issuances used to develop the annual cost for long-term debt. It is evident from this exhibit that the rates on the Company's long-term debt issuances have decreased substantially after 2010. The Company's cost of long-term debt, as reflected in its August 2010 gas rate case filing (Case No. U-16418), was 5.95%, 233 basis points higher than the current case annual cost of 3.62%.

Q. Does the Company's lower cost of long-term debt equate to lower cost of equity?

A. No. The Company's lower cost of long-term debt should not be confused with a lower cost of equity. Cost of equity is impacted by several other factors, such as current economic uncertainty, market uncertainty and potential dislocation, higher equity risk premiums in low interest rate environments, and the sensitivity of utilities to movements in interest rates.

Q. How are the Company's credit ratings, long-term debt rates, and ROE connected?

A. The Company's favorable credit ratings over the past several years has resulted in lower long-term debt rates. The favorable credit ratings are due, at least in part, to the historically supportive regulatory environment and a reasonable authorized ROE.

Q. Is it a fair conclusion to believe a low interest rate environment, paired with the Company's strong credit ratings and financial stability, should justify a lower ROE?

A. No. This conclusion is erroneous and confuses the risk faced by bond investors with the risk faced by equity investors, which are important to differentiate.

Q. Please explain the difference between a bond investor and an equity investor and their relative investment risk.

A. Bond investors simply lend money to the company they invest in. The bonds receive interest payments over the life of the bond and the bonds deliver more consistent returns. In the event of a corporate liquidity issue, bondholders are always paid first. On the other hand, equity investors do not just lend their money, rather, they invest in the Company in exchange for part ownership. As such, their returns are not based on a stated rate of return and are much less consistent. In the event of a corporate liquidity issue, equity holders only have rights to what is left *after* the bondholders are paid.

Q. How does lower cost of debt function differently than lower cost of equity?

A. As stated above, the Company's improved credit ratings and lower interest rates lead to a lower cost of debt. Having a lower cost of debt decreases the overall cost of capital, and this benefit is passed on to customers. Exhibit A-14 (TAW-1), Schedule D-5, page 7, demonstrates how increased credit ratings save customers $102 million annually in interest savings. However, once again, a lower cost of debt should not be confused with a lower cost of equity. A downward movement in interest rates would not necessarily equate to a lower ROE for several reasons, including:

- Lower interest rates as a result of economic uncertainty and volatility can lead to lower Treasury Rates since they provide investors low risk safe havens for their investments; however, a higher ROE is necessary for investors willing to invest in higher risk stock to compensate for the additional risk;
- Equity risk premiums (the excess return that investing in higher risk stock provides over a risk-free rate (i.e., bond rate)) are higher when interest rates are lower which would lead to higher required ROE; and
- Utility stocks are particularly sensitive to interest rates and face increased risk, given that long-term interest rates have been and continue to remain artificially low due to monetary actions taken by the Federal Reserve.

Q. Has the Commission commented on the current low rate environment and its impact on ROE?

A. No. The Commission has not specifically commented on the impact that unprecedented monetary policy has had on ROE. However, in the development of appropriate ROEs, there has been federal and state recognition of the anomalous market conditions that have existed for more than a decade and should be, similarly, recognized by the Commission in this case. For example, in direct testimony before the Federal Energy Regulatory Commission ("FERC"), the former chairman of the MPSC, John D. Quackenbush, cited anomalous market conditions, and cited to the recognition by FERC of these anomalous market conditions in a number of FERC matters when testifying in support of ROEs in the high end of the zone of reasonableness in FERC Docket No. EL16-64-002. See Exhibit A-146 (TAW-4).

An additional example is found in a 2012 decision for PPL Electric Utilities, wherein the Pennsylvania Public Utility Commission recognized that market conditions may have caused certain models to understate the cost of equity. See Exhibit A-147

(TAW-5), page 81. These recognitions highlight the fact that quantitative models provide output estimates that need to be carefully considered in light of current market conditions.

Q. How were limitations of mechanical application of quantitative models considered in the Company's ROE analysis?

A. The quantitative models typically utilized to determine required ROE rely on either static conditions or use of historical data as benchmarks that do not correctly reflect today's current market conditions or the market conditions in the future test year. The limitations of various models were addressed in part by employing multiple methodologies, using projections for market inputs (risk-free rates, dividends, and risk premiums), and using independent judgment based on conversations with, and feedback from, the investment community. Furthermore, the Company's analysis includes a methodology for calculating the impact of both ROE and equity ratio on credit metrics.

b. <u>Short-Term Interest Rates</u>

Q. How are interest rates anticipated to move going forward?

A. The Federal Reserve has kept short-term rates near zero since late 2008 and, as a result, its purchase of longer duration assets has kept longer-term rates artificially low. Over time, the Federal Reserve will continue to look for ways to bring down the size of its balance sheet to more normal levels, which will put additional upward pressure on interest rates. The process had begun in late 2015 when the Federal Reserve increased short-term interest rates for the first time in nearly a decade. However, the process reversed course in 2019 and has once again been held at zero since March 15, 2020. It is important to recognize that these movements in short-term interest rates do not directly correspond with a move in long-term interest rates.

Q. Does the average of the interest rate expectations utilized in the analysis reflect the conditions in the test year?

A. No. Near-term expectations usually have some relative consensus; however, given the continued uncertainty regarding the economy, geopolitical actions, and actions from the Federal Reserve, near-term expectations have larger-than-normal variation, and future periods demonstrate considerable variability as to expected yields. Given the sensitivity of utility stocks to interest rates, using simple averages would understate the risk given the elevated variability of expected outcomes. When interest rates rise, utility stocks are often the most impacted and, therefore, the cost of equity for utilities increases. This relationship has been apparent since late 2017 and continues today. With interest rates near historic lows, mean reversion suggests that interest rates will eventually rise, and this movement will increase utility cost of equity. It is, therefore, important to keep these circumstances in mind in setting the cost of equity for utilities. The quantitative analysis performed takes this critical factor into consideration.

3. <u>ROE Trends</u>

Q. Is there a source that serves as a complete provider of authorized ROEs around the country?

A. No. There is no accurate or complete source for the national ROE trends.

Q. Do you consider the *S&P Global Regulatory Research Associates* ("RRA") database a complete source for national ROE trends?

A. No. While the RRA database has increased data in an attempt to become a complete and comprehensive resource, it still remains incomplete.

Q. Is the national average ROE that RRA publishes a complete metric that can be relied upon by commissions?

A. No. While the RRA database reflects a growing number of ROE metrics, the national average ROE metric that it publishes, and intervenors have referenced in the past, is not complete and should not be relied upon. The RRA metric does not include the following: (i) alternative regulatory jurisdictions (i.e., Alabama, Georgia); (ii) ROEs set outside of general rate cases; (iii) cases where ROEs are settled/unstated; and (iv) jurisdictions that have separate riders (i.e., Wisconsin, Iowa, Virginia).

Q. Is this significant?

A. Yes. The data excluded from RRA's headline national average tends to support higher ROE values. One such exclusion type is the attractive authorized ROEs for generation assets in jurisdictions such as Iowa[5] (12.23%) and Wisconsin[6] (12.7%). These are not included in the headline average number reported by RRA as they are not completed inside of a general rate case. Another type of exclusion are the limited-issue riders such as those utilized in Virginia. RRA provided the following commentary:

> Over the last several years, the annual average authorized ROEs in electric cases that involve limited-issue riders were typically meaningfully higher than those approved in general rate cases… [RRA, October 17, 2019.]

Q. How does this missing data affect an analysis of national ROE averages?

A. The missing data skews RRA's national ROE averages lower because numerous jurisdictions with strong regulatory frameworks that have constructive ROEs are simply not reflected in the RRA national average metrics that are so often referenced in cases

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[5] IPL's Emery Generating Station. See Alliant Energy's November 2020 Investor Fact Book.
[6] WEC Energy's Power the Future. See WEC Energy's December 2020 Investor Update.

before this Commission. With jurisdictions increasingly approving ROEs outside of general rate cases, and with the majority of them receiving ROEs above the average number reported by RRA, it is no surprise that the average of remaining general rate cases has trended lower over time.

Q. What is the interplay between regulatory environments and ROEs?

A. UBS produces an annual report ranking individual states and Canadian provinces according to the quality of their regulatory environments. The 2018 UBS report, shown in Exhibit A-148 (TAW-6), demonstrated a clear, positive relationship between the quality of the regulatory environment and ROE with top quartile states producing earned ROEs on average of 11.5% versus 10.0%, 9.8%, and 9.6% in the lower quartiles, respectively. While UBS reports have not since included the same ROE data, analysts continue to recognize the positive relationship and incorporate their expectations into their ROE estimates. This virtuous cycle of strong regulations coupled with an attractive ROE enables continued investment in necessary infrastructure, as discussed above.

Q. Are there examples of top tier regulatory jurisdictions and factors impacting their inclusion in that positive ranking?

A. Yes. RRA considers numerous factors in determining their regulatory jurisdiction rankings, including:

- ROE and equity ratio;
- Commissioner selection;
- Elected officials, legislation, and court actions; and
- Settlements, alternative regulation, adjustment clauses, rate structure, and rate case timing.

Exhibit A-28 (MRB-12) demonstrates examples of several utilities operating in top tier regulatory jurisdictions as well as how they compare to the Company.

Top tier regulatory jurisdictions examine more than just one of the factors listed above, and jurisdictions with strong regulatory frameworks have higher customer satisfaction as well as higher ROEs.

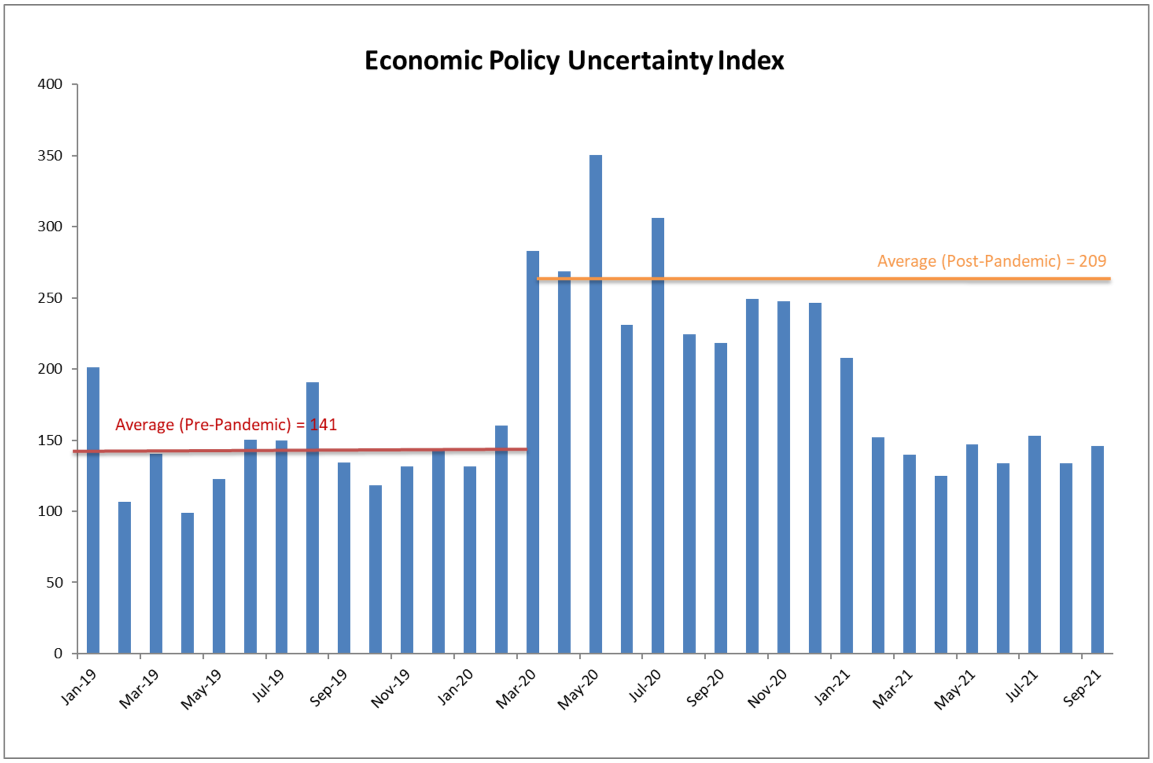
4. Economic Outlook and Uncertainty

Q. Was the current state of the economy considered in performing the Company's ROE analysis?

A. Yes, national and global factors were considered. Several of the analyses require market observations that are impacted by the current state of the United States economy. In addition, global economic factors play into investor considerations because of the ripple effects on the United States economy and the integrated nature of global financial markets.

Q. How would you assess the uncertainty in the market, and how does uncertainty impact risk?

A. There are several ways to estimate the current level of market uncertainty. Levels of uncertainty were considered high pre-pandemic and rose dramatically post-pandemic. The chart below shows the United States Economic Policy Uncertainty Index compiled by the Federal Reserve, and the increase in average uncertainty observed after the onset of the COVID-19 pandemic is dramatic. The previous monthly maximum in the data set going back to 1985 was at a level of 245 in August of 2011. The monthly average during the pandemic has been 209, approaching the pre-pandemic high.



Increased uncertainty is a clear sign of increased market risk, which in turn increases the required returns by investors.

Q. Why is it important to consider the economy in performing an ROE analysis?

A. The Company makes long-term investments in infrastructure to serve customers, but markets can and do face significant dislocations from time to time, which affects risk to investors. The competition for capital investment to fund projects has continued to increase, and all of these factors have increased uncertainty and utility investor risk in the market and, thus, impact an analysis of ROE.

5. <u>Capital Investment</u>

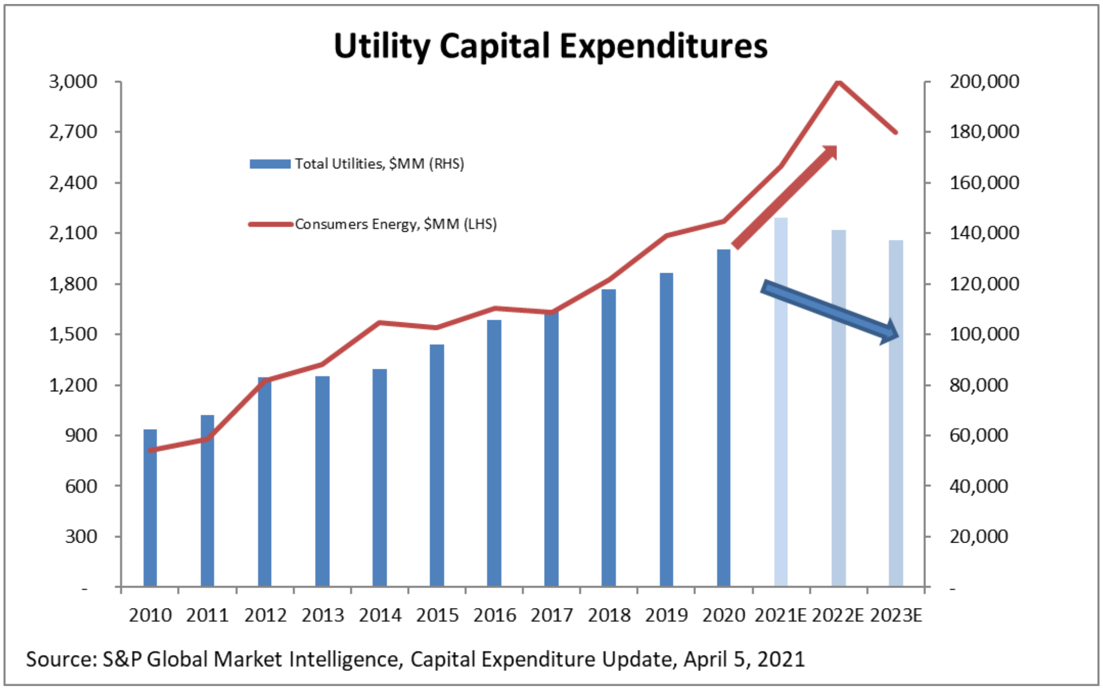
Q. Does the Company's significant capital investment program impact the appropriate ROE determined in this case?

A. Yes. Consumers Energy plans to continue making significant needed capital investments in Michigan to provide safe and reliable service to customers, in compliance with federal and state requirements. The Company's five-year plan includes investment of approximately $13.2 billion on a total company basis, $5.3 billion of which is earmarked for gas utilities operations investment.[7] This significant level of capital investment increases the risk profile of the Company for investors and the rating agencies. Authorizing an ROE in this case at a level that investors view as adequate to compensate them for the risk is necessary to attract such large amounts of cost-effective capital to Michigan and to keep Consumers Energy financially healthy to the benefit of customers. Authorizing an ROE that investors consider to be below expectations could lead to increases in cost of capital or hinder the Company's ability to access capital altogether, neither of which is in the best interest of customers.

Q. What is the trend in capital expenditures across the utility industry?

A. The following chart shows the historic and projected capital expenditures for the utility industry per *S&P Global* as well as historical and projected capital expenditures for Consumers Energy.

[7] See Consumers Energy 2020 10-K report, page 75.



As the chart illustrates, while the industry is projected to have declining capital investment needs in the near term, Consumers Energy's investment has grown, and the projected investment will remain elevated to make necessary upgrades to critical energy infrastructure. This heightened need for investment will require Consumers Energy to raise significant amounts of capital and a competitive ROE is critical to attract capital and enable investment.

Q. Please discuss the role of ROE in attracting capital.

A. One of the key principles in setting an ROE is to maintain the financial integrity of the utility so that it maintains its credit. Equally as important is setting an ROE that attracts capital. The State of Michigan has ambitious goals to improve the energy infrastructure which will require significant capital. While undertaking any major projects increases the risk profile of a company, public utilities are a primary vehicle to fund and execute these infrastructure investments. However, utility management teams cannot simply invest capital without evaluating its impact on investors, as they owe a fiduciary obligation to their shareowners and must be cautious when investing capital in a business where the ROE, relative to other projects, is less attractive. Michigan must compete for investment dollars with all the state jurisdictions highlighted earlier which provide ROEs that are significantly more attractive than the Company's current 9.9%. Further, if investors and management teams perceive the risk that invested capital would be subject to further downward pressure (ROE creep) in the future, they will be increasingly cautious about current investments in order to avoid this risk.

Q. How have other jurisdictions responded to this regulatory risk and what is your recommendation?

A. Given the existence of this regulatory risk, several jurisdictions have established ROE riders and alternative mechanisms to ensure that the ROEs will not be subject to reduction though I am not advocating in this case for the Commission to authorize a permanent ROE that is not subject to change. An ROE of 10.50%, 60 basis points higher than is currently authorized is within the range of reasonable returns, as will be demonstrated through the discussions of the quantitative analysis below. This ROE would send an important signal to investors that management is not investing in a company or state that has a declining regulatory environment.

E. <u>Quantitative Equity Cost Rate Analyses</u>

1. <u>Selection of Proxy Companies</u>

Q. Why was a group of proxy companies selected to perform the quantitative analyses?

A. Since the common stock of Consumers Energy is not publicly traded, it is necessary to use indirect or proxy approaches to calculate an appropriately representative ROE.

Q. Please describe how a proxy group of companies was chosen.

A. The focus of this case is on Consumers Energy's natural gas operations and companies similar to the Company's natural gas operations. Thus, the primary focus was on publicly traded companies, companies headquartered in and with operations in the United States, companies with a comparable amount of designated generation capacity, and companies with a comparable amount of Property Plant and Equipment ("PP&E").

Q. Please explain.

A. Proxy companies were selected as follows:

(i) The initial selection criteria were selected to identify gas utility companies that are publicly traded and for which public data is available. The *S&P Global* published data set, formerly referred to as *SNL Financial*, was utilized as the primary data set to select the initial proxy group;

(ii) In order to be included in the proxy group, the company had to be headquartered in and have the vast majority of operations within the United States;

(iii) The companies were required to have a market capitalization greater than $1 billion and less than $30 billion. This filter excludes both the very small as well as the extremely large ends of the spectrum of utility companies, thereby focusing on comparably sized companies in the relative range of Consumers Energy's natural gas business. Academic literature has shown a correlation between company size and ROE (Fama, French, K. R. (1992) – *The Cross-Section of Expected Stock Returns*), making this an important criterion to include. See Exhibit A-149 (TAW-7);

(iv) The companies were required to have a dividend payout ratio in the last 12 months greater than or equal to 55%;

(vi) The company could not be a recent merger target or be recently or currently engaged in significant restructuring, as this type of activity can materially distort a company's data to the extent it should not be credibly included in a proxy group; and

(vii) The company's bonds must be rated at or above a minimum investment grade of Baa3 by Moody's and BBB- by S&P.

Q. Which companies were excluded due to merger or restructuring issues?

A. DTE Energy was excluded due to their recent restructuring, with the spin-off of their midstream business. While Southwest Gas announced the acquisition of Questar Pipeline from Dominion Energy on October 5, 2021, they were not the target entity and because my analysis utilized data prior to the announcement, I do not believe that this negatively impacts the analysis in any way.

Q. How does this proxy group differ from the most recent gas rate case?

A. I have applied the same broad criteria as the most recent gas rate case and applying the described limitations resulted in a proxy group of 12 companies, the only difference being the elimination in this case of DTE Energy. The list of the proxy group companies, the selection criteria, and the data supporting inclusion is set forth on Exhibit A-14 (TAW-1), Schedule D-5, page 1.

2. <u>Empirical Capital Asset Pricing Model Analyses</u>

Q. Please describe the Empirical Capital Asset Pricing Model ("ECAPM") model.

A. The ECAPM is derived from the Capital Asset Pricing Model ("CAPM") model which describes the expected rate of return on any security or portfolio of securities. The CAPM was first developed in the 1960s by William F. Sharpe, John Lintner, and Jack Treynor and had been used to estimate the cost of equity.

Q. What is the theory behind CAPM and ECAPM?

A. The principal assumption of the CAPM and ECAPM is that the expected return on an asset is related to risk – that is, risk taking by investors is rewarded with appropriate returns. The

CAPM and ECAPM state that an investor's expected rate of return on an investment is equal to a risk-free rate of return plus a risk premium as a form of additional compensation for investors' additional risk tolerance. The size of the risk premium for an investment is dependent on the amount of unavoidable (or systematic) risk taken. An investment's systematic risk is obtained by the application of a beta, which is a measure of the risk arising from exposure to general market movement and is used as an indication of the risk of an investment relative to the risk of a market portfolio consisting of all types of risk-oriented assets.

Q. Please explain the application of beta to determine risk premium.

A. Under the theory of CAPM, beta is a measure of the systematic risk of a security as compared to the systematic risk of the market as a whole. Beta is a coefficient resulting from a regression of the return of a single stock to the return of the market. The beta for the market is always equal to 1.00. Companies whose securities have betas greater than 1.00, therefore, are generally considered riskier than the market as a whole, while companies with betas less than 1.00 are generally considered less risky than the market as a whole. CAPM is based on the concept that investors demand higher returns for assuming additional risk and, accordingly, higher risk securities are priced to yield higher returns than lower risk securities. Under CAPM theory, there is an incremental premium for bearing additional risk, as measured by beta, above the risk-free rate, which is traditionally seen as the income return available from investing in United States Government Treasury securities (bonds). The model assumes that prices for individual securities are determined in efficient markets where information is freely available and instantaneously reflected in security prices. The specific CAPM formula is expressed as:

Equation (5): $K_e = R_f + F + B \times (R_p)$

Where:

K_e = annual required cost of equity;
R_f = risk-free rate;
F = flotation cost adjustment;
β = beta; and
Rp = risk premium which reflects the market return less the risk-free rate.

Q. Do CAPM results capture all the risk faced by utility investors?

A. No. The CAPM has a number of shortcomings which are particularly relevant to public utilities and are well documented in academic literature:

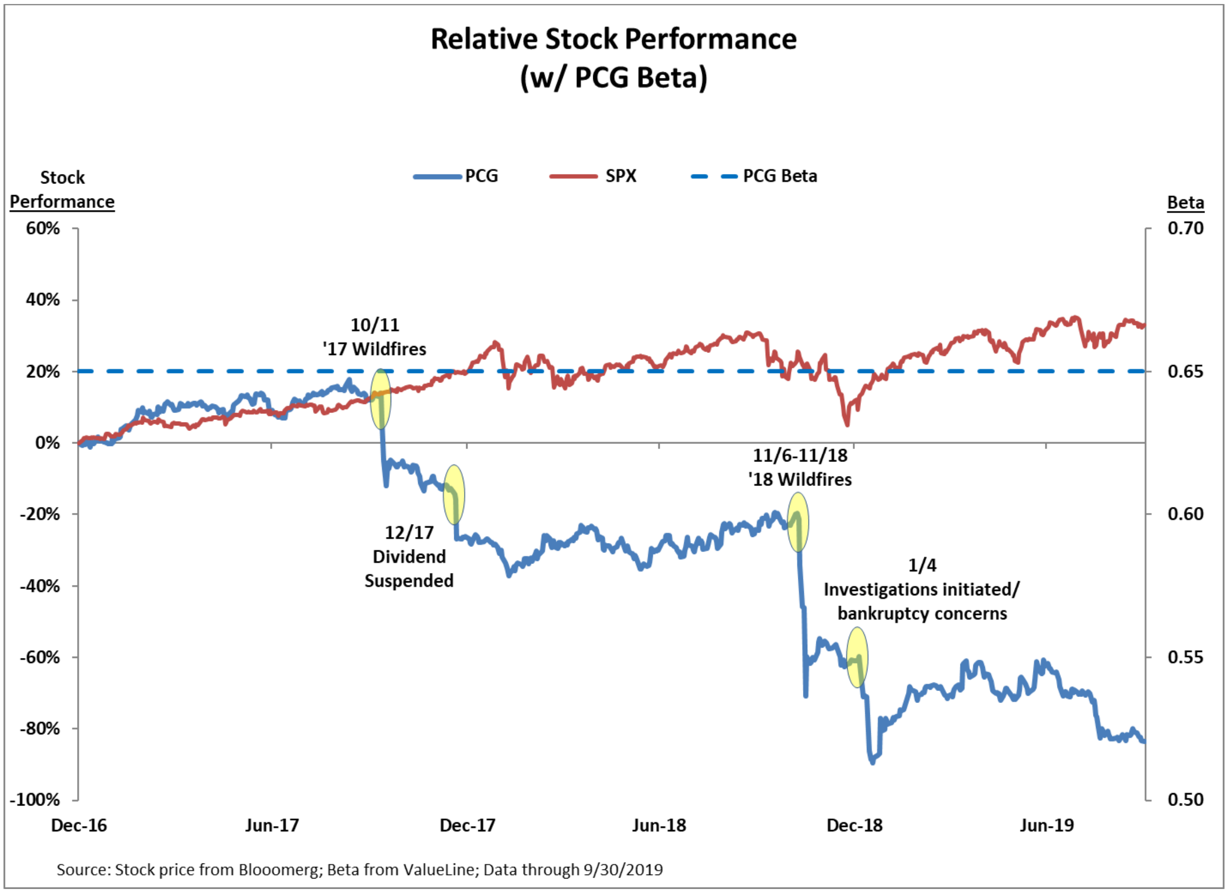
- Fama and French: "*The CAPM is Wanted, Dead or Alive,*" (Exhibit A-150 (TAW-8));
- Tony Tassell: *"The time has come for the CAPM to RIP," Financial Times,* (Exhibit A-151 (TAW-9));
- Chartoff, Mayo, and Smith: "*The Case Against the Use of the Capital Asset Pricing Model in Public Utility Ratemaking,"* (Exhibit A-152 (TAW-10));
- Chretien and Coggins: "*Cost of Equity for Energy Utilities: Beyond the CAPM,*" (Exhibit A-153 (TAW-11)); and
- Robert Morin: "*New Regulatory Finance."*

Q. Please summarize the shortcomings.

A. First, studies have shown that the CAPM tends to overstate the sensitivity of the cost of capital to beta. Low beta assets tend to have higher average returns than would be predicted, while high beta assets have lower returns. The beta of utilities, including the Company's proxy group, as shown on Exhibit A-14 (TAW-1), Schedule D-5, page 2, are typically less than 1.00 and would, therefore, tend to have higher average returns than predicted by the model. Second, CAPM relies on beta to capture all the systemic risk faced by a company and assumes that the only unavoidable (or systemic) risks are fluctuations in the market. Market beta calculates a low result for a company with a low correlation to the broad market when, in fact, the company could experience high stock volatility that is simply not correlated with the market. Utilities are interest rate sensitive and exposed to regulatory risk, neither of which market force is captured by the traditional CAPM analysis.

Q. Is there an example of how beta does not capture all the risk faced by a company?

A. Yes. As an example of how beta does not appropriately capture the risks associated with a stock, one can consider the example of Pacific Gas and Electric Company ("PG&E"). The chart below shows PG&E's stock price over in 2016-2019 as compared to the S&P 500 Index. During this time PG&E was faced with increased risk of wildfire liabilities, along with ensuing dividend suspensions, investigations, and bankruptcy concerns. Clearly the stock exemplified heightened risks over the period as the stock performance underperformed both the Philadelphia Utilities index as well as the S&P 500 Index over the course of this time. The stock also demonstrated a high correlation with wildfire risk rather than a correlation with the market performance as a whole. However, PG&E's Value Line Investment Survey ("Value Line") beta was 0.65 on January 27, 2017, as filed in the Company's 2017 electric rate case, Case No. U-18322, and remained at 0.65 in 2019. The Value Line beta of 0.65 is a low beta, which would normally be indicative of low risk compared to the market. However, knowing PG&E's situation, this clearly demonstrates that traditional Value Line utility beta customarily applied to CAPM does not fully capture the entire risk faced by the underlying company, even when those risks have threatened the viability of the company itself.



Q. Did the Company perform its customary CAPM methodology?

A. In previous cases before the Commission, the Company performed and relied upon a CAPM analysis but, given the significant evidence that the unadjusted CAPM methodology understates the required rate of return for utilities, it was not specifically relied upon in forming the recommended ROE range in this case. See Exhibit A-162 (TAW-20), page 1, for the Company's CAPM analysis.

Q. How did the Company address the customary CAPM model shortcomings referenced above?

A. In order to adjust for the shortcomings of the CAPM model, the Company performed the ECAPM analysis as well as CAPM analysis using total beta.

Q. Please describe the ECAPM approach.

A. The ECAPM begins with the same assumptions as the CAPM. To better predict the relationship between asset returns and risk, the ECAPM includes an "alpha" adjustment to the risk-return line. The specific formula of ECAPM is expressed as:

Equation (5a): $K_e = R_f + \alpha + F + B \text{ x } (R_p - \alpha)$

Where:

K_e	=	annual required cost of equity;
R_f	=	risk-free rate;
α	=	alpha;
F	=	flotation cost adjustment;
β	=	beta; and
Rp	=	risk premium which reflects the market return less the risk-free rate.

Q. What is alpha in this ECAPM approach?

A. The alpha adjustment in the ECAPM approach is simply an adjustment made to the CAPM formula to more closely align the expected returns with market observed results.

Q. What values were assumed for the components of this analysis?

A. Except for alpha, which is not a component of the CAPM formula, the same values as the CAPM were used. For alpha, 1.5% was applied, which is the mid-point in the range of 1% to 2% described as reasonable by Dr. Morin in his book *New Regulatory Finance*.

Q. Does the application of long-term risk-free rates and adjusted betas fully address the concerns that ECAPM is meant to reconcile?

A. No. Application of a long-term risk-free rate and adjusted betas address some of the CAPM shortcomings, but it does not fully address the shortcomings of CAPM. Alpha adjustment is still necessary to address the key differences between CAPM and ECAPM. In fact, without the use of adjusted beta and long-term risk-free rates, the alpha adjustment would need to be higher than the proposed 1.5%.

Q. What are the results of applying the ECAPM on the group of proxy companies?

A. The ECAPM results are found on Exhibit A-14 (TAW-1), Schedule D-5, page 2. The Projected Risk Premium ECAPM ROEs are displayed in column (h) and show the average ROE for the proxy group is 12.48% and range from a minimum of 11.52% to a maximum of 14.74%.

Q. How was the market risk premium determined?

A. Since the equity risk premium may be fundamentally higher in different market conditions, the analysis must use market periods which mirror the conditions in the current environment in order to best approximate the current equity risk premium. As shown in Exhibit A-14 (TAW-1), Schedule D-5, page 11, a projected, or forward-looking, market risk premium was estimated based on the expected market return of the S&P 500 Index and the expected yield of the 30-year United States Treasuries during the projected test year was subtracted from it. The expected market return was calculated as the summation of the dividend yield and the long-term Earnings Per Share ("EPS") growth estimates for the entire index. The estimated market capitalization weighted dividend yield of 1.39% and long-term EPS growth estimate of 11.97% resulted in a sum expected market return of 13.36% as of September 27, 2021. Subtracting the expected 30-year United States Treasury yield of 2.68% for the test period results in an estimated market risk premium of 10.68% for the test period.

Q. Is there support for a forward-looking market risk premium such as this?

A. Yes. Because the test year is in the future, it makes sense that the analyses supporting Company recommendations rely on projected market data to estimate returns for the forward-looking period; therefore, projected inputs and assumptions are appropriate to use where possible. In fact, in Opinion 531-B, FERC gave specific endorsement to a method that is similar to the method the Company has applied to calculate the forward-looking market risk premium, referencing both the S&P 500 Index as well as the 30-year United States Treasury bond yields. See Exhibit A-154 (TAW-12), at paragraphs 109-111.

Q. Did any other analyses support the Company's projected estimate?

A. Yes. Three additional equity risk premium estimates have been considered which are supportive of the resulting 10.68% value utilized in the analyses: (i) equity risk premium since quantitative easing began; (ii) equity risk premium during periods of Federal Reserve intervention in long-term interest rate markets; and (iii) equity risk premiums from Federal Reserve research. The first two utilize Roger Ibbotson's *2020 Stocks, Bonds, Bills, and Inflation (SBBI) Yearbook.* In Exhibit A-14 (TAW-1), Schedule D-5, page 8, the calculation on line 56 focuses on the low interest rate periods of 2011 through 2019 while the calculation on line 58 focuses on the larger low interest rate periods of 1942 through 1951 and 2011 through 2019. The Ibbotson data is often used in developing the market risk premium. These calculations take the average large company's total stock market return for the period and subtract the average income return of long-term government bonds for the period. The equity risk premium is not a known and static number, but it varies around a central average. Academic literature shows that, in low-interest rate environments, the average equity risk premium is higher. This is not to suggest that the realized equity risk premium will not vary in a low-interest rate environment but, instead, that the average is fundamentally higher. Taking the average of the available data during low-interest rate environments provides a more reasonable and accurate measure of the expected equity risk premium than applying one for all historical data available. The resulting market premiums for these periods are 11.23% and 13.59%, respectively.

The third estimate relies upon a recently published report by the Federal Reserve, *The Equity Risk Premium: A Review of Models*, Exhibit A-155 (TAW-13), which indicates that equity risk premiums in low interest rate environments are much higher – 12%. Each of these estimates is shown in the following table and the average of 12.27% is supportive of the 10.68% estimate calculated and applied in the analyses. A fourth estimate could be observed from page 16 of the direct testimony of Staff witness Megginson in Indiana Michigan Power Company's Case No. U-20359 on October 17, 2019 where Staff estimated the risk premium to be 12.10%. This Staff estimate is also higher than my estimate in this case and therefore supportive of the estimate.

Equity Risk Premium	
Risk Premium During Most Recent Low Interest Rates (2011-2019)	11.23%
Risk Premium During Federal Reserve Action (1942-1951 and 2011-2019)	13.59%
Federal Reserve Research	12.00%
Average	**12.27**

Q. Is it appropriate to use the average from 1926 to 2019 for the Ibbotson equity risk premiums with current risk-free rates?

A. No. The Ibbotson equity risk premium is an estimate based on historical data which is not appropriate to use with current interest rates, in particular during a period where the Federal Reserve is purposefully keeping long-term interest rates low. Utilizing <u>current</u> risk-free rates requires estimating a current equity risk premium as set forth in the Company's primary calculation.

Q. How were the projected risk-free rates calculated?

A. As in the past, the test year risk-free rate was calculated by utilizing an average of *Blue Chip* and *IHS Markit* 30-year United States Treasury Bond yield estimates. According to the December 2020 edition of *IHS Markit's* United States Economic Outlook, the average yield on 30-year United States Treasury Bonds for the test year is projected to be 2.60%. The estimate for 30-year United States Treasury Bonds from the December 2020 *Blue Chip* Financial Forecast for the test year is 2.75%. The average of the two results in an estimate of 2.68%.

Q. Why were longer dated bonds chosen?

A. The time horizon of the chosen Treasury security should match the time horizon of whatever is being valued. When valuing a business that is being treated as a going concern, the yield of a long-term Treasury bond is appropriate.

Q. What beta was used for purposes of the Company's ECAPM analysis?

A. The values of beta calculated by Value Line were used. Value Line computes historical betas using data over the last five years and adjusts this historical beta using the method prescribed by the great academic Marshall E. Blume to make it an expected beta. The resulting betas are used in ECAPM analyses, and the values of beta for the Company's proxy group of companies are found on Exhibit A-14 (TAW-1), Schedule D-5, page 2. The average current beta for the Company's proxy group is 0.90.

Q. Does the ECAPM address all the shortcomings of CAPM?

A. No. ECAPM is focused on the understatement of ROE for low beta stocks and does not necessarily capture all the systematic risk associated with a stock.

Q. Is there third-party support for the use of ECAPM?

A. Yes. As discussed earlier in this direct testimony, the CAPM has several deficiencies which impact utilities in particular. There are numerous academic articles that have discussed the shortcomings of CAPM. The simple adjustments formulated by Dr. Morin to correct these deficiencies were used. Dr. Morin's detailed analysis of the ECAPM can be found in chapter 13, page 189, of his 1994 book, *Regulatory Finance*, and chapter 6 of his latest book, *The New Regulatory Finance*, both published by Public Utilities Report Inc. In addition, findings from a February 2013 report from the Brattle Group entitled "*Estimating the Cost of Equity for Regulated Companies*" (Exhibit A-156 (TAW-14), pages 15-20) reinforce the many weaknesses in the CAPM model as well as the suitable application of the ECAPM to correct for these deficiencies.

Furthermore, an academic research paper focused specifically on utility companies in North America titled *"Cost of Equity for Energy Utilities: Beyond the CAPM"* (Exhibit A-153 (TAW-11)) concluded the following:

> We find that the CAPM significantly underestimates the risk premium for energy utilities compared to its historical value by an annualized average of more than 4%.

The study looked at CAPM extensions to remove the underestimation error, one of which is an adjusted CAPM similar to the ECAPM in the Company's analysis. The research states that, unlike CAPM, the adjusted CAPM, "[p]rovide(s) econometric estimates of the risk premium that do not present a significant misevaluation." This is yet another clear example that the use of ECAPM in the Company's analysis is not only supported and logical, but necessary in setting a fair ROE.

Q. Beyond academic literature, are there examples of applications of the ECAPM analysis as used by the Company?

A. Yes. The ECAPM has been utilized in rate case proceedings and is included among the models relied upon by some regulatory witnesses and decision makers. For example:

(i) A 2013 study by Christensen Associates commissioned by the Mississippi Public Utilities Commission Staff called *Discussion of the Return on Equity and Performance Indicators of Entergy Mississippi Inc. and Mississippi Power Company*, explicitly acknowledges the Mississippi Power Company's use of Value Line betas in the applied CAPM (Empirical) calculations. The rate schedule from Mississippi Power showing the use of ECAPM with a Value Line adjusted beta has been included. Please refer to Exhibit A-157 (TAW-15), page 24;

(ii) The ECAPM approach has been relied on by the staffs of the Maryland Public Service Commission ("Maryland PSC"). For example, staffs witness Julie McKenna in Maryland PSC Case No. 9299 noted that "the ECAPM model adjusts for the tendency of the CAPM model to underestimate returns for low Beta stocks," and concluded that, "I believe under current economic conditions that the ECAPM gives a more realistic measure of the ROE than the CAPM model does";[8]

(iii) The Regulatory Commission of Alaska has also relied on the ECAPM approach, noting that:

> Tesoro averaged the results it obtained from CAPM and ECAPM while at the same time providing empirical testimony that the ECAPM results are more accurate then [sic] traditional CAPM results. The reasonable investor would be aware of these empirical results. Therefore, we adjust Tesoro's recommendation to reflect only the ECAPM result;[9]

(iv) The Staff of the Colorado Public Utilities Commission has also recognized that, "[t]he ECAPM is an empirical method that attempts to enhance the

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[8] Direct testimony and exhibits of Julie McKenna, Maryland PSC Case No. 9299 (October 12, 2012), page 9.
[9] Regulatory Commission of Alaska, Order No. P-97-004(151) (Nov. 27, 2002), page 145.

CAPM analysis by flattening the risk-return relationship,"[10] and relied on the same standard ECAPM equation presented above;

(v) The Wyoming Office of Consumer Advocate, an independent division of the Wyoming Public Service Commission, has also relied on this same ECAPM formula in estimating the cost of equity for a natural gas utility, as have representatives of the Office of Arkansas Attorney General and the Office of Oklahoma Attorney General;[11]

(vi) Additionally, Shannon Pratt and Roger Grabowski's book, *Cost of Capital in Regulated Utilities: Applications and Examples*, describes how the Surface Transportation Board significantly revised its approach to setting the cost of capital to include the ECAPM analysis as one of only two methods over eight years ago. The Minnesota Department of Revenue included ECAPM as one of the methodologies used in determining the value of property in their 2019 Assessment;[12]

(vii) The New York State Public Service Commission has utilized what they refer to as the zero beta CAPM analysis dating back as early as the 1980s. Zero-beta CAPM is another name for ECAPM, as it references the traditional CAPM model's inability to capture necessary return for a zero-beta stock in excess of the riskless rate. The commission confirmed their reliance upon the zero-beta model as recently as April 20, 2017 in the final order in Case No. 16-G-0257, at page 53; and

(viii) Outside the United States, the Alberta Utility Commission's decision 20622-D01-2016 in October 2016 determined the ECAPM model could contribute to that commission's established fair allowed ROE. The commission in that jurisdiction noted in its findings, "[t]he use of ECAPM is an approach recognized in the academic literature and is used to address a perceived issue with the CAPM…." While this case did not have enough information to rely heavily on the ECAPM, they did recognize its relevance as well as academic support and stated that it could be used to determine an ROE. Please refer to Exhibit A-158 (TAW-16).

While not an exhaustive list of examples, the use of ECAPM in these regulatory proceedings demonstrates the methodology is neither new nor novel.

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[10] Proceeding No. 13AL-0067G, answer testimony and exhibits of Scott England (July 31, 2013), page 47.
[11] Docket No. 30011-97-GR-17, pre-filed direct testimony of Anthony J. Ornelas (May 1, 2018), pages 52-53; Docket No. 17-071-U, direct testimony of Marlon F. Griffing, Ph.D. (May 29, 2018), page 47; and Case No. PUD 201800140, responsive testimony of Marlon F. Griffing, Ph.D, (April 22, 2019), pages 41-43.
[12] 2019 Capitalization Rate Study, Minnesota Department of Revenue (May 13, 2019).

Q. Is the use of Value Line adjusted beta consistent with ECAPM?

A. Yes. Adjusted betas are used in the ECAPM analysis performed by regulatory witnesses referenced above in at least Alaska, Arkansas, Colorado, Maryland, New York, and Oklahoma, as well as the cost of capital proceedings in Mississippi. Furthermore, in Dr. Morin's book, *The New Regulatory Finance*, at page 191, he explicitly states the use of adjusted beta is necessary and that suggestions to the contrary are erroneous. He wrote:

> Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. **This argument is erroneous**. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated.…**Both adjustments are necessary**. [Emphasis added.]

Further, Value Line clearly discloses in Exhibit A-159 (TAW-17) that the Value Line calculation for beta uses historical data, and the adjustment prescribed by Marshall Blume <u>does not incorporate the effects captured in ECAPM</u>. The use of Value Line adjusted betas is, therefore, very much consistent with the application of ECAPM.

Q. Has Staff challenged the use of ECAPM in prior rate cases?

A. Yes. In past cases Staff has cited Dr. Morin's book, *The New Regulatory Finance,* to assert that the application of Value Line beta and long-term treasury rates address the shortcomings of CAPM and make ECAPM unnecessary.

Q. Was Staff correct in its assertion regarding Dr. Morin's treatise?

A. No. First, other practitioners use ECAPM with both long-term Treasury Rates and Value Line beta. Further, in Dr. Morin's book, he notes that the empirical evidence on the appropriate range of the alpha factor is higher than the 1% to 2% alpha adjustment that the Company has proposed. Dr. Morin specifically states in *New Regulatory Finance,*

> An alpha adjustment of **<u>1%-2% is somewhat lower than that estimated empirically</u>**. The use of lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk free rate rather than a short-term risk free rate already incorporates **<u>some</u>** of the desired effect of using the ECAPM. [*New Regulatory Finance*, page 190. (Emphasis added.)]

Consistent with his book, Dr. Morin has testified in regulatory proceedings in other jurisdictions where he uses both Value Line beta and long-term interest rates with the ECAPM. Thus, Staff's argument has demonstrated a misunderstanding of the use of adjusted betas with ECAPM.

Finally, in the academic literature the "*Cost of Equity for Energy Utilities: Beyond the CAPM*" the authors explicitly note the use of adjusted betas with ECAPM and say:

> In summary, the two modifications incorporated in the Adjusted CAPM [ECAPM] involve first using the adjusted beta instead of the historical [raw] beta and second including the bias correction in the risk premium calculation. Considering the documented usefulness of the two adjustments, the Adjusted CAPM has the potential to estimate a reasonable risk premium for the energy utilities. [Exhibit A-153 (TAW-11), page 19].

Q. Please describe the CAPM approach using total beta.

A As noted earlier, the CAPM approach relies on the use of market beta to capture the risk associated with a company but as highlighted with examples and academic literature, market beta simply fails to capture all the risks of an investment.

Furthermore, using a traditional CAPM to calculate Consumers Energy's ROE inherently makes several assumptions including that Consumers Energy is publicly traded, and faces no company-specific risks or can diversify those risks by making other investments. This is clearly not true – Consumers Energy is not publicly traded and, given its role as a Michigan-based public utility, cannot diversify away from Michigan.

To account for these shortcomings of a traditional CAPM, practitioners have used the CAPM model with total beta. Total beta is similar to market beta, but it accounts for the company-specific risks. Total beta is calculated simply as the standard deviation of a stock divided by the standard deviation of the market. As discussed above, market beta does not address all the risk of a market. The total beta is focused on volatility of returns and better identifies all associated risk – systematic risk *and* company specific or sector specific risk – which are not fully addressed by market beta for utility stocks. The simplicity of this approach allows for analysts to address the company-specific risk of a privately held company by comparing the volatility of a proxy group to that of the market.

Q. What are the results of applying CAPM using total beta on the group of proxy companies?

A. The CAPM with total beta results are found on Exhibit A-14 (TAW-1), Schedule D-5, page 3. The results are displayed in column (h) and shows an ROE estimate of 15.72%.

Q. Is this a new or novel approach to calculating CAPM?

A. No. The merits of total beta have been discussed and analyzed by experts for well over a decade. The total beta concept was further popularized by its inclusion in Peter Butler and Keith Pinkerton's Butler Pinkerton Model.[13]

3. Projected Risk Premium Analysis

Q. Please describe the risk premium analysis that was performed.

A. Investors can choose to invest in either debt or equity in a company. Debt is subject to less risk as it receives a priority claim on assets in bankruptcy relative to equity. Further, interest payments, unlike dividends paid on equity, are mandatory and cannot be deferred. Investors in equity securities, therefore, demand a premium relative to the return paid on the debt. The risk premium analysis estimates the required rate of return on equity by estimating the future yield of utility bonds and then adding the estimated risk premium.

Q. Please describe how the future utility bond yield was calculated.

A. To determine the future yield of utility bonds (i) the risk-free rate, and (ii) the bond spread over United States Treasury Bonds were added together. The applied risk-free rate in the Projected Risk Premium Analysis is the projected long-term government bond return of 2.68%, which was developed in the ECAPM analysis and is supported in Exhibit A-14 (TAW-1), Schedule D-5, page 2. The risk premium analysis calculations were performed separately for each of the bond rating spreads from A to BBB.

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13 http://www.valtrend.com/downloads/income/Empirical%20Support%20for%20Company%20Specific%20Risk.pdf

Q. Please discuss how the risk premium relative to utility bonds was determined.

A. One methodology to determine the risk premium would be to use the historical risk premium of utility stocks over utility bonds. Exhibit A-14 (TAW-1), Schedule D-5, page 9, column (i), shows that gas utility common stocks have an average historical risk premium of 4.09% (line 66) over the yields of A-rated utility bonds. However, an article published by the Federal Reserve, Exhibit A-155 (TAW-13), page 21, indicates that equity risk premiums in low interest rate environments are much higher than normal, which renders the application of historical data without additional adjustments inaccurate and unreliable. In fact, Staff acknowledged this fact in Case No. U-20479 (SEMCO Energy Gas Company's general rate case) noting "the fact that in low interest rate environments the risk premium tends to be higher than usual. Although this is not traditionally a factor in Staff's methodology, the data backs this methodology."[14]

To adjust for the fact that risk premiums are higher when interest rates are low, the risk premium was calculated from the time the Federal Reserve began its recent accommodative period (2011 to 2020) when interest rates were held artificially low. During this period gas utility common stocks had an average risk premium of 7.94% over the yields of A-rated utility bonds. See Exhibit A-14 (TAW-1), Schedule D-5, page 9, line 67.

Q. What is the result of the risk premium analysis?

A. The Projected Risk Premium Analysis shows that the average ROE is 12.21% and ranges from a minimum of 11.81% to a maximum of 12.95%. These results are shown in Exhibit A-14 (TAW-1), Schedule D-5, page 4.

[14] Direct Testimony of Joseph E. Ufolla, MPSC Case No. U-20479 (September 27, 2019), page 36.

4. Comparable Earnings Analysis

Q. Briefly describe the comparable earnings analysis method.

A. Under this method, projected ROEs for the proxy group were analyzed. Earned ROEs for the proxy group are based on earnings per share and book value per share from Value Line. This information is readily available to investors. The actual results from this method are important in understanding the projected market expectations for the group. Exhibit A-14 (TAW-1), Schedule D-5, page 6, shows the results for the group of proxy companies by year for the period 2024 through 2026. The average projected earned ROE for the proxy group is 10.49% and ranges from a minimum of 6.72% to a maximum of 16.62%.

Q. Why was this method included as part of the ROE analyses?

A. The earnings of a regulated utility are driven to a large extent by the equity book value since most utilities are authorized an earning level based on the book value of equity. As indicated above, the comparable earnings analysis calculates an ROE for the proxy group based on the ratio of earnings per share to projected book value per share using information that is available to investors. This is the same as the cost of equity for a regulated utility and provides a reasonable proxy of analyst and investor expectations for a regulated utility return. Given that earnings in any single year can vary from the authorized ROE, results for multiple years need to be kept in mind while determining the cost of equity capital using this method.

Q. Has the Commission previously commented on the use of the comparable earnings analysis?

A. Yes. In Case No. U-16794, the Commission specifically considered and gave weight to use of the ROE calculated using Value Line book value and earnings.

Q. Has any other jurisdiction given weight to the comparable earnings analysis?

A. Yes. Not only have they given weight to the analysis, the Virginia State Corporation Commission ("VSCC") is required by statute (Virginia Code, section 56-585.1.A.2.a) to consider the earned returns on book value of gas utilities in the region, which establish lower and upper boundaries for the allowed ROE.[15]

5. <u>Discounted Cash Flow Analysis</u>

Q. Briefly describe the Discounted Cash Flow ("DCF") model.

A. The DCF model, which is a type of income model, was developed by John Burr Williams and elaborated by Myron J. Gordon and Eli Shapiro. It was initially employed as a method of valuing the price of common stock by discounting future cash flows by the cost of capital. In its simplest form, this model can be used to estimate the required cost of equity capital for a dividend paying stock with an assumed constant expected growth rate to perpetuity. This is generally projected as follows:

Equation (6): $K_e = (D_1 / P_0) + g + F$

Where:

D_1 = D_0 x (1 + g);
K_e = annual required cost of equity capital;
D_0 = current annual dividend;
D_1 = annual dividend at the end of the first year;
P_0 = current stock price;
g = expected growth rate; and
F = flotation cost adjustment.

This application of the model is displayed on Exhibit A-14 (TAW-1), Schedule D-5, page 5.

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15 In orders issued on November 7, 2018, and November 30, 2011, in Case Nos. PUR-2018-00048 and PUE-2011-00037, for example, the VSCC established the allowed ROE for Appalachian Power Company based on the earned returns on book value for a peer group of other gas utilities.

Q. What is the theoretical basis underlying the DCF model?

A. The DCF model is based upon an analysis of publicly traded common stock. The DCF theory holds that an investor who agrees to purchase common stock at a given market price is purchasing the rights to an income stream. That income stream includes the present and anticipated earnings, the portion of those earnings that are currently and prospectively being paid to investors in the form of dividends, and the proceeds of capital appreciation derived from the ultimate sale of the stock at some future market price.

Implicit in the investor's decision to buy is the assumption that the investor considers the magnitude of that income stream. This includes the rate at which those dividends are expected to grow and the expected future selling price of the stock. The investor also considers the quality or risk of that income stream; that is, the likelihood that expectations will, in fact, be realized.

Based upon all these considerations, the investor agrees to pay a given market price for the stock at a given moment in time. Presumably, that market price represents the present value of that anticipated income stream, including dividend and price appreciation, at some discounted rate. This can be expressed as follows:

Equation (7): $P_0 = D_1/(1+K_e)^1 + D_2/(1+K_e)^2 + \ldots + D_n/(1+K_e)^n + P_n/(1+K_e)^n$

Here, the value of the future anticipated stock price (P_n) and dividends (D_1, $D_2 \ldots D_n$) are discounted based upon the perceived risk of the investment (K_e). Note, however, that even the future stock price (P_n) becomes a function of anticipated dividend appreciation so that, ultimately, the price of the stock today is a function of the present value of growth of the dividend stream to infinity.

The standard annual form of the DCF model presented in Equation (7) above can be referred to as the dividend growth model. It is equal to the expected dividend yield (D_1/P_0) plus the expected rate of growth in dividends (g) plus the flotation cost adjustment (F). The model assumes an annual dividend payment and that dividends, earnings, book value, and price per share grow at the same constant annual rate over time.

Q. Please explain how dividend yield was calculated.

A. In theory, the DCF method calls for the "spot dividend yield" that is anticipated by investors at the time the required cost of equity capital is determined. Consequently, the theoretical yield would be calculated by dividing the expected annual dividend by the most current stock price. However, spot stock prices are subject to short-term market fluctuations, and an average price is more reliable and more typically applied. As a result, an average of 30 daily closing stock prices covering the period August 20, 2021 through September 30, 2021 was used. For each of the proxy companies, the average closing stock price for the period identified above was first determined. This provided an estimate of P_0. Then, the latest annual dividend amount was obtained. The annualized dividend was then divided by the average stock price (P_0) to determine the current dividend yield. The annualized dividend was determined by multiplying the latest quarterly dividend payment amount by four. Next, the current dividend yield was adjusted by multiplying by one plus the growth rate to obtain the expected dividend yield. The expected dividend yield is based on the expected dividend at the end of the first year (D_1) versus the current dividend (D_0). This process was repeated for each of the proxy companies. The stock average prices, dividend amounts, and dividend yields are shown on Exhibit A-14 (TAW-1), Schedule D-5, page 5.

Q. How was the growth rate for the DCF calculations determined?

A. One of the difficult steps in applying the DCF model is determining the appropriate growth rate. The DCF analysis should utilize, whenever possible, a single "long-term" (i.e., perpetual) dividend growth rate of the company required by the investors who own the company's stock. However, analysts do not typically provide long-term growth for dividends and, therefore, analyst projections for dividends over the next three years were used to estimate dividend growth. In addition to analyst dividend growth, company management will often provide guidance for projected growth and, therefore, two methods of analysis were performed: the first utilized consensus analyst dividend per share growth estimates, and the second utilized the mid-point of company long-term growth guidance. However, Staff and intervenors have been critical of the company guidance DCF as inappropriate in the past. While the Company disagrees with the assertions that have been made attempting to invalidate a company guidance DCF estimate, the analyst guidance DCF methodology was the only one considered in forming the Company's recommended ROE range in this case.

Q. Why was dividend growth instead of earnings growth applied as an input to your analysis?

A. The use of dividend growth is consistent with the fundamental basis of the model, as validated by the original paper, *Capital Equipment Analysis,* from Gordon and Shapiro.

This paper is included as Exhibit A-160 (TAW-18), and page 5 of the exhibit makes very clear the intent of the original authors:

> Translated, this means that the rate of profit at which a share of common stock is selling is equal to the current dividend, divided by the current price (the dividend yield), plus **the**

rate at which the <u>dividend</u> is expected to grow. [Emphasis added.]

Q. What were the results of the DCF cost of equity analyses for the proxy companies?

A. Exhibit A-14 (TAW-1), Schedule D-5, page 5, shows the results for the Company's group of proxy companies. Proxy group company returns for the Analyst Consensus DCF ROE have a range from 8.76% to 10.63% with an average return of 9.44%.

Q. Was any additional DCF analysis performed?

A. Yes. The DCF analysis was performed using dividend growth estimates from analysts. The use of dividend growth is consistent with the fundamental basis of this model, as validated by the original paper, *Capital Equipment Analysis,* from Gordon and Shapiro, the very same work that Staff continues to cite in their analysis. However, because of Staff's preference for an earnings growth based DCF, one was included in Exhibit A-162 (TAW-20), page 2. An application utilizing earnings growth for a DCF should also apply earnings yield rather than dividend yield in the calculation, and the Company's supporting analysis shows this as well. This application results in an average estimated ROE of 10.06%, a full 62 basis point increase over the dividend growth DCF included in the analysis.

Q. Does the result of the DCF analysis fully reflect the cost of equity required for utilities?

A. No, it does not. The reliability of the DCF, considering the unprecedented low yields on bonds, including United States Treasury bonds, provides a mechanical application of the DCF that delivers results that are less reliable and does not produce a risk-appropriate ROE, as required by *Hope* and *Bluefield*. The DCF results can be compared against both the ECAPM, Risk Premium, and Comparable Earnings, and can be viewed as an outlier.

Further, considering an ROE of 9.44% and the Company's recommended equity ratio of 52.0% would result in an implied long term FFO to Debt of only 17.9%, further deteriorating the Company's credit.

The DCF analysis provides output of four companies with estimated ROEs less than 8%. I am not aware of a single commission in the entire country that has authorized an ROE less than 8%. This disparity highlights why regulators such as FERC have had concern with overreliance on the DCF model. The average output of the DCF analysis would not provide sufficient risk premium to fairly compensate investors for the risks associated with owning the stock, particularly because equity owners have the lowest claim to the Company assets and income. Because the resulting average of the DCF clearly underestimates the required ROE, the Company's ROE recommendation considers the full range of results provided by the ECAPM, CAPM, DCF, Risk Premium, and Comparable Earnings analyses.

III. <u>DISCUSSION OF EICP FINANCIAL INCENTIVES</u>

Q. Are there additional topics you would like to address with your direct testimony?

A. Yes. Specifically, I would like to address the financial metrics included in the EICP as presented by Company witness Amy M. Conrad.

Q. Do the financial measures in the Company's proposed EICP provide tangible benefits to customers?

A. Yes. Including financial measures as part of the performance measures in the Company's EICP provides customers with both qualitative and quantitative benefits. A financially healthy utility benefits customers in part through lower funding costs which reduce natural gas bills as highlighted above and helps to provide customers with better service. As stated earlier, a virtuous cycle is created by constructive regulation, which creates a financially healthy utility capable of attracting capital, which it then invests in order to improve customer experience/service. It is not simply enough for a utility to have the opportunity to earn a fair return – in order to attract capital, the management and employees must actually achieve results. The inclusion of financial measures in the Company's incentive compensation plans ensures that employees are incented to achieve results which benefit customers as well as attract capital. Additionally, financial performance is required to maintain healthy credit ratings – if the Company were to not meet certain financial measures, it would lead to credit degradation of the Company which would in turn result in higher interest costs being borne by the Company. Because of these dynamics, including financial incentive measures in the EICP provides appreciable benefits to Consumers Energy's customers.

Q. Please discuss the role both Earnings and Operating Cash Flow ("OCF") play in maintaining the Company's credit.

A. The amount and perceived stability of Consumers Energy's OCF, which is one of the financial measures in the Company's EICP, are vital metrics directly observed by credit rating agencies and are reflected in their annual assessments of the Company's credit quality. Given the Company is investing a significant amount of capital and, therefore, raising substantial debt, the Company's ability to achieve stated OCF goals, which is driven primarily by the Company delivering stated earnings, is a key factor in determining its credit ratings and ultimately attracting investment to achieve lower cost of capital. Customers, therefore, have a strong vested interest in the Company maintaining attractive debt pricing. As discussed earlier and shown in Exhibit A-14 (TAW-1), Schedule D-5, page 7, the Company has saved ratepayers $102 million *annually* as a result of improved credit ratings and lowered interest costs. Incentivizing employees to achieve both Earnings and OCF targets is critical to maintain ratings and provides tangible benefits to customers.

Q. Is OCF a duplicative financial measure to EPS?

A. No. While earnings and cash flow are related, they are not the same. EPS is a measure of profit generated by a company's daily operations. The figure includes revenues and expenses. Some of the expenses used to calculate earnings are considered "non-cash" items, such as depreciation and amortization, and do not impact cash flow. Moreover, select financing decisions made by the Company such as issuing or repurchasing stock can have a direct impact on EPS without impact to OCF. OCF is a measure of cash generated from operations and is necessary to make investments in the utility. The cash flow measure in the incentive plan starts with generally accepted accounting principles OCF, and it is then adjusted as discussed in Ms. Conrad's direct testimony.

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-21148

DIRECT TESTIMONY

OF

PAUL M. WOLVEN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2021

Q. Please state your name and business address.

A. My name is Paul M. Wolven, and my business address is 3201 E. Court Street, Flint, Michigan 48501.

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 and any prior experience?

A. I am the Director of System Integrity, a position I have held since December 16, 2014. Prior to that, I was Director of Gas Customer Deliverability at Consumers Energy, a position I held since May 16, 2012. As Director of Gas Customer Deliverability, I was responsible for gas distribution system improvement project planning, customer engineering analysis and solutions, proactive new customer connections, and distribution engineering field oversight. Before that role, I was the Gas Distribution System Engineer for Consumers Energy's Macomb Service Territory, beginning April 15, 2008. In this role, I was responsible for gas distribution system improvement project planning, customer engineering analysis and solutions, proactive new customer connections, and distribution engineering field oversight within the Macomb Service Territory. I have been employed by Consumers Energy for 19 years in various engineering capacities.

Q. What are your responsibilities as Director of System Integrity?

A. I am responsible for the management, planning, and risk analysis for the Company's Transmission Integrity Management, Distribution Integrity Management, and Storage Integrity Management programs. This includes threat identification and mitigation, risk assessment modeling, pipeline assessments through Inline Inspection ("ILI") and direct assessment, distribution and transmission corrosion control, and leak management.

Additionally, the team manages and directs contracted services that executes ILIs and direct assessments of the Company's transmission pipelines. The team also manages the Company's underground storage assets.

Q. Are you a member of any professional societies or trade associations?

A. Yes. I represent the Company at the American Gas Association as a member of the Transmission Integrity Management Program Operating Committee.

Q. What is your formal educational experience?

A. I graduated from the University of Michigan – Flint with a Master of Business Administration. I also graduated from Michigan State University with a Bachelor of Science in Chemical Engineering.

Q. Are you a registered professional engineer in the state of Michigan?

A. Yes, I am.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I previously testified in the Company's general gas rate cases, Case Nos. U-20322 and U-20650. I have also testified in two recent Act 9 proceedings: Case No. U-20618, which resulted in Commission approval regarding the Company's Mid-Michigan Pipeline, and Case No. U-18166, which resulted in Commission approval of a settlement agreement regarding the Company's Saginaw Trail Pipeline.

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 the Company's Pipeline Integrity and Cathodic Protection programs, and includes the following:

i. A description of the Operating and Maintenance ("O&M") expenses and capital expenditures related to the Company's Pipeline Integrity programs;

ii. A description of the O&M expenses and capital expenditures related to the Company's Cathodic Protection programs; and

iii. A description of the projects associated with supporting Information Technology ("IT") expenses, such as the Gas Transmission Probabilistic Risk Model.

These programs and the related technology ensure the Company can continue to deliver a safe, reliable, and affordable distribution and transmission system.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-163 (PMW-1)	Summary of Actual & Projected Pipeline Integrity, Corrosion Control, and Cathodic Protection O&M Expense For the Years 2020, 2021, 2022, and Test Year 12 Months Ending September 30, 2023.
Exhibit A-12 (PMW-2) Schedule B-5.11	Summary of Actual & Projected Gas Capital Expenditures, Regulatory Compliance Program.
Exhibit A-164 (PMW-3)	Actual & Projected Gas Capital Expenditures, Regulatory Compliance Program.
Exhibit A-165 (PMW-4)	Projected Capital Expenditures - Transmission & Distribution Plant, Summary of Actual & Projected Gas and Common Capital Expenditures.

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

A. Yes.

PIPELINE INTEGRITY 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 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. The Federal Regulations, 49 CFR Part 192, Subpart O, specifies how pipeline operators must identify, prioritize, assess, evaluate, repair, and validate the integrity of gas transmission pipelines that could, in the event of a leak or failure, affect High Consequence Areas ("HCA"), which 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 Integrity Management Program that addresses the risks on each covered transmission pipeline segment.

Q. Please describe the MPSC's requirements for a Pipeline Integrity Program.

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 Area ("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. As indicated above, Consumers Energy developed a written Transmission Integrity Management Program ("TIMP") in 2004. The 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. To minimize environmental and safety risks, Consumers Energy's TIMP delivers the following:

- Identify 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 plan;
- 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 Natural Gas Delivery Plan ("NGDP"), Exhibit A-45 (NPD-1), discuss Consumers Energy's 10-year plan related to the Pipeline Integrity Program?

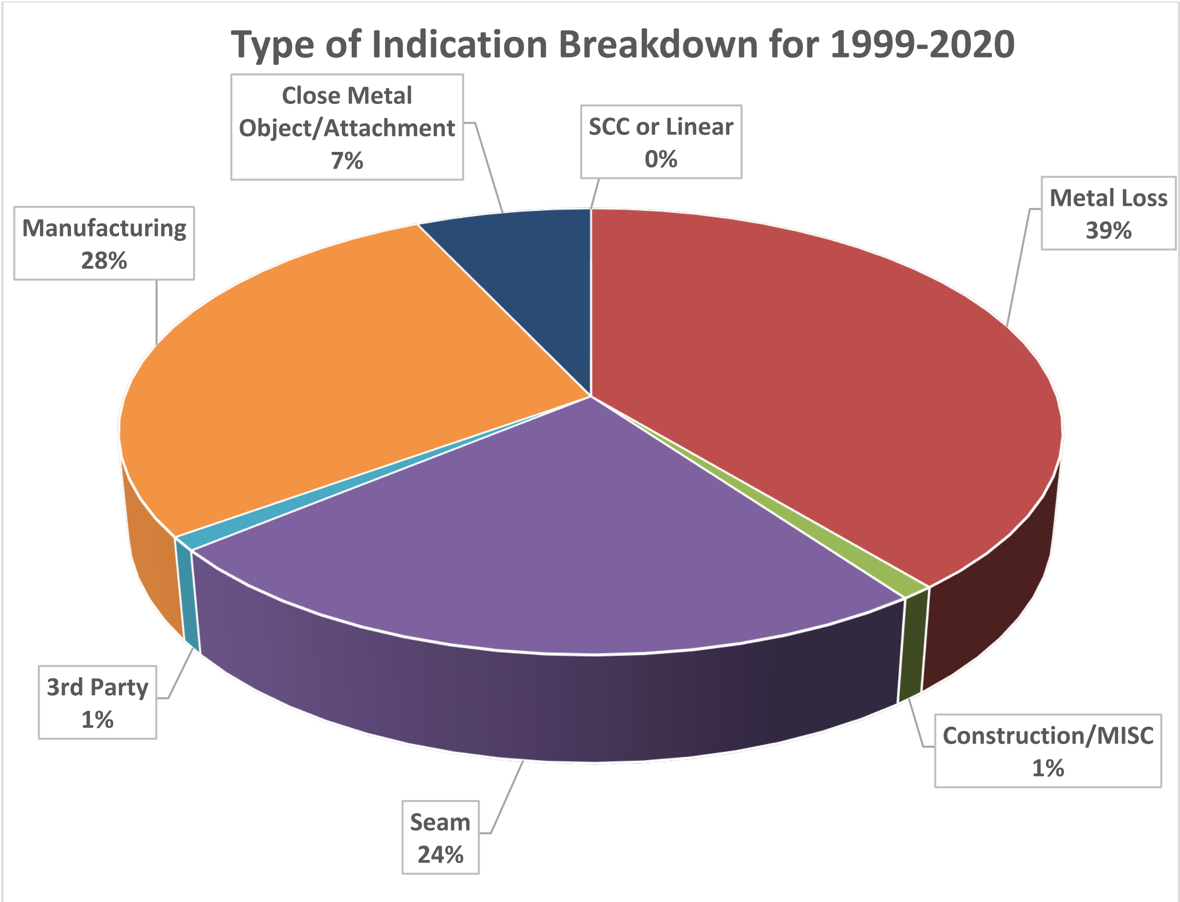
A. Yes. Over the 10-year period of the NGDP, the Company is focusing on improving inspections, de-risking, and increasing its remediation pace for critical assets. The Company is continuing its current practice of striving toward six-year inspection and remediation cycles. The Company is updating its risk ranking methodology and transitioning its current relative risk model into a probabilistic risk model over time to ensure investments are concentrated on the right assets. Under the NGDP, the Company will undertake the following:

- Complete baseline inspections for approximately 90 miles of the Company's mainline transmission system pipeline by year's-end 2022, and maintain that plan based on a reassessment plan;
- Assess and remediate an estimated 200-300 miles of high-risk pipelines that are prone to Stress Corrosion Cracking ("SCC"), specifically on lines 100A, 100B, 100C, 400, 600, 1300, and 1200A over the next 10 years;
- Assess and develop a plan to proactively remediate high-risk pipe segments that are prone to higher risk threats like SCC and corrosion and assess the need for a recoating program for this system; and
- Evaluate transmission classified segments embedded in the distribution system—referred to as Transmission Operated by Distribution ("TOD")—to determine if a baseline assessment or replacement is needed on a prioritized basis.

Exhibit A-45 (NPD-1), Section IV, part C, 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 that 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 ILI tool runs from 1999 to 2020 is shown in the chart below:



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; and

7. SCC or Linear includes crack indications found in the body of the pipe and not on a seam.

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.

Q. Is there any additional information you would like to provide regarding the threats shown above?

A. Yes. I would like to discuss further the threat of SCC, a form of environmental cracking that requires three conditions to develop:

1. A susceptible material – (pipeline steel);
2. Stresses on the pipeline that are higher than the threshold stress for SCC – (supplied by pressurized gas); and
3. An environment that supports cracking – (i.e., local soils, groundwater, and other factors).

There are two types of SCC commonly identified in the pipeline industry: (a) high pH SCC, and (b) near-neutral pH 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. In 2015, Consumers Energy had a pipeline rupture attributed to SCC. Since that time, 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 table below indicates the SCC conditions that were discovered through the Company's Pipeline Integrity Program.

Instances of SCC (2016-2021)					
2016	2017	2018	2019	2020	2021 (through June 30)
3	1	0	19	15	3

Q. Is the Company still addressing bending strain and/or pipe movement on pipelines due to compressible soils?

A. Yes. The Company continues to conduct bending strain analyses and pipe movement studies on sections of its gas transmission system that are located in compressible soils. These analyses are performed using data from the traditional ILI tools, but vendors are performing additional work for the bending strain analysis and engineering that is now required to assess and mitigate the risk. To perform accurate pipe movement studies, a comparison of ILI runs is required where the Inertial Measurement Units ("IMU") tool has also been run. The Company has used the IMU technology in prior inspection runs and the data from those runs continues to be a useful resource for comparison to current studies on pipe movement.

Q. Does the Company have any results available from the bending strain analysis and pipe movement studies performed to date?

A. Yes, since 2017, the Company has performed 29 bending strain analyses. The resulting percentage of strain determines the actions necessary by the Company.

A total of two locations have been reported above 0.4% strain. One location was the site of the 2017 rupture on Line 600 in Lake Orion. This strain assessment was performed on data that had been collected prior to the rupture and resulted in an expansion of strain assessments on the Company's gas transmission system. The second location above 0.4% strain was on Line 2010 in Auburn Hills where a sewer line had been installed below the pipeline without proper soil compaction applied above the sewer line and beneath the gas transmission line. In July 2021, approximately 150' of Line 2010 was replaced to address the strain condition. Strain conditions at both locations have been remediated.

There have been four locations reported with predicted strain between 0.3% strain and 0.4% strain. These locations were all identified in 2021 and an Engineering Acceptability Assessment and a geotechnical site assessment will be conducted to determine if any additional mitigation is needed and appropriate. There were 48 locations reported with between 0.2% strain and 0.3% strain that are subject to a tabletop assessment and site documentation. The balance of the remaining 148 strain features will be monitored for changes in strain and movement during future ILI assessments.

The Company has identified four pipelines where pipe movement has occurred. A total of 12 pipe movement areas (or locations) of pipeline movement combined with a strain component have been identified to date on these four pipelines. Based on the available information, the strain component in six of these locations is currently considered stable. In other words, the strain level and pipe movement is not expected to substantially increase based on the conditions where the pipeline is located. No remedial action is planned at this time and the Company will continue to monitor these six locations during subsequent bending strain and pipe movement studies. The other six pipe movement locations were recently identified during 2021 inspections and are currently under review.

Q. Will this data collected from the bending strain analyses and pipe movement studies be used in the Company risk modeling and analysis?

A. Yes. As the Company moves toward the implementation of a transmission probabilistic risk model, as recommended in the MPSC's 2019 Statewide Energy Assessment, the additional data gathered from the bending strain analyses and pipe movement studies will feed into the model and enhance the results obtained. The transmission probabilistic risk model is discussed below.

Q. Is the Company proposing to include a Gas Transmission Probabilistic Risk Model in this case?

A. Yes. Company witness Duncan Paterson includes, in his direct testimony and exhibits, a Gas Transmission Probabilistic Risk Model. This project is critically important in supporting certain gas functions within the Company. The costs associated with this project are contained within the exhibits sponsored by Company witness Paterson. The Gas Transmission Probabilistic Risk Model project and the benefits of the project are described below.

- The **Gas Transmission Probabilistic Risk Model** project requires $147,500 in capital and $54,650 in O&M in the test year. The project will implement a risk analysis model for comprehensive predictive risk analysis and modeling on gas transmission 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 with 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. Furthermore, the current model does not meet the requirements of the MPSC, as indicated in a letter of noncompliance (dated January 15, 2019), citing gaps in the model with respect to known-failure data for welding and fabrication threats, inadequate depth-of-cover calculations, level of corrosion, and inability to provide statistical validation. Inability to mitigate these non-compliances without a probabilistic risk model or through significant manual workarounds will likely result in continued non-compliances. 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 modelling supports the changes planned for in the Company's NGDP, including the Company Gas Management Safety System ("GSMS"). GSMS incorporates the Company's plan to implement the American Petroleum Institute 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 transmission. 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) Continue the use of the relative risk model, but investing in substantial effort to build customization to bring the model into compliance. This alternative was not selected because although custom workarounds may bring the model into compliance, those work-arounds still result in arbitrary, relative rankings and do not provide confidence in the ability to provide statistical validation of results;
- (2) 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"; and
- (3) Implement an on-premise probabilistic risk model. This alternative was not selected because the on-premise solutions analyzed are not mature and have not been widely tested with transmission operators. The option of implementing the cloud-based 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.

Q. Is a probabilistic risk model recommended by federal or state regulators?

A. Yes. 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, as mentioned earlier, the MPSC recommended the transition in the Statewide Energy Assessment.

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 is currently being used by the Company.

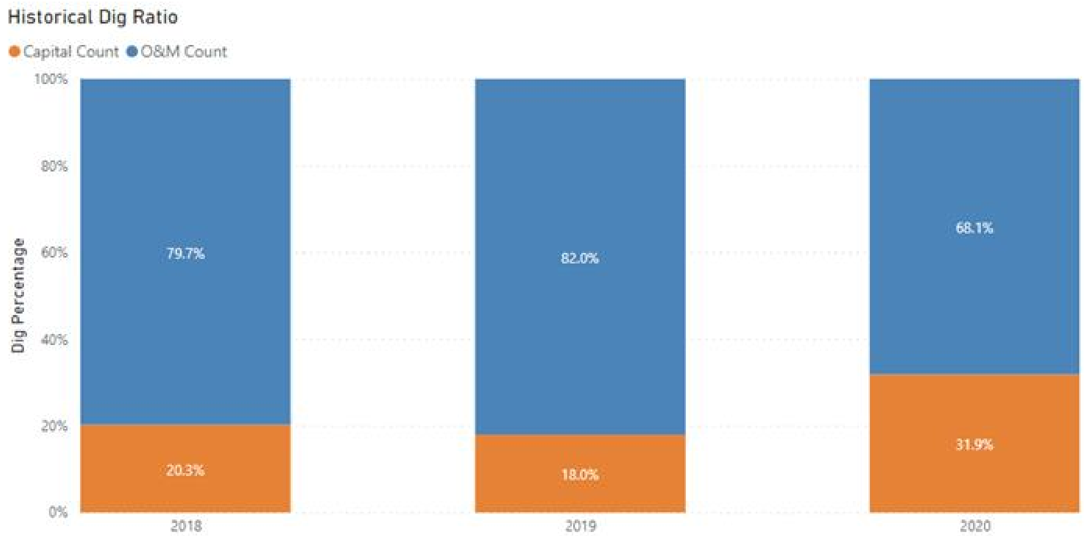
In the last several years probabilistic models have been developed and show great promise as a tool in more accurately assessing pipeline risk. The use of a model that is entirely data driven, provides a more accurate representation of the risks associated with pipelines. This in turn will allow the 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 result. 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.

Q. Is the Company complying with the Case No. U-18424 requirements for Pipeline Integrity reporting?

A. Yes, the Company continues to comply with the requirements agreed to as part of Case No. U-18424. The required documentation was submitted to Staff on March 15, 2019, March 13, 2020, and March 12, 2021. Additionally, in Case No. U-20322, Staff and the Company agreed that, in the event of an anomaly, Consumers Energy should not replace more than 1.5 times the diameter or 8 feet of pipe (whichever is greater) unless there are other anomalies downstream or upstream of the targeted joint with response time less than twenty (20) years, or construction constraints (i.e., proper fit up, bends, obstructions) that would require additional pipe replacement. The Commission approved this agreement.

Q. How were the O&M and Capital percentages for remediation developed for the Company's Pipeline Integrity Program?

A. During the projected test year, the Company projects that 20% of the remediation digs will be a capital expenditure while 80% of the remediation digs will be an O&M expense, which are the same percentages projected in Case No. U-20650. This percentage was developed based on the Company's experience during 2018 through 2020, which is shown in the graph below.



Although the percentage of capital remediation digs is slightly higher in 2020 than in 2018 and 2019, this is due to two specific segments driving a higher capital dig count. Remediation on Line 100A – Dansville to Ovid and Line 300 Muskegon River to Coleman resulted in the replacement footage being extended due to pipe tie-in locations unfit for welding. If these two segments are removed from the data in the above chart, the O&M/Capital percentage is 79%/21%.

Q. Please explain the development of the Pipeline Integrity Transmission O&M expenses.

A. As shown on Exhibit A-163 (PMW-1), the Company's Pipeline Integrity - Transmission O&M expense was $21,344,000 in 2020, and are projected to be $28,364,000 in 2021; $32,481,000 in 2022; and $24,216,000 for the test year ending September 30, 2023. These expenses are shown on line 4 of the exhibit. The mileage the Company intends to inspect is shown in the table below.

Table 1

Inspection Mileage			
2020	2021	2022	2023
162.10	365.6	307.8	241.3

Additionally, there are certain baseline assessments on longer pipeline segments that will lead to additional digs. These 44 inspections are for scheduled reassessments, newly identified HCA segments, covered segments outside of HCA, and the non-HCA segments, in compliance with 49 CFR 192.917.

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. The Company's projection includes the use of Light Detection and Ranging to assist in the identification of geohazards and potential right-of-way encroachments. This information will also inform the risk/threat assessments of the Company's 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: Maximum Allowable Operating Pressure ("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 in areas where transmission pipelines run through compressible soils. Additionally, running Electro Magnetic Acoustic Transducer ("EMAT") tools on pipelines that are susceptible to SCC is part of this projection.

Q. Does the use of the EMAT tools provide additional benefits to customers?

A. Yes. 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. As discussed above, the Company has identified SCC and linear or other crack-like indications using EMAT tools, thus increasing the safety of the pipelines through timely discovery and remediation of those indications. Running EMAT tools also provides the Company with information regarding the coating condition of the pipeline. Online chemical cleaning of pipelines is included for those pipelines scheduled for EMAT tool runs to increase the effectiveness and data quality from those runs. Pre-cleaning before use of this additional inspection tool will effectively enhance reliability, deliverability, and safety. Such ongoing inspections and use of the advancing inspection techniques in pipeline integrity are critical to the Company's continued ability to deliver gas safely and reliably to customers. Based on the Company's experience, EMAT inspections provide the most accurate indications of SCC as EMAT was specifically designed to look for SCC type cracking, therefore allowing the Company to prudently address SCC.

In 2018, 2019, 2020, and 2021, the Company completed EMAT tool runs on four pipelines, one pipeline, three pipelines, and five pipelines, respectively. By including expenses for the use of EMAT tools and the subsequent remediation in the Pipeline Integrity – Transmission Program in 2018-2021 the Company has used the data from the tool runs in its assessment of the pipelines for SCC. As a result of the EMAT tool runs, the Company identified and removed 37 locations, which has increased safety, reliability, and resiliency of the pipelines.

Q. What additional benefits to customers does the use of EMAT tools provide?

A. Based on the Company's experience, EMAT inspections provide the most accurate indications of SCC as EMAT was specifically designed to look for SCC type cracking. In fact, PHMSA recently published the Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments rule on October 1, 2019. This rule allows operators to use crack detection tools, such as EMAT, as a standalone assessment tool for SCC as of the effective date of the rule, July 1, 2020. While other ILI tools or indirect (above ground) surveys provide data that when analyzed with soil information may provide possible areas to investigate, these tools do not specifically identify cracking. For example, above ground tools like close interval survey and direct current voltage gradient provide information on cathodic protection levels, coating damage, and possible external corrosion. However, they do not provide indications of coating disbondment or corrosion under disbonded and shielding coating. Using the above grade surveys with prior ILI information can provide indications of possible disbonded coating. SCC Direct Assessment (without EMAT) identifies general areas, which may cover several hundred feet, where SCC may occur. EMAT on the other hand identifies specific locations to investigate and inspect.

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-163 (PMW-1), line 3, the Company's Pipeline Integrity – TOD Program O&M expenses were $2,980,000 in 2020 and are projected to be $1,224,000 in 2021; $2,383,000 in 2022; and for the projected test year, the Company projects O&M expenses in the amount of $1,929,000. The Company will assess 63.1 miles of pipe in 2021, 51.6 miles in 2022, and 145.5 miles in 2023. Assessments include inspection digs for External Corrosion Direct Assessment, inspection digs for Internal Corrosion Threat Evaluation, or Internal Corrosion Direct Assessment. Dig locations are determined from analysis of survey and historical corrosion issues. The indirect surveys needed to perform the direct assessments are included in the O&M expense. Also, External Corrosion Direct Assessment digs that result in coating repairs only, verification digs, and additional assessments on non-HCA pipelines are included in the projection.

Q. Are there any additional details you would like to provide regarding the projected O&M for the Pipeline Integrity – TOD Program?

A. Yes. During the Company's robotic ILI of Lines 1002 f and g in Macomb County in 2018, it was discovered that the pipeline had areas of sediment that restricted the tool from inspecting the pipe wall. The sediment build-up is significant enough that it is also restricting gas flow in the 26" gas line. To correct this issue, the Company has a two-part plan consisting of pipe replacement and pipeline cleaning using pigging. It was determined that the pipe along the ITC corridor in Macomb County could likely be cleaned using cleaning solution and cleaning pigs to break up the sediment and remove it from the pipeline. After the pipeline was cleaned, an ILI using a traditional free-floating pig was performed on the same segment of pipe to complete inspection of the pipeline. Approximately three miles of pipeline was cleaned and inspected in 2020 using ILI tools. This project increased the Company's O&M expenses in 2020. During the test year of this case, the Company is not projecting any cleaning or ILI in this program.

Q. Please explain the development of the Pipeline Integrity - Transmission capital expenditures.

A. As shown on Exhibit A-12 (PMW-2), Schedule B-5.11, line 1, the capital expenditures for this program were $15,887,000 in 2020, and are projected to be $10,604,000 in 2021; $13,116,000 for the nine months ending September 30, 2022; and $14,421,000 for the 12 months ending September 30, 2023, 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. The table below shows the Pipeline Integrity capital expenditures.

Table 2

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line No.	Program Description	12 Mos Ended 12/31/2020	12 Mos Ending 12/31/2021	9 Mos Ending 9/30/2022	21 Mos Ending 9/30/2022	12 mos. Ending 9/30/2023
1	Pipeline Integrity - (Transmission)	15,887	10,604	13,116	23,720	14,421

Pipeline Integrity expenditures include remediation of pipeline anomalies where 50 feet of pipe or more 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. Corrosion coupons (external corrosion) tell the Company the corrosivity of the soil and the adequacy of the cathodic protection to help ensure system integrity. As discussed previously, the Company anticipates 20% of the remediation digs will be capital. Exhibit A-164 (PMW-3) provides further details of the expenditures included in this program.

Q. Please explain the development of the Pipeline Integrity – TOD Program capital expenditures.

A. As shown on Exhibit A-12 (PMW-2), Schedule B-5.11, line 2, the capital expenditures for this program were $7,436,000 in 2020, and are projected to be $7,331,000 in 2021; $10,215,000 for the nine months ending September 30, 2022; and $12,102,000 for the 12 months ending September 30, 2023, 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. The table below shows the capital expenditures for the Pipeline Integrity TOD program.

Table 3

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line No.	Program Description	12 Mos Ended 12/31/2020	12 Mos Ending 12/31/2021	9 Mos Ending 9/30/2022	21 Mos Ending 9/30/2022	12 mos. Ending 9/30/2023
2	Pipeline Integrity- Transmission Operated by Distribution (TOD)	7,436	7,331	10,215	17,546	12,102

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 1002 UT sensors and 526 UT coupons have been installed. The Company is also starting to use ILI, or pig runs performed on TOD pipe, as that technology becomes available. Robotic ILI can be used when a direct assessment dig is not feasible or to assess lines with casings. A robotic ILI may also be used on lines in which direct assessment has revealed significant defects and more are suspected. This allows Consumers Energy to prudently inspect a larger section of the pipeline. Typical remediation of pipe found during the inspections includes pipe repairs or replacements. Exhibit A-164 (PMW-3) provides further details of the expenditures included in this program.

Q. Are there any additional details you would like to provide regarding significant projects included in the Pipeline Integrity – TOD Program?

A. Yes. In 2020, the Company completed a pipe replacement project on Line 1002 f and g in Macomb County due to sediment build-up being discovered during an integrity assessment. Additionally, the Company has a pipe replacement project planned on Line 1002 f and g in Macomb County and a replacement project on Line 1008 also in Macomb County. The Line 1002 f and g replacement project is the replacement of the final section of pipeline that had sediment build-up in the pipeline. The replacement on Line 1008 is to replace a section of pipeline that is underneath the Clinton River, which makes this section of pipe unable to be assessed using Direct Assessment. A portion of the Line 1002 and Line 1008 pipe replacement projects is included in the Company's capital projections in the Pipeline Integrity – TOD Program.

CATHODIC PROTECTION PROGRAM

Q. Please describe the Distribution Cathodic Protection Program and its O&M expenses.

A. As shown on Exhibit A-163 (PMW-1), line 1, the O&M expense was $3,190,000 in 2020 and are projected to be $3,168,000 in 2021; $2,483,000 in 2022; and for the test year ending September 30, 2023 is $3,141,000for the Distribution Cathodic Protection Program. This program is associated with corrosion control, including 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. The Company has 53,227 test points that it reads annually, and 1,025 that are read on a bi-monthly schedule. It is projected that 2,563 sectors will not meet cathodic protection criteria within the given test year. In addition to the survey and testing, the O&M expenses include dollars to complete 530 repairs in combinations of coating repair, above- and below-grade short removal, test wire repairs, rectifier repairs, and groundbed repairs. These expenses are projected based on historical information, adjusted for inflation, and include the number of annual survey reads and the bi-monthly reads that must be completed each year/month. Additionally, the O&M expenses include dollars to complete the atmospheric corrosion inspections at 254 locations where distribution main is located on bridges.

Q. Please describe the Corrosion Control – Transmission O&M Program.

A. The O&M expense for the Corrosion Control – Transmission Program was $638,000 in 2020 and are projected to be $1,195,000 in 2021; $2,020,000 in 2022; and for the test year ending September 30, 2023 is $2,019,000, as shown on Exhibit A-163 (PMW-1), line 2. O&M expenses for the transmission system include special projects like large atmospheric painting projects, pipeline recoating projects 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 time frame. The Company's projected expense amount is based on historical averages (200 miles of close interval survey), the recoating 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 ensure and enhance the safety of its gas delivery systems.

Q. Please describe the Cathodic Distribution Program capital expenditures.

A. As shown on Exhibit A-12 (PMW-2), Schedule B-5.11, line 3, the capital expenditures for this program were $6,664,000 in 2020, and are projected to be $7,159,000 in 2021, $4,422,000 for the nine months ending September 30, 2022, and $6,326,000 for the 12 months ending September 30, 2023, 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 table below shows the capital expenditures for the Cathodic Distribution capital program.

Table 4

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line No.	Program Description	12 Mos Ended 12/31/2020	12 Mos Ending 12/31/2021	9 Mos Ending 9/30/2022	21 Mos Ending 9/30/2022	12 mos. Ending 9/30/2023
3	Cathodic Distribution	6,664	7,159	4,422	11,581	6,326

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. The galvanic anode systems include 17- and 20-pound magnesium anodes that are installed near the main to attract corrosion to the anodes as opposed to the pipe. 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 anodes consisting of relatively inert properties (such as mixed metal oxides). 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. Statewide, distribution corrosion has a total of 913 rectifiers that must be read every two months, six times per calendar year. Historically these bi-monthly reads had to be read manually each of these times. RMUs are now being installed and are reducing the number of required physical visits of each rectifier. This will help reduce the carbon footprint caused by the additional driving to each of these rectifiers and keep costs down. Also, with the RMU installations, the Company receives notification when the rectifiers are not operating the way they are supposed to be operating so diagnostic work can be initiated quicker, thus improving the integrity of the distribution system. In addition, the installation of RMUs allows the Company to remotely interrupt rectifiers to perform cathodic surveys and testing more efficiently. Exhibit A-164 (PMW-3) provides further details of the expenditures included in this program.

Q. Please describe the Cathodic Compression, Storage, and Pipeline Program.

A. The Cathodic Compression, Storage, and Pipeline Program allows the Company to maintain compliance with federal regulations for cathodic protection of facilities. As shown on Exhibit A-12 (PMW-2), Schedule B-5.11, line 4, the capital expenditures for the Cathodic Compression, Storage, and Pipeline Program were $2,618,000 in 2020 and are projected to be $7,072,000 in 2021, $2,770,000 for the nine months ending September 30, 2022, and $6,602,000 for the 12 months ending September 30, 2023, 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 capital expenditures for the Cathodic Compression, Storage, and Pipeline Program is shown in the table below.

Table 5

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line No.	Program Description	12 Mos Ended 12/31/2020	12 Mos Ending 12/31/2021	9 Mos Ending 9/30/2022	21 Mos Ending 9/30/2022	12 mos. Ending 9/30/2023
4	Cathodic Compression, Storage & Pipeline	2,618	7,072	2,770	9,842	6,602

The capital activities included in this program are the installation of new or replacement rectifiers and anode beds, the installation of RMUs, installation of 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 test station RMUs. These installations will allow the Company to monitor the cathodic protection system in areas that are difficult to access on a yearly basis. Examples of these locations include areas with no road access, which would require employees to walk a mile or more into the location to obtain a reading or locations where there are landowner issues. The readings can be taken automatically and uploaded to a website. This will increase the ability for the Company to monitor these difficult to reach locations and reduce the resulting O&M costs. Exhibit A-164 (PMW-3) provides further details of the expenditures included in this program.

Q. Please explain Exhibit A-163 (PMW-1), page 2.

A. Page 2 of Exhibit A-163 (PMW-1) presents an illustration of 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. The expenses that I am supporting are generally driven by the inspection schedules for the Pipeline Integrity Programs, the cathodic protection needs of the pipeline systems for Cathodic Protection Programs, and the regulatory requirements for each of the programs.

Q. Please describe Exhibit A-165 (PMW-4).

A. Exhibit A-165 (PMW-4), 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 gas rate case, Case No. U-20650.

Q. Can you explain why columns (c), (e), and (f) of Exhibit A-165 (PMW-4) do not contain any data?

A. Yes, the information for column (c), the "Last Rate Case Approved Spending Plan Case No. U-20650," cannot be provided because Case No. U-20650 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. Since there is no data to display in column (c), the information for columns (e) and (f), which seek information concerning the variances from (c), cannot be completed.

Q. Please summarize your direct testimony.

A. My direct testimony describes the required expenditures for the Pipeline Integrity Program, the Cathodic Distribution Program, and for IT support for the engineering, asset planning, design, construction, and maintenance of a safe, reliable, and affordable distribution and transmission system.

Q. Does this conclude your direct testimony?

A. Yes, it does.