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-20650

DIRECT TESTIMONY

OF

CHAD L. ALLEY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

Q. Please state your name and business address.

A. My name is Chad L. Alley, 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 Principal Engineer Lead in the Gas Asset Management ("GAM") Department.

Q. Please describe your educational background and work experience.

A. I graduated from Tri-State University in 1992 with a Bachelor of Science degree in Mechanical Engineering. I presently hold the Principal Engineer Lead position in the Transmission Engineering Department. Prior to that, I held the titles of Senior Engineer Lead II and Senior Engineer Lead in my time in the department. Prior to that, I was a Project Manager from 2004 through July 1, 2012 for the GAM Department. I was also in the Metering and Regulation Department from April 2000 to 2004. Additionally, I am a certified Project Management Professional.

Q. What are your responsibilities as Principal Engineer Lead**?**

A. As Principal Engineer Lead, I am responsible for the planning, engineering, and design for the Company's gas transmission pipeline systems. The Company has 2,426 miles of transmission lines, of which 1,643 miles are mainline pipelines, 223 miles are storage laterals, and 560 are operated on the distribution system. This includes identifying and prioritizing system improvements and enhancements and ensuring pipeline integrity.

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

A. Yes. I am a member of the American Society of Mechanical Engineers.

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

A. Yes, I previously testified in Case No. U-20322.

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 Distribution capital expenditures 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-36 (CCD-1), sponsored by Company witness Craig C. Degenfelder.

I have divided my direct testimony into four capital programs through the test year ending September 30, 2021: (i) Asset Relocation Transmission; (ii) Regulatory Compliance; (iii) Capacity/Deliverability; and (iv) Gas Operations Other. In Section (v) 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-12 (CLA-1)	Schedule B-5.3	Projected Capital Expenditures Transmission Plant - Summary of Actual & Projected Gas and Common Capital Expenditures;
Exhibit A-17 (CLA-2)		Actual & Projected Gas Transmission Capital Expenditures - Asset Relocation Transmission Program;
Exhibit A-18 (CLA-3)		Actual & Projected Gas Transmission Capital Expenditures – Regulatory Compliance;
Exhibit A-19 (CLA-4)		Actual & Projected Gas Transmission and Distribution Capital Expenditures - Capacity/Deliverability Program;
Exhibit A-20 (CLA-5)		Actual & Projected Gas & Common Transmission Capital Expenditures - Gas Operations Other Program;
Exhibit A-21 (CLA-6)		Actual & Projected Gas Transmission Capital Expenditures for Year 2018 through September 30, 2021 - Capacity/Deliverability Program – TED-I; and
Exhibit A-22 (CLA-7)		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 or supervision?

A. Yes.

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 assets.

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 VII, Transmission Asset Plan of the NGDP, as shown in Exhibit A-36 (CCD-1).

I. ASSET RELOCATION TRANSMISSION PROGRAM

Q. Please describe the capital expenditures related to the Asset Relocation Transmission Program as shown on Exhibit A-12 (CLA-1), Schedule B-5.3, line 1.

A. The Asset Relocation Transmission Program includes gas transmission infrastructure replacement projects which 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 scoped as a result of civic improvement projects, to minimize scope and expense, the Company works with the governmental units involved to coordinate work and 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 2018 13 Mile Road/Minnow Pond drain project, in which the Company lowered Line 1600 to accommodate a new box culvert installation by the City of Farmington Hills. Another example, in which cooperation with municipalities allowed conflicts to be resolved without a pipe relocation, is the Company's coordination with the Michigan Department of Transportation ("MDOT") on a planned 2019 traffic signal project at the intersection of M-1 (Woodward Avenue) and 13 Mile Road. MDOT's original design was in conflict with the Company's Line 1600 and would have required its relocation. However, as a result of the Company's negotiations with them, MDOT revised its design which eliminated the need to relocate Line 1600.

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. These project types are described in more detail later in my direct testimony.

As shown on Exhibit A-12 (CLA-1), Schedule B-5.3, line 1, the capital expenditures for this program were $7,051,000 in 2018 and are projected to be $4,923,000 in 2019; $4,599,000 for the nine months ending September 30, 2020; and $8,718,000 for the 12 months ending September 30, 2021. These expenditures are shown in Table 1 below.

Table 1

($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 12/31/2018	12 Mos Ending 12/31/2019	9 Mos Ending 9/30/2020	21 Mos Ending 9/30/2020	12 Mos Ending 9/30/2021
1	Asset Relocation - Transmission	7,051	4,923	4,599	9,522	8,718

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 13 Mile Road/Minnow Pond drain civic improvement in Oakland County;
- Line 1200A McCarty Drain in Branch County;
- Line 1200A Needham Road county drain in St. Joseph County;
- Line 1200A County Drain 15 in Branch County;
- Line 100A County Drain 197 in Gratiot County;

- Line 100B County Drain 197 in Gratiot County; and
- Line 300 Vasold Road line lowering in farm field in Saginaw 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-17 (CLA-2) 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 GAM 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. 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. 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 (CLA-1), Schedule B-5.3, line 2.

A. As shown on Exhibit A-12 (CLA-1), Schedule B-5.3, line 2, the capital expenditures for this program were $15,261,000 in 2018 and are projected to be $2,600,000 in 2019; $852,000 for the nine months ending September 30, 2020; and $12,524,000 for the 12 months ending September 30, 2021. These expenditures are shown in Table 2 below.

Table 2

	(a)	(b)	(c)	(d)	(e)	(f)
		Regulatory Compliance Capital Expenditures				
($000)		Historical	Projected Bridge Year			Projected Test Year
Line No.	Program Description	12 mos. Ended 12/31/2018	12 mos. Ending 12/31/2019	9 mos. Ending 9/30/2020	21 mos. Ending 9/30/2020	12 mos. Ending 9/30/2021
1	MAOP Pipeline	1,544	570	454	1,024	7,422
2	MAOP M&R	13,717	2,030	398	2,428	5,102
3	**Total Capital**	15,261	2,600	852	3,452	12,524

These projections are based upon knowledge of specific projects planned for the next several years. The Regulatory Compliance Program consists of two transmission programs: Maximum Allowable Operating Pressure ("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 pipeline, 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 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, resulting in either hydrotesting, which is part of the MAOP Transmission Operating and Maintenance ("O&M") Program, material verification, or replacement. 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 CRF §192.614 Damage Prevention Program. When exposed, these segments would require either destructive or nondestructive testing to attain material property values. Evaluation is based on an analysis including but not limited to the following factors:

- Nature of the records gap identified (e.g., segments with material verification issues prioritized for replacement);
- Pipeline performance history and pipeline field evaluations;
- Minimizing the impact of service to customers;
- Coordination with other planned work and the need to maintain service to customers; and
- Pipeline location and cost to replace (i.e., population density).

The Company's MAOP projections are based on previously completed work orders of similar magnitude and requirements. Projects planned for 2021 include replacement of Valve 1322 and associated piping at G Avenue valve site in Kalamazoo County. Also in scope for completion in the MAOP Compliance Pipeline Program are replacements of records gap segments on Line 600 (proposed construction year 2021), Line 2010 (year 2021), and Line 2070 (year 2022). Expenditures are also included for the Company's engineering analysis which is described 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 the projects mentioned below were undertaken primarily due to the age and condition of the facilities described, this work will allow for the reduction of MAOP on pipelines in order to reduce risk. The 2018, 2019, and test year expenditures are for:

- Tecumseh City Gate – Installation of the Tecumseh City Gate at the pipeline tap site, which will allow for the retirement of the 3060 lateral. This city gate has been in operation for more than 40 years. The facilities have reached the end of their useful life;

- Williamston City Gate – Rebuild of the city gate so that it can have two high pressure outlets, with the ability to bypass, to ensure MAOP compliance on Line 1040. This city gate had reached the end of its useful life and required rebuild;

- 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;

- Novi/Wixom City Gate - Replacement of the bath heater that was being used beyond its capacity, and associated piping. This will ensure the entire city gate has not only accurate pressure test records, but also has the ability to provide high gas quality; and

- Line 1048 and city gate – Installation of a new city gate station and associated pipe will allow for the reduction of MAOP on Line 1048 to a level that would allow for less than 20%specified minimum yield strength.

III. CAPACITY/DELIVERABILITY PROGRAM

Q. Please describe the capital expenditures relating to the Capacity/Deliverability Program as shown on Exhibit A-12 (CLA-1), Schedule B-5.3, line 3.

A. As shown on Exhibit A-12 (CLA-1), Schedule B-5.3, line 3, the capital expenditures for this program were $73,394,000 in 2018 and are projected to be $96,766,000 in 2019; $82,009,000 for the nine months ending September 30, 2020; and $123,433,000 for the 12 months ending September 30, 2021. These expenditures are shown in Table 3 below.

Table 3

Line No.	Program Description	(a) Historical 12 Mos Ended 12/31/2018	(b) Capacity/Deliverability Capital Expenditures: Projected Bridge Year 12 Mos Ending 12/31/2019	(c) Projected Bridge Year 9 Mos Ending 9/30/2020	(d) Projected Bridge Year 21 Mos Ending 9/30/2020	(e) Projected Test Year 12 Mos Ending 9/30/2021
($000)						
1	TED-I Projects (see Exhibit A-21 (CLA-6) for Project Detail)	7,947	20,746	15,397	36,143	23,618
2	Deliverability Base Compression/Storage	163	-	-	-	-
3	Deliverability Base Field Measurement	10,547	10,841	9,352	20,194	25,432
4	Deliverability Base Pipeline	11,135	11,715	12,258	23,973	11,114
5	Regulator Stations - Distribution	21,199	32,617	28,751	61,367	35,110
6	T&S City Gates	22,403	20,847	16,251	37,098	28,158
7	**Total Capital**	**73,394**	**96,766**	**82,009**	**178,775**	**123,433**

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, 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 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 705 regulator stations. The Company has developed a comprehensive regulator station installation plan as outlined in Section VIII, sub-section E of the Company's NGDP, Exhibit A-36 (CCD-1), sponsored by Company witness Degenfelder. The Company currently has 96 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 stream, which is a critical safety element, and is required by code (49 CFR 192.625). Planned projects, location, and scope are listed below. This program also funds emergent issues, as well as SCADA installations at regulator stations. Investments being made to regulator stations improve employee safety and ergonomics. In 2020, the Company will begin to utilize a quantifiable risk ranking, which I will describe below, for City Gate and Regulator Station future planning of these investments. This ranking will take into account the variables that the Company currently uses in project selection. The major projects in this filing include:

2018

- Ballenger and Westcombe (Rebuild - Flint);

- Dequindre and 12 Mile (Rebuild - Warren);
- West Saginaw at Waverly (Rebuild - Lansing);
- West Prairie - Vicksburg (Rebuild - Vicksburg);
- Teel and Norman (Rebuild - Lansing);
- Miller and Bristol (Rebuild - Flint);
- Grand River and Kensington (Rebuild - Howell); and
- North Waters and Riverside (New station - Lowell).

2019

- Square Lake and Rochester (Rebuild - Troy);
- 14 Mile and Ryan (Rebuild – Sterling Heights);
- Rochester and Big Beaver (Rebuild - Troy);
- St. Louis (Rebuild - St. Louis));
- Tausend (Rebuild - Saginaw);
- Gagetown (Rebuild - Gagetown);
- Hanover (Rebuild - Hanover);
- M24 and Minnetonka (rebuild – Oxford Township);
- King and Gould (Rebuild - Owosso);
- Pierson and Elms (Rebuild – Mt. Morris Township);
- Harrison and Warner (Rebuild – Sumner Township);
- Burcham and Hagadorn (Rebuild – East Lansing);
- Prospect and Ballenger (Bypass valve assembly replacement - Flint);
- Lone Pine and Telegraph (Valve Replacement - Bloomfield Township); and
- Squirrel Road odorizer (Rebuild – Auburn Hills).

2020

- Bayport (Rebuild – Bayport);
- Ransom (Rebuild - Ransom);
- Beaverton (Rebuild - Beaverton);
- Omer (Rebuild - Omer);
- Leonard (Rebuild - Leonard);
- Dutton Road odorizer (Rebuild – Auburn Hills)
- Isbell and Marion (Rebuild - Howell);
- South and Hampton (Rebuild - Pontiac);
- Lawton & Main (Rebuild – Lawton);
- Ford and Wayne (Rebuild – Wayne);
- Patrick and Waldo (Rebuild – Midland);
- Fisher and Walnut (Rebuild – Bay City);
- Michigan and California (Rebuild – Kalamazoo);
- Waverly and Grand River (Rebuild - Lansing);
- Elizabeth & Broadway (Rebuild – Orion Township);
- Hegel Rd, Goodrich (Station Retirement – Atlas Township); and
- Atlas - Perry (Station Retirement – Atlas Township).

2021

- Akron (Rebuild - Akron);
- Mt. Pleasant (Rebuild – Mt. Pleasant);
- Ruth and Atwater (Rebuild – Sherman Township);
- Waldo and Ashman (Rebuild – Midland);

- Joslyn and Clarkston (Rebuild – Orion Township);
- 10 Mile and Kelly (Rebuild – Eastpointe);
- 10 Mile and Rushton (Rebuild – South Lyon);
- Sheldon and Territorial (Rebuild – Plymouth);
- 24th Street (Rebuild – Jackson);
- Barberry (Rebuild – Jackson);
- Harrison and Railroad (Rebuild – East Lansing);
- Wildwood and Chestnut (Rebuild – Jackson);
- Elba and Genesee (Station Retirement – Elba Township); and
- Elba and Hammond (Station Retirement – Elba Township).

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 VII of the Company's NGDP, Exhibit A-36 (CCD-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. 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:

2018

- Red Run City Gate (Rebuild - Sterling Heights);
- Alma City Gate (Rebuild - Alma);
- Lahser City Gate (Install filter / separator - Beverly Hills); and
- Salem City Gate (Rebuild - Northville).

2019

- Pinckney City Gate (Rebuild - Pinckney);
- Grass Lake City Gate (Rebuild - Grass Lake);
- Midland City Gate (Rebuild - Midland);
- Coleman - Beaverton City Gate (Rebuild - Coleman); and
- Flint Irish Road City Gate (Install filter / separator - Flint).

2020

- Woodbury City Gate (Rebuild - Woodbury);
- Greenfield City Gate (Rebuild - Royal Oak);
- North Lyons City Gate (Rebuild – New Hudson);
- Chelsea Boys School City Gate (Retirement - Grass Lake);
- Morrow peaker plant fuel station (Retirement – Galesburg); and
- Hemlock City Gate (Install filter / separator - Hemlock).

2021

- Marshall Lansing Road City Gate (Rebuild - Marshall);
- Dewitt Turner Road City Gate (Rebuild - Dewitt);
- Mt. Pleasant City Gate (Rebuild - Mt. Pleasant);
- Mt. Clemens City Gate (Replace heater - Mt. Clemens); and
- Orion City Gate (Rebuild - Lake Orion).

Q. In the Company's recent general gas rate case, Case No. U-20322, the Company committed to work on developing a quantifiable risk ranking for city gate and regulator station investments by the end of 2019. Can you provide an update on the progress of this project?

A. Yes, the risk ranking for city gates and regulator stations is in development by the Company's Gas Engineering and Operations departments. The ranking rubric will be finalized by the end of 2019. The ranking will be utilized for the Company's next planning cycle in mid-2020. As needed, improvements will be made to the model year over year in order to capture the best ranking information possible.

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:

- Northville Reef site moisture removal and metering site upgrade projects (Salem Township);
- Michcon Goose Creek and Blue Lake 36 metering system upgrades (Blue Lake Township);
- Ray storage facilities gas quality filtering and monitoring equipment installations (Armada Township);
- Ray compression station orifice metering upgrade (Armada Township);
- White Pigeon compression station plant 3 outlet gas quality improvement project (White Pigeon Township);
- Plainwell Junction site gas quality monitoring and metering system upgrade project (Gunplain Township); and
- Electronic Gas Measurement system installation project (Statewide).

Q. Please describe the Northville Reef project.

A. The Northville Reef 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 Northville Reef 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 and 2019, 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, requiring pre-mature shut-in of withdrawal operations. The Northville Reef facility upgrade project will help improve gas purities, 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 will be for project engineering and design. The 2021 expenditures will be for materials and construction. 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 would 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, as per TMS contractual obligations. Expenditures associated with the activities and projects within this program can be found in Exhibit A-12 (CLA-1), Schedule B-5.3, line 3, and Exhibit A-19 (CLA-4), line 4.

Q. Please explain the TED-I projects you are sponsoring.

A. The TED-I projects are focused on maintaining deliverability and integrity, and on improving the ability to control gas flows. 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 in order to enable abandonment of a pipeline or to reduce pressures on pipeline segments in order to comply with any new MAOP of replacement pipelines. Exhibit A-21 (CLA-6) provides project level detail for the TED-I projects sponsored in my direct testimony. Company witness Degenfelder is sponsoring the major TED-I pipeline projects, which include Saginaw Trail, South Oakland Macomb Network, and Mid-Michigan pipelines. Additionally, crossover piping is installed to maintain deliverability and improve the ability to control gas flows increasing system resiliency, such as at Thetford and Wilson Rd. valve sites. Wilson Rd. Crossover also provides a second feed to Akron City Gate. Both provide access to the northern transmission system via the Saginaw Trail Pipeline.

Q. Are there other enhancements included in the TED-I projects?

A. Yes. 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. 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 VII of the NGDP, Exhibit A-36 (CCD-1). The Company is planning to install RCVs on complete pipeline replacements, such as Line 2800 (Saginaw Trail Pipeline), which was previously approved in an Act 9 case, MPSC Case No. U-18166, March 28, 2017, Order Approving Settlement Agreement. 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. The amounts for the TED-I non-major pipeline projects are shown on Exhibit A-21 (CLA-6).

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 our 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 overprotection 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. Project examples include:

- Line 2700 Clarkston Interchange, Holly;
- Line 2700 Dixie-Waterford City Gate, Clarkston;
- Line 600 Clarkston Interchange, Holly; and
- Line 400 Clarkston Junction, Holly.

The installation of PLDs will improve the operation of the system and provide enhanced public safety. Project level detail is shown in Exhibit A-21 (CLA-6).

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. Has the Company provided a project-level basis for the TED-I capital expenditures including expenditures for material, labor, contractor, engineering, and other costs?

A. Yes. Exhibit A-21 (CLA-6) identifies the 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, but 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.

IV. GAS OPERATIONS OTHER PROGRAM

Q. Please describe the capital expenditures relating to the Gas Operations Other Program as shown on Exhibit A-12 (CLA-1), Schedule B-5.3, line 4.

A. The Gas Operations Other Program includes costs associated with Right-of-Way specialists supporting gas projects. As shown on Exhibit A-20 (CLA-5), the capital expenditures for this program were $768,000 in 2018 and are projected to be $794,000 in 2019; $615,000 for the nine months ending September 30, 2020; and $855,000 for the 12 months ending September 30, 2021. These expenditures are shown in Table 4 below:

Table 4

		(a)	(b)	(c)	(d)	(e)	(f)
($000)			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	12/31/2018	12/31/2019	9/30/2020	9/30/2020	9/30/2021
1		Land and Right-of-Way	768	794	615	1,409	855

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

A. Exhibit A-22 (CLA-7), in accordance with Attachment 11 to the filing requirements prescribed in Case No. U-18238, provides the variances in the capital program amounts for the distribution and transmission programs which I am sponsoring to the Company's most recent general gas rate case, Case No. U-20322.

Q. Can you explain why columns (d), (e), and (f) of Exhibit A-22 (CLA-7), do not contain any data?

A. Yes, the information for column (d), the "Actual Spending in the Test Year," cannot be completed as the test year in Case No. U-20322, which was the 12 months ending September 30, 2020, is a time period that has yet to transpire as of the filing of this case. Since there is no data to display in column (d), the information for columns (e) and (f), which seek information concerning the variances from (c) and (d), cannot be completed at this time.

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, and 1600, replacing pipe and fittings for Lines 3070 and the Lahser Lateral, which were 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 and Line 300 pipe replacement projects were completed.

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 Christopher J. Varvatos 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 Varvatos. The project and the benefits of the project which will provide benefits for the area which I am sponsoring is described below:

- The **Gas Measurement Application Server** project requires $6,375 in capital and $20,875 in O&M. The Gas Measurement Application Server project is the installation of remote monitoring and engineering configuration software on a standalone secure network server for gas measurement equipment including meters and chromatographs currently in use at Consumers Energy. The Company will benefit from decreased LAUF gas volume through improvements in measurement accuracy at the sites that these will be installed. Additionally, the project will:

  (1) Reduce physical witnessing and meter inspections from quarterly trips to annual trips while still maintaining Sarbanes-Oxley compliance requirements;

  (2) Reduce chromatograph and meter troubleshooting field trips;

  (3) Increase visibility and response time to equipment alarms; and

(4) Reduce Capital expenditures by reducing the number of sites that require gas chromatograph installations.

The scope of this project will implement a scalable secure network server capable of hosting multiple software applications that add functionality to:

(1) Remotely monitor gas equipment for performance and measurement;

(2) Perform remote inspections;

(3) Implement dynamic gas quality factors; and

(4) Automate field measurement equipment diagnostic parameters for monitoring and alarming on gas equipment.

As part of the review process, two alternatives were considered for this project:

(1) Continue with the current system while revising process and adding inspection resources; and

(2) Defer implementation to a future year.

The first alternative, implementing process improvements, was not chosen because it will not reduce field inspections or calibrations and would likely increase diagnostic field trips because this alternative does not provide remote visibility of field equipment for office technicians. The second alternative was not chosen because although the project can be deferred to a future year, this alternative continues to defer projected gas measurement improvements, diminishing return on investment over time. The option to implement an electronic gas measurement system, optimizing measurement improvements, was selected due to the specific nature of the measurement equipment, that the software applications are vendor-specific and that cloud solutions are not available as an alternative.

Q. Can you summarize your direct testimony?

A. Yes. The four programs I've 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 ensure adequate capacity and deliverability throughout the system. These investments will help the Company meet its objectives of supplying safe, reliable, affordable, and clean energy to customers as described in the NGDP.

Q. Does this complete your direct testimony?

A. Yes it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-20650

DIRECT TESTIMONY

OF

MARC R. BLECKMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

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; and
- Case No. U-20322, the Company's 2018 Gas Rate Case.

PURPOSE

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. SUMMARY OF RECOMMENDATIONS

II. CAPITAL STRUCTURE AND COST RATES

A. Development of Capital Structure

B. Development of Cost Rates

III. EXHIBITS FOR CERTAIN FILING REQUIREMENTS – CREDIT RATINGS AND RECENT UTILITY BOND ISSUANCES

IV. SUMMARY AND CONCLUSIONS

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 for the Projected Year Ending September 30, 2021;
Exhibit A-14 (MRB-2)	Schedule D-1a	Capital Structure Development for the Projected Year Ending September 30, 2021;
Exhibit A-14 (MRB-3)	Schedule D-1b	Comparison of Development of Capital Structure for the Projected Year Ending September 30, 2021;
Exhibit A-14 (MRB-4)	Schedule D-2	Cost of Long-Term Debt for the Projected Year Ending September 30, 2021;

Exhibit A-14 (MRB-5)	Schedule D-3	Cost of Short-Term Debt - Revolver/Commercial Paper for the Projected Year Ending September 30, 2021;
Exhibit A-14 (MRB-6)	Schedule D-4	Cost of Preferred Stock for the Projected Year Ending September 30, 2021;
Exhibit A-14 (MRB-7)	Schedule D-6	Short-Term Debt Utilization for the Projected Year Ending September 30, 2021;
Exhibit A-23 (MRB-8)		Current and Historical Credit Ratings for the Projected Year Ending September 30, 2021;
Exhibit A-24 (MRB-9)		Recent Utility Corporate Bond Issuances for the Projected Year Ending September 30, 2021;
Exhibit A-25 (MRB-10)		Peer Company Equity Ratios for the Projected Year Ending September 30, 2021;
Exhibit A-26 (MRB-11)		Rating Agency Adjusted FFO Analysis for the Projected Year Ending September 30, 2021;
Exhibit A-27 (MRB-12)		Peer Company Rate of Return Comparison; and
Exhibit A-137 (MRB-13)		Moody's Rating Action for DTE Energy Gas.

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 Exhibit A-14 (MRB-1), Schedule D-1, be used in this case. This represents the actual capital structure as of

December 31, 2018, 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, 2021. 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 52.50%. The equity ratio as a percentage of total capital is 42.60%.

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 Srikanth Maddipati 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 6.08% 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. 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 include borrowings under the Company's credit facilities, including commercial paper. 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, 2018, 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, 2021, in column (g) that I am recommending be used in this case.

Q. Please explain the common equity adjustment of $1.84 billion.

A. I have projected that the 13-month common equity balance for the test year will be $1.84 billion higher than the December 31, 2018 balance. The common equity adjustment of $1.84 billion consists of two components. The first is an adjustment to reflect $269 million in projected retained earnings from January 2019 through September 2021. The second is an adjustment of $1.571 billion to reflect the projected equity infusions from January 2019 through September 2021.

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 $269 million.

A. Since I started with the December 31, 2018 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 through September 30, 2021.

Q. Please explain how you calculated the change in Consumers Energy's retained earnings from January 2019 to July 2019.

A. For the period of January 2019 through July 2019, I relied on actual changes in retained earnings, as reported by the Company's Rate Department in its monthly cost of capital study.

Q. Please explain how you projected the change in Consumers Energy's retained earnings from August 2019 through December 2019.

A. Since retained earnings do not increase evenly throughout the year, I assumed that the change in retained earnings from August 2019 through December 2019 will be equal to the actual change in retained earnings for the same time period in 2018.

Q. Please explain how you projected the change in Consumers Energy's retained earnings from January 2020 through the test period ending September 2021.

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 $11.75 million per month, or $247 million from January 2020 through September 2021. 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 $141 million per year.

A. Based on Consumers Energy's Securities and Exchange Commission ("SEC") Form 10-K for 2018, I determined that Consumers Energy's net income for the 12-month period ended December 31, 2018, was $703 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 $141 million [$703 * (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, 2021.

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 $1.571 billion adjustment for the new equity infusions in your recommended capital structure?

A. This is the amount needed to hold a 52.50% equity ratio for the test period in this case. CMS Energy made an equity infusion into Consumers Energy of $350 million in January 2019 and made an equity infusion of $325 million into Consumers Energy in June 2019. The timing and amounts of each of these 2019 infusions are consistent with the Company's filing in Case No. U-20322. In addition, CMS Energy plans to make an equity infusion into Consumers Energy of $350 million by February 2020, $300 million by June 2020, $275 million by February 2021, and $250 million by June 2021. Accordingly, I reflected this in the equity balance for the test year for this case. 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, 2021 is $1.571 billion. When the 13-month average for the equity infusions of $1.571 billion is combined with the $269 million retained earnings adjustment, the increase to equity capital is the $1.84 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 2020 and 2021?

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 lower its overall equity ratio, from 53.46% for the 13-months ended December 2018, by almost 100 basis points in the test year of this case.

Q. How did you determine that 52.50% was the optimal level for the Company and customers and why is it important to approve the proposed equity ratio?

A. My testimony describing the key factors and providing evidence that supports the proposed equity ratio of 52.50% is organized as follows:

i. Peer Equity Ratios are Higher and are Trending Up

ii. Tax Cuts and Jobs Act of 2017 ("TCJA" or "Tax Reform") has Negatively Impacted Cash Flow and Credit Metrics

iii. Optimal Equity Ratio / ROE Balance

iv. Ability to Fund Significant Capital Expenditures at Optimal Rates

v. Rating Agency Adjustments Lower the Equity Ratio

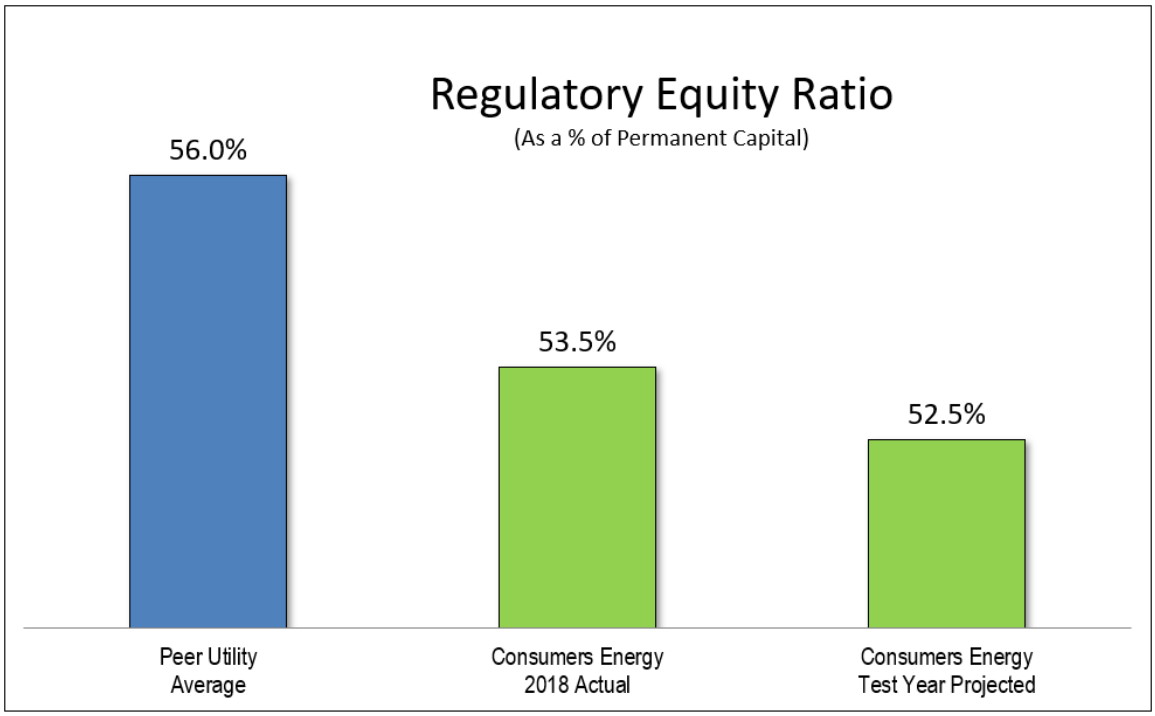
vi. Debt on a Financial Basis Lowers the Equity Ratio

vii. Summary

i. Peer Equity Ratios are Higher and are Trending Up

Q. Have you performed an assessment of how the 52.50% equity ratio proposed in this case compares to other utilities?

A. Yes. For each of the companies represented in Company witness Maddipati's ROE proxy group, I calculated the equity ratio (as a percentage of permanent capital at the regulated subsidiary level) at year-end 2018. This is reflected on Exhibit A-25 (MRB-10). The average equity ratio for the Company's peer group was 56.0%, well above the Company's equity ratio in 2018 of 53.46%, and even further above the 52.50% proposed for Consumers Energy in this case. This is reflected in the following chart:



Despite this higher peer average, I am proposing a ratio of 52.50%, which balances capital investment plans, credit metrics, and customer rate impacts, and continues to support affordable utility infrastructure financing for the state of Michigan.

Q. What been the recent trend in authorized equity ratios?

A. Average authorized equity ratios have increased. To combat the negative cash flow impacts of recently passed Tax Reform legislation (which I will discuss later in my testimony), many utilities have requested higher equity ratios. The average authorized equity ratios adopted by utility commissions so far in 2019 have been higher than 2018 and 2017. As noted by MPSC Staff ("Staff") in Case No. U-20479 (SEMCO Energy Gas Company's recent general rate case), the average authorized equity ratio for 2017, 2018, and the first half of 2019 are 49.88%, 50.09%, and 54.60% respectively. Staff recommended an equity ratio of 55.15% in that case, somewhat higher than the 2019 national average authorized equity ratio.

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-20322, the Company's most recent gas 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 in 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.

ii. Tax Reform has Negatively Impacted Cash Flow and Credit Metrics

Q. Should recently enacted Tax Reform legislation be considered in determining the appropriate common equity balance and equity ratio for the Company in this case?

A. Yes. The TCJA, signed into law in December 2017, brought broad, widespread changes to the federal tax system, and has had significant impacts on U.S. utilities. The TCJA, effective beginning in January 2018, reduced the corporate tax rate, and affects current and deferred tax accounting methods used by utilities. While the savings from lower tax rates will be passed on directly to our customers, those same savings reduce future cash inflows to the Company. The reduced cash inflows weaken the Company's credit metrics which degrades the Company's credit quality, potentially increasing financing costs. It is important to note that, although Tax Reform became effective in January 2018, the unfavorable cash impact of the TCJA was not fully realized in 2018.

Q. When did the Company begin to experience the negative cash impacts of the TCJA?

A. On February 22, 2018, after the enactment of the TCJA, the Commission issued an order in Case No. U-18494 adopting a three-step approach to address the impacts of the federal income tax reduction arising from the TCJA. The first step, the Credit A proceeding, determined the rate credit based on the new tax rate going-forward. The second step, the Credit B proceeding, determined the rate credit from January 1, 2018, to the date of the order in the utility's Credit A case. The third step, the Calculation C proceeding, captured the remaining impacts of the TCJA. The reduction in current tax expense collection (Credit A) did not begin until July 2018 for the gas utility, and August 2018 for the electric utility. Additionally, the reduction in deferred tax expense collection (Calculation C) did not begin until October 2019.

Q. How do these impacts of the TCJA relate to the appropriate equity ratio that should be approved in this case?

A. A key financial metric used by rating agencies is the ratio of Funds From Operations ("FFO") to Debt ("FFO to Debt ratio"). The calculation of this financial metric includes, in part, both the equity ratio and the authorized ROE of the Company; thus there needs to be a balance between the Company's equity ratio and ROE that will ensure that this key financial metric does not drop and cause significant credit deterioration. An equity ratio of 52.50% 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 payback ratio, reflecting the company's ability to repay its outstanding debt with operating cash flow. 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. 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 are better able to repay debt with their income, indicating a relatively higher credit quality.

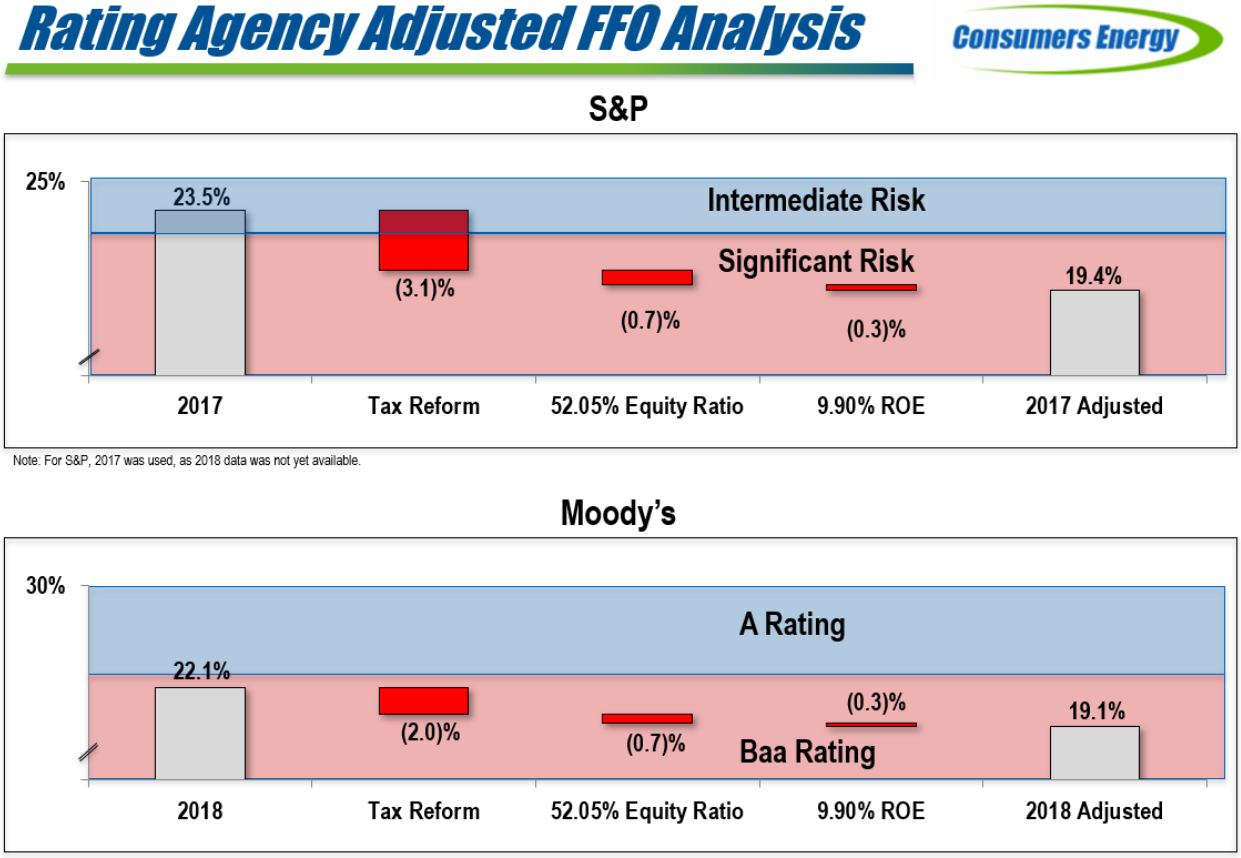
Q. What is the impact to the rating agencies' calculation of FFO to Debt ratios for the Company as a result of the enactment of the TCJA?

A. I have calculated the impact of the TCJA on the Company's FFO to Debt ratio on Exhibit A-26 (MRB-11). Starting with actual historical ratios for Standard and Poor's ("S&P") and Moody's Investors Service ("Moody's"), I layered in the impact of the TCJA as an adjustment to FFO and debt. This provides an indication of this key metric for the Company post-Tax Reform. As shown on Exhibit A-26 (MRB-11), column (b), FFO is reduced by $207 million for S&P (starting with 2017 actuals). Assuming approximately half of this reduction in cash is replaced with long-term debt, the S&P ratio is reduced by 310 basis points. For Moody's, FFO is reduced by $138 million (starting with 2018 actuals, which already include partial impacts of the TCJA). Assuming approximately half of this reduction is replaced with long-term debt, the Moody's ratio is reduced by 200 basis points. The impact of this significant deterioration in credit metrics on the Company's credit quality is discussed in more detail in Company witness Maddipati's direct testimony.

Q. What would the impact to the rating agencies' FFO to Debt ratios be assuming, in addition to the impacts of the TCJA, the Company realized an equity ratio of 52.05% and an ROE of 9.90%?

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 an equity ratio of 52.05%. This increase in debt would also weaken the Company's FFO to Debt ratio. As shown on Exhibit A-26 (MRB-11), moving to a 52.05% equity ratio and a

9.90% ROE would lower the FFO to Debt ratio by an additional 100 basis points, approximately, for S&P and for Moody's. This is on top of the significant reduction already caused by the enactment of the TCJA, and would lead to a major deterioration in the credit quality of the Company as assessed by the rating agencies' key financial metric. The impacts of these adjustments are summarized in the following table:



Q. What are the risk category / credit rating thresholds for S&P and Moody's depicted in this table?

A. According to paragraph 123, Table 18, of S&P's published Corporate Methodology, which can be found on their website (www.standardandpoors.com), an adjusted FFO to Debt ratio of 23% is the threshold between an Intermediate Risk profile and a Significant Risk profile. According to page 22 of Moody's published Regulated Electric and Gas

Utilities rating methodology which can be found on their website (www.moodys.com), an adjusted FFO to Debt ratio of 22% is the threshold between an "A" rating and a "Baa" rating when evaluating a Company's financial strength. As demonstrated in Exhibit A-26 (MRB-11), the impacts of Tax Reform, in combination with an equity ratio of 52.05% and a 9.90% ROE (as approved in Case No. U-20322), are reflective of FFO to Debt ratios of just above 19%, which is well below the thresholds established by S&P and Moody's. This places the Company's credit quality at risk.

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 DTE Gas earlier this year. In July 2019, Moody's downgraded DTE Gas from A2 to A3. This rating action is shown on Exhibit A-137 (MRB-13). In conjunction with this action, Moody's downgraded the ratings on DTE Gas' debt, including its senior secured First Mortgage Bonds, which were downgraded from Aa3 to A1. In its statement on the downgrade, Moody's stated that "the 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." See Exhibit A-137 (MRB-13). In light of Moody's actions, the maintenance of the Company's strong credit ratings will be critical in allowing the Company to finance significant capital investments while keeping the cost of capital lower. The Company is being proactive in recommending an equity ratio and ROE in this case that is supportive of the Company's current credit ratings.

Q. Are you aware of any recent changes in the Company's credit ratings?

A. Yes. In October 2019, S&P raised the issuer credit rating on Consumers Energy from BBB+ to A-.

Q. Why did S&P change the Company's credit ratings?

A. In July 2019, S&P issued a revised credit rating methodology. The methodology was revised to take into account the impact of the credit profile of a company's parent on the subsidiary, and vice versa.

Q. Does S&P's change in the Company's credit rating indicate an improvement in the Company's underlying business?

A. No. This rating action was the direct result of the change in S&P's rating methodology, and not a change or improvement in the Company's underlying business. Further, this rating action affects only Consumers Energy's issuer (overall) credit rating. There was no change to the ratings on the Company's senior secured debt or commercial paper, either of which would impact the Company's cost of debt financing.

iii. <u>Optimal Equity Ratio / ROE Balance</u>

Q. Discuss the relationship between the Company's ROE, its equity ratio, and the Company's credit metrics.

A. As shown 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 Maddipati's Exhibit

A-79 (SM-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 together with an equity ratio of 52.50% results in an FFO to Debt ratio that is supportive of the Company's current credit ratings. 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 Maddipati'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. On line 6 of this exhibit, the equity ratio of 52.50% from column (c) is multiplied by the ROE of 10.50% from column (e) to produce a weighted cost of 5.51%, 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. This rate of return should be set at an appropriate level that is comparable to other utilities and that is supportive of the Company's current credit quality.

Q. How does the Company's recommended equity ratio and ROE combination compare to other utilities?

A. On Exhibit A-27 (MRB-12), I calculated the weighted cost of equity (rate of return) for the Company's peer group. As shown on this exhibit, the Company's weighted cost of 5.51% is consistent (just slightly above) the weighted cost of peers of 5.34%.

Q. What is the weighted cost of the equity ratio and ROE combination from the Order in Case No. U-20332, the Company's previous gas rate case?

A. Multiplying the equity ratio of 52.05% by the ROE of 9.90% from the Order in Case No. U-20332 results in a weighted cost of 5.15%. As shown on Exhibit A-27 (MRB-12), this is below the weighted cost of peers of 5.34%.

Q. Assuming the Commission also approved an ROE of 9.90% in this case, what would the approved equity ratio need to be in order to achieve a weighted cost comparable to peers?

A. Assuming an ROE of 9.90%, an equity ratio of 53.94% (5.34% / 9.90%) would be required to achieve a weighted cost of 5.34%, comparable to peers. Maintaining an authorized ROE of 9.90% without raising the approved equity ratio would put the Company below peers from a weighted cost perspective, resulting in cash flow and credit metric deterioration. It should be noted that DTE Gas was downgraded by Moody's in July 2019. As reflected on Exhibit A-27 (MRB-12), the combined DTE electric and gas companies have a weighted cost of 5.12%, which is below the average weighted cost for peers and comparable to the weighted cost from the Company's Order in Case No. U-20322.

iv. <u>Ability to Fund Significant Capital Expenditures at Optimal Rates</u>

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 Company witnesses Alley, Degenfelder, Martin, DeLacy, Joyce, Parker, Wolven, Saba, Jones, McLean, and Varvatos, 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 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 $850 million refinancing that the Company executed in November 2018. By refinancing at a lower interest rate, the Company eliminates interest rate risk, while realizing interest savings through 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." Thus, it is 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 this 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 capital projects. The capital expenditures in this case are identified, quantified, and supported by the Company's various capital witnesses.

v. Rating Agency Adjustments Lower the Equity Ratio

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

A. Certain credit rating agencies (e.g., Moody's) include securitization debt as additional debt when calculating equity ratios. Other credit rating agencies (e.g., S&P) also include Power Purchase Agreements ("PPAs"), benefit obligations, and leases as additional debt when calculating equity ratios. When credit rating agencies increase debt in this way to include securitization debt, PPAs, benefit obligations, and leases, the equity ratio (the ratio of equity to debt) used to evaluate the Company's credit-worthiness is lowered. Thus, a 52.50% equity ratio calculated by the Company gets adjusted to a lower ratio by the credit rating agencies, which, in turn, diminishes the Company's credit strength. Incorporating the projected equity infusions in 2020 and 2021 in the common equity balance enables the Company to maintain reasonable equity ratios after the upward adjustments to debt made by credit agencies for securitization debt, PPAs, benefit obligations, and leases. The Commission recognized that these circumstances support the need for a slightly higher equity ratio in Case No. U-17735. These rating agency adjustments do truly reflect the debt-like nature of long-term fixed payment obligations, such as PPAs, and cannot be ignored.

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 2017, S&P increased the Company's debt balance for the following items:

- $992 million to reflect the impact of PPAs;
- $246 million for pension obligations; and
- $339 million for Asset Retirement Obligations.

This equates to $1.6 billion of additional debt as evaluated by S&P in their credit assessment. Adding this level of debt to the Company's proposed capital structure in this case would reduce the equity ratio from 52.50% to 47.96%. The rating agencies' debt adjustments support the need for the Company to maintain a relatively higher equity ratio before adjustment to be on par with comparable utilities after adjustment. In addition to lowering the Company's equity ratio, rating agency 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. Yes. 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 52.50% is necessary to support the Commission's desire, as stated in Case No. U-20322, for Consumers Energy to maintain an evenly balanced capital structure.

vi. <u>Debt on a Financial Basis Lowers the Equity Ratio</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. How does the Company's equity ratio on a regulatory (ratemaking) basis differ from the equity ratio on a financial basis?

A. Since items such as securitization debt, revolver borrowings, and capital leases are included in the calculation of the Company's equity ratio on a financial basis, the Company's debt is higher, and the resulting equity ratio is lower compared to a regulatory basis. For example, at the end of 2018, securitization debt was $277 million. Including securitization debt decreases the Company's equity ratio by 110 basis points at the end of 2018. Also, while the Company excludes revolver/commercial paper borrowings from permanent capital in its regulatory capital structure, these borrowings are considered "debt" on a financial basis. Including the $312 million short-term borrowings would decrease the Company's equity ratio an additional 110 basis points.

Q. What is the Company's equity ratio on a financial basis?

A. Based on Consumers Energy's balance sheet as reported in the Company's 2018 Form 10-K, the equity ratio for the Company, on a financial basis, was 50.26% at year-end 2018. While certain rating agencies exclude securitization debt from their credit metrics, most analysts and investors evaluate the Company based on SEC (financial-basis) reported results.

Q. Is the Company's capital structure balanced from a financial-basis perspective?

A. Yes. As shown above, the Company's equity ratio on a financial basis was just over 50%. Financial basis adjustments, taken together with rating agency debt adjustments, make it necessary for the Company to maintain a regulatory equity ratio of at least

52.50%. This regulatory equity ratio level is critical to support a balanced capital structure (preferred by the Commission) after these adjustments.

vii. Summary

Q. In summary, why is having a 52.50% 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 authorized equity ratios across the country are trending up and are, on average, at 56.0%. This is substantially higher than the 52.50% recommended by the Company in this case. I have also shown that, in the wake of Tax Reform, an ROE below 10.50% and an equity ratio below 52.50% would lead to an FFO to Debt ratio that would not be supportive of maintaining the Company's current credit ratings. In addition, the Company is in the midst of a major infrastructure upgrade cycle throughout our service territory in Michigan. This will require billions of dollars in new capital funding to complete these needed upgrades for our customers. A healthy equity ratio and credit quality will be key in raising the necessary capital at the lowest overall cost to customers over the long term. Lastly, I have shown that rating agency adjustments, together with looking at debt on a financial basis, effectively lowers the equity ratio in the eyes of investors, analysts and rating agencies. On a rating agency adjusted basis and on a financial basis, the Company's capital structure is evenly balanced or (in the case of rating agency adjusted metrics) is reflective of an equity ratio below 50%. Therefore, it is necessary for the Company to maintain a regulatory equity ratio of 52.50% to support the Commission's desire, as stated in previous rate cases, for Consumers Energy to maintain an evenly balanced capital structure

While lowering the Company's equity ratio from 53.46% in 2018 to the 52.50% 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 our customers paying higher financing costs over the long-term. The equity ratio of 52.50% is appropriate and reasonable under the current circumstances in the wake of federal Tax Reform, made in conjunction with the 10.50% ROE proposed by Company witness Maddipati. 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 agencies by holding the equity ratio at the Company's filed position of 52.50%.

Q. Please explain the long-term debt adjustment of $1.565 billion.

A. I have projected that the average debt balance for the test year ending September 30, 2021 will be $1.565 billion higher than the December 31, 2018 balance. This adjustment consists of the following components:

Long-Term Debt (in millions)			Sep 30, 2021 Test Year
Month	Issuance	Retirement	Impact
May 2019	$300	$0	$300
May 2019	$0	($300)	($300)
Sep. 2019	$625	$0	$625
Oct. 2019	$75	$0	$75
May 2020	$850	$0	$850
Oct. 2020	$0	($100)	($92)
Aug. 2021	$750	$0	$116
Subtotal			$1,574
Changes in Unamortized Fees			(9)
Total			**$1,565**

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 2020 and August 2021.

A. The debt planned to be issued in May 2020 will be used for general corporate purposes of the Company including financing capital expenditures. The debt will also be used for the October 2020 retirement of $100 million. The debt planned to be issued in August 2021 will be used for general corporate purposes of the Company including financing capital expenditures. 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, 2021?

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, 2021. The average amount outstanding on line 54, 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, 2021?

A. I have projected an average short-term debt balance for the test year of $138 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 – revolver/commercial paper balance of $135 million. The second is the average short-term debt – renewable liability balance of $3 million. These balances are shown on Exhibit A-14 (MRB-5), Schedule D-3, page 1, lines 1 and 3.

Q. What is revolver/commercial paper?

A. Revolver and commercial paper are two short-term financing options available to the Company. Revolver represents a revolving line of credit that allows the Company to borrow and repay as long as the outstanding balance remains within the credit limit, 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.

Q. How was the revolver/commercial paper short-term debt balance of $135 million developed?

A. Exhibit A-14 (MRB-7), Schedule D-6, shows the projected balances of short-term debt - revolver/commercial paper for the test year ending September 30, 2021, 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 $135 million.

Q. Are the projections for short-term debt – revolver/commercial paper reflected on Exhibit A-14 (MRB-7), Schedule D-6, expected to be issued under the Company's revolvers or its Commercial Paper Program?

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:

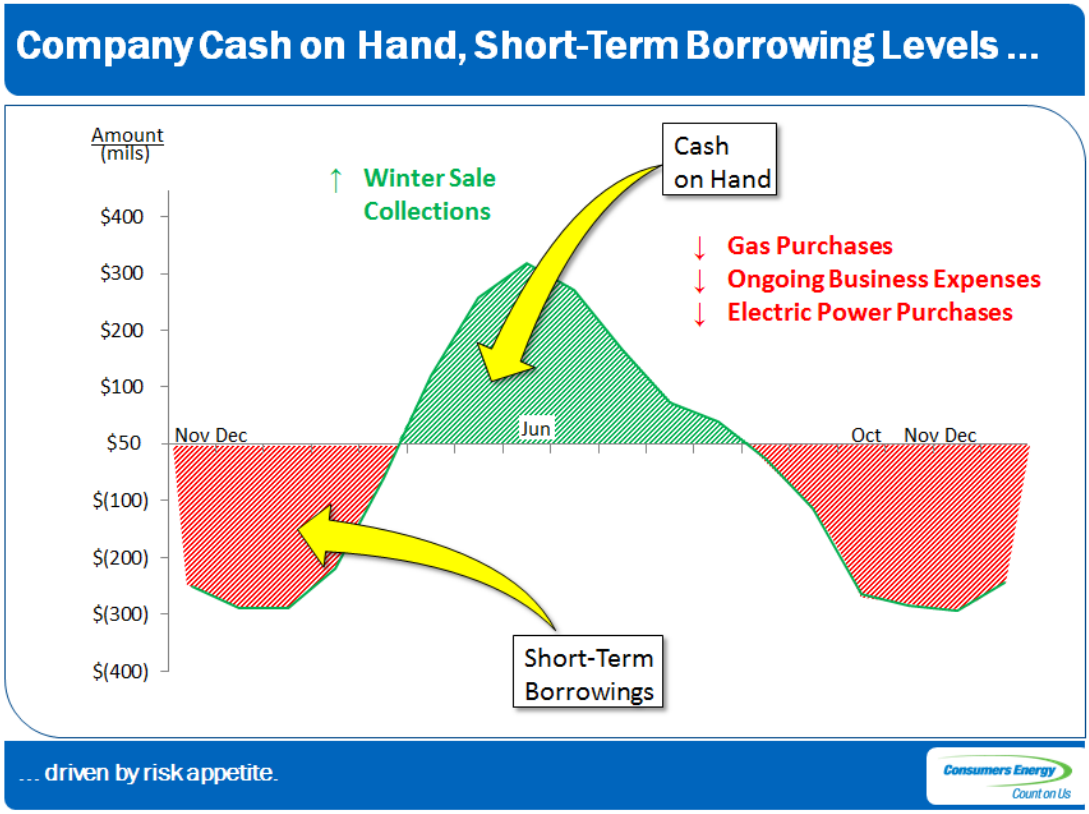
1.	Commercial Paper	$500 million*
2.	Scotiabank Revolver	$250 million
3.	JPMorgan Revolver	$350 million

*Takes away $500 million of the JPMorgan revolver's $850 million capacity (leaving $350 million available).

All of the projected balances for short-term debt – revolver/commercial paper are assumed to be issued under the Company's Commercial Paper Program. This is the least expensive short-term financing option to the Company and is assumed to be used first when the need arises, up to the $500 million capacity. The Company's $250 million Scotiabank revolving credit facility is the next least-costly short-term financing option, with the remaining $350 million revolver ($850 million 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 coincides with 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 we witnessed less than a decade ago during the credit crisis. 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 comfortable financing between $200 million and

$400 million of this gap with short-term borrowings. This 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 was to establish and maintain a permanent level of short-term debt, this would be taken into account in calculating the appropriate equity ratio in this case. If the short-term debt balance was included in the debt-to-equity ratio calculation, the equity balance would need to increase in order to achieve the appropriate 52.50% equity ratio. This 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-20322.

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 $1.1 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 and, in addition, extra or "backup" 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 $350 million of short-term borrowings in November 2020. The most cost-effective method of financing this level of short-term debt is commercial paper. 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 $1.1 billion of revolving credit facilities, $500 million is used to support commercial paper issuance. The remaining $600 million of revolver capacity is a vital back-stop 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 reflected the average balance of renewable surcharge liability. I have projected an average renewable surcharge liability of $3 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-18231.

Q. Please explain the deferred income tax adjustment of $273 million.

A. The Company's Tax Department has projected that the average deferred income tax balance for the test year ending September 30, 2021 will be $273 million higher than the December 31, 2018 balance. This increase is based on projecting book versus tax differences that the Company expects to record from January 2019 through September 2021. These adjustments total $273 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, 2021, will be $127 million, $28 million higher than the December 2018 balance. The balance is based on forecasted balances of both existing and anticipated new ITC credits that the Company expects to record from January 2019 through September 2021. These adjustments total $28 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, 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) times 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).

Long-Term Debt Cost Rate

Q. What long-term debt annual cost rate did you use in this case?

A. I developed a 3.97% 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, 2018. I then added the new debt issuances in May 2019, September 2019, and October 2019. I then added the planned new debt issuances in May 2020 and August 2021. These new debt issuances are shown on Exhibit A-14 (MRB-4), Schedule D-2**,** lines 31 through 35 and line 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 May 2019, September 2019, and October 2019.

A. Since the debt issuances in May 2019, September 2019, and October 2019 have already taken place, I used the actual interest rates specified in those bond issuances.

Q. The long-term debt issuances in September 2019 and October 2019 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 two issuances in 2019. While the Company continuously seeks financing alternatives that

maximize interest savings, these two most recent 2019 issuances are not repeatable in the near term. The September 2019 issuance of $76 million provided a unique security for a very limited investor pool. The debt will bear interest at a rate of 3-month London Interbank Offered Rate ("LIBOR") minus 30 basis points, maturing 2069. The October 2019 issuance of $75 million was for a Pollution Control Revenue Bond ("PCRB"). The security will mature in 2049 and is locked in at a fixed rate of 1.80% for the initial 5-year term. 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 and identify similar opportunities, there are not any currently identified, and similar offerings are not and should not be expected or anticipated a regular basis going forward.

Q. Please explain the cost rate you assumed for the planned debt issuances in May 2020 and August 2021.

A. I assumed that both 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 three planned debt issuances, I then added a 136 basis point spread. For the May 2020 planned debt issuance, the average of the IHS and Blue Chip 30-year U.S. Treasury rate forecasts for 2020 was 2.50%. Adding the 136 basis point spread resulted in a total coupon interest rate of 3.86% for this issuance. For the August 2021 planned debt issuance, the average of the IHS and Blue Chip 30-year U.S. Treasury rate forecasts for 2021 was 3.22%. Adding the 136 basis point spread resulted in a total coupon interest rate of 4.58% for this issuance. These interest rate calculations are shown on Exhibit A-14 (MRB-4), Schedule D-2.

Q. What is a spread?

A. A spread (also called a credit spread) reflects the extra compensation investors receive for bearing credit risk. Therefore, the total interest rate on a corporate bond is a function of both the Treasury rate and the credit spread.

Q. How was your assumed spread of 136 basis points over the U.S. Treasury rate calculated?

A. Unlike U.S. Treasury rates, spreads on 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 used the average from the last 11 years. From 2008 to current, the average spread on a 30-year debt issuance for investment grade utilities was approximately 136 basis points.

Q. Are there any existing long-term debt issuances that have variable interest rates?

A. Yes. There are two debt issuances shown on Exhibit A-14 (MRB-4), Schedule D-2, that have a variable interest rates. The Floating Rate First Mortgage Bond ("FMB") issuance shown on line 33 and the PCRB issuance shown on line 39 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 is equal to LIBOR less 30 basis points. Therefore, I took the average of the projected three-month LIBOR rates from IHS and Blue Chip Forecasts (equal to 2.48%) and subtracted 30 basis points for an interest rate of 2.18%. For the PCRB, the interest rate has historically been approximately 70% of the three-month LIBOR rate. Accordingly, I used 70% of the projected three-month LIBOR rate for the test year ending September 30, 2021 to estimate the cost of the PCRB. The estimated interest rate on the PCRB is 1.736% (2.48% * 70%).

Q. Please explain Exhibit A-14 (MRB-4), Schedule D-2, line 46.

A. Exhibit A-14 (MRB-4), Schedule D-2, line 46, 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 46?

A. The amount of $5,196,000 shown on line 46 is based on the projected amortization expense during the 12-month period ending September 30, 2021.

Q. Please explain line 48 – PCRB Fees shown on Exhibit A-14 (MRB-4), Schedule D-2.

A. These PCRB Fees are related to the April 2005 PCRB issuance shown on line 39 of Exhibit A-14 (MRB-4), Schedule D-2. Consumers Energy incurs certain ongoing fees to maintain this debt security, which is included in long-term debt for ratemaking purposes. These fees include ongoing bond remarketing expense and the trustee expense. I have included $46,000 for these expenses based on actual experience. These fees are prudent, reasonable, and customary for these types of tax-exempt securities and were approved for recovery in Case No. U-16794.

Q. Was this cost included in the development of the cost based on net proceeds for the PCRB issuance shown on Exhibit A-14 (MRB-4), Schedule D-2, line 39?

A. No. This cost was not incurred at the inception of this security, but rather incurred on an ongoing basis over the life of the security. Consequently, the cost is not included in the net proceeds calculation and are shown separately.

Q. Does the amount shown on Exhibit A-14 (MRB-4), Schedule D-2, line 48 – PCRB Fees include any PCRB Letter of Credit Fees?

A. No. Since the refinancing of these securities in 2008, the Company is required to provide Letters of Credit pursuant to bond arrangements and incurs costs to do the same. I have included the PCRB Letter of Credit Fees in the calculation of short-term debt cost, rather than as part of long-term debt cost, in this case.

Short-Term Debt Cost Rate

Q. What short-term debt cost rate did you use in this case?

A. I used a short-term debt cost rate of 3.99%. 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 – revolver/commercial paper. I calculated the annual cost of short-term debt – revolver/commercial paper to be $5.4 million. The second component is short-term debt – renewable liability. I calculated the annual cost of short-term debt - renewable liability to be $0.1 million. These costs are shown on lines 1 and 3 of Exhibit A-14 (MRB-5), Schedule D-3, page 1, column (b), and total $5.5 million. 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 $138.0 million. Dividing the total cost of $5.5 million by the total average short-term debt balance results in a total short-term debt cost rate of 3.99%, as shown in column (c).

Q. Please explain the cost of short-term debt – revolver/commercial paper.

A. As indicated above, I projected a cost of short-term debt – revolver/commercial paper of $5.4 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 $135.4 million, calculated on Exhibit A-14 (MRB-7), Schedule D-6. Commercial paper issuances are short term in nature, typically 1 to 90-day maturities. Interest charged on these short-term borrowings are based on several different factors, including market conditions, investor demand, and the tenor (number of days borrowed) of the issuance. I approximated the interest on commercial paper borrowings using the projected LIBOR[1] rate for the test year of 2.48%. This was multiplied by the projected balance of $135.4 million. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $3.4 million for borrowings under the Commercial Paper Program;

[1] Intercontinental Exchange LIBOR, a benchmark interest rate used in calculating short-term variable interest rates throughout the world.

2. **Letter of Credit Fees** – Equal to the projected Letters of Credit outstanding times a rate set forth by the facility the Letters of Credit are issued under. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $0.7 million for Letter of Credit Fees. The Letter of Credit Fees shown on Exhibit A-14 (MRB-5), Schedule D-3, page 2, pertains to the following:

   - Item 1 (line 28) - Normal business Letters of Credit to cover ongoing items such as fuel purchases or margin support;
   - Item 3 (line 30) – Letter of Credit to cover Midcontinent Independent System Operator, Inc. margin obligations;
   - Item 4 (line 31) – Letter of Credit related to the Palisades Power Purchase Agreement; and
   - Item 5 (line 32) – Letter of Credit related to PCRB tax exempt bonds;

3. **Unused (Commitment) Fees** – This cost consists of Annual Revolver Commitment Fees, which the Company is required to pay quarterly to the banks on the "unused" portion of the JPMorgan revolver and the Scotiabank revolver, and other required annual fees under the Revolving Credit agreements. The Revolver Commitment Fees are associated with maintaining fund availability. It should be noted that borrowings under the Company's Commercial Paper Program reduce the "availability" (or the amount the Company is able to draw) of the JPMorgan revolver, but do not reduce the "unused" portion of the revolver in calculating the unused (commitment) fees. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $0.8 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 $0.5 million for amortization of upfront revolver fees.

Q. Why is it important to allow for the recovery of commitment fees and amortization of facility fees in addition to the interest on short-term borrowings and interest on letters of credit?

A. These fees and costs are customary in revolving credit and commercial paper agreements and are necessary to secure the availability of 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 – revolver/Commercial Paper Program represents the cost to provide $1.1 billion of needed liquidity to Consumers Energy.

Q. Why did you include Letter of Credit Fees for the Tax Exempt Bond in the calculation of Letter of Credit Fees?

A. The Letter of Credit facility for the Tax Exempt Bond is for the PCRB Letter of Credit that the Company is required to provide pursuant to bond arrangements. These Letter of Credit Fees are prudent, reasonable, and customary. If these Letter of Credit Fees are not included as part of the short-term debt cost, then the fees should be included either as part of the long-term debt cost calculation or as separate expense items.

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 2.48%. I then applied this rate to the projected average renewable liability balance for the test period of $2.6 million, shown on Exhibit A-14 (MRB-7), Schedule D-6. This results in a cost for the renewable liability of $0.1 million.

Q. Have renewable liability costs been included in short-term debt in previous cases before the Commission?

A. Yes. The inclusion of the cost related to the Company's renewable liability in short-term debt is based on long-standing practice and, as explained earlier, is authorized by legislation. This cost has also been recognized and approved by the Commission, in Case No. U-20322. If it is determined that the short-term debt cost rate is not the appropriate place to include interest on the renewable liability, the liability balance should be removed from the Company's capital structure entirely. It would not be logical to include a liability balance but not include the borrowing cost for that liability. There are certain items, such as power suply cost recovery overrecoveries where liabilities are recorded, but are excluded from general ratemaking. In these cases, both the liability balance and the related interest costs are excluded from general rates. The Company believes, however, that these costs should be included in the cost of short-term debt, as supported by long-standing ratemaking history and legislation.

Preferred Stock Cost Rate

Q. What is the annual cost of preferred stock?

A. The annual cost of preferred stock is shown on Exhibit A-14 (MRB-6), Schedule D-4. This cost is 4.50%.

Common Equity Cost Rate

Q. What rate did you use for the cost of common equity?

A. Mr. Maddipati recommended an ROE range of 10% to 11%. Based on my recommended equity ratio of 52.50%, I used a 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.

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-23 (MRB-8).

A. Exhibit A-23 (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-23 (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-24 (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-24 (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. SUMMARY AND CONCLUSIONS

Q. Please summarize your recommendations and conclusions.

A. Consumers Energy's capital structure should be based on the capital structure as of December 31, 2018, 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. The cash flow and credit impacts of federal Tax Reform must be considered in evaluating capital structure and ROE in this case to proactively avoid credit deterioration. The Company has taken great care to do what is best for Michigan and balance both the short-term and long-term considerations in an attempt to optimize its capital structure and overall cost of capital for its customers. As shown on Exhibit A-14 (MRB-1), Schedule D-1, I recommend an overall after-tax rate of return of 6.08%.

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-20650

DIRECT TESTIMONY

OF

LORA B. CHRISTOPHER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

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 Director of Employee Benefits.

Q. What are your responsibilities as 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 (formerly known as 24 Hour Accident), 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.

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-28 (LBC-1)	Summary of Actual and Projected Benefits O&M Expenses for the Years 2018, 2019, 2020, Test Year Oct 2020 – Sept 2021;

Exhibit A-29 (LBC-2)	CMS Energy – Pension Plans A and B - ASC 715 Pension Expense Estimates ($ millions);
Exhibit A-30 (LBC-3)	CMS Energy - ASC 715 OPEB Expense Estimates ($ millions); and
Confidential Exhibit A-31 (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-28 (LBC-1).

A. Exhibit A-28 (LBC-1) summarizes 2018 through the 12 months ending September 30, 2021, 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 2018 actual expense for each plan. Column (c) provides the projected expense in 2019 for each plan. Column (d) provides the projected expense in 2020 for each plan. Column (e) provides the projected expense in 2021 for each plan. Column (f) provides the projected expense for the 12 months ending September 30, 2021, which is the test year, for each plan.

Q. Please describe Exhibits A-29 (LBC-2), A-30 (LBC-3), and Confidential A-31 (LBC-4).

A. Exhibits A-29 (LBC-2) and A-30 (LBC-3) provide the Aon actuarial projections for Pension and Other Post-Employment Benefits ("OPEB") expenses for 2019, 2020, and 2021. The projected Pension and OPEB expenses for the 12 months ending September 30, 2021 were calculated using 25% of 2020 projected expense and adding 75% of the 2021 projected expense to it. Both the Pension and OPEB projections in these exhibits provided by the Aon actuaries are updated from the year-end 2018 measurement of the Pension and

OPEB plans and reported in the Company's 2018 Form 10-K filing to more closely align with current market conditions and January 1, 2019 census data. A letter from the actuary regarding the accuracy and completeness of the updated projections is included in Confidential Exhibit A-31 (LBC-4).

I. RETIREMENT BENEFITS PLANS

Q. Which retirement benefits are you addressing in this section of your direct testimony?

A. I am addressing the Pension Plans, DCCP, and ESP. These expenses are shown on Exhibit A-28 (LBC-1), lines 1 through 3.

Q. How are the Pension Plans, DCCP, and ESP expenses that are common to electric and gas operations allocated to the gas portion of the business?

A. Expenses common to both the electric and gas operations associated with the Pension Plans, DCCP, and ESP are allocated 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-28 (LBC-1).

Pension Plans

Q. Would you please explain your Exhibit A-28 (LBC-1), line 1, which begins with $16,871,000 in 2018?

A. Exhibit A-28 (LBC-1), line 1, shows the actual 2018 pension expense and the projected expense for 2019, 2020, 2021, and 12 months ending September 30, 2021 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 on December 31, 2018 for year-end purposes and updated as of August 31, 2019. The mid-year projections were updated by the Company's actuary, Aon. Pension expense in this case, including 2020 and 12 months ending September 30, 2021, is based upon this updated 2019 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. Has the Company applied the new Financial Accounting Standards Board ("FASB") Presentation of Pension/OPEB Costs Standard in this case?

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. This new 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 new 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-28 (LBC 1), line 1, which begins with $16,871,000 for 2018.

A. Each of the annual pension expense levels shown on Exhibit A-28 (LBC-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 $16,871,000 in 2018, projected expense of $2,418,000 in 2019, and projected expense of $22,049,000 in 2020. For the 12 months ending September 30, 2021, the gas utility's portion of the projected O&M pension expense is $20,104,000.

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 2018?

A. Yes, the Company contributed $102,600,000 to Pension Plan A in December 2018.

Q. Will the Company make any cash contributions to the Pension Plan in 2019 or the 12 months ending September 30, 2020?

A. No cash Pension Plan contributions are required in 2019 or 2020 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 is the pension expense expected to increase for 2020 from 2019?

A. The pension expense is projected to increase in 2020 mainly due to the decrease in projected discount rate. Aon created new projections based on market conditions as of August 31, 2019 and these projections indicate a decreased discount rate for year end. This projection will be finalized when the actual discount rate is determined after year-end. Additionally, the Amortization of Outstanding Components is increasing. The unamortized loss grew in size so the amount needed to be recognized in each fiscal year is increasing.

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. The changes in the projected pension expense estimates from 2018, 2019, and 2020 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 5% to 7% 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 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-28 (LBC-1), line 2, which begins with $4,537,000 in 2018?

A. Exhibit A-28 (LBC-1), line 2, represents the gas operations O&M expense related to the DCCP. The actual gas operations expense for this plan in 2018 was $4,537,000 as shown in column (b). Column (c) shows the projected 2019 gas DCCP expense of $4,986,000. Column (d) shows the projected gas DCCP expense of $5,734,000 for 2020. Column (f) shows the projected gas DCCP expense of $6,379,000 for the 12 months ending September 30, 2021.

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. The Company currently matches 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% are 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 2016, the Company match changed to 100% of employee contributions of up to 3% of the employee's salary, and then 50% of employee contributions of up to the next 2% of the employee's salary (previously 60% of employee contributions up to 6% were matched). Employee contributions beyond 5% 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.

Q. Would you please explain your Exhibit A-28 (LBC-1), line 3, which begins with $4,752,000 in 2018?

A. Exhibit A-28 (LBC-1), line 3, represents the Company's gas operations expense related to the ESP. In 2018, the actual gas utility O&M expense for the ESP was $4,752,000. For 2019, the projected gas utility O&M expense for the ESP is $4,835,000. For 2020, the gas utility O&M expense projected for the ESP is $5,123,000. For the 12 months ending September 30, 2021, the gas utility O&M expense projected for the ESP is $5,352,000.

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 2015. 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-28 (LBC-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.

Active Health Care (Including HSAs and HCFSAs), Life Insurance, LTD, and Other Benefits

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-28 (LBC-1), line 4, which begins with $16,017,000 in 2018.

A. Exhibit A-28 (LBC-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 2018, the Company incurred an actual combined expense of $16,017,000 for health care, life insurance, LTD, and other benefits for gas operations. The Company's projected expense for these benefits is $17,150,000 in 2019. The projected gas operation expense for these benefits in 2020 is $17,891,000. For the 12 months ending September 30, 2021, the projected gas utility expense is $18,672,000.

Q. What factors did you consider in projecting the Company's 2019, 2020, and 2021 health care, life insurance, LTD, and other benefits expenses?

A. In projecting expected 2019, 2020, and 2021 health care expenses, a number of factors were considered. Primary factors included review of 2018 and 2019 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 2016 through 2020 OM&C/VCC/Steelworkers union employee health care benefit contract provisions, changes to 2019 and 2020

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 2019 and 2020 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 2019, 2020, and the 12 months ending September 30, 2021.

A. To help understand projected health care trends and costs in 2019 and 2020, the Company and WTW reviewed expected health care trends and costs survey information from several large consulting firms. Recent 2019 health care trend and cost surveys included in the review were Aon and WTW. For 2020, medical health care trend (per capita claims cost) is expected to increase 6% on just medical expenses. The leading medical trend contributor is prescription drugs, which is expected to trend 10% higher in 2019. 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 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, Express Scripts, Priority Health, and Blue Care Network. 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 December 31, 2018, 48% of employees are over age 45; 34% are over age 50; and 19% 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 2018 and 2019. Historical claims experience data for Consumers Energy participants was also gathered from these health care companies to be used in the 2018 and 2019 health care expense impact studies completed with WTW to determine the Company's projected expense increases in 2019 and 2020.

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 2016 through 2020 contracts as well as changes made to the employees' health care benefit plans in 2020 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 2020, the expected health care expense increase for the Company will be 4.5% after all plan design and premium contribution changes are considered for 2020. Although the 2021 plan changes are not yet known, the Company will continue to seek to contain expense, and the Company's health care expense is projected to increase 6.1% in 2021 over 2020 expense. The Company used these WTW actuarially based studies to set its projected active health care expenses for 2020 and 2021. As a result, the Company projects its expected health care expense will increase 4.5% for 2020 (the projected 2020 increase from the 2019 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-28 (LBC-1), line 4.

A. For 2020 and 2021, the Company used a 3.5% annual increase in cost for both years. This means 2020 life insurance and LTD expense is expected to be 3.5% higher than 2019 and 2021 expense will be 3.5% higher than 2020. 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 2020 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 will be made to the 2020 health care plans?

A. In 2020, we will discontinue offering our HMO plans for our active employees. This change is due to declining enrollment and higher medical and prescription costs in the HMO plans. Active employees will have the option to choose from three other high-quality PPO plans for 2020 coverage. The PPO plans offer an expanded network of providers both in and out-of-network. Active employees who elect our CDHP will have the ability for saving options for current and future health care expenses through a health savings account. The employee share of health care plans will also increase.

The active employee health care expense for the Company, after consideration of all these changes, is expected to increase 4.5% in 2020 as document in the WTW rate study.

Retiree Health Care and Life Insurance

Q. Would you please explain your Exhibit A-28 (LBC-1), line 5, for retiree health care and life insurance, which begins with ($42,991,000) in 2018?

A. Exhibit A-28 (LBC-1), line 5, reflects the actual 2018 and projected 2019, 2020, and 12 months ending September 30, 2021 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, 2018 and updated on August 31, 2019 to reflect updated market conditions. The OPEB expense in this case, including 2020 and 2021, is based upon the August 31, 2019 actuarial update 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-28 (LBC-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-28 (LBC-1), line 5.

Q. What changes were made to retiree health care coverage from 2011 to 2019?

A. The same plan changes described previously for active union and nonunion employees from 2011 to 2019 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 will be made to the 2020 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 will no longer have the option to select the HMO plans. The Medicare eligible retirees who receive a company subsidized HRA, will receive a 2% increase into their HRA. These retirees select their retiree health care coverage through an individual Medicare marketplace. 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 on December 31, 2018 for year-end purposes and updated as of August 31, 2019 based upon the 2019 mid-year projections received from the Company's

actuary, Aon. OPEB expense in this case, including 2020 and 12 months ending September 30, 2021, 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-28 (LBC-1), line 5, which begins with ($42,991,000) in 2018.

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 2018 O&M retiree health care and life insurance expense for the gas utility was ($42,991,000). In 2019, the projected gas O&M expense for these benefits is ($30,631,000). The projected gas O&M retiree health care and life insurance expense is ($32,966,000) in 2020. For the 12 months ending September 30, 2021, the projected gas O&M retiree health care and life insurance expense is ($33,289,000).

To determine the projected 2020 ASC 715 expense for Consumers Energy retiree health care and life insurance, key actuarial assumptions (discount rate, expected return on assets, mortality table, health cost trends, etc.) were updated as of August 31, 2019 and

used by the actuary to develop the projected 2020 and 12 months ending September 30, 2021 expenses.

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-28 (LBC-1). Line 6, for Other Benefits, which begins with $588,000 in 2018?

A. Exhibit A-28 (LBC-1), line 6, reflects the actual 2018 and projected 2019, 2020, and 12 months ending September 30, 2021 gas utility benefits for absence management and educational assistance program (the employee assistance program, which is a new program that I discuss below, was not included in 2018).

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 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 distribution of natural gas and for other relief.	)))))	Case No. U-20650

DIRECT TESTIMONY

OF

JASON R. COKER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

Q. Please state your name and business address.

A. My name is Jason R. Coker, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Principal Rate Analyst in the Revenue Requirement and Analysis Section of the Rates and Regulation Department.

Q. Please state your educational background.

A. I graduated from Western Michigan University in 1999 with a Bachelor of Business Administration Degree, majoring in Accounting. I am also a Certified Public Accountant registered in the state of Michigan.

Q. Please describe your business experience.

A. After receiving my accounting degree in 1999, I joined Willis and Jurasek, PC in Jackson, Michigan as a staff auditor working on financial audits and income tax returns. I remained in that position for approximately four years. In 2003, I became the Director of Accounting for Delhi Charter Township in Holt, Michigan. In that role, I had overall responsibility for the Township's payroll, accounts payable, accounting, financial reporting, and budgeting. In 2005, I joined Consumers Energy as a General Accounting Analyst II in the Technical Accounting and Accounting Policy Department. My responsibilities included the implementation of new financial accounting standards, research of technical accounting issues, and review of contracts for accounting issues. In 2009, I was promoted to Senior Accounting Analyst and assumed responsibility for restricted stock accounting and some Securities and Exchange Commission reporting

disclosures while maintaining my previous duties. In 2012, I assumed responsibility for accounting and reporting of contingencies, including Consumers Energy's manufactured gas plants. In 2016, I accepted the position of Senior Rate Analyst II in the Revenue Requirement Section of the Rates and Regulation Department. In 2018, I was promoted to Principal Rate Analyst.

Q. What are your job responsibilities?

A. As a Principal Rate Analyst, I am responsible for forecasting the Gas Cost Recovery ("GCR") factor on a monthly basis. I am also responsible for developing, analyzing, and reviewing the Company's monthly return studies. These include studies pertaining to balance sheet working capital, cost of capital, return on investment, and Return on Equity ("ROE"). In addition, I assist in the development of analyses related to the Company's revenue requirements and the preparation of electric and gas rate case filings at the Michigan Public Service Commission ("MPSC" or the "Commission"). I am also responsible for various ad hoc studies pertaining to cost of capital, ROE, and revenue requirements.

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 provided testimony in the following cases:

Electric General Rate Case	Case No. U-18322;
Gas General Rate Cases	Case Nos. U-18424, U-20322;
Saginaw Trail Pipeline Act 9 Filing	Case No. U-18166;

GCR Reconciliation	Case Nos. U-17943-R, U-20075, U-20209; and
GCR Plan	Case Nos. U-18411, U-20233.

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. In Section I, I present the supporting testimony and exhibits for the Historical Year results. In Section II, I present the supporting testimony and exhibits for the Projected Test Year revenue requirement calculation.

Q. Please describe the revenue requirements determination.

A. To comply with the historical Filing Requirements, my direct testimony presents the revenue requirement for the Historical Year. To comply with the Projected Test Year Filing Requirements, my direct testimony presents and explains the development of the revenue requirement for the Projected Test Year. I also reconcile the Historic 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. The Historical Year exhibits that I am sponsoring are identified in Section I of my direct testimony. The Projected Test Year exhibits that I am sponsoring are identified in Section II of my direct testimony.

I. HISTORICAL YEAR

Q. What is the Historical Year used in your exhibits and supporting direct testimony?

A. Calendar year 2018 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 (JRC-1)	Schedule A-1	Revenue Deficiency (Sufficiency) for the Historical Year Ended December 31, 2018;
Exhibit A-1 (JRC-2)	Schedule A-2	Financial Metrics - Gas Results Only;
Exhibit A-2 (JRC-3)	Schedule B-1	Total Rate Base for the Historical Year Ended December 31, 2018;
Exhibit A-2 (JRC-4)	Schedule B-2	Total Utility Plant for the Historical Year Ended December 31, 2018;
Exhibit A-2 (JRC-5)	Schedule B-3	Depreciation Reserve and Other Deductions for the Historical Year Ended December 31, 2018;
Exhibit A-2 (JRC-6)	Schedule B-4	Working Capital for the Historical Year Ended December 31, 2018;
Exhibit A-2 (JRC-7)	Schedule B-5	13-Month Average Working Capital Balance Sheet Summary for the Historical Year Ended December 31, 2018;
Exhibit A-2 (JRC-8)	Schedule B-6	Point in Time Working Capital Balance Sheet Summary for the Historical Year Ended December 31, 2018;
Exhibit A-3 (JRC-9)	Schedule C-1	Adjusted Net Operating Income for the Historical Year Ended December 31, 2018;

Exhibit A-3 (JRC-10)	Schedule C-2	Computation of the Revenue Multiplier for the Historical Year Ended December 31, 2018;
Exhibit A-3 (JRC-11)	Schedule C-3	Total Operating Revenue for the Historical Year Ended December 31, 2018;
Exhibit A-3 (JRC-12)	Schedule C-4	Total Cost of Gas Sold for the Historical Year Ended December 31, 2018;
Exhibit A-3 (JRC-13)	Schedule C-5	Other Operation and Maintenance Expense for the Historical Year Ended December 31, 2018;
Exhibit A-3 (JRC-14)	Schedule C-6	Depreciation and Amortization Expense for the Historical Year Ended December 31, 2018;
Exhibit A-3 (JRC-15)	Schedule C-7	General Taxes for the Historical Year Ended December 31, 2018;
Exhibit A-3 (JRC-16)	Schedule C-8	Federal Income Tax for the Historical Year Ended December 31, 2018;
Exhibit A-3 (JRC-17)	Schedule C-9	State Income Tax for the Historical Year Ended December 31, 2018;
Exhibit A-3 (JRC-18)	Schedule C-10	Other (or Local) Taxes for the Historical Year Ended December 31, 2018;
Exhibit A-3 (JRC-19)	Schedule C-11	Allowance for Funds Used During Construction for the Historical Year Ended December 31, 2018;
Exhibit A-3 (JRC-20)	Schedule C-12	Compensation Disallowances Impact on Net Operating Income for the Historical Year Ended December 31, 2018;
Exhibit A-3 (JRC-21)	Schedule C-13	Dues and Donations Disallowances Impact on Net Operating Income for the Historical Year Ended December 31, 2018;

Exhibit A-3 (JRC-22)	Schedule C-14	Advertising Classification and Disallowance for the Historical Year Ended December 31, 2018;
Exhibit A-3 (JRC-23)	Schedule C-15	Corporate Giving & Communications Disallowances Impact on Net Operating Income for the Historical Year Ended December 31, 2018;
Exhibit A-3 (JRC-24)	Schedule C-16	LAUF-Deferred Gas Storage Loss Regulatory Assets Impact on Net Operating Income for the Historical Year Ended December 31, 2018;
Exhibit A-3 (JRC-25)	Schedule C-17	Weather and Other Gas Revenue Normalizing Adjustments Impact on Net Operating Income for the Historical Year Ended December 31, 2018;
Exhibit A-3 (JRC-26)	Schedule C-18	EO Surcharge Revenue & Expense Impact on Net Operating Income for the Historical Year Ended December 31, 2018;
Exhibit A-3 (JRC-27)	Schedule C-19	Jobwork Revenue Impact on Net Operating Income for the Historical Year Ended December 31, 2018;
Exhibit A-3 (JRC-28)	Schedule C-20	Jobwork Expense Impact on Net Operating Income for the Historical Year Ended December 31, 2018;
Exhibit A-3 (JRC-29)	Schedule C-21	Interest on Customer Deposits Impact on Net Operating Income for the Historical Year Ended December 31, 2018;
Exhibit A-3 (JRC-30)	Schedule C-22	Interest on Cash Operating Accounts Impact on Net Operating Income for the Historical Year Ended December 31, 2018;
Exhibit A-3 (JRC-31)	Schedule C-23	Tax Effect of Pro-Forma Interest Adjustment for the Historical Year Ended December 31, 2018;

Exhibit A-3 (JRC-32)	Schedule C-24	Tax Effect of Interest Synchronization Adjustment for the Historical Year Ended December 31, 2018;
Exhibit A-4 (JRC-33)	Schedule D-1	Overall Rate of Return Summary for the Historical Year Ended December 31, 2018;
Exhibit A-4 (JRC-34)	Schedule D-2	Cost of Long Term Debt for the Historical Year Ended December 31, 2018;
Exhibit A-4 (JRC-35)	Schedule D-3	Cost of Short Term Debt for the Historical Year Ended December 31, 2018;
Exhibit A-4 (JRC-36)	Schedule D-4	Cost of Preferred Stock for the Historical Year Ended December 31, 2018; and
Exhibit A-4 (JRC-37)	Schedule D-5	Cost of Common Equity for the Historical Year Ended December 31, 2018.

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

A. Yes.

Q. How are these exhibits organized?

A. The exhibits I am sponsoring are organized into schedules that present the development of the revenue requirement (Schedule A), rate base (Schedule B), adjusted Net Operating Income ("NOI") (Schedule C), and rate of return (Schedule D).

Q. Who is sponsoring Historical Year Schedule E and Schedule F exhibits?

A. Historical Year Schedule E exhibits are sponsored by Company witness Eric J. Keaton. Historical Year Schedule F exhibits are sponsored by Company witness Emily A. Davis.

Q. Please describe the Schedule A exhibits for the Historical Year.

A. Exhibit A-1 (JRC-1), Schedule A-1, presents the computation of the gas revenue requirement for the year ended December 31, 2018. Schedule A-1 is developed from financial data presented in Schedules B, C, and D described below.

Exhibit A-1 (JRC-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 2014 through 2018. Pages 1 and 4 calculate a gas ROE for each of these years.

Q. Please describe the Schedule B exhibits for the Historical Year.

A. Exhibit A-2 (JRC-3), Schedule B-1, presents the calculation of the average rate base for the year ended December 31, 2018 in the amount of $5,200,283,000 as shown on line 6, which is carried forward to Exhibit A-1 (JRC-1), Schedule A-1, line 1. Exhibit A-2 (JRC-4), Schedule B-2, through Exhibit A-2 (JRC-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 (JRC-9), Schedule C-1, presents the calculation of adjusted NOI for the year ended December 31, 2018 in the amount of $240,799,000 shown on line 33, which is carried forward to Exhibit A-1 (JRC-1), Schedule A-1, line 2. Exhibit A-3 (JRC-10), Schedule C-2, through Exhibit A-3 (JRC-31), Schedule C-23, support the development of the various components of adjusted NOI. Schedule C data for the Historical Year are generally sourced to the Company's 2018 Form P-522 Annual Report to the MPSC.

Q. Please describe the Schedule D exhibits for the Historical Year.

A. Exhibit A-4 (JRC-33), Schedule D-1, presents the overall rate of return summary for the year ended December 31, 2018. The weighted cost of capital is shown on line 11, column (h), and is carried forward to Exhibit A-1 (JRC-1), Schedule A-1, line 4. Exhibit A-4 (JRC-34), Schedule D-2, through Exhibit A-4 (JRC-37), 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. Yes, I have calculated a Historical Year gas revenue deficiency of $83,936,000 for the year ended December 31, 2018.

Q. Please summarize the key findings for the Historical Year exhibits.

A. The Historical Year exhibits demonstrate that for the year ended December 31, 2018:

	(In Thousands)
Rate Base	**$5,200,283**
Adjusted NOI	**$240,799**
Overall Rate of Return	**4.63%**
Required Rate of Return	**5.84%**
Income Required	**$303,481**
Income Deficiency/ (Sufficiency)	**$62,682**
Revenue Multiplier	**1.3391**
Revenue Deficiency/ (Sufficiency)	**$83,936**

The above information is presented on Exhibit A-1 (JRC-1), Schedule A-1.

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. Ratemaking adjustments and normalizations are recognized, where appropriate, as summarized on Exhibit A-3 (JRC-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. PROJECTED TEST YEAR

Q. What is the Projected Test Year used in your exhibits and supporting testimony?

A. The 12-month period ending September 30, 2021 was chosen for the Projected Test Year.

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 (JRC-38)	Schedule A-1	Revenue Deficiency (Sufficiency) for the Projected 12-month Period Ending September 30, 2021;
Exhibit A-11 (JRC-39)	Schedule A-2	Financial Metrics – Ratemaking Basis – Gas Results Only;
Exhibit A-11 (JRC-40)	Schedule A-3	Comparison of the Gas Revenue Requirement between the Historical Year and the Test Year;
Exhibit A-12 (JRC-41)	Schedule B-1	Projected Rate Base for the Projected 12-Month Period Ending September 30, 2021;
Exhibit A-12 (JRC-42)	Schedule B-1a	Development of Projected Rate Base for the Projected 12-Month Period Ending September 30, 2021;
Exhibit A-12 (JRC-43)	Schedule B-2	Projected Utility Plant for the Projected 12-Month Period Ending

			September 30, 2021;
	Exhibit A-12 (JRC-44)	Schedule B-3	Depreciation Reserve for the Projected 12-Month Period Ending September 30, 2021;
	Exhibit A-12 (JRC-45)	Schedule B-4	Gas 13-Month Average Working Capital Balance Sheet for the Projected 12-Month Period Ending September 30, 2021;
	Exhibit A-12 (JRC-46)	Schedule B-5	Projected Capital Expenditures;
	Exhibit A-13 (JRC-47)	Schedule C-1	Adjusted Net Operating Income for the Projected 12-Month Period Ending September 30, 2021;
	Exhibit A-13 (JRC-48)	Schedule C-2	Projected Revenue Conversion Factor for the Projected 12-Month Period Ending September 30, 2021;
	Exhibit A-13 (JRC-49)	Schedule C-3	Projected Operating Revenue for the Projected 12-Month Period Ending September 30, 2021;
	Exhibit A-13 (JRC-50)	Schedule C-4	Projected Cost of Gas Sold for the Projected 12-Month Period Ending September 30, 2021;
	Exhibit A-13 (JRC-51)	Schedule C-5	Projected Other Operation and Maintenance Expenses for the Projected 12-Month Period Ending September 30, 2021;
	Exhibit A-13 (JRC-52)	Schedule C-6	Projected Depreciation and Amortization Expenses for the Projected 12-Month Period Ending September 30, 2021;
	Exhibit A-13 (JRC-53)	Schedule C-7	Projected General Taxes for the Projected 12-Month Period Ending September 30, 2021;
	Exhibit A-13 (JRC-54)	Schedule C-8	Projected Federal Income Taxes for the Projected 12-Month Period Ending September 30, 2021;

Exhibit A-13 (JRC-55)	Schedule C-9	Projected State Income Taxes for the Projected 12-Month Period Ending September 30, 2021;
Exhibit A-13 (JRC-56)	Schedule C-10	Projected Other (or Local) Taxes for the Projected 12-Month Period Ending September 30, 2021;
Exhibit A-13 (JRC-57)	Schedule C-11	Projected Allowance for Funds Used During Construction for the Projected 12-Month Period Ending g September 30, 2021;
Exhibit A-13 (JRC-58)	Schedule C-12	Tax Effect of Pro-Forma Interest Adjustment for the Projected 12-Month Period Ending September 30, 2021;
Exhibit A-13 (JRC-59)	Schedule C-13	Tax Effect of Interest Synchronization Adjustment for the Projected 12-Month Period Ending September 30, 2021; and
Exhibit A-13 (JRC-60)	Schedule C-14	Development of Net Operating Income for the Projected 12-Month Period Ending September 30, 2021.

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. I am sponsoring schedules that present the development of the revenue requirement (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 Davis, Alex M. Gast, and

Karen J. Miles 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. The Projected Test Year exhibits demonstrate the following for the twelve months ending September 30, 2021:

	(In Thousands)
Rate Base	**$7,377,332**
Adjusted NOI	**$265,593**
Overall Rate of Return	**3.60%**
Required Rate of Return	**6.08%**
Income Required	**$448,365**
Income Deficiency/ (Sufficiency)	**$182,771**
Revenue Multiplier	**1.3391**
Revenue Deficiency/ (Sufficiency)	**$244,744**

The data for the above are presented on Exhibit A-11 (JRC-38), Schedule A-1.

Q. What inflation factors is the Company using in its presentation?

A. The Company is using an inflation factor of 1.9% for 2019, 2.2% for 2020, and an inflation factor of 2.2% for 2021, as forecast by IHS Markit and reported in the July 2019 edition of their publication *U.S. Economic Outlook.* IHS Markit is a leader in economic and financial analysis, forecasting, and market intelligence.

Q. How has Consumers Energy addressed the filing requirement to reconcile the Projected Test Year to the most recent calendar year?

A. The following is a list of exhibits that reconcile the Projected Test Year to the Historical Year: Exhibit A-11 (JRC-40), Schedule A-3; Exhibit A-12 (JRC-42), Schedule B-1a;

Exhibit A-12 (JRC-45), Schedule B-4; Exhibit A-13 (JRC-51), Schedule C-5; and Exhibit A-13 (JRC-60), Schedule C-14.

Q. Please explain Exhibit A-11 (JRC-39), 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 (JRC-40), Schedule A-3.

A. This exhibit presents the Projected Test Year revenue deficiency for Consumers Energy of $244,744,000 (line 10, column (f)). Column (d) of the exhibit presents pertinent 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 months ending September 30, 2021.

Q. What are the major differences between Historical Year and Projected Test Year results shown on Exhibit A-11 (JRC-40), Schedule A-3?

A. The comparison of historical and projected results in Exhibit A-11 (JRC-40), Schedule A-3 shows that rate base increases by approximately $2.177 billion (line 4) and the rate of return increases from 5.84% to 6.08% (line 5). In addition, adjusted NOI (line 7) increases by approximately $25 million when moving from the Historical Year to the Projected Test Year.

Q. Please describe Exhibit A-12 (JRC-41), Schedule B-1.

A. Exhibit A-12 (JRC-41), Schedule B-1, is a summary presentation of the Projected Test Year average rate base. The year ended September 30, 2021 average rate base is $7,377,332,000 as shown on line 11.

Q. Please describe Exhibit A-12 (JRC-42), Schedule B-1a.

A. Schedule B-1a is a summary presentation of the development of the Projected Test Year average rate base from Exhibit A-12 (JRC-41), Schedule B-1. Line 4 shows the average rate base for the Historical Year. Lines 5 through 11 show the adjustments to the Historical Year rate base necessary to develop the Projected Test Year rate base. The adjustments to historical net plant (line 5) are the result of projected capital expenditures for 2019 through September 30, 2021, as provided by Company witnesses Chad L. Alley, Craig C. Degenfelder, Jared J. Martin, Lisa M. DeLacy, Timothy K. Joyce, Jeffrey R. Parker, Paul M. Wolven, LaTina D. Saba, Kyle P. Jones, Steven Q. McLean, and Christopher J. Varvatos. These capital expenditures are summarized on Exhibit A-12 (JRC-46), Schedule B-5. Manufactured Gas Plant (line 6) is adjusted to reflect Projected Test Year amounts supplied by Company witness Karen M. Gaston. Working capital is adjusted to reflect July 2019 balances (line 7). Pension and Other Post-Employment Benefits ("OPEB") accounts (line 8 and line 9) were adjusted to reflect Projected Test Year amounts based on projections supplied by Company witness Lora B. Christopher. The adjustment shown on line 10 is necessary to reflect differences in Gas Stored Underground. The adjustment on line 11 adjusts working capital for accrued taxes. The Projected Test Year rate base of $7,377,332,000 is shown on line 13.

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, 2020 and September 30, 2021. Actual calendar year 2018 balances for Construction Work In Progress ("CWIP"), gross plant, and depreciation reserve 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 2019, calendar year 2020, and 9 months ending September 30, 2021. Projected retirements, depreciation, cost of removal, ending balances for CWIP, plant, and depreciation reserve were calculated.

Q. Please describe the treatment of capital expenditures related to the Lansing Board of Water and Light large new business project.

A. Projected capital expenditures related to the Lansing Board of Water and Light large new business project in the amount of $52 million were included in the calculation of projected utility plant. Contributions from the customer that may be refundable in the amount of $52 million are considered customer advances and have been included as an offset to projected rate base. The amount of projected capital expenditures included in rate base has been completely offset by the amount of customer advances. Therefore, the projected capital expenditures related to the Lansing Board of Water and Light large new business project have no impact on the projected rate base or revenue deficiency in this case.

Q. Please describe Exhibit A-12 (JRC-43), Schedule B-2.

A. Exhibit A-12 (JRC-43), 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 4 on Exhibit A-12 (JRC-41), Schedule B-1.

Q. Please describe Exhibit A-12 (JRC-44), Schedule B-3.

A. Exhibit A-12 (JRC-44), Schedule B-3, presents the depreciation reserve for the Projected Test Year by functional group. The total on line 18 is carried forward to line 5 on Exhibit A-12 (JRC-41), Schedule B-1.

Q. Please explain Exhibit A-12 (JRC-45), Schedule B-4.

A. Exhibit A-12 (JRC-45), Schedule B-4, develops the Company's proposed Projected Test Year working capital balance sheet. The starting point for this exhibit is the 2018 historical working capital shown in column (b), which is first adjusted to reflect July 2019 balances shown in column (d). The July 2019 balances are then adjusted to (i) reflect changes to gas stored underground as sponsored by Company witness Eric T. Salsbury; (ii) reflect changes to pension and OPEB balances based on projections sponsored by Company witness Christopher; and (iii) reflect an adjustment to accrued taxes. Details for the adjustments made to calculate the Projected Test Year working capital are shown on page 2 of the exhibit.

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 Commission 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 (JRC-46), Schedule B-5?

A. This exhibit provides a summary of historical and projected capital expenditures presented in this case as required by the Filing Requirements.

Q. Based on your analyses, what is Consumers Energy's adjusted NOI for the Projected Test Year?

A. Adjusted NOI for the Projected Test Year of $265,593,000 is shown on line 22 of Exhibit A-13 (JRC-47), Schedule C-1. Total operating revenue on line 4 is netted against total operating expense on line 15 to arrive at NOI on line 16. Further adjustments are made on lines 17 through 20, which utilize normal ratemaking practices to arrive at adjusted NOI on line 22.

Q. Please describe Exhibit A-13 (JRC-48), Schedule C-2.

A. Exhibit A-13 (JRC-48), Schedule C-2, shows the development of the revenue multiplier, or revenue conversion factor, for the Projected Test Year. The revenue multiplier is a factor that 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 21.0%, the Michigan Corporate Income Tax ("MCIT") rate is 5.310%, and the City Income Tax ("CIT") rate is 0.16%, which results in a 1.3391 revenue multiplier.

Q. Please explain Exhibit A-13 (JRC-49), Schedule C-3.

A. This exhibit presents the total operating revenue 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 5 is carried forward to line 4 on Exhibit A-13 (JRC-47), Schedule C-1.

Q. Please explain Exhibit A-13 (JRC-50), Schedule C-4.

A. This exhibit presents the cost of gas sold for the Projected Test Year. This total is carried forward to line 5 on Exhibit A-13 (JRC-47), Schedule C-1.

Q. Please explain Exhibit A-13 (JRC-51), Schedule C-5.

A. Exhibit A-13 (JRC-51), Schedule C-5, presents the other Operating and Maintenance ("O&M") expense for the Projected Test Year. The starting point for this exhibit is 2018 historical amounts in column (c), column (d) shows the changes resulting from adjustments as supported by the various Company witnesses, and column (e) shows the projected Other O&M expense for the 12-month period ending September 30, 2021. The amounts on lines 1 through 27 and 29 were provided by Company witnesses Martin, Wolven, Parker, Joyce, McLean, Saba, Jones, Varvatos, DeLacy, Christopher, Gaston, and Amy M. Conrad and are supported in their direct testimony and exhibits. Lost and Unaccounted for ("LAUF") on line 29 is carried forward to line 6 Exhibit A-13 (JRC-47), Schedule C-1. Company Use on line 30 is carried forward to line 7 on Exhibit A-13 (JRC-47), Schedule C-1. The total on line 31 is carried forward to line 8 on Exhibit A-13 (JRC-47), Schedule C-1.

Q. Please explain Exhibit A-13 (JRC-52), Schedule C-6.

A. Exhibit A-13 (JRC-52), Schedule C-6, presents depreciation and amortization expense by functional grouping for the Projected Test Year. The total on line 19 is carried forward to line 9 on Exhibit A-13 (JRC-47), Schedule C-1.

Q. Please explain Exhibit A-13 (JRC-53), Schedule C-7, through Exhibit A-13 (JRC-57), Schedule C-11.

A. These exhibits present the following: (i) projected general taxes; (ii) projected federal income taxes; (iii) projected state income taxes; (iv) projected other (or local) taxes; and (v) projected AFUDC. The total from each schedule is carried forward to Exhibit A-13 (JRC-47), Schedule C-1.

Q. Please describe Exhibit A-13 (JRC-58), Schedule C-12.

A. Exhibit A-13 (JRC-58), Schedule C-12, shows the calculation of pro-forma interest expense for the Projected Test Year and the corresponding change in FIT.

Q. Please describe Exhibit A-13 (JRC-59), Schedule C-13.

A. Exhibit A-13 (JRC-59), 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 (JRC-58), Schedule C-12, and Exhibit A-13 (JRC-59), 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.

Q. Please explain Exhibit A-13 (JRC-60), Schedule C-14.

A. This exhibit presents the reconciliation of Historical Year NOI to Projected Test Year NOI. The amounts within this schedule are taken from other exhibits in my presentation. The exhibit presents revenue in columns (b) through (e), expense in columns (f) through (m), and the resulting adjusted NOI in column (p). The exhibit begins with the Historical Year on line 1, adjustments to the historical year on lines 2 through 14, and Projected

Test Year adjustments on lines 17 through 30. Total NOI for the Projected Test Year is shown on line 32. In general, the revenue and expense adjustments are shown with their accompanying tax impacts to arrive at adjusted NOI. Historic Year NOI of $257 million on line 1 column (p) ties to the Historic NOI on line 18 of Exhibit A-3 (JRC-9), Schedule C-1.

Q. Please explain the adjustments on Exhibit A-13 (JRC-60), Schedule C-14.

A. The adjustments on lines 2 through 13 are made to comply with prior Commission orders and follow traditional ratemaking adjustments to historical results such as removing regulatory disallowances, normalizing for unusual, one-time, or out-of-period items, bringing certain revenues and expenses "above the line," adjusting historical revenues to reflect "normal" weather, and related adjustments to 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 Exhibit A-3 (JRC-20), Schedule C-12, through Exhibit A-3 (JRC-32), Schedule C-24. Compensation disallowances on line 2 are supported by Exhibit A-3 (JRC-20), Schedule C-12. Dues and donations disallowances on line 3 are supported by Exhibit A-3 (JRC-21), Schedule C-13. Advertising disallowances on line 4 are supported by Exhibit A-3 (JRC-22), Schedule C-14. Corporate giving and communications disallowances on line 5 are supported by Exhibit A-3 (JRC-23), Schedule C-15. Line 6 is a normalizing adjustment for a one-time write off of deferred gas storage loss regulatory assets and is supported by Exhibit A-3 (JRC-24), Schedule C-16. Weather and other gas revenue normalizations on line 7 are supported by Exhibit A-3 (JRC-25), Schedule C-17. The adjustment for energy optimization surcharge revenue and expense on line 8 is

supported by Exhibit A-3 (JRC-26), Schedule C-18. Including jobwork revenue on line 9 in the determination of NOI (i.e., "above the line") is supported by Exhibit A-3 (JRC-27), Schedule C-19. Including the accompanying jobwork expense on line 10 is supported by Exhibit A-3 (JRC-28), Schedule C-20. The adjustment for Interest on customer deposits on line 11 is supported by Exhibit A-3 (JRC-29), Schedule C-21. The adjustment for interest on cash operating accounts on line 12 is supported by Exhibit A-3 (JRC-30), Schedule C-22. The pro-forma income tax savings and interest synchronization on lines 13 and 14 are longstanding ratemaking conventions that are supported on Exhibit A-3 (JRC-31), Schedule C-23, and Exhibit A-3 (JRC-32), Schedule C-24, respectively. Adjusted Historical Year NOI on Exhibit A-13 (JRC-60), Schedule C-14, line 16, column (p), of $241 million ties to the adjusted NOI on Exhibit A-3 (JRC-9), Schedule C-1, line 33.

Q. How were the Projected Test Year adjustments on Exhibit A-13 (JRC-60), Schedule C-14, developed?

A. These adjustments represent the movement from adjusted Historical Year NOI to the Projected Test Year NOI. The adjustments on lines 17 through 30 are developed from my exhibits and supporting workpapers and from the exhibits of Company witnesses Keaton, Salsbury, Martin, Wolven, Parker, Joyce, McLean, Saba, Jones, Varvatos, DeLacy, Christopher, Gaston, and Conrad. The Projected Test Year NOI on line 32 is the result of netting the Projected Test Year adjustments on line 31 against the adjusted Historical Year NOI on line 16. Projected Test Year NOI of $266 million on line 32, column (p), ties to the adjusted NOI on Exhibit A-13 (JRC-47), Schedule C-1, line 22.

Q. Please explain the Projected Test Year adjustments on Exhibit A-13 (JRC-60), Schedule C-14.

A. Lines 17 through 22 represent the changes in gross margin from the adjusted Historical Year to the Projected Test Year and are related to the sales forecast supported by Company witness Keaton, the cost of gas sold forecast supported by Company witness Salsbury, and projected other gas revenue supported by my workpapers.

Lines 21 and 22 represent the change in LAUF and Company Use, respectively.

Line 23 represents the change in Other O&M expense from the adjusted Historical Year to the Projected Test Year and is supported by Company witnesses Martin, Wolven, Parker, Joyce, McLean, Saba, Jones, Varvatos, DeLacy, Christopher, Gaston, and Conrad.

Line 24 represents the change in the book depreciation expense from the adjusted Historical Year to the Projected Test Year. The Company used the depreciation rates approved by the Commission in its March 28, 2017 Order in Case No. U-18127, along with the projected capital expenditures and assumed plant retirements in the determination of this depreciation expense adjustment necessary to arrive at an appropriate level of book depreciation expense. Book depreciation expense was developed by applying the functional composite book depreciation rates to the average Projected Test Year depreciable plant balances. The adjustment on line 24 increases depreciation expense for the Projected Test Year due to significant new investment.

Line 25 represents the change in real and personal property tax from the adjusted Historical Year to the Projected Test Year and is supported by Company witness Brian J. VanBlarcum.

Line 26 represents the change in payroll and other general taxes from the adjusted Historical Year to the Projected Test Year.

Line 27 represents the change in CIT from the adjusted Historical Year to the Projected Test Year.

Line 28 reflects the impact of MCIT. The Projected Test Year MCIT expense is shown on Exhibit A-13 (JRC-55), Schedule C-9.

Line 29 represents an adjustment to AFUDC from the adjusted Historical Year to the Projected Test Year. 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 reduces AFUDC because AFUDC is expected to be less in the Projected Test Year than in the Historical Year.

Line 30 represents the FIT adjustments which result from the other changes in revenue and expense levels for the Projected Test Year. Line 30 also reflects the differences between the FIT expense calculated at the current federal statutory rate and the actual total income tax expense.

III. DEFERRED CAPITAL SPENDING RECOVERY ACCOUNTING REQUEST

Q. How would the deferred capital spending recovery mechanism discussed in Company witness Parker's and Gaston's testimony work if approved by the Commission?

A. The Company is seeking approval of a deferred capital spending recovery mechanism for specific programs specified in Company witness Parker's testimony only if the Commission approves spending on those programs in amounts less than projected by the Company. The specific programs are distribution new business and distribution asset relocation. Company witness Parker explains the reason this deferred accounting is necessary if the Commission does not approve the projected amounts.

For programs specified in Company witness Parker's testimony, the revenue requirement of the capital spending above the amounts approved in this case would be deferred and recorded as regulatory assets. For capital spending, this would equal the impact of the capital spending on rate base multiplied by the approved rate of return, plus depreciation and property tax. The Company would request approval of the deferred revenue requirement in a subsequent rate case.

Q. Does this complete your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-20650

DIRECT TESTIMONY

OF

AMY M. CONRAD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

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 Committees of the Consumers Energy and CMS Energy Boards of Directors, including the Compensation Discussion & Analysis section of the annual proxy statement for the named executive officers.

In May 2018, I took on the role of Director of Executive and Incentive Compensation. My responsibilities consist of assisting with preparation of materials for the Compensation Committees of the Consumers Energy and CMS Energy Boards of Directors, including the Compensation Discussion & Analysis section of the annual proxy statement for the named executive officers. My responsibilities also 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 MPSC Case Nos. U-17087, U-17197, U-17643, U-17735, U-17882, U-17990, U-18124, U-18322, U-18424, U-20134, and U-20322.

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. 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. CONCLUSION

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-32 (AMC-1)	EICP Performance Measures;
Exhibit A-33 (AMC-2)	Target Pay Level Market Analysis; and
Exhibit A-34 (AMC-3)	Summary of Actual and Projected Annual Incentive O&M Expenses.

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

A. Yes.

I. OVERVIEW

Q. What is the Company's compensation philosophy for non-officer employees?

A. Consumers Energy's compensation philosophy for its non-officer non-union employees is to provide market-based compensation tied to performance. A competitive compensation policy benefits customers by attracting and retaining employees with the necessary skills and experience to deliver world class customer service and minimize the risks and costs of employee turnover. Incentive pay is a component of providing market-based compensation.

Q. What is the Company's compensation philosophy for officer employees?

A. Consumers Energy's compensation philosophy for its officers is centered around four principles:

1. Align With Increasing Shareholder and Customer Value;
2. Enable Us 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 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 Committees of the Boards of Directors of Consumers Energy and CMS Energy. The Company creates a compensation package for officers that deliver base salary, annual incentive compensation, and long-term incentive compensation targeted at the median or 50th percentile of the competitive market. In determining individual officer compensation levels, the Compensation Committees are advised by an independent third-party consultant and take into consideration market research, experience levels, and individual contributions.

Q. 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 recovery in rates of all Operating and Maintenance ("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 recovery in rates 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 "moderate" 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.

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 2018, 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 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. EMPLOYEE COMPENSATION PHILOSOPHY

Q. What is Consumer Energy's philosophy about the overall level of compensation?

A. The Company's management believes Consumers Energy should pay a fair and reasonable salary, comparable to the market that is equitable to employees, consistent with Company values and strategies, and that supports the highest level of customer service at a reasonable cost.

Q. What are the components of Consumers Energy's compensation for non-officer employees?

A. There are two parts of overall compensation for non-officer employees of Consumers Energy. The first part is base pay. 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). 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 our 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 them 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 our 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-33 (AMC-2) provides a summary of average exempt and non-exempt pay for Company benchmark jobs compared to market using 2018 data for 2019 pay structure purposes.

Paying compensation that approximates the market median is particularly important given that Consumers Energy will continue to experience significant attrition 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 Craig C. Degenfelder 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 Employee Assistance Program 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. The Company also looks at data from

companies who are in the utility and energy industry, not data from high paying technology companies or pharmaceutical companies. 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 (75 employees) job, the Company's average salary plus incentive target (overall compensation target) is 9.5% below the market. For Administrative Specialist II (120 employees), the Company's level is 0.5% below the market. For Technical Specialist II (100 employees), the Company's level is 1.8% below the market. For Senior Technician (74 employees), the Company's level is 6.7% below the market. For Senior Engineer II (152 employees), the Company's level is 1.3% below the market. For Gas Field Leader (112 employees), the Company's level is 2.1% below the market. For IT Technical Senior Analyst II (93 employees), the Company's level is 7.0% above the market. For Senior Business Support II (91 employees), the Company's level is 2.4% above the market. For Senior Engineering Technical Analyst II (74 employees), the Company's level is 4.7% above the market. These nine jobs are among the most highly populated of Consumers Energy's salaried workforce.

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 our customers.

Dividing overall compensation between base salary and incentive compensation is an approach that is common and effective in business today.

Q. How many employees does the Company have that will be eligible for the non-officer EICP payout?

A. Consumers Energy has approximately 4,400 employees (total utility) that 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 19 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 was $50,000 for a hypothetical job and market base 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 deliver base salary, annual incentives, and long-term incentives

(excluded from the Company's request in this rate case) targeted at the 50th percentile of the market, as defined by a Compensation Peer Group approved by the Compensation Committees of the Boards of Directors. The Compensation Peer Group consists of energy companies comparable in business focus and size to CMS Energy with which the Company might compete for executive talent. The Compensation Peer Group currently includes 18 companies.

Q. How do you know the market data that you are using for officer compensation are appropriate and are not inflating salary levels?

A. Annually, the Compensation Committees engage an independent third-party consultant to provide advice and information regarding compensation practices of the Compensation Peer Group as well as additional information from published surveys of compensation in the public utility sector and general industry. During the Compensation Committees' review of officers' compensation levels, consideration is given to the advice and information received from the independent compensation consultant; however, the Compensation Committees are 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, Pay Governance 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 indicates 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 98% in favor to approve executive compensation as described in the 2019 Proxy Statement.

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 Committees 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 Committees; 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 Committees consider 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 2019.

A. The EICP for 2019 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 our customers. The Company's EICP goals seek to encourage employees to provide reliable energy, customer value, and responsive service to our 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 2019, there are nine specific operational performance measures and two measures related to being financially healthy. The EICP Performance Measures are summarized on Exhibit A-32 (AMC-1).

Q. Please describe Exhibit A-32 (AMC-1).

A. Exhibit A-32 (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 2020 be similar to 2019?

A. The specific performance measures and targets for 2020 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 2019, for non-officers the operational performance and financial health goals will be weighted equally. I anticipate that for officers the attainment of the financial measures will again be a threshold component with the operational goals as a modifier.

Q. Will the 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 2019, areas of focus will continue to

include employee safety, public safety, reliability, cost, delivery, and customer care and financial health.

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 set that are shown on Exhibit A-32 (AMC-1)?

A. When setting payout levels, threshold is set at a level of achievement that can typically be reached eight or nine times out of every ten years. Maximum payout is for exceptional performance (one to two times out of every ten 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 was 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 a gas rate case?

A. For purposes of efficiency and improved service, the Company has combined operations as one organization. For that reason, the plan contains both gas and electric measures.

Q. Are the two 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 Srikanth Maddipati in his direct testimony and Exhibit A-14 (SM-1), Schedule D-5, page 7 in this case. Having a financially healthy utility is important to delivering the energy our 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 two 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 two 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.

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; (iii) changes in accounting principles from those used in the budget; (iv) large restructuring and severance expenses greater than $5 million; (v) legal and settlement costs or gains related to previously sold assets; (vi) Federal tax reform; and (vii) regulatory recovery for prior year changes. 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; and (iv) gas-price changes (favorable or unfavorable) related to gas cost recovery in January and February of the following performance year. The Compensation Committees review 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 Committees determine the target amounts of the annual officer incentives. In determining the amount of target incentives, the Compensation Committees 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 Committees' compensation consultant as to compensation practices at other companies in the Compensation Peer Group and the utility industry.

B. <u>Assessment of Customer Benefits of the Incentive Compensation Plans</u>

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 $3.5 million as illustrated in Exhibit A-34 (AMC-3). Incentive compensation for the proxy officers is not included in these amounts.

Q. How are the gas expenses of $3.5 million related to annual incentive compensation calculated?

A. The $3.5 million for EICP incentive compensation is based on the following:

- For officers: The rate case expense amount is based on 2018 salaries (excluding the proxy officers) multiplied by the approved target incentive percentage of salary from the 2018 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) and forecasted salary increases (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 based on labor studies performed by each business unit.

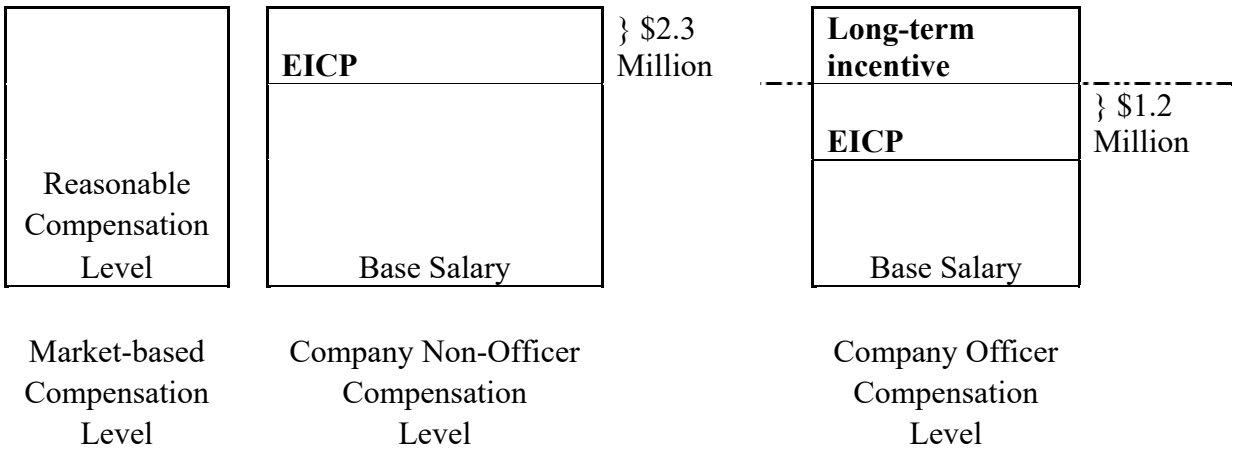
Q. Do Consumers Energy's gas customers benefit from making a portion of employee compensation subject to incentives?

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 reasonable 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 our 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 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 Maddipati 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 EICP encourages employees to deliver their best performance for customers. This is illustrated in the area of safety. For seven of the last twelve 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, and 102 in 2018. This decrease from 2007 to 2018 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 $3.5 million for the test year. The benefits illustrated in Company witness Stuart's direct testimony are $85 million, which shows that the benefits to customers of the Company's EICP outweigh the costs of the program. Since this amount is part of the overall level of reasonable compensation, rather than being in addition to it, all benefits to customers are achieved at zero additional cost to customers. Achievement of the Company's EICP goals and objectives result in pay that is competitive with the labor market, not above the market. The EICP costs are not in addition to the reasonable level of compensation, they are part of the reasonable level of market-based compensation. If these amounts are not paid, then overall compensation would be at a level which is below the market level. There is no valid basis to eliminate incentive costs from the cost of service recovered in rates because they are a part of an incentive plan rather than including these costs as part of base pay. As stated before, overall levels of compensation are at levels that are not excessive. Rate recovery of 100.0% should be allowed.

IV. CONCLUSION

Q. Is the Company's overall compensation program, including the customer-focused incentive, reasonable?

A. Yes. The approach used by the Company is a reasonable approach, is consistent with industry standards, and represents well-established best practices for creating customer

focus through compensation design, and it does so without any additional customer cost above the market. The overall compensation levels are reasonable relative to the market, are determined in a reasonable manner, and are a reasonable cost of doing business. Compensation is structured in a manner that rewards improved operational and financial performance that benefits customers. The incentive compensation costs should, therefore, be included in the cost of service recovered from customers. These are legitimate and reasonable costs of doing business. Rates established in this rate case should include approximately $3.5 million for incentive compensation expense.

Q. Please summarize reasons why full recovery of incentive compensation costs should be allowed in this case.

A. Reasons that full recovery of 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 quantitative 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. 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-20650

DIRECT TESTIMONY

OF

EMILY A. DAVIS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

Q. Please state your name and business address.

A. My name is Emily A. Davis, 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 II in the Cost Analysis section of the Rates and Regulation Department.

Q. Please describe your educational background.

A. In May 2008, I graduated summa cum laude from Illinois State University with a Bachelor of Science Degree in Economics and a minor in Business Administration. In May 2010, I graduated from Illinois State University with a Master of Science Degree in Applied Economics with a specialization in the Electricity, Natural Gas, and Telecommunications Economics Regulatory Sequence.

Q. What is your professional experience?

A. Before joining Consumers Energy in March 2018, I held various positions with Nicor Gas and its parent company, including Rate Design Analyst, Strategic Planning Consultant, and Manager of Regulatory Affairs. I have also published a number of papers in professional energy journals including:[1]

- Chupp, B., Hickey, E. & Loomis, D. (2011). "Optimal Wind Portfolios in Illinois." Energy Policy, 25(1), 46-56;
- Hickey, E., Loomis, D. & Mohammadi, H. (2011). "Forecasting Hourly Electricity Prices using ARMAX-GARCH Models: An Application to MISO Hubs." Energy Economics, 34(1), 307-315;

[1] Articles published under maiden name Emily Hickey.

- Hickey, E., Carlson, J.L. & Loomis, D. (2010). "Issues in the Determination of the Optimal Portfolio of Electricity Supply Options." Energy Policy, 38(5), 2198-2207; and

- Hickey, E. & Carlson, J.L. (2010). "An Analysis of Trends in Restructuring of Electricity Markets." The Electricity Journal, 23(5), 47-56.

Q. What are your responsibilities as a Senior Rate Analyst II for Consumers Energy?

A. I am responsible for conducting analyses in support of the Company's Cost-of-Service Studies ("COSS") 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 provided testimony before the Commission?

A. Yes. I provided written testimony on behalf of the Company in Case No. U-20322 (2018 Gas Rate Case), Case No. U-20287 (Gas Credit B) and Case Nos. U-20102 and U-20103 (Electric and Gas Credit A).

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 COSS for the 12-month period ending September 30, 2021 ("test year").

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-16 (EAD-1)	Schedule F-1	Gas Cost-of-Service Study – Version 1 - Projected 12 Month Period: October 2020 – September 2021;
Exhibit A-16 (EAD-2)	Schedule F-1a	Gas Cost-of-Service Study – Version 2 - Projected 12 Month Period: October 2020 – September 2021; and

Exhibit A-35 (EAD-3)	Minimum Size Distribution Main Study - Projected 12 Month Period: October 2020 – September 2021.

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. TEST YEAR COST OF SERVICE - VERSION 1

IV. TEST YEAR COST OF SERVICE - VERSION 2

I. COST OF SERVICE OVERVIEW

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 customer or group of customers should reflect how those customers drive or influence the utility's costs.

Q. What are the three parts or steps involved in performing a COSS?

A. The first step is functionalization, followed by classification, and finally allocation. Cost functionalization involves the identification and separation of plant and expenses into specific categories based on the activity or "function" that each cost is incurred to provide or support. Consumers Energy's functional cost categories are Transmission,

Distribution, and Storage. Cost classification, the second step, involves the categorization of functionalized costs into demand, customer, and energy components according to the primary cost drivers. The final step is cost allocation. Allocation assigns costs to each customer class using a variety of factors that correlate to the identified cost drivers. Common allocation factors include the number of customers, throughput or usage, and peak consumption among others. This process is relatively standard across the utility industry and supported by the National Association of Regulatory Utility Commissioners ("NARUC") Gas Distribution Rate Design Manual.

II. TEST YEAR COST OF SERVICE PROPOSAL

Q. Is the Company proposing any changes to the COSS methodologies previously approved by the Commission?

A. Yes. Because the Company is proposing a change to a methodology approved by the Commission in its prior case, in accordance with the Commission's rate case filing requirements established in Case No. U-18238, the Company is sponsoring two COSS. The first COSS (Version 1) employs the COSS methodologies previously adopted by the Commission in the Company's last gas general rate case (Case No. U-20322), updated for the financial information and supporting data sponsored by other witnesses in this case. The second COSS (Version 2) includes the same financial information and supporting data in Version 1, plus it incorporates the results of the Company's proposed minimum size distribution main study which is described in greater detail later in my testimony.

Q. Please elaborate on the updates made to Version 1 of the COSS.

A. The Company made routine updates for historical and test year data, which is used to derive both the revenue requirement and the various functional, classification, and allocation factors. The Company also made two minor revisions to the COSS Model. First, to be consistent with the revenue requirement model, revenue from interest earned on cash was moved from the expense section of the COSS to other revenue. Second, the Company corrected for an inadvertent reference error in the model that classified property taxes as energy related when the approved classification methodology for property taxes is plant in service. Neither of these revisions change the costs and revenues allocated to customers.

Q. Please elaborate on the change proposed in Version 2 of the COSS.

A. Version 2 of the COSS incorporates the results of a minimum size distribution main study which affects the classification and allocation of distribution main costs. Currently the Commission classifies these costs as 100% demand related. However, distribution main costs are driven by both the number of customers connected to the system and the demand these customers put on the system. To arrive at the classification factor for distribution main, the Company performed a minimum size study and determined that 42.84% of distribution main costs are customer-related with the remaining 57.16% being demand-related.

Q. What is a minimum size study?

A. A minimum size study is a common methodology used in the industry to separate distribution main costs into demand and customer components. A minimum size study compares the cost to build the utility's distribution system using the smallest,

least-expensive pipe presently being installed (i.e., 2-inch plastic main) to the actual system parameters and cost. The minimum size system represents the portion of the system installed to provide customers with system access without any consideration of peak demand, or in other words, the portion of the system that is customer-related. To calculate the minimum size system, the Company: (i) gathered information from the Company's Geographic Information System ("GIS") on the size and diameter of distribution main in service; (ii) calculated the replacement cost per foot of distribution main by adjusting actual original cost accounting data for inflation using the Handy-Whitman Index; and (iii) applied the cost of 2-inch plastic main (calculated in step (ii)) to the total system footage from GIS (from step (i)) to arrive at the cost of building the system using the minimum size pipe. In step (iv), the Company then compared the results from step (iii) to the calculated cost to build the system as designed (i.e., using the materials and pipe sizes in service) applying the same inflation adjusted accounting information (calculated in step (ii)). The share of the distribution system investment that is customer-related was found by dividing the cost of building the 2-inch plastic system in step (iii) by the cost of building the actual system as designed in step (iv). This calculation is shown in Exhibit A-35 (EAD-3). The minimum size system study indicates that 42.84% of distribution main investment is customer-related with the remainder (57.16%) classified as demand-related.

Q. Why is it important to classify costs according to the primary cost drivers?

A. Cost classification is an important step in the cost of service process. Identifying what causes or drives costs (e.g. demand, customers, or energy) provides valuable information

that instructs the allocation of costs. Neglecting to correctly classify or allocate costs will result in inequitable rates by failing to assign costs to those who caused them.

When classifying costs, the Company evaluates the cost driver for a particular cost item to verify that there is a sound rationale and basis for the assignment of a given classification factor. As part of its evaluation, the Company also considers industry best practice and guidance from the NARUC Gas Distribution Rate Design Manual. Assigning the appropriate classification factor requires consideration of the difference between demand, customer, and energy-related costs.

Demand costs are those plant and expense items that are installed or necessitated by the requirement to size facilities and services to meet customers' peak demand. Storage plant, for example, is classified as a demand cost because the investment is largely necessitated/driven by the size of peak demand.

Customer costs are those plant and expense items that are incurred to provide system access to a customer regardless of the customer's consumption level. Meter and services costs are examples of customer costs, since the investments are largely driven by the number of customers on the system.

Commodity or energy costs are costs that are driven by the amount of system throughput. One example is the cost for the natural gas commodity itself which is recovered through the volumetric gas cost recovery charge.

Some costs have multiple cost drivers and can be customer, demand, and energy-related or some combination thereof. Distribution main is an example of a significant cost item that is both demand and customer-related. As described above, to

arrive at the classification factor for distribution main, the Company performed a minimum size study.

Q. What is the impact if the Commission adopts the Company's minimum size study proposal?

A. Adopting the Company's proposal, which uses the Average and Peak measure of demand to allocate demand costs and customer count to allocate customer costs, increases the Residential customer class cost of service by $38.3 million or 3.9%, decreases the General Service Sales customer class cost of service by $24.1 million or 9.9%, and decreases the Transportation customer class cost of service by $14.2 million or 14.7%.

Q. Has the Commission evaluated the Company's proposed minimum size study in a previous gas rate case?

A. Yes. The Company proposed adoption of the minimum size study to classify and allocate distribution main costs in the Company's last gas rate case, Case No. U-20322. The Commission did not adopt the Company's proposal based on the Commission's following conclusions: (i) additional customers only require new service laterals until demand exceeds the amount that may be served by that particular main; (ii) if a customer leaves the system and demand increases from the other customers, the investment in distribution main does not change; (iii) the presence of autocorrelation in the Company's statistical regression analysis; and (iv) the Commission was not persuaded that it should adopt a minimum size study because other jurisdictions have done so.

Q. What drives the cost of constructing distribution main?

A. The total cost of constructing distribution main is driven by: (i) the size or diameter of the main; and (ii) the length or quantity of main installed.[2] On the first item, the size or diameter of the main is influenced by customer peak demand; a larger peak demand requires larger diameter main to ensure the Company can meet its peak load. The second item, the length or quantity of the main installed, is driven by the need to connect customers to the system. Said another way, distribution mains are installed to serve peak demand and to provide customers access to the utility's system regardless of their peak consumption. The more customers that attach to the system, and/or the greater the peak demand, the greater the Company's investment in distribution main. Classifying all distribution system costs on peak demand alone ignores an important factor that drives distribution system costs and investment. This can be demonstrated through an illustrative example. Assume there is a single industrial customer on Consumers Energy's system with a peak demand of 50,000 Mcf. Further, assume that elsewhere on the system there are two neighborhoods with 175 residential customers in each community (350 total) that have an aggregate peak demand of 50,000 Mcf. The Company would have to construct more footage of distribution mains to connect the 350 residential customers to the system than it would have to construct for the one industrial customer. That extra cost is due to the number of customers on the system, not peak demand. The minimum size study performed by the Company recognizes that investment in distribution main is driven by both peak demand and the need to attach customers and provide system access, regardless of peak demand or consumption.

[2] Note that the method of installation and the pressure of gas in the main can also affect the cost to install main.

Q. Do you agree that the addition of new customers only requires new service laterals until the demand exceeds what can be served by a particular main?

A. No. As explained in my testimony, and as described in the direct testimony of Company witness Jeffrey R. Parker, the total cost of constructing distribution main is driven by: (i) the diameter of the main, and (ii) the length or quantity of main installed. The size of a customer's demand does not affect how many feet of main are required to attach them to the system. For example, if Customer A and Customer B have identical demand but Customer A requires a longer extension of main to attach to the system, the cost to connect Customer A will be greater than Customer B. Said another way, the total footage or length of main installed will have a direct impact on the total investment in distribution main and that cost cannot be attributed to the size of the customer's demand. The Company does not dispute that customer demand impacts distribution main costs; however, customer demand is not the sole driver of these costs.

Q. Does the Company reduce its investment in distribution main if a customer leaves Consumers Energy's system?

A. No. The Company does not uninstall or remove its infrastructure when a customer leaves the system; that is true for distribution main, but it is also true for meters and services. The reason is simple – it is uneconomical to pay for crews to remove these facilities every time a customer moves out. The fact that the Company's investment in distribution main, meters, and services does not decrease when a customer moves out does not indicate that these investments are not customer related. In fact, the Commission has consistently indicated that meters and services are 100% customer related.

Q. How is the Company's investment in distribution main impacted by changes in demand and changes in the number of customers?

A. As stated above, a decrease in the number of customers will not reduce the Company's investment in distribution main because the Company does not uninstall or remove its infrastructure when a customer leaves the system. Similarly, if a customer leaves the system and demand decreases, the Company does not remove the existing main and install smaller diameter main in its place.

Alternatively, an increase in either the number of customers or demand can result in an increase in investment in distribution main if the Company installs (1) additional footage of main to attach those customers or (2) larger diameter main to accommodate the increased demand placed on the system.

The fact that the investment in distribution main does not change when the number of customers and/or demand decreases does not indicate that this investment cannot be customer or demand related. Rather, this provides further support that both customers and demand drive the Company's investment in distribution main.

Q. In Case No. U-20322, MPSC Staff ("Staff") raised a concern that was shared by the Commission that the Company's regression analysis suffered from autocorrelation. What is autocorrelation?

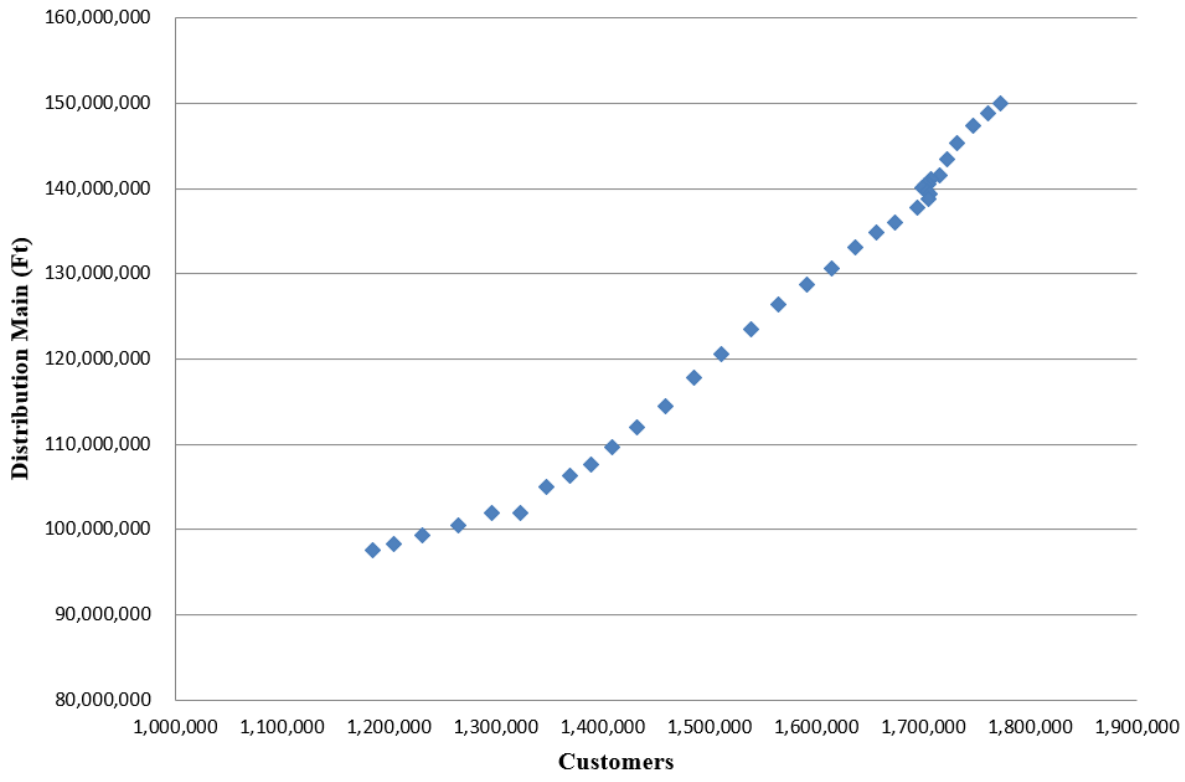
A. Autocorrelation can occur when the observation in one period is related to an observation in a subsequent period. For example, when the number of customers observed this year are related with the number of customers observed next year. In the presence of autocorrelation, the estimated regression coefficient is unbiased but the t-statistic, which measures the statistical significance of the variable, is affected. However, the presence of

autocorrelation does not necessitate the conclusion that the relationship being explained is not statistically significant, but may indicate that the strength of the statistical significance is higher or lower than what was reported. The existence of autocorrelation is commonly discussed when evaluating time series data.

Q. Is the Company relying on the same regression analysis in this case that the Commission expressed concern with in Case No. U-20322?

A. No. In Case No. U-20322, the Company performed a simple regression analysis and provided a plot of annual customer and distribution main data from 1984 through 2017 to show the strong relationship between the number of customers and the footage of main installed over time. That same data is provided in Figure 1 below.

Figure 1: Plot of Distribution Main Footage & Customer Count



The relationship between the number of customers and the footage of main installed over time can be shown even more simply and without the regression analysis with which Staff and the Commission expressed concern in Case No. U-20322. Correlation is a simple, frequently used measure of the strength and direction of a relationship between two variables. The correlation between the number of customers and footage of main is .9909. Perfect positive correlation is 1. The concern expressed in Case No. U-20322 regarding autocorrelation does not apply to the above simple calculation of correlation which is not related to or a byproduct of regression analysis.

Q. Does the presence of correlation between two variables necessitate a finding that there is a causal relationship?

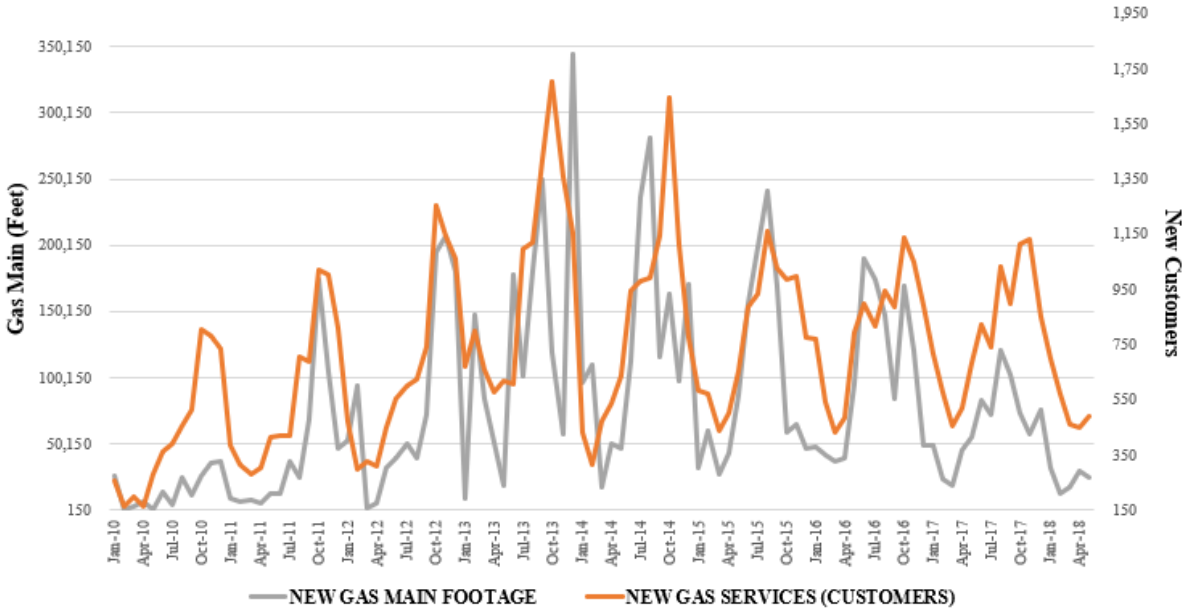
A. Not without additional information and a theory that supports such a conclusion. The Company has provided strong practical and theoretical support, data, and a finding of correlation; together this provides strong support that the number of customers, by virtue of the need to install main to attach customers to the system, drives investment in distribution main.

Q. Is there any additional data demonstrating the relationship between the footage distribution main installed and the number of customers?

A. Yes. Figure 1 above shows the relationship between total main footage installed by the Company and customer count over time. The Company has also gathered over ten years of monthly data on new customer additions and distribution main installed on those projects. As shown in Figure 2 below, the footage of main installed for new customers trends closely with the number of new customers added. As discussed throughout my testimony and also discussed by Company witness Parker, gas main is extended to give

customers system access - demand does not have any impact on the footage of main installed to attach customers to the system.

Figure 2: Gas Main (Ft) Installed for New Customers Jan 2010- May 2019



Looking at the last three years (2016-2018), the Company added roughly 9,600 customers per year which required the installation of 1.3 million feet of service line and 1.1 million feet of main annually. That works out to 133 feet of service and 110 feet of main per customer. If the Company added 0 customers in that timeframe, it would have added 0 feet of new business main. The peak demand on the system could have still increased in that time, with no direct impact on the cost of distribution main installed.

Q. Have other jurisdictions classified a portion of distribution main as customer related?

A. Yes, a number of regulatory commissions across the country have classified a portion of distribution main as customer related. As shown in Table 1, of the Midwestern[3] states with a recent decision in the record,[4] 11 out of 12 or over 90% have relied at least in part on studies that classify a portion of distribution main as customer-related:

Table 1: Classification of Distribution Main Costs (Midwest Region)

State	*Customer Cost Component of Distribution Main*	*Study*	*Docket Ref.*
ND[(b)]	-	-	-
SD[(b)]	-	-	-
NE	**Yes**	Relative Capacity (Minimum Size)	NG-0067
KS[(b)]	-	-	-
KY[(a)]	**Yes**	Minimum Size & Zero Intercept	2017-00349
MN[(a)]	**Yes**	Minimum Size	GR-15-424
IA	No	-	RPU-2012-0002
MO	**Yes**	Zero Intercept	GR-2004-0209
WI [(a)]	**Yes**	Minimum Size	4220-UR-123
IL	**Yes**	Minimum Size	17-0124
AR	**Yes**	Minimum Size	05-006-U
OK	**Yes**	Minimum Size	PUD 201500118
TX	**Yes**	Minimum Size	GUD-10170
IN	**Yes**	Zero Intercept	Cause 44063
OH	**Yes**	Zero Intercept	08-72-GA-AIR

(a) Commission averages results from a number of different COSS to arrive at approved rates, including the results of a minimum size or zero intercept study performed by the Company; and

(b) Major gas utility cases since 2000 have resulted in settlement with no clear decision on the classification of distribution main costs.

[3] Midwestern states identified as those states within the Mid-America Regulatory Conference footprint - a regional organization made up of the commissions from the Midwestern states including Michigan. Recent is defined as decisions on or after the year 2000.

[4] States where decisions since 2000 have relied on black box type settlements are listed in Table 1; however, because of the nature of the settlements the commissions' position is unknown or unclear.

This benchmarking analysis is not meant to imply that the Commission is required to reach the same result as these other jurisdictions. However, benchmarking offers valuable information to the Commission and stakeholders on the prevalence and industry acceptance of a given method and is commonly used by utilities and other stakeholders for that reason. In this case, these decisions show that there are a significant number of state commissions and industry professionals that have concluded that the number of customers on a utility's system contributes to the need for additional distribution main investments.

III. TEST YEAR COST OF SERVICE - VERSION 1

Q. Please describe Exhibit A-16 (EAD-1), Schedule F-1.

A. Exhibit A-16 (EAD-1), Schedule F-1, summarizes the results of the Test Year Gas COSS – Version 1 ("Test Year Gas COSS – V1"). As noted earlier in my direct testimony, the Company is sponsoring two COSS; Test Year Gas COSS – V1 relies on the COSS methodologies adopted by the Commission in Case No. U-20322 updated for the financial information and supporting data sponsored by other Company witnesses in this case.

Exhibit A-16 (EAD-1), Schedule F-1, is a 16-page exhibit. Page 1 of the exhibit summarizes the results of the COSS; total Company gas information for the test year is found in column (d) while columns (e) through (l) breakout the cost to serve for each rate. Total rate base by rate is shown on line 33 with the return on rate base shown on line 37. Adjusted net operating income is shown on line 32 and is calculated by subtracting test year total expenses from revenue, adjusting for Allowance for Funds Used During Construction. The associated income and revenue deficiencies are shown

on lines 41 and 42 respectively and are supported by Company witness Jason R. Coker. The proposed base rate design revenue target for each rate class, which is shown on line 46, is found by removing Cost of Goods Sold and miscellaneous revenue from the total cost of service. Page 2 provides a breakout of the proposed base rate design revenue target by rate class for each functional cost category (transmission, storage, and distribution).

Exhibit A-16 (EAD-1), Schedule F-1, pages 3 through 10, provide detail on rate base, O&M, and revenue that supports the summary information presented on Exhibit A-16 (EAD-1), Schedule F-1, pages 1 and 2. Exhibit A-16 (EAD-1), Schedule F-1, pages 11 through 16, support the functionalization, classification, and allocation factors utilized in the COSS.

IV. TEST YEAR COST OF SERVICE - VERSION 2

Q. Please describe Exhibit A-16 (EAD-2), Schedule F-1a.

A. Exhibit A-16 (EAD-2), Schedule F-1a, summarizes the results of the Test Year Gas COSS – Version 2 ("Test Year Gas COSS – V2"). It relies on the same financial information and supporting data in Version 1 and incorporates the results of the minimum size study described in my direct testimony. The page numbers and line references cited in Version 1 also apply to Version 2. A summary of the results of the Test Year Gas COSS – V2 are shown below:

Table 2: Proposed Rate Design Revenue by Class ($000)				
	Residential	Rate GS-1	Rate GS-2	Rate GS-3
Proposed Rate Design Revenue	$1,030,060	$125,313	$72,565	$20,604
	ST	LT	XLT	XXLT
Proposed Rate Design Revenue	$29,073	$22,142	$22,824	$7,955

Q. Is the Company proposing that the Test Year Gas COSS – V2 be used to determine the rate class revenue design targets?

A. Yes, to the extent that Cost of Service is used to determine each rate class' cost responsibility, the Commission should rely on Version 2 for the purposes of establishing rate design because it is a more accurate reflection of costs to serve each rate class.

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-20650

DIRECT TESTIMONY

OF

CRAIG C. DEGENFELDER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

Q. Please state your name and business address.

A. My name is Craig C. Degenfelder, 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 presently hold a position as Executive Director of Gas Delivery Plan in the Gas Engineering and Supply Department, a position I have held since October 2018. Prior to my current position, I was Executive Director of Enterprise Projects.

Q. What are your responsibilities as Executive Director of Gas Delivery Plan?

A. I am responsible for the creation of a 10-year plan for the gas side of the Company, which includes the mobilization and implementation of the plan. This encompasses all gas compression, storage, transmission, and distribution assets, and includes assessing current and future gas markets, industry conditions, and regulations to inform current and future investment planning for the Company's financial predictability and customer affordability.

Q. What is your educational background?

A. I graduated from Oakland Community College with an Associate's degree in Business Administration in 1997, and then graduated from Lawrence Technological University in 2000 with a Bachelor of Science degree in Technology Management – Construction from the school of engineering. Concurrently, I graduated from the International Brotherhood of Electrical Workers ("IBEW") Local 58 electrical apprenticeship program as a Journeyman Electrician in 2004 and also obtained a Master Electrician's license from the

State of Michigan in 2004. In 2010, I received a Master's certificate in Project Management from George Washington University, and also obtained my Project Management Professional certification from the Project Management Institute in 2011. In addition, I am currently enrolled in a Masters of Business Administration program at Purdue University Global.

Q. What is your work experience?

A. In 1997, I entered the skilled building trades through the IBEW, Detroit Local 58, where I started in the field as an electrical apprentice with continual growth up to a general foreman and superintendent, and then I moved into the office as an estimator and project manager. I obtained construction experience on a variety of projects such as: service & maintenance, manufacturing, electric substation and generation, commercial, tenant improvements, and hospital renovations of various sizes consisting of many critical shutdowns and cutovers of both high and low voltage systems. In 2008, I was hired by Consumers Energy as a Project Manager where I was responsible to lead the engineering, procurement and construction for an Air Quality Control Systems project at the D.E. Karn coal fuel generation plant, and then transitioned to the Ludington Pumped Storage Station for the plant overhaul/upgrade project. In 2011, I went back to the electrical construction industry as a project manager, and then became the Executive Vice President ("EVP") of Select Electric, Inc. in 2012. My responsibilities as the EVP were to serve the company's employees and customers by leading all operations, estimating, business development, and strategic planning. In 2014, I returned to Consumers Energy as a Sr. Project Manager to lead the decommissioning program of the Classic 7 coal generation plants with increasing responsibility in the Enterprise Project Management department over the last

few years up to becoming Executive Director of Enterprise Projects in 2016 with the responsibility over all project management and construction for gas, electric, and facilities projects which led up to my current role.

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. The purpose of my direct testimony is to provide an overview of the Company's gas transmission, distribution, storage, and compression systems, and to explain the request for rate relief related to certain major projects that the Company is undertaking in alignment with the Company's 10-year plan called the *Natural Gas Delivery Plan* per Exhibit A-36 (CCD-1). I will support the benefits related to a number of technology projects that are critically important in supporting the gas activities within the Company. Additionally, my direct testimony explains Consumers Energy's request for rate relief as it relates to investments in three major projects in the Company's Transmission Enhancements for Deliverability and Integrity ("TED-I") Program. They are:

- The Saginaw Trail Pipeline project (replacement of Line 2800 from Zilwaukee City Gate to Clawson Control);
- The Mid-Michigan Pipeline project (replacement of sections of Line 100A from Chelsea Interchange to Ovid city gate); and
- The South Oakland Macomb Network ("SOMN") projects (enable retirement of Line 3100 and a portion of Line 600).

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-36 (CCD-1)		Natural Gas Delivery Plan
Exhibit A-12 (CCD-2)	Schedule B-5.4	Projected Capital Expenditures, Transmission and Distribution Plant, TED-I Program – Major Projects, Summary of Actual and Projected Gas Capital Expenditures;
Exhibit A-37 (CCD-3)		Summary of Actual & Projected Capital Expenditures - Transmission & Distribution Plant, Saginaw Trail Pipeline Project
Exhibit A-38 (CCD-4)		2018 Monthly Capital Expenditures for TED-I Gas Pipeline Projects – Saginaw Trail;
Exhibit A-39 (CCD-5)		2019 Monthly Capital Expenditures for TED-I Gas Pipeline Projects – Saginaw Trail;
Exhibit A-40 (CCD-6)		2020 Monthly Capital Expenditures for TED-I Gas Pipeline Projects – Saginaw Trail;
Exhibit A-41 (CCD-7)		2021 Monthly Capital Expenditures for TED-I Gas Pipeline Projects – Saginaw Trail;
Exhibit A-42 (CCD-8)		Projected Capital Expenditures - Transmission & Distribution Plant, Mid-Michigan Pipeline Project, Summary of Actual & Projected Gas Capital Expenditures;
Exhibit A-43 (CCD-9)		2018 Monthly Capital Expenditures for TED-I Gas Pipeline Projects – Mid-Michigan Pipeline;
Exhibit A-44 (CCD-10)		2019 Monthly Capital Expenditures for TED-I Gas Pipeline Projects – Mid-Michigan Pipeline;

Exhibit A-45 (CCD-11)	2020 Monthly Capital Expenditures for TED-I Gas Pipeline Projects – Mid-Michigan Pipeline;
Exhibit A-46 (CCD-12)	2021 Monthly Capital Expenditures for TED-I Gas Pipeline Projects – Mid-Michigan Pipeline;
Exhibit A-47 (CCD-13)	Projected Capital Expenditures - Transmission & Distribution Plant, South Oakland Macomb Network Project, Summary of Actual & Projected Gas Capital Expenditures;
Exhibit A-48 (CCD-14)	2018 Monthly Capital Expenditures for TED-I Major Projects – South Oakland Macomb Network;
Exhibit A-49 (CCD-15)	2019 Monthly Capital Expenditures for TED-I Major Projects – South Oakland Macomb Network;
Exhibit A-50 (CCD-16)	2020 Monthly Capital Expenditures for TED-I Major Projects – South Oakland Macomb Network;
Exhibit A-51 (CCD-17)	2021 Monthly Capital Expenditures for TED-I Major Projects – South Oakland Macomb Network; and
Exhibit A-52 (CCD-18)	Projected Capital Expenditures - Transmission & Distribution Plant, Summary of Actual & Projected Gas Expenditures.

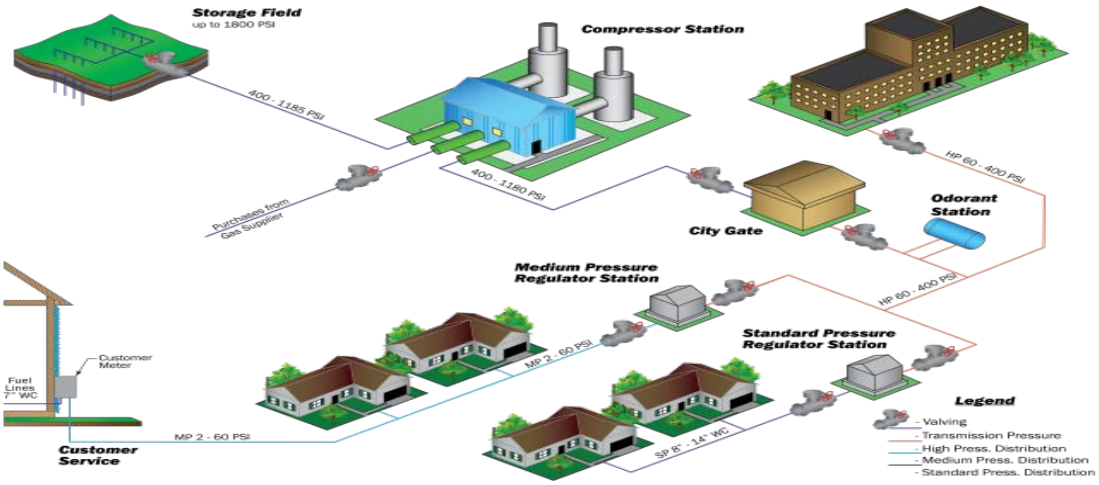
Q. Were these exhibits prepared by you or under your direction and supervision?

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 2,426 miles of transmission pipelines, over 27,641[1] miles of distribution mains, and approximately 1,584,931[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 pipelines that operate between 400 – 1,185 psig. Consumers Energy's compressor stations boost pressure to move gas in and out of its storage fields and into city gate stations. The city gate stations feed distribution mains that generally operate up to 400 psig. This system is depicted in the picture below.

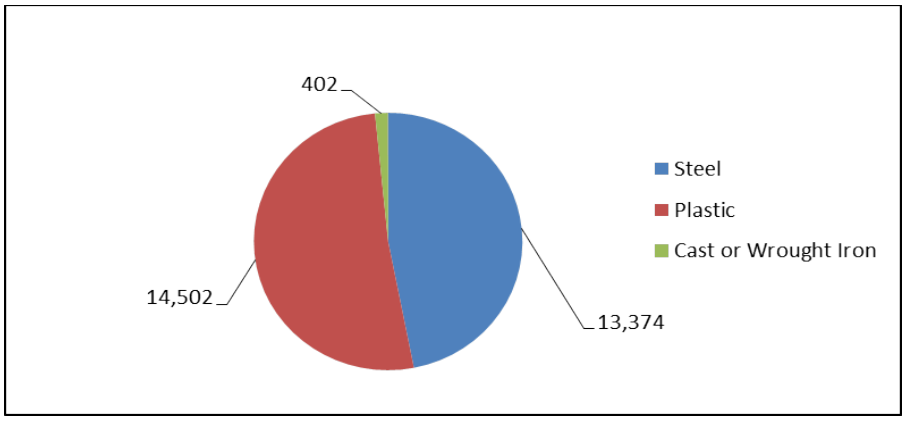


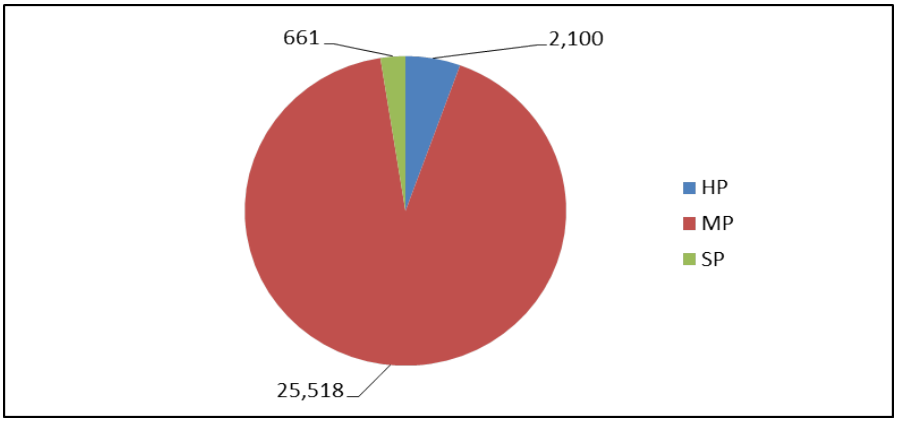
[1] Source: U.S. Department of Transportation, Gas Distribution System Annual Report for Calendar Year 2018 submitted 03/11/2019

[2] Source: U.S. Department of Transportation, Gas Distribution System Annual Report for Calendar Year 2018 submitted 03/11/2019

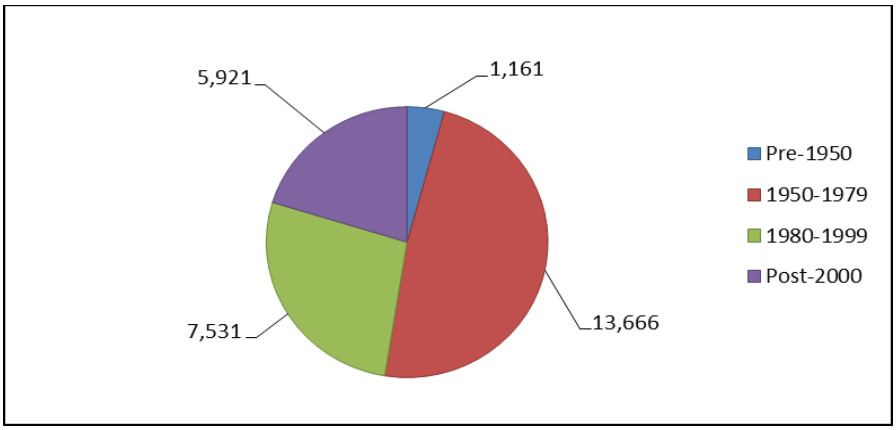
Q. Can you provide additional statistics regarding the gas distribution system?

A. Yes. Shown below is information regarding the gas distribution system composition based on the Company's United States Department of Transportation annual filing for 2018 year-end with the gas distribution system composition summarized in the figures below.[3]





[3] Source: U.S. Department of Transportation, Gas Distribution System Annual Report for Calendar Year 2018 submitted 03/11/2019



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 $2.9 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 2014 and year-end 2018, the Company connected 50,495 new gas customers. Between the years of 2012 and year-end 2018, the Company replaced 401.2 miles of high risk pipe via the Enhanced Infrastructure Replacement Program ("EIRP") including 157.3 miles of cast iron and more than 45,793 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 high-risk pipe. Under the TED-I Program, replacement of transmission pipe segments are made to reduce risk and to increase capacity and to better control gas flow. Investments in gas storage wells and compressor stations improve public safety and

ensure reliability. In addition, the Company projects to connect over 32,900 new customers from the beginning of 2018 through the year 2021.

OVERVIEW OF LONG-TERM GAS PLAN

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 genesis of the Natural Gas Delivery Plan ("NGDP") was an effort to provide a clear and transparent framework for the next decade of investments in the Company's natural gas assets, planning for natural gas supply and demand, and continuing to evolve how the Company operates in accordance with the Gas Pipeline industry standard API RP 1173 Pipeline Safety Management Systems framework. This also aligns with a similar effort undertaken by the Company's electric utility. Further, in its order in MPSC 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. As the Company has been developing this plan over the last 16 months, the Company is including the NGDP in this filing.

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 limited gas supply growth and price variability. The Company expects the safe, efficient production of natural gas to continue because of hydraulic fracture stimulation 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. It is projected that this would occur before renewable generation and electric storage technologies constrain power demand growth; and

4. **Environmental Focus** –The impact of natural gas usage on climate change through carbon emissions and methane emissions is becoming a focal point of environmentally conscious customers and regulators as coal-based emissions enter a downward trend.

Q. Has the Company considered the MPSC's Statewide Energy Assessment in its NGDP?

A. Yes.

Q. Please describe how the NGDP has incorporated elements of the Statewide Energy Assessment.

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 Statewide Energy Assessment ("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, utilize 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.

The NGDP documents the Company's analysis with consultant input on the drivers. It is built on specific objectives that enables the Company to evolve and continue to be an energy provider that customers, regulators, and the people of Michigan can count on to provide safe, affordable, reliable, and clean natural gas.

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-36 (CCD-1).

Q. What are the main objectives for the NGDP?

A. The Company has four main objectives for the NGDP. These are:

1. **Safety** – Safety remains Consumers Energy's top priority. This means:

   - Continuously reducing system risk;
   - Focusing on process safety; and
   - Modernizing the system by remediating distribution and transmission assets and replacing higher-risk vintage distribution mains and services.

   There is also an emphasis on implementing best practices in Gas Safety Management Systems 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. In addition, the Company is 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 Jared J. Martin in his direct testimony;

- Vintage Service Replacements ("VSR") 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 Martin in his 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; and

- TED-I projects advance public safety and improve system resilience during winter operations and the summer outage season as well as during injection seasons. 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 ("RCV") for flow control. RCVs are intended to minimize the time to stop the flow of gas if a failure occurs. This is discussed further by Company witness Chad L. Alley in his direct testimony.

  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, our employees.

2. **Reliability –** Consumers Energy is continuing to create a reliable system through dependable assets, measured through metrics such as system optimization and gas flow path resiliency to avoid unplanned outages, and to provide a resilient storage and market supply plan for peak demand days and proactively balance peak demand with the implementation of gas demand response. System resiliency is essential. Consumers Energy views resiliency as the gas system's ability to quickly adapt to unforeseen disruptions while maintaining operations that provide for safe and continuous customer service. Considering the fire incident at the Ray Compressor Station in January 2019,

the SEA recommendations, and the need to ensure supply resiliency and system optimization, the Company's objective is to assess available interstate supply, optimize storage, and improve its compression fleet reliability.

3. **Affordability** – Consumers Energy believes that stable, predictable, and reasonable growth in total bills, where investment in gas assets to improve safety and reliability is mitigated by continuing low commodity costs and natural gas remains a small percentage of a customer's household spending, provides a highly valuable product that improves quality of life. 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.

4. **Clean** – Consumers Energy is committed to reducing the Company's and its customers' impact on climate change by reducing methane emissions and providing options for environmentally engaged customers to offset their impact through the use of renewable natural gas as well as demand reduction options. Please refer to the Natural Gas Delivery Plan, Exhibit A-36 (CCD-1), for further elaboration on the Company's efforts as it pertains to its clean natural gas system.

GAS SAFETY ENHANCEMENTS

Q. Does Consumers Energy assess its system and procedures based on industry gas events to reduce risk and improve safety?

A. Yes.

Q. Please describe the assessment.

A. After significant gas industry events, like the recent events which occurred in Massachusetts, Consumers Energy reviews internal procedures, standards, and its gas system to identify opportunities to reduce risk, improve public safety, and mitigate abnormal operating conditions. This includes reviewing National Transportation Safety Board ("NTSB") recommendations, industry best practices, and other considerations. Additionally, the Company conducts an assessment on the gas system and procedures to mitigate risk to public safety. System assessments due to industry gas events are initiated

and scoped on a cas- by-case basis. A cross-functional group of engineering, operations and compliance employees reviews industry reports, recommendations, etc. and outlines scopes for system review based on the nature of the incident or report. Newly identified threats and mitigations are included in the Company's integrity management programs and lessons learned are incorporated into procedures, process, and gas system enhancement decision-making.

Q. In its Order in MPSC Case No. U-20322, the Commission stated that it expected Consumers Energy to develop and implement a Pipeline Safety Management System ("PSMS") in accordance with American Petroleum Institute ("API") Recommended Practice 1173. Further, in the order, the Commission directed the Company to provide an update on its efforts to develop and implement a PSMS in its next gas rate case. Can you provide an update on the Company's PSMS?

A. Yes. As discussed in the NGDP, the focus of the Company's long-term plan is on safety. The NTSB and PHMSA have encouraged natural gas operators to implement API Recommended Practice 1173. Recommended Practice 1173 is industry developed guidance for implementing and overseeing safety management systems for gas pipeline operators. Consumers Energy will implement the API Recommended Practice 1173 – PSMS. To enhance safety, the Company is implementing a variation of the PSMS - a Gas Safety Management System ("GSMS") - to achieve beyond the basic compliance requirements.

Q. Please describe GSMS.

A. The NTSB recommended that the pipeline industry (natural gas and oil) develop guidance for a safety management systems as they have proven to help in other

industries, such as aviation, nuclear power, and chemical manufacturing, to reduce incidents, gain a better understanding of how to systematically manage pipeline safety, and continuously measure progress to improve overall pipeline safety performance and ensure public safety. Pipeline Operators, through the API and PHMSA, developed API Recommended Practice 1173. Please refer to the NGDP, Exhibit A-36 (CCD-1), for further discussion on the Company's efforts in implementing the GSMS.

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 of the GSMS to achieve our compliance requirements. Documentation and Record Keeping is an element of the management system. The Company will utilize the Gas Technical Informational Excellence Program as a means to ensure the Company's gas technical records and information are accurate, complete, and accessible. Although there are currently programs around these topics in place, the NGDP will provide a platform to accelerate the Company's progress along these initiatives as it works to address any potential challenges to the successful delivery on the goals of the GSMS and the Association of Records Managers and Administrators Information Governance model as described in the NGDP, in Exhibit A-36 (CCD-1), Section IX.

<u>GAS ASSETS – TRANSMISSION MAJOR PROJECTS</u>

Q. Please describe Consumers Energy's investments in its gas transmission system as part of the TED-I projects that you are sponsoring and how they benefit customers.

A. As described in the NGDP, Exhibit A-36 (CCD-1), 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. The Company evaluates its overall TED-I plan continually based on integrity assessment results, analysis, construction efficiencies, and system modeling.

Q. Does the NGDP discuss gas transmission assets?

A. Yes.

Q. Please describe the Company's long-term plan for its gas transmission assets.

A. For its transmission assets, Consumers Energy will continue improving on amount of inspections, de-risking, and increasing its remediation pace for critical assets. Therefore, the Company will move forward with its currently scheduled TED-I projects and the re-build schedule for city gate facilities. This information can be found in the NGDP, Section VII, Transmission Asset Plan.

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 (started in 2017), Mid-Michigan Pipeline, and the SOMN. Capacity requirements are factored into line replacements to ensure customer deliverability. Capital expenditures for the planned major TED-I pipeline projects are shown on Exhibit A-12 (CCD-2), Schedule B-5.4.

Q. Please describe Exhibit A-12 (CCD-2), Schedule B-5.4.

A. This exhibit presents the capital expenditures for the TED-I major projects from 2018 through the test year ending September 30, 2021, that I am sponsoring.

Q. Please describe Exhibits A-37 (CCD-3) through A-51 (CCD-17).

A. These exhibits expand on Exhibit A-12 (CCD-2), Schedule B-5.4, 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 2018, 2019, 2020, and 2021. The expenditures are broken out by contractor, labor, materials, engineering, contingency, and other costs.

Q. What is the Company's projected capital spending level associated with the TED-I Major projects?

A. As shown on Exhibit A-12 (CCD-2), Schedule B-5.4, line 4, the capital expenditures for the TED-I Major projects were $124,599,000 in 2018, and are projected to be $240,983,000 for 2019; $159,824,000 the 9 months ending September 30, 2020; and $169,506,000 for the 12 months ending September 30, 2021, 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. These expenditures are shown in the table below.

Table 1

($000)	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test
Line No.	Project Description	12 Mos Ended 12/31/2018	12 Mos Ending 12/31/2019	9 Mos Ending 9/30/2020	21 Mos Ending 9/30/2020	12 mos. Ending 9/30/2021
1	Saginaw Trail Pipeline Project	115,406	173,344	125,594	298,937	65,859
2	Mid-Michigan Pipeline Project	1,129	1,635	2,842	4,476	44,224
3	South Oakland Macomb Network Project	8,063	66,005	31,389	97,394	59,423
4	Total Capital	124,599	240,983	159,824	400,807	169,506

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. Any unused contingency funding will go into the capital plan to expand work already approved. The Saginaw Trail Pipeline project contains contingency expenditures in the amount of $1,042,000 in 2019; $2,050,000 within the 9 months ending September 30, 2020; and $17,273,000 in the 12 months ending September 30, 2021. These contingency expenditures are identified on Exhibit A-12 (CCD-2), Schedule B-5.4, page 1, line 1. The Mid-Michigan Pipeline project contains contingency expenditures in the amount of $478,000 within the 9 months ending September 30, 2020

and $2,148,000 in the 12 months ending September 30, 2021. These contingency expenditures are identified in Exhibit A-12 (CCD-2), Schedule B-5.4, line 2. The SOMN project contains contingency expenditures in the amount of $960,000 in 2019; $1,881,000 within the 9 months ending September 30, 2020; and $7,695,000 in the 12 months ending September 30, 2021. These contingency expenditures are identified on Exhibit A-12 (CCD-2), Schedule B-5.4.

Q. Please identify the capital expenditures planned for the Saginaw Trail Pipeline.

A. Exhibit A-12 (CCD-2), Schedule B-5.4, line 1, identifies the total capital expenditures for the Saginaw Trail Pipeline project. In 2018, costs were incurred for constructing 18.50 miles of pipeline along with associated city gates, distribution augmentation and engineering, design, materials, permitting, surveying, and real estate for future segments. The table provided later in my direct testimony shows the projects and costs incurred for 2018. During 2019 and 2020 costs will be incurred for installing 29.2 and 28.2 miles of pipeline (respectively) along with associate city gates, distribution augmentation, engineering and design, materials, permitting, surveying, and real estate for future segments. The 2021 expenditures are for final clean up and site restoration. The table provided later in my direct testimony shows the projects and costs projected for 2018 through 2020.

Q. Please describe the Saginaw Trail Pipeline project.

A. The Saginaw Trail Pipeline project increases 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 includes 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 this project requires are also included to ensure supply to the distribution system.

Q. Why is the Saginaw Trail Pipeline project necessary?

A. The project will: (i) address the high number of corrosion-related defects on Line 2800; (ii) reduce the risk of an unplanned outage on Line 2800; (iii) reduce the risks of supply capacity restrictions and cuts to customers; (iv) enable refilling of storage at lower summer natural gas prices; (v) increase transmission capacity; and (vi) position 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 which authorizes Consumers Energy to construct and operate this pipeline.

Q. Please describe the planned construction sequence for Saginaw Trail and provide the current anticipated spend for each segment.

A. Each segment of the Saginaw Trail Pipeline shown in Exhibit A-37 (CCD-3) is anticipated to follow the sequence shown in the table shown on the next page. Additionally, Exhibits A-38 (CCD-4) through A-41 (CCD-7) provides a breakdown of the monthly capital expenditures for the Saginaw Trail project.

Planned Construction Sequence for Saginaw Trail

Year	Scope	Length	Projected Spend
2018	- Evon Road Valve Site to Clio City Gate Cleanup Restoration - Zilwaukee Jct to Evon Road Valve Site (Saginaw Reroute) Construction - Engineering, Long-Lead Materials Procurement, Real Estate, Environmental, Permitting, Valve Site Construction Clio CG to Grand Blanc Jct - Engineering, Real Estate, Environmental, Permitting Grand Blanc Jct to Clawson Control Station - Saginaw Dutch Rd City Gate, Thomas Township Valve Site Odorizer, Birch Run-Montrose City Gate, Shields City Gate to Saginaw Dutch Rd Distribution Augment, and Saginaw Dutch Rd City Gate Distribution Augment Construction - Engineering, Long-Lead Materials Procurement, Real Estate, Environmental, Permitting for Zilwaukee City Gate Rebuild, Flint-Lapeer City Gate Install, Lapeer-Bristol Distribution Augment, Carpenter Rd Valve Site Odorizer, and Lapeer Rd City Gate Distribution Augment - Bridgeport City Gate and Clio City Gate Clean-up	18.50 miles	$115.406 million (actual)
2019	- Clio CG to Grand Blanc Jct (Flint Reroute) Construction - Clean-Up/Restoration for Zilwaukee Jct to Evon Road Valve Site (Saginaw Re-route) Clean-up/Restoration - Engineering, Long-Lead Materials Procurement, Real Estate, Environmental, Permitting for Grand Blanc Jct to Clawson Control - Flint-Lapeer City Gate, Lapeer-Bristol Distribution Augmentation, Carpenter Rd Valve Site Odorizer, and Lapeer Rd City Gate Distribution Augment Construction - Engineering, Long-lead Materials Procurement, Real Estate, Environmental, Permitting for Zilwaukee City Gate & Flint Branch Rd City Gate	29.18 miles	$173.344 million
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 & Flint Irish City Gate Construction -	28.23 miles	$181.351 million
2021	- Grand Blanc Jct to Clawson Control Restoration		$10.101 million

Q. Have right-of-way agreements been secured for construction of the pipeline?

A. Most of the necessary right of ways for this project have been secured. Consumers Energy's existing easements provide second line rights in most areas, granting the authority to construct a line parallel to an existing line. Removal and replacement will occur in some locations. The Company has completed its plan to abandon two portions of the pipeline and re-route the pipeline around the urban areas west of Saginaw. As part of the same project, a re-reroute in an area east of Flint is currently in progress.

Q. Is the Company on track for completion of the Saginaw Trail Pipeline in 2021?

A. Yes. Pipeline construction of Phase 3 of the project was completed in October 2019. Final restoration costs will occur in 2020, and the Phase 4 construction will commence in May of 2020. This is projected to be completed by the end of October of 2020. The major pipeline materials have been procured for Phase 4 of the project.

Q. Please identify capital expenditures for the Mid-Michigan Pipeline.

A. Exhibit A-12 (CCD-2), Schedule B-5.4, line 2 identifies the total capital expenditures for the Mid-Michigan Pipeline project. In 2018 through September 30, 2021, projected costs will be incurred for engineering and design, environmental assessment, surveying, and real estate. This work was necessary to be performed in order to provide the necessary information required to accurately complete the application for an Act 9 certificate and to continue preparing for construction to commence. In Case No. U-20618, the Company submitted its request for approval of an Act 9 certificate.

Q. Please describe the Mid-Michigan Pipeline project.

A. The Mid-Michigan Pipeline project increases the diameter of approximately 55 miles of Line 100A, between Ovid city gate in Clinton County and Chelsea Interchange in Washtenaw County, from 20-inch to 36-inch within existing pipeline right of way.

Q. What is the projected capital spending for the Mid-Michigan Pipeline project included in this filing?

A. The projected spend for the Mid-Michigan Pipeline project's engineering, environmental, pipeline procurement, and real estate costs are shown on Exhibit A-42 (CCD-8). Additionally, Exhibits A-43 (CCD-9) through A-46 (CCD-12) provide a breakdown of the monthly capital expenditures for the Mid-Michigan Pipeline project. A summary of this information is provided in the table below:

Year	Segment	Length	Projected Spend
2018	Engineering, Real Estate, Construction Planning	n/a	$1.129 million (actual)
2019	Engineering, Environmental, Real Estate	n/a	$1.635 million
2020 (full year)	Engineering, Environmental, Real Estate	n/a	$3.2972 million
2021 (9 mos)	Engineering, Environmental, Real Estate, Pipe Procurement Deposit on Pipeline Phases 1 & 2, & Construct Hell Distribution Augment	n/a	$43.769 million

In 2021, approximately $30 million of the projected capital expenditures is necessary for the pipe procurement. It is necessary to procure the pipe in 2021 because it takes a considerable amount of time for the manufacturing and delivering processes, which would allow the pipe to arrive to the site in the summer months of 2022 in preparation of installation 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 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. The Line 100A project will replace 1949 vintage pipe. Additionally, in May 2015, the line experienced a rupture just north of Chelsea.

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 B31.8S-2004. The next hydro test is required by the end of 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 any TED-I pipeline project historical capital expenditures in this proceeding?

A. Yes. In Case No. U-20322, the Commission found that capital expenditures associated with the Mid-Michigan Pipeline project should not be included in rate base at the time of the Commission's Order. The Company has reasonably incurred actual capital expenditures of $1.322 million during 2016 and $2.095 million during 2017 associated with the Mid-Michigan Pipeline project. The $8.522 million disallowance approved by the Commission in Case No. U-20322 included these historic time period expenditures. Upon the pending, and needed, 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 and 2017 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 the 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 backups 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. 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 estimated timeline and projected spend for the SOMN project through the year 2021?

A. A breakdown of the projected spending for the SOMN project is shown on Exhibit A-47 (CCD-13). Additionally, Exhibits A-48 (CCD-14) through A-51 (CCD-17) provide a breakdown of the monthly capital expenditures for the project. The anticipated timeline and projected spend for SOMN project are shown in the table below.

Year	Major Project	Length	Projected Costs
2018	Engineering, Long-Lead Materials Procurement, Real Estate, Environmental, West Wayne City Gate Pre-Fabrication	n/a	$8.063 million
2019	Construction of Macomb Corridor, Shelby City Gate, West Wayne City Gate, Pontiac Trail Odorizer Upgrade, Engineering, Real Estate, Procurement, Permitting and Site Restoration	7.5 miles	$66.005 million
2020	Construction of Utica Lateral, Coolidge City Gate Rebuild, Real Estate, Engineering Procurement, Permitting and Site Restoration	1.6 miles	$38.481million
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	4.6 miles	$64.488 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, for approximately $68,000,000, to perform construction on 2021 and 2022 planned projects will be made to Board of Directors Finance Committee upon making significant progress in engineering. This is expected to happen in the fall of 2020.

Q. Please describe Exhibit A-52 (CLA-18).

A. Exhibit A-52 (CLA-18), 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 rate case, Case No. U-20322. .

Q. Can you explain why columns (d), (e), and (f) of Exhibit A-52 (CCD-18), do not contain any data?

A. Yes, the information for column (d), the "Actual Spending in the Test Year," cannot be completed as the test year in Case No. U-20322, which was the 12 months ending September 30, 2020, is a time period that has yet to transpire as of the filing of this case. Since there is no data to display in columns (d), the information for columns (e) and (f), which seek information concerning the variances from (c) and (d), cannot be completed at this time.

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 the 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-36 (CCD-1),

Section XII.C, the technology (i.e. IT) or digital projects are essential to enabling the expected NGDP outcomes in the future. Company witness Christopher J. Varvatos 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 Varvatos. These projects and the benefits of the digital projects are described below:

- The **Gas SCADA System** project requires $795,000 in O&M. The Gas SCADA System project will replace the current Gas SCADA Software (Citect SCADA) with a more standardized software package enabling the Company to more efficiently meet Federal and Local requirements.
  - 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 local requirements for Gas Pipeline and Gas Distribution companies;
    (5) Improving reliability by using proven gas industry standardized software with customization 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 these results; and

(7) Improving gas delivery plan efficiencies. 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. These version enhancements are typically based on gas industry user input, and become part of the standard solution, thereby minimizing customization and subsequent maintenance.

– The project scope includes the following:

(1) Significant consulting assistance and planning to define the implementation strategy for the effort, given the magnitude of the technology effort;

(2) Selection and implementation of a new Gas SCADA system;

(3) Planning of a phased rollout of new hardware and software; and

(4) Retirement and decommissioning of the legacy gas SCADA system 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 continued reliability issues that result in controlling and monitoring the Company's gas system;

(2) Invest in enhancing the existing Gas SCADA system (Citect SCADA) which would introduce additional custom development and more specialized functions not supported in future vendor releases; and

(3) Replace the solution with a gas SCADA system that meets requirements to support theNGDP. Alternative 3 has been selected to ensure sustainability for this critical solution.

- The **Gas T&D Historian** project requires $978,750 in capital and $169,500 in O&M. The Gas Transmission and Distribution (T&D) Historian project will replace the current historian for Gas T&D, eDNA (a traditional SCADA historian product from Schneider Electric), and migrate to the standard enterprise historian system. This project will create a more accessible and accurate centralized data source that can be leveraged as the system of record.

– The project will add value for both Engineering and Operations organizations within the Company by:

(1) Informing decision-making based on real-time data;

(2) Improving real-time situational awareness such as timely identification of odorizer flatlines and set up alerts for tolerances;

(3) Improving the ability to respond to abnormal situations; and

(4) Providing proactive analytics to reduce potential catastrophic events. From an IT perspective, consolidating to one standard platform for historians results in savings in hardware, software, maintenance, resources and training.

– This scope of this project includes:

(1) Replacing the eDNA Gas T&D historian, a traditional SCADA historian, and migrating to the enterprise historian, OSIsoft Pi System;

(2) Developing reporting capability to support tracking of metrics;

(3) Replacing the decades-old Microsoft Access-based custom Daily Gas Reports solution; and

(4) Retiring the legacy Gas T&D eDNA system (hardware and software).

– An alternative considered for the project was to upgrade eDNA Gas Historian to the latest version. This option was not selected because it requires a significant investment and does not meet analytics, reporting, usability and accessibility needs. Furthermore, the company standard for historians is OSISoft PI and maintaining two platforms results in duplicate training, support personnel and technology.

– The option to replace eDNA with the company standard Pi historian was selected to eliminate duplicate training, support personnel, and technology, and to leverage the more robust data analytic capabilities in the Pi tool set.

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-36 (CCD-1), the activities outlined above represent the first year of the Company's 10-year plan. Fully funding both the capital and O&M expense for the NGDP technology projects described in this testimony and the testimony of Company witnesses Martin, Jeffrey R. Parker, Alley, and Wolven, and

executing the projects, will set the stage for predictable, prudent, and affordable outcomes throughout the 10 years of theNGDP.

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-20650

DIRECT TESTIMONY

OF

LISA M. DELACY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

Q. Please state your name and business address.

A. My name is Lisa M. DeLacy, 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 Advanced Distribution Management System in the Company's Enterprise Project Management and Environmental Services Department.

Q. Please describe your educational background and work experience.

A. I received a Bachelor of Science degree in Electric Engineering from Michigan Technological University in 1993. For the first five years of my career, I worked at Wisconsin Public Service ("WPS") as a Procurement Engineer at the Kewanee Nuclear Plant, and as a Distribution Engineer in WPS's Green Bay offices. I joined Consumers Energy in 1998 as a High Voltage Distribution Engineer advancing to a supervisory role in that department before accepting a lead supervisory role in the Customer Operations Department on the Business Customer Technical Services Engineering team in 2007. I then advanced to the Director of the Business Customer Technical Services team in 2008. In 2010, I joined the Liaison team in the Company's Regulatory Affairs Department, supporting the Customer Operations area. In 2012, I advanced within this department to the Manager of the Regulatory Affairs Liaison team, with specific responsibility for administration and coordination of the Liaison team, and improving communications with the Michigan Public Service Commission ("MPSC" or the "Commission") Staff with focus on electric and gas rate cases, general Company operations, and the plans for

the addition of new generation capacity. In July 2014, I was promoted to the position of Executive Director for the Smart Energy Program. In 2016, my responsibilities were expanded to include the implementation of the Gas Automated Meter Reading ("AMR") project. In December 2017, my responsibilities for Smart Energy concluded with the completion of the project. In June 2018, my responsibilities expanded to include the project lead for the implementation of an Advanced Distribution Management System for our electric business. With the conclusion of the Gas AMR project, the Advanced Distribution Management System is my focus.

Q. What were your responsibilities as the Executive Director related to Gas AMR?

A. My responsibilities generally consisted of leading the management of the scope, schedule, and cost of the recently completed installation of AMR technology in our gas-only service areas. Specific responsibilities included:

- Leadership of the project management office for the AMR program, including the management of program scope, schedule, and budget. This also included vendor management responsibilities and coordinating closely with the Company's supply chain function;

- Leadership of the AMR device deployment efforts, including providing support for the deployment team lead in day-to-day operations, measuring and taking corrective actions on deployment targets, ensuring alignment and performance with internal stakeholders responsible for installations performed by Company employees, ensuring alignment and performance with the meter installation vendor, ensuring proper priority is given to any system issues affecting deployment, and responding to customer inquiries and concerns; and

- Oversight of the necessary information systems upgrades that were completed during 2017. This included responsibility for business process blueprinting and system requirements documentation and the design, testing, and implementation of the hardware, software, and infrastructure necessary to support the AMR drive-by meter reading solution.

The AMR Program concluded on June 30, 2019 with 1,125,913 gas communication modules deployed and 1,113,766 modules cutover to AMR billing. The

Meter Reading team is responsible for the cutover process going forward and continues to cutover eligible communication modules to AMR billing.

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

A. My direct testimony describes the project's final results, given its conclusion in June 2019, and how this technology is providing value.

Q. In this case, what is the Company including for Gas AMR?

A. There are no capital or Operating & Management ("O&M") expenditures for AMR implementation in the 12 months ending September 30, 2021. Note that gas meter purchases include the gas module as our meter standard.

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

A. My direct testimony includes the following five major sections: (i) Gas-Only AMR Program Summary; (ii) Gas AMR Benefits; (iii) Gas AMR Technology, Capabilities and Status; (iv) Gas AMR Program Costs/Benefits Analysis; and (v) Summary.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-12 (LMD-1)	Schedule B-5.1	Summary of Actual and Projected Gas Capital Expenditures for the years 2018 through September 2021 ($000);
Exhibit A-53 (LMD-2)		Summary of Actual and Projected Gas O&M Expenses for the years 2018, 2019, 2020, and the 12-Month period ending September 30, 2021 ($000); and
Exhibit A-54 (LMD-3)		Summary of AMR Business Case Costs and Benefits 2014-2037.

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

A. Yes.

I. GAS-ONLY AMR PROGRAM SUMMARY

Q. Did the Gas AMR project reach its planned targets?

A. Yes. At the project's conclusion on June 30, 2019, both the deployment and cutover planned project targets were exceeded due to new business and performing better than planned. See the results in the table below.

Gas AMR Totals			
	Target Number of Modules	**Actual Number of Modules**	
Deployment	**1,125,121**	**1,125,913**	**792 over target**
Cutover to AMR billing	**1,102,619**	**1,113,766**	**11,147 over target**

II. GAS AMR BENEFITS

Q. What customer benefits result from the implementation of Gas AMR?

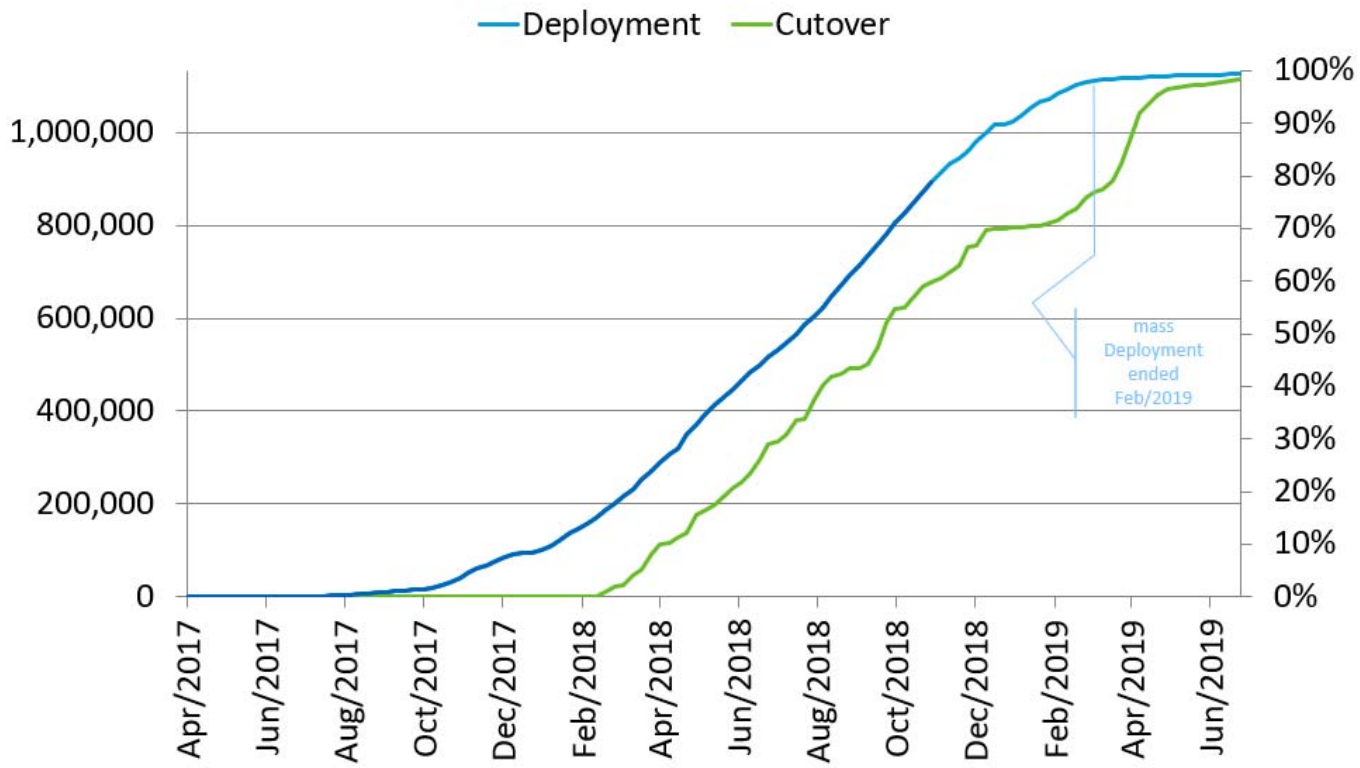
A. Like AMI, Consumers Energy Gas AMR customers realize benefits related to:

- Reduced meter reading cost;
- Improved billing accuracy as a result of higher actual meter read rates; and
- Reductions in energy theft resulting from the analysis of meter tamper alerts and energy consumption patterns.

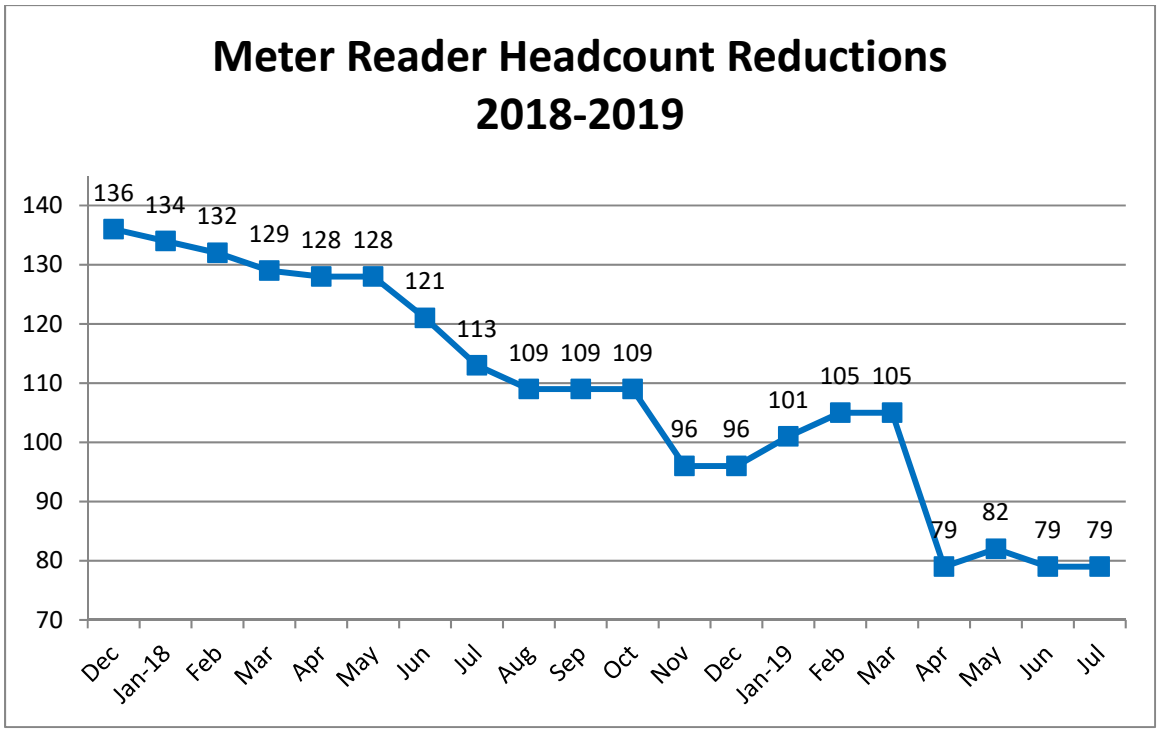
Upgrading our meter reading technology has been an important element to our objective to improve customer satisfaction and deliver value to our customers. Aggressive project deployment and cutover targets were established and exceeded to achieve this objective and deliver the above benefits as quickly as possible.

As an example, to bring more value to customers and to realize more operational value sooner than planned, the cutover target for 2018 was increased to over 765,000 of the total 1.1 million customers by the year end. The project finished 2018 with 792,463 customers cutover to Gas AMR billing, which exceeded the increased 2018 cutover target

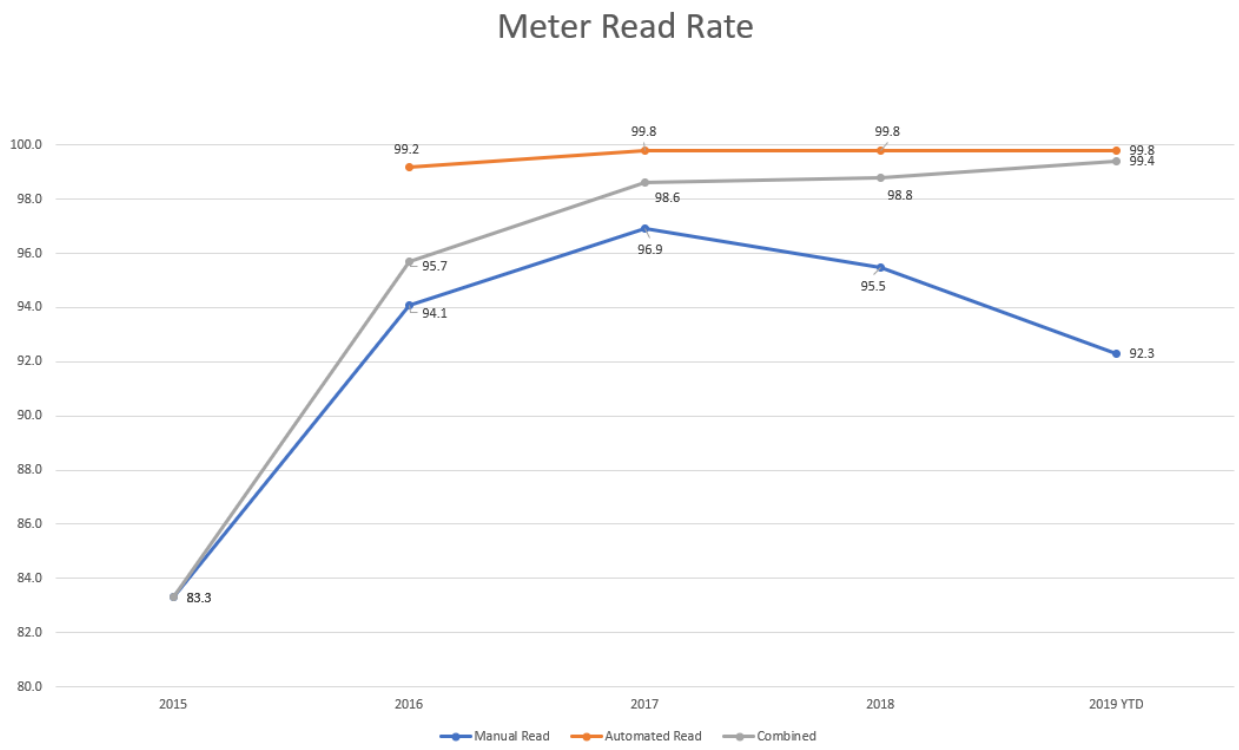
by 27,463 customers. At the project's conclusion on June 30, 2019, there were 1,113,766 customers cutover to Gas AMR billing. The graph below shows the actual deployment and cutover results for the project.



The aggressive cutover targets supported the planned Meter Reading headcount reductions. At the conclusion of the AMR project, Meter Reading had realized 57 actual headcount reductions from January 1, 2018 through June 30, 2019 due to the implementation of Gas AMR.



The Company is experiencing the best meter read rate in our Company's history at 99.4%. See the graph below demonstrating this improvement and the significant contribution from automation. Note that 2019 values in the graph below are year-to-date values as of September 30, 2019.



Our gas-only customers are experiencing benefits today with higher meter read rates and lower operating costs due to the reduced number of meter readers. To date, Gas AMR has achieved a 99.89% read rate. The following tables demonstrate the consistent performance of the Gas AMR read rate.

2018	AMR Gas Modules	
	Actual Reads	Read Rate
January	N/A	N/A
February	679	100.00%
March	35,011	99.94%
April	107,499	99.97%
May	170,308	99.97%
June	256,699	99.92%
July	351,619	99.95%
August	498,716	99.89%
September	444,141	99.88%
October	688,720	99.81%
November	620,885	99.84%
December	725,033	99.95%
YTD	3,899,310	99.89%

2019	AMR Gas Modules	
	Actual Reads	Read Rate
January	794,289	99.89%
February	795,433	99.86%
March	865,424	99.93%
April	1,046,932	99.90%
May	1,118,037	99.87%
June	1,069,480	99.90%
July	1,132,563	99.89%
August	1,165,991	99.87%
September	1,065,806	99.82%
YTD	9,053,955	99.88%

Revenue assurance benefits will be realized by enabling energy theft investigations with automated analysis of meter tampering events and access to daily usage data when theft analytic development work is complete. The analytics being implemented will provide flexibility to the Company's Corporate Security/Theft staff for configurable business rules that will be utilized in the automated analysis process for energy theft detection. The loading of the gas meter read data into the Company's data lake – an area setup as standard practice for manipulating large volumes of data, such as meter read data – has been the focus of the first half of 2019. As of August 2019, gas AMI and gas AMR meter data has been loaded into the data lake. This is the foundational step that provides for the analysis and development of algorithms that will lead to the identification of gas theft cases. Analysis of the data and algorithm development is an iterative process that requires continual tweaking and testing until the desired confidence level of theft cases

generated can be achieved. Examples of algorithms that are currently in flight include disconnects with consumption, tilt tamper, and magnetic tamper events. This step-by-step foundational data loading and iterative algorithm development approach is the same methodology that was utilized in successfully identifying electric theft. Further details on energy theft reduction are provided in the "Gas AMR Program Costs/Benefits Analysis" section of my direct testimony.

III. GAS AMR TECHNOLOGY, CAPABILITIES, AND STATUS

Q. Please discuss the Company's investment in updated meter technology for gas-only customers.

A. The Gas AMR project is complete. To achieve AMR capabilities, the Company updated existing gas meters with communications modules, installed mobile collectors in meter reading vehicles, and implemented an Itron Field Collection System ("FCS"). The project also leveraged and built upon existing operational systems.[1] Together, all these components provide the infrastructure necessary to provide the benefits of AMR to our customers.

[1] Examples of existing operational systems include the Enterprise Service Bus ("ESB"), SAP, Itron Enterprise Edition ("IEE"), Meter Data Management, Process Information ("PI") Historian, and the Web Portal.

Q. What is the status of the Company's implementation of AMR meter reading technology enhancements?

A. The Gas AMR Program was built on existing systems infrastructure and implemented AMR functionality to deliver customer benefits to the Company's gas-only utility customers. The additional necessary systems functionality was installed through a series of three system upgrade releases that began in December 2016 and concluded with the final system release implemented in July 2017.

- Phase 1 - Customer Service and Front Office Processes (December 2016) – This systems release updated the customer service and front office processes to include Gas AMR, enabling customer accounts to be identified within the Company's SAP system as having an AMR enabled gas meter;

- Phase 2 (March 2017) – This systems release updated Device Lifecycle Management/Deployment and Smart Energy Operations Center (SEOC) operations to include Gas AMR. This release enhanced SAP and other systems to support supply chain processes, work management, quality, and audit management. Work order processing between the Company and our meter installation vendor was also enabled with this release. This release also included Route Planning and Optimization, specifically the interfaces necessary to perform the data exchange with the third-party route optimization vendor to create the optimized routes for the most efficient deployment of gas communication modules and cutover to meter reading vehicle routes; and

- Phase 3 (July 2017) – This AMR systems release delivered all the remaining functionality necessary for the Gas AMR drive-by solution. It integrated the new equipment and software for the FCS. This release also implemented the Route Planning and Optimization software from the third-party route optimization vendor that will be used by Meter Reading Planning and Scheduling for vehicle-based meter reading route development and maintenance.

With the last AMR systems release (Phase 3) in July 2017, the delivery of all remaining functionality for the drive-by meter reading solution was implemented. The ongoing installation of Gas AMR modules was completed during the first half of 2019.

Q. Please describe the gas meter modules that were selected for the Company's Gas AMR customers.

A. The Company selected the Itron 100G DLS Datalogging ERT® module as our gas meter module, which is the same gas communication module utilized for gas AMI. While it is the same gas communication module, it was programmed for Gas AMR's drive-by meter reading solution. This gas communication module can easily be programmed from AMI to AMR and from AMR to AMI. See examples of the module (behind the index) and installed on the gas meter in the Itron pictures below.

(Pictures not to scale)

The Gas AMR project did not replace existing assets but represented an upgrade to the existing gas meter assets with the addition of the gas communication module. The gas modules were installed by removing the existing index at the front of the gas meter that measures gas consumption. The installer removed the existing index and inserted the gas module on the back of the index. Once that was complete, the installer ensured that the read on the module matched the read on the index. The integrated module/index was then placed back on the gas meter and the reads from the communication module are

used for billing. In most cases, the existing gas meter remained in place, thereby avoiding additional meter acquisition costs.

Q. Please describe Itron's FCS.

A. The FCS is a key element of the Gas AMR implementation, as it is the system that is used to collect meter reads and meter event data from a vehicle-based mobile collector. The FCS includes both hardware and software components. The FCS also manages the scheduling of the meters to be read each day by importing a list of meters to be read from SAP and assigning daily routes to individual meter reading vehicle drivers. When daily meter read data is collected by vehicle-based mobile collectors, the FCS then updates the operational systems used for billing and other operational processes.

The Company is utilizing 16 mobile collectors (see Itron picture below of the mobile collector components) and 12 assigned vehicles in the gas only territory.

Once per month, a driving meter reader with a mobile collector will receive 40 days' worth of daily reads, the consumption amount at the time of the read, and the event count at the time of the read. This data is collected securely using enhanced security encryption which is the highest security level available from Itron. AMR drive-by meter reading

was initiated in February 2018 and has consistently realized monthly meter read rates in excess of 99.80%.

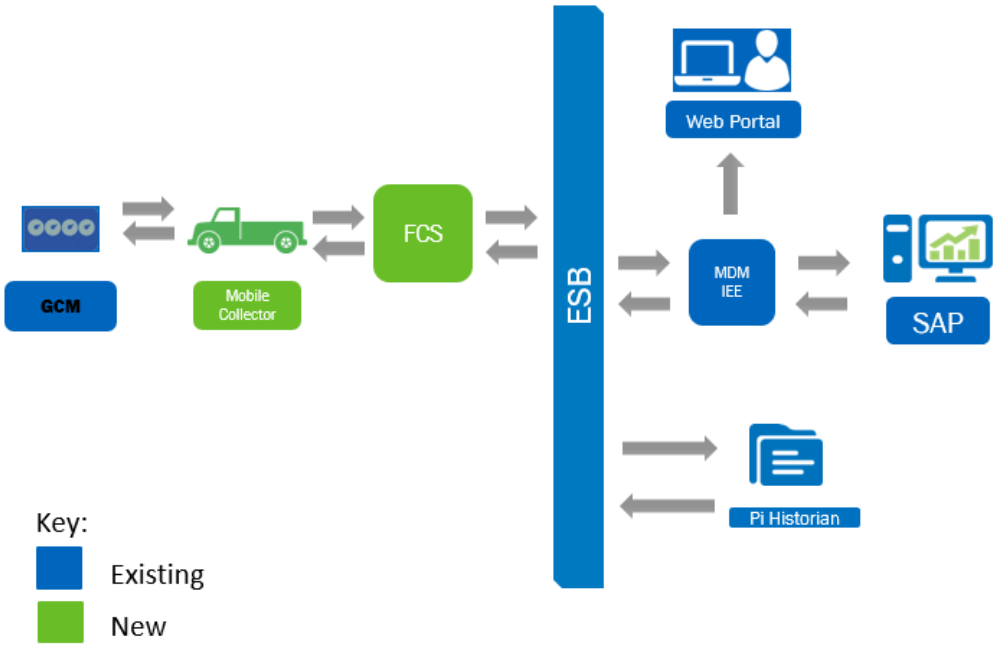
Q. Previously, you discussed three phases of AMR system upgrades. Were the AMR system upgrades necessary?

A. Absolutely. Without the upgrades, the Company could not install gas communication modules, validate the FCS meter read with a manual meter read, cutover the gas communication module to an FCS drive-by route, redistrict manual meter read routes into optimized driving routes based on the information from the third-party route optimization vendor, and optimize module installation routes for efficiency and timely realization of operational benefits.

Q. What were the major capital expense categories related to the AMR system upgrades?

A. The major categories were: (i) infrastructure hardware, which includes mobile field devices and associated antennas; (ii) the FCS, which is used to collect gas meter data stored in individual gas modules; and (iii) design work, which included all the labor associated with integrating the drive-by solution. This design work included blueprinting and requirements identification, code and interface development, testing, and implementation. To integrate Itron's FCS into the Company's IT infrastructure, interfaces or upgrades to the following systems were necessary: Enterprise Service Bus ("ESB"), Itron Enterprise Edition ("IEE"), Meter Data Management, SAP, Process Information ("PI") Historian, and the web portal, as well as interfaces to support the Itron cloud and optimized routes from the third-party route optimization vendor. See the

diagram below for the simplified architecture. Note that Gas AMR leveraged the Smart Energy infrastructure, mainly ESB, IEE, PI Historian, and the web portal.



IV. GAS AMR PROGRAM COSTS/BENEFITS ANALYSIS

Q. What is the total capital investment in conjunction with the implementation of Consumers Energy's Gas AMR Program?

A. The AMR Program cost/benefit analysis, Exhibit A-54 (LMD-3), page 1, line 15, rows (c) through (h), indicates that projected investments for the purchase, testing, processing, and installation of gas communication modules, as well as the design, testing, and implementation of systems were originally estimated to require approximately $170 million in capital investment for the period 2014 through 2019. However, my Exhibit A-12 (LMD-1), Schedule B-5.1, pages 1 through 4, reduces this projection by removing approximately $64 million of projected investment related to three specific business case investment components. Business case program contingency of $33 million has been removed from the projections in this case, program management

cost estimates have been reduced by $24 million, and costs associated with the deployment of gas modules have also been reduced by $7 million, resulting in an updated and final capital expenditure of approximately $106 million as the total 2014 through 2019 capital expenditure requirement. Because AMR expenditures were completed prior to the test year in this case, there are no AMR expenditures projected in the test year.

Q. Please explain your decision to exclude the approximately $33 million of capital investment contingency and $31 million of other program expenditures from your capital expenditure in Exhibit A-12 (LMD-1), Schedule B-5.1.

A. The decision to exclude contingency from the projected capital investments is the direct result of the reduction in overall program investment risk resulting from the successful implementation of software and system development components of the AMR implementation. The business case estimated program management costs were determined to exceed the actual requirements necessary to complete the planned meter upgrade scope. These reductions were appropriate, since at its conclusion the Gas AMR Program total cost was $106 million.

Q. Please describe Exhibit A-12 (LMD-1), Schedule B-5.1, pages 1 through 4.

A. This exhibit presents the capital expenditures associated with the Gas AMR Program and includes the following:

(i) **Field Equipment/Facilities** refers to $0.869 million in actual equipment investments during 2017 through 2019 to support the AMR Program. These investments included purchases of mobile field devices and associated antennas used in the mobile collection of meter read and meter event data;

(ii) **Modules** are the direct investments associated with the purchase and installation of more than 1.1 million gas meter modules. The overall investment for AMR module purchases and installation was $81.001 million. Annual expenses reflect gas module purchases that supported the scheduled installation of gas modules, as well as the installation costs. The

actual purchase cost of gas modules included the vendor price and State of Michigan sales tax;

(iii) **Software/Systems Development** included new systems development, systems modifications, and software licensing costs. The overall investment was $17.704 million. The FCS and other system modifications required to implement a drive-by meter reading approach are described earlier in my direct testimony;

(iv) **Smart Energy Infrastructure** included investments in computer and network infrastructure to support the installation of gas modules and their associated systems. Because the Company utilized existing corporate data storage capabilities for AMR data, there were no actual investments for this category; and

(v) **Program Engineering/Design and Management** refers to a total of $6.486 million in actual project investments. These costs were primarily incurred for the design, integration, and management of the gas meter modules, and overall support of the program (labor and expenses, customer communications, and associated corporate allocations).

Q. Please describe Exhibit A-53 (LMD-2), pages 1 and 5.

A. This exhibit presents the actual O&M expenses for Gas AMR Program activities from 2016 to 2019 and includes the following:

(i) **Program Management and Other** refers to the program management and other related costs. Total project costs were $1.290 million in actual expense. These costs primarily include ongoing hardware and software maintenance, and other outside services expense; and

(ii) **Deployment and Meter** O&M costs are expenses associated with the purchase and installation of gas meter modules. Total project costs were -$0.415 million. This category of costs included program staff salaries and expenses related to the O&M of the AMR technology. This category also included costs related to the installation of gas modules by the Company's installation contractor, which were offset by first set credits that resulted from the accrual of first set costs at the time modules were purchased.

Q. Please discuss the overall results of the cost-benefit analysis as summarized in Exhibit A-54 (LMD-3).

A. The Company's business case for Gas AMR included both costs and benefits associated with implementing drive-by AMR for gas-only customers. The Net Present

Value ("NPV") calculation in the business case was based on numerous assumptions for both costs and benefits, and the analysis that is presented in Exhibit A-54 (LMD-3) was last updated during 2016. The key areas of variability in annual capital investments and O&M costs were the meter/module installation schedules and the systems modifications and new systems development requirements. The area of focus on the benefits side is the transition to drive-by AMR and the ancillary impacts of meter read rate and billing accuracy improvements that will result from the use of enhanced gas meter reading technology. Savings to customers were measured by the program NPV of revenue requirements calculation of $24.2 million. The details of this calculation are provided in Exhibit A-54 (LMD-3), page 5.

Q. Please explain the gas meter reading benefits in the Company's Summary of Business Case Costs and Benefits.

A. Automation of meter reading provides several benefits to customers relative to existing manual meter reading processes. These benefits include improved meter read accuracy and reduced estimates of energy consumption for billing purposes. The automation of meter reading also enables the reduction of manual meter reading staff levels. At the time of full AMR implementation, the Company expects to achieve meter reading savings equivalent to approximately 80% of baseline gas-only area manual meter reading expenses. These savings will ramp up over the meter installation period as customers transition from energy billings based on manual meter reads to billings based on automated meter reads. Annual gas meter reading benefits are shown on Exhibit A-54 (LMD-3), pages 3 and 4, line 53. The meter reading benefits calculated in the

cost/benefit analysis include direct-labor and non-labor O&M savings, as well as estimated savings in employee benefit costs and payroll taxes.

Q. Please explain the gas other O&M expense benefits in the Company's Summary of Business Case Costs and Benefits.

A. The Company expects that the technological enhancements associated with AMR will generate operating efficiencies in customer service and billing areas of the Company. For example, the improved meter read accuracy and reduced estimates associated with AMR reduces the need for gas operations workers to make field trips associated with special manual read requests to resolve billing issues and customer concerns about meter reading accuracy. Improved meter read rates and higher accuracy levels will also allow billing staff to avoid the need to request special manual reads. The Company is planning for a 70% reduction in special gas reads for gas-only service customers, which would result in a 45.5% reduction in all special gas reads.

Q. Please explain the gas theft reduction benefits in the Company's Summary of Business Case Costs and Benefits.

A. The Company's pre-AMR theft detection process relied upon tips from meter reading or field service employees and contacts received from customers to initiate investigations of suspected energy theft. The most common form of gas energy theft identified using our existing theft tip process are customers who attempt to reconnect gas service after being disconnected for non-payment of past-due energy billings. In our enhanced AMR theft detection process, the Company will receive meter tilt tamper alerts and magnetic tamper alerts from gas modules as part of our drive-by AMR data collection process. This data

will be analyzed for correlation with service work orders, customer notifications, and daily consumption patterns to identify locations where energy theft has been attempted.

Other theft detection activities occurred during the AMR installation process. Examples of these activities included visual inspection by gas module installers and billing/theft reviews of pre-deployment reports that listed inactive meters with energy consumption.

Customers also benefit from the incremental gas sales revenue that results from the improved identification of energy theft. The theft benefit is expected to grow to 0.75% of gas AMR area residential and commercial gas sales revenue as gas modules and analytical systems for gas module data are implemented. Annual gas theft reduction benefits are shown on Exhibit A-54 (LMD-3), pages 3 and 4, line 56.

Q. Please explain the Gas AMR induced conservation and energy efficiency benefits in the Company's Summary of Business Case Costs and Benefits.

A. Customers typically receive feedback from the Company regarding their natural gas consumption when they receive their monthly billing statement. During the systems work effort, the Company determined that the estimated energy savings benefits of periodic updates of web portal data views with historical daily gas consumption were too small relative to updated cost estimates to pursue the integration of AMR data. As a result, the web portal continues to display monthly consumption for customers with AMR meter upgrades, and benefits estimated for gas energy conservation were not pursued as part of the AMR implementation. The following explanation describes the calculations included in the cost/benefit analysis:

- Residential GCR revenue is multiplied by 65.7% to account for the natural gas customers that are located in our gas-only service area. The percentage of gas

meters converted to AMR is also considered in each annual benefit calculation, starting in 2018. No natural gas consumption benefits are quantified for the commercial and industrial class;

- Participation is expected to be 27% of gas-only residential customers;
- Participating customers are expected to realize a 1% reduction in natural gas consumption; and
- Overall, a 0.27% reduction (27% participation x 1% conservation) is expected for the portion of residential customer class that takes gas-only utility service from the Company.

Q. Please explain the Lost and Unaccounted For ("LAUF") gas reduction benefits in the Company's Summary of Business Case Costs and Benefits.

A. AMR usage data and the corresponding systems[2] being developed will enable improvements in LAUF analysis for geographic areas served by individual gas city gate stations. Daily meter index reads will provide enhanced information for analysis as gas volumes at a city gate level for a particular time period can be directly compared to the gas volumes reported from meters served by that city gate. This analysis will identify local areas that require action to reduce LAUF volumes and costs.

Annual gas LAUF reduction benefits are shown on Exhibit A-54 (LMD-3), pages 3 and 4, line 58.

Q. Please explain the terminal value benefits in the Company's Summary of Business Case Costs and Benefits.

A. The calculation of the terminal value started with the business case calculation of AMR net revenue requirements modeled for the calendar year 2037. In that year, the business case value of AMR customer savings is $33.4 million[3], and the business case value of

[2] PI MODM is the operational system that will provide data extracts used for LAUF analysis.
[3] Source: AMR Business Case spreadsheet.

AMR customer costs is $8.3 million[4], resulting in a net revenue requirement savings of $25.1 million. This value was then adjusted each year from 2038 to 2039 based on the percentage of all AMR modules installed that have remaining useful life based on the expected AMR module useful life of 20 years. The adjusted annual values are then discounted back to their present value in 2037 using two variables: the Company's weighted average cost of capital and the number of years difference between each year and 2037. The annual adjusted values and discounted annual values for 2038 to 2039 were then summed together to arrive at the 2037 terminal value of $15.4 million that is shown on Exhibit A-54 (LMD-3), page 4, line 77.

Q. Does the cost/benefit of the program as summarized in Exhibit A-54 (LMD-3) support the Company's continued gas AMR investment for gas-only customers?

A. Yes. The Company's business case demonstrates that gas customers will realize benefits that exceed program costs, resulting in an NPV benefit for customers of $24.2 million. As mentioned previously in my direct testimony, the cost/benefit analysis includes capital investment contingency amounts that were excluded from the Company's request for capital investment; so, even without the AMR energy conservation benefits included in the business case, the investment in AMR will still provide positive benefits to customers through reduced overall cost to provide utility service.

[4] Source: AMR Business Case spreadsheet.

V. SUMMARY

Q. On what basis are the Gas AMR expenses concluded to be reasonable and appropriate?

A. As described throughout this testimony, our customers and the Company continue to realize benefits from the implementation of the AMR technology. Gas AMR technology is a major contributor to our best meter read rate in the Company's history. Gas AMR will continue to result in improved billing accuracy and reductions in estimated bills. Meter tamper notification data and the related analysis will result in gas theft reductions. The Gas AMR Program established aggressive targets to realize these benefits. Deployment and cutover performance exceeded planned targets. The overall program, which concluded in June 2019, was on-time and on-budget.

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 distribution of natural gas and for other relief.	)))))	Case No. U-20650

DIRECT TESTIMONY

OF

ALEX M. GAST

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

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 and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Senior Rate Analyst in the Pricing Section of the Rates and Regulation Department.

Q. Please describe your educational background and business experience.

A. In 2011, I graduated from Central Michigan University with a Bachelor of Science degree in Business Administration, majoring 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 2019, I joined the Pricing Section of the Rates and Regulation Department.

Q. What are your responsibilities as a Senior Rate Analyst for Consumers Energy?

A. My current responsibilities include rate design activities for electric and gas regulated service. I also conduct rate-related research, economic 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 direct testimony on behalf of the Company in Case No. U-20365, the Company's 2018 Energy Waste Reduction ("EWR") Reconciliation, and Case No. U-20372, the Company's 2020-2023 EWR Plan.

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

A. The purpose of my direct testimony is to present the Company's proposed rate design, which collects the proposed revenue requirement from customers in an equitable manner reflecting the cost of providing service and taking into consideration rate impacts. 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-2	Summary of Present and Proposed Revenue by Rate Schedule;
Exhibit A-16 (AMG-2)	Schedule F-2.1	Summary of Present and Proposed Rates by Rate Schedule;
Exhibit A-16 (AMG-3)	Schedule F-2.2	Calculation of Rate Design Targets;
Exhibit A-16 (AMG-4)	Schedule F-3	Present and Proposed Revenue Detail;
Exhibit A-16 (AMG-5)	Schedule F-4	Comparison of Present and Proposed Monthly Bills;

Exhibit A-55 (AMG-6)	Development of Rates for Transportation ATL Services; and
Exhibit A-56 (AMG-7)	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.

SUMMARY OF PROPOSED RATE DESIGN CHANGES

Q. Please describe Exhibit A-16 (AMG-1), Schedule F-2.

A. Exhibit A-16 (AMG-1), Schedule F-2, provides a summary of the proposed changes in revenue by rate schedule. The proposed change is derived from the calculated difference between test year present revenue and proposed revenue that incorporate the Company's revenue deficiency. The present and proposed revenues shown in Exhibit A-16 (AMG-1), Schedule F-2, are calculated by applying the test year billing determinants provided by Company witness Eric J. 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 MPSC Case No. U-20322 September 26, 2019 Order ("September 26 Order") to the test year billing determinants to calculate present revenue in Exhibit A-16 (AMG-1), Schedule F-2.

Q. Please describe the Company's objectives and approach to rate design in this case.

A. Generally, the Company has designed rates so that the revenue recovered from each customer class reflects the adjusted costs for that class in the Company's test year Cost-of-Service Study ("COSS"), as provided by Company witness Emily A. Davis. The Company also considers: (i) establishing rates that promote efficient use of the

Company's gas system and promoting energy efficiency; (ii) establishing rates that promote a favorable business climate; and (iii) designing rates that provide the Company with a fair opportunity to collect its revenue requirements. The proposed gas delivery revenue and associated rate increases/(decreases) for each rate class are shown on Exhibit A-16 (AMG-1), Schedule F-2, page 2.

Residential Rates

The Company is proposing to maintain its existing residential rate structure for Rate Schedules A and A-1, which include a fixed monthly customer charge and volumetric distribution charges. The proposed increase in distribution for Rates A and A-1 is 28.2%, as shown on Exhibit A-16 (AMG-1), Schedule F-2, page 2. The total proposed increase for the residential class is 18.5% when including the forecasted cost of the gas commodity, as shown on Exhibit A-16 (AMG-1), Schedule F-2, page 1.

General Service Rates

The Company is proposing to maintain its existing rate structure for General Service Rate Schedules GS-1, GS-2, and GS-3. The proposed increase in distribution for the General Service rate class is 5.0%, as shown on Exhibit A-16 (AMG-1), Schedule F-2, page 2. The total proposed increase for the General Service class is 2.8% when including the forecasted cost of the gas commodity, as shown on Exhibit A-16 (AMG-1), Schedule F-2, page 1. The proposed rates maintain the currently established economic breakeven points between the General Service Rate Schedules, GS-1, GS-2, and GS-3.

Transportation Rates

The Company is proposing to maintain its existing transportation rate structure for Rate Schedules ST, LT, XLT, and XXLT, but is proposing to add a new Authorized

Tolerance Level of 2.0%. The proposed increase for the Transportation rate class is 10.8%, as shown on Exhibit A-16 (AMG-1), Schedule F-2, page 1. The proposed rates maintain the currently established economic breakeven points between the Transportation Rate Schedules ST, LT, and XLT.

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 13.4% decrease for Rate GL. Based on the Company's projected cost of gas of $2.635 per Mcf, which is supported by Company witness Eric T. Salsbury on page 4 of his direct testimony, the proposed monthly rate for single fixtures is $5.00 per month, which reflects a reduction of $1.00 per month. The proposed monthly rate for multiple fixtures is $9.00 per month, which reflects a reduction of $1.00 per month. The cost of gas is included with other distribution costs in the fixed monthly rate for single and multiple gas fixtures.

ALLOCATION OF THE PROPOSED REVENUE DEFICIENCY

Q. Please describe Exhibit A-16 (AMG-3), Schedule F-2.2.

A. Exhibit A-16 (AMG-3), Schedule F-2.2, shows the calculation of the revenue targets used for designing rates, including proposed adjustments, to the test year revenue requirement by rate schedule. The exhibit illustrates test year revenues based on the Company's test year COSS, as provided by Company witness Davis. 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-3), Schedule F-2.2?

A. As shown on Exhibit A-16 (AMG-3), Schedule F-2.2, page 1, line 1, the Company started with the test year COSS provided by Company witness Davis. 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-3), Schedule F-2.2, page 1, line 2. Furthermore, the COSS was adjusted to reflect the storage adjustment for Rate XXLT, as shown on Exhibit A-16 (AMG 3), Schedule F-2.2, page 1, line 3. Consistent with the methodology approved by the Commission in prior gas cases, the COSS was also adjusted to maintain economic breakeven points within the General Service and Transportation rate classes. 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-3), Schedule F-2.2, page 1, line 11.

Q. How did the Company allocate the low income credits associated with the RIA credit and LIAC?

A. The allocation of the RIA credit and LIAC is shown on Exhibit A-16 (AMG-3), Schedule F-2.2, page 2. The credits are allocated to each rate class based on that class's pro rata share of the total revenue requirement from the COSS.

Q. What is the basis for allocating the RIA credit and LIAC among all rate schedules?

A. The Company is maintaining the allocation ordered by the Commission in its June 3, 2010 Order in Case No. U-15985 (Michigan Consolidated Gas Company's gas general rate case) ("U-15985 Order"). The Order states:

> The ALJ found that the revenue shortfall should be recovered from all rate classes, on the basis of Allocation Factor No. 20 rather than on the basis of throughput. [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-4), Schedule F-3.

A. Exhibit A-16 (AMG-4), Schedule F-3, calculates the test year proposed gas rates required to collect the revenue requirement derived from the test year calculation of rate design targets shown in Exhibit A-16 (AMG-3), 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-1), Schedule F-2. The rates from this exhibit are the source of the proposed rates that appear in the redlined tariffs filed by Company witness Karen J. Miles in this case.

Q. How does the Company propose to design rates to recover the residential revenue requirement?

A. The Company's proposed COSS uses the minimum size study methodology to calculate the residential customer charge of $26.07 per month. In comparison, the Company also

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 $15.53 per month.

While the minimum size study methodology and the Case No. U-4331 methodology support an increase of greater than $3.00 to the Company's current residential customer charge, the Company proposes a residential customer charge for Rates A and A-1 of $13.75 per month. This proposal reflects a $2.00 increase from the current $11.75 residential customer charge. Using this approach, the Company can move the residential customer charge closer to the cost to serve while at the same time allow for a more gradual increase in the fixed charge.

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 $0.24 per Mcf, from $5.0241 to $4.7816, which is 5.1% less than the volumetric charge associated with the $11.75 monthly customer charge ordered in the September 26 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-4), 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. Consumers Energy proposes master customer charges of $20.18 per month for Rate GS-1, $58.83 per month for Rate GS-2, and $738.71 per month for Rate GS-3. The Company also proposes to maintain the contiguous customer charges at $14 per month for Rate GS-1, $40 per month for Rate GS-2, $80 per month for Rate GS-3, and to collect the remainder of the proposed revenues through the volumetric distribution charges. 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-2), Schedule F-2.1.

Q. How does the Company propose to set rates to recover the transportation class's revenue requirement?

A. The Company proposes master customer charges of $852.95 per month for Rate ST, $1,569.90 per month for Rate LT, $14,859.43 per month for Rate XLT, and $53,440.30 per month for Rate XXLT. The Company also proposes to maintain the contiguous customer charge at $60 for all ST, LT, and XLT contiguous accounts. These rate changes maintain the economic breakeven point between Rate ST and Rate LT at 100,000 Mcf annually and the breakeven point between Rate LT and Rate XLT at 500,000 Mcf annually, as well as provide for recovery of the annual revenue requirement for the

Transportation class. Furthermore, as approved in the September 26 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-2), Schedule F-2.1.

Q. Please explain economic breakeven points.

A. An economic breakeven point is the point of volumetric usage where revenue collected from one rate would equal revenue collected on a different rate.

Q. Is the Company proposing to reset the economic breakeven points?

A. No. The Company's proposed rates in this case maintain the breakeven points established in Case No. U-18124, and subsequently approved in Case No. U-18424 and Case No. U-20322.

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 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. Yes. Based on customer feedback, the Company is proposing to offer a 2.0% ATL credit of $(0.0663) per Mcf to all transportation customers. The Company estimates half of the customers contracting for the 4.0% ATL today could switch to a 2.0% ATL. Rate Exhibit A-55 (AMG-6) provides the credit calculation, and Exhibit A-16 (AMG-2), Schedule F-2.1, provides the revenue calculation for each transportation rate class.

Q. Can an XXLT customer contract for a 2.0% ATL?

A. Yes. Because the standard XXLT rate is offered at a 4.0% ATL, if an XXLT customer contracts for a 2.0% ATL, a credit of $(0.0204) per Mcf will be applied as shown on Exhibit A-16 (KJM-2), Schedule F-5, page 24.

Q. Is the Company proposing changes to the transportation charge adjustment associated with the ATLs?

A. No. Consistent with the September 26 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 6.7%. 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-55 (AMG-6), provides this adjustment calculation.

Q. Is the Company proposing any other changes related to the 4.0% ATL adjustment for Rate XXLT?

A. No. Consistent with the September 26 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 6.7%.

TYPICAL BILLS

Q. Please describe Exhibit A-16 (AMG-5), Schedule F-4.

A. Exhibit A-16 (AMG-5), Schedule F-4, provides the impacts resulting from the proposed gas rates and rate design changes for customers on each rate schedule at various usage levels. This exhibit is used to gauge the distribution of the rate impacts across the population of customers taking gas service under the various rate schedules.

CUSTOMER ATTACHMENT PROGRAM DISCOUNT AND CARRYING COST

Q. Please explain Exhibit A-56 (AMG-7).

A. Exhibit A-56 (AMG-7) provides the calculation of the test year discount and carrying cost rates for the Customer Attachment Program ("CAP") and is used to support the changes to the CAP tariff sheet sponsored by Company witness Miles.

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 26 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 26 Order.

Q. Please describe the RDM approved by the Commission in Case No. U-20322.

A. The calculation of the RDM approved by the Commission 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 re-approved 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 distribution of natural gas and for other relief.	)))))	Case No. U-20650

DIRECT TESTIMONY

OF

KAREN M. GASTON

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

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 for Consumers Energy Company ("Consumers Energy" or the "Company").

Q. How long have you been employed by Consumers Energy?

A. I have been employed by Consumers Energy since 2003.

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, I am responsible for development of the financial plans, budgets, outlooks, forecasts, and analysis for corporate departments 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. 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") 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.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-57 (KMG-1)	Summary of Gas O&M Expense for the Years 2018, 2019, 2020; and the 12 Months Ending September 30, 2021;
Exhibit A-58 (KMG-2)	Adjusted Gas Corporate Services O&M for the Years 2018, 2019, 2020; and the 12 Months Ending September 30, 2021;
Exhibit A-59 (KMG-3)	Gas Uncollectible Accounts Expense for the Years 2018, 2019, 2020; and the 12 Months Ending September 30, 2021;
Exhibit A-60 (KMG-4)	Gas Injuries and Damages Expense for the Years 2014 through the 12 Months Ending September 30, 2021;

Exhibit A-61 (KMG-5)	Manufactured Gas Plant Amortization Schedule and Direct Project Management Costs 2005 through the 12 Months Ending September 30, 2021;
Exhibit A-62 (KMG-6)	Organization Chart, Affiliate Group of Companies Doing Business with Consumers Energy Company – 2018; and Purpose of Business, Affiliate Group of Companies Doing Business with Consumers Energy Company – 2018;
Exhibit A-63 (KMG-7)	Summary of Costs Billed to Affiliated Companies for the Year Ended December 31, 2018; and Summary of Payments Made to Affiliated Companies Year Ended December 31, 2018;
Exhibit A-64 (KMG-8)	Impact on Gas Operations for Costs Billed to Affiliated Companies for the Year Ended December 31, 2018;
Exhibit A-65 (KMG-9)	Impact on Gas Operations for Payments Made to Affiliated Companies for the Year Ended December 31, 2018;
Exhibit A-66 (KMG-10)	Affiliated Companies – Rate of Return on Common Equity for the Year Ended December 31, 2018; and
Exhibit A-67 (KMG-11)	2017 Gas Utilities Ranked by A&G per Customer (less Pension and Benefits).

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

A. Yes.

PART 1 – GAS CORPORATE SERVICES O&M EXPENSE

Q. Please describe Exhibit A-57 (KMG-1).

A. Exhibit A-57 (KMG-1) summarizes the Company's total 2018 through the 12 months ending September 30, 2021 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 2018 actual O&M, column (d) provides the 2019

O&M projection, column (e) provides the 2020 O&M projection, and column (f) provides the total test year O&M projection of $50 million. These expense categories are discussed in more detail below.

Corporate Services O&M Expense

Q. What areas are included within the Corporate Services O&M expense category that you are addressing?

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, and advances clean energy programs for the benefit of its 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, and shareholder services. 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) – 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, customer billing, payment processing, 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 Board of Director costs; 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 businesses, 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. How was the Corporate Services O&M calculated?

A. Exhibit A-58 (KMG-2), line 13, provides the Company's gas portion of total Corporate Services expenses, before adjustments. The 2018 actual O&M expenses were obtained from the Company's records. Exhibit A-58 (KMG-2), line 15, column (d), shows the

total normalizations of one-time costs from 2018 total Corporate Services expense. There were no normalized items in 2018. Also, the total of items disallowed by Commission order related to advertising, lobbying, and donation payments were removed on Exhibit A-58 (KMG-2), line 17. Total adjusted Corporate Services expense is found on Exhibit A-58 (KMG-2), line 18. Corporate Services Labor is escalated using an assumed 3.2% inflation rate. Headcount is projected to remain at 2018 levels through the test year. The use of contract labor in the Corporate area is de minimis. Consumers Energy uses the inflation rate 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 projected rate of inflation?

A. The assumed rate of non-labor inflation is based on the Consumer Price Index. The Consumer Price Index is 1.9% for 2019, 2.2% for 2020, and 2.2% for 2021.

Q. What is the source for the Consumer Price Index?

A. The July 2019 IHS Markit forecast.

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 Amy M. Conrad.

Q. Is the Company planning technology projects that support the Corporate Services functions?

A. Yes. Company witness Christopher J. Varvatos 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 **Accounts Payable ("AP") Automation** project requires $60,672 in capital and $54,443 in O&M in the test year. The AP Automation project will provide an end-to-end AP solution to optimize invoice capture via Optimal Character Recognition ("OCR") software; leverage workflows to automate invoice approvals and processing; manage electronic document retention; provide insights via improved reporting; and minimize human intervention. The value of completing the project includes: (1) centralizing invoice processing resulting in reductions to invoice entry costs, number of paper invoices, duplicate vendor payments, and late vendor payments; (2) automating validation of an invoice against contract rates; (3) increasing transparency of invoice processing status; (4) providing more accurate accruals; (5) improving the ability to capture discounts; (6) enabling cash flow benefits and reduced financing costs; and (7) improving internal controls. The scope of the project includes: (1) enabling OCR technology; (2) creating automated workflows for receiving, managing, routing, and monitoring invoices and related documentation; (3) automating posting of invoices; (4) creating new reports; (5) enabling electronic document retention; and (6) data cleanup. Four alternatives were considered for the AP Automation Project:

  (1) Continue current process using outline agreements without a third party tool. While this requires no capital investment, the Company continues to

have duplicate payments, be ineligible to receive discounts, have inefficient processes, and lack end-to-end automation.

(2) Develop a custom solution which would meet all requirements, but would result in higher overall costs, higher maintenance costs, fewer upgrades, and won't leverage AP best practices.

(3) Choose an on-premise software tool resulting in cost savings and efficiencies related to processing, storing data in house, and implementing AP best practices. It would also introduce new licensing and ongoing maintenance costs.

(4) Choose a cloud solution resulting in reduced infrastructure costs, less internal maintenance than an on-premise solution, capability for vendors to access the system and see invoices, and implementing AP best practices. This solution would introduce new licensing and ongoing maintenance costs and upgrades would be forced upon the Company that require testing, which could impact and interrupt operations.

The preferred options are (3) and (4) since these options will provide a solution which will deliver cost savings and reflects AP best practices. A final decision will be made after a Request for Proposal ("RFP") is issued and a vendor is selected.

- The **Enterprise Content Management ("ECM") - Managing Business Records** project requires $117,362 in capital and $254,852 in O&M in the test year. Using the Company's ECM system, this project will manage business records for high-focus areas contained in SharePoint and Shared Drives. The

records will be classified, categorized, and placed under formal retention rules, via metadata assignment. This project will add value through: (1) consistent practices for records management; (2) defensible process for validating completeness and accuracy of records produced and records deleted; (3) deletion of excess, irrelevant, or inappropriate information; (4) easy generation of electronic records in the event of litigation; (5) achieving Generally Accepted Recordkeeping Principle maturity of 3.0 or greater through functional capabilities of ECM coupled with business practices to align to ARMA (formerly the Association of Records Managers and Administrators) principles; and (6) mitigating the possibility of fines as a result of being unable to produce records. For high-focus areas, the scope includes: (1) integrating SharePoint and Shared Drive content into ECM; (2) assigning taxonomy and records classification values through metadata on content and records; (3) assigning standard retention rules; (4) mapping, building routines, and migrating existing content to new taxonomy and retention schedules; (5) ensuring records can be located; and (6) allowing legal holds and lineage audits to be conducted on content. Three alternatives were considered for this project:

(1) Continue managing business records on shared network drives and in SharePoint without ECM integration. This option was not chosen as it would provide minimal visibility to the records from within the ECM system, retention rules will not be applied to the records, taxonomy or metadata will not be applied making it more difficult to find and manage

records, the problem will continue to get worse over time as the amount of data grows, and the Company could face substantial fines if it is unable to find records.

(2) Integrate all SharePoint and shared drive content in the ECM. This option was not chosen as it will be costly and not all content is considered a business record.

(3) Start by focusing on integrating business critical records with ECM for the high-focus areas.

Alternative (3) was selected as it mitigates risk with the high-focus areas and requires less funding than managing all SharePoint and shared drive content in ECM.

- The **Environmental Health and Safety ("EHS") Compliance** project requires $86,016 in capital and $39,819 in O&M in the test year. The EHS Compliance project will implement a comprehensive Company-wide solution to ensure accurate and consistent reporting of health, safety, environmental, and security issues and activities including: (1) compliance calendaring, (2) incident and risk management, (3) inspections, (4) waste management, and (5) sustainability. Completion of this project will provide value to both the Company and its customers by incorporating the improved processes built into the new solution, including incident management and prevention, that ensure a productive workforce able to complete work for customers. Additionally, the project will: (1) support the Company's "Planet" goal through enhanced tracking and reporting for air quality, waste management, and sustainability;

(2) support risk avoidance for environmental penalties; (3) increase productivity and quality; (4) enable transparency in tracking of goals; and (5) create awareness of and improve response to emerging environmental regulations through the addition of visual management and dashboards. The scope of this project is to implement a cloud solution which includes installing and configuring: (1) incident investigation, incident risk assessment, and task management; (2) corrective action tracking, workflows, and reminders; (3) environmental waste management; (4) inspections; (5) compliance calendar; and (6) sustainability. The project also includes implementation of standard business processes for EHS incident management, near misses, and safety observations. Three alternatives were considered for this project: (1) continue with disparate Excel and SharePoint solutions, which was not selected because the Excel and SharePoint solutions would require lengthy manual efforts and include risk to accurate and central tracking of EHS data; (2) pursue separate projects for Environmental Compliance and for Safety and Health Compliance, which was not selected because formal Requests for Information revealed that industry standards for these solutions utilize integrated functionality for Environmental Compliance and Safety and Health Compliance; (3) implement a single solution for both Environmental Compliance and Safety and Health Compliance. Alternative (3) was selected because it consolidates data in one system and requires less ongoing expense than two individual solutions would require. The selected alternative also considered both on-premise and cloud solutions. The single cloud-based

solution was selected as the most efficient due to lower implementation and ongoing maintenance costs.

- The **Financial Planning Transformation - Intake and Monthly Plan Management** project requires $1,133,107 in capital and $124,780 in O&M in the test year. The Financial Planning Transformation – Intake and Monthly Plan Management project will improve portfolio management capabilities in financial planning processes (also referred to as integrated business planning). Benefits from this project include: (1) labor savings across the Company, (2) improved data quality for decision making, (3) improved data analysis and reporting, and (4) automation of manual processes and reconciliation. The project scope includes: (1) managing Work Intake (the submission of programs and projects within the financial planning process); (2) developing Intake Scenarios Prioritization and Workflow (the process through which all projects are reviewed then prioritized, creating different scenarios for management review and decision making, and implementing the workflow needed to take an idea from creation to inclusion in the financial plan); (3) connecting planning, prioritization, and decision making to Company objectives and goals; (4) storing plans and scenarios for future reference of historical data; (5) bringing actuals and plan/forecast together for monthly review and forecast updates; (6) providing the ability to track and store risks and opportunities; and (7) bringing both financial and work volume (units) together for forecasting and planning. The three alternatives considered for this project were: (1) leverage and make changes to the Company's

home-grown Business Planning System, which was not chosen due to technology limitations in the existing system, and use of a custom-developed program that does not offer the improved capabilities; (2) consider other third-party applications to provide the functionality; and (3) use the existing SAP system to provide the functionality, which provides the advantages of including existing integrations to forecasting and budgeting in SAP, directly connecting the planning system to the financial management system, using existing investments in SAP, and realizing benefits of updating processes and eliminating manual processes. The preferred options are (2) and (3) as they would integrate more seamlessly with the Company's existing technology and provide a comprehensive planning solution. A final decision will be made after an RFP is issued and a vendor is selected.

- The **Human Resources - 2020 Union Changes** project requires $118,414 in O&M in the test year. The Human Resources - 2020 Union Changes project will implement SAP and other system changes required as a result of three collective bargaining agreements which will be renegotiated and ratified. Collective bargaining agreements expire every five years for Operating Maintenance and Construction ("OM&C"), Virtual Contact Center ("VCC"), and Zeeland employee groups. For OM&C, the current agreement ends June 1, 2020. The VCC agreement ends August 1, 2020. The Zeeland agreement ends October 1, 2020. Completion of this project will provide value to the Company and its customers through: (1) waste elimination by making changes in the software for any pay and benefit changes as required

by the new agreements; (2) defect reduction by adding process automation to otherwise manual processes for tracking and recording work, premium, and absence time; and (3) improved employee engagement among the OM&C, VCC, and Zeeland union employees. The scope of this project encompasses making any system changes required to support the new working agreement for the OM&C, VCC, and Zeeland employees. Exact details will be finalized after the negotiation process is completed and contracts are approved. Three alternatives were considered for this project:

(1) Make no system changes after the contracts are ratified. This option was not chosen because it exposes the Company to possible fines, disengaged employees, union grievances, significant manual processes leading to greater possibility of error, hiring additional staff to perform activities outlined in the agreements, and increased legal costs due to employee grievances.

(2) Find other third-party software to support the changes required by the union agreements. This option was not chosen because it would require SAP integration along with additional software licensing and maintenance costs.

(3) Make system changes to eliminate manual updating, comply with the working agreement language, support union employee engagement, and reduce grievances was chosen because it uses current SAP technology, automates what would otherwise require manual processing, and is the least costly option.

- The **Rates Case Implementation** project requires $88,676 in O&M in the test year. The Rates Case Implementation project will modify SAP billing in accordance with MPSC requirements, allowing rate structure changes and improved billing accuracy. The project will add value for both the Company and its customers through: (1) improved customer satisfaction by providing accurate billing; and (2) timely updates to Company applications that incorporate mandatory changes to the rate structure that include new surcharges, price changes, and energy efficiency programs. The scope of this project encompasses implementation of annual or monthly (or both) electric and gas customer price changes, and rate structure changes as approved by the MSPC. An alternative considered for this effort was an offshore development model. 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 timing it would take for testing of this model.
- The **Workforce Connect – Talent Enablement** project requires $109,728 in capital and $552,196 in O&M in the test year. This project is part of an overarching talent enablement plan which will enable the Company to move forward in creating an employee experience to better serve customers. Improving the employee experience is focused on two outcomes: (1) enabling employees to be more engaged and productive; and (2) attracting and retaining new skill sets and talent, both of which result in providing better service to customers, an improved customer experience, and and higher

customer satisfaction. This project will provide the following value: (1) increased employee retention for continuity of knowledge and long-term customer relationships, as well as reduction in costs associated with recruiting and onboarding new employees; (2) positive direct customer interactions facilitated through strong employee engagement; (3) enhanced employee development to meet customer needs during a time where retirement eligibility is high and risk of knowledge loss has the potential to negatively impact customer service and satisfaction; (4) enable the Company to operationalize a new career framework and competency model which will support training and development of employees to deliver strong customer service and will enhance the ability to hire candidates capable of delivering on the Company's initiatives and goals; (5) advanced workforce analytics that provide data-driven insights in support of maintaining and enhancing the workforce to continue to deliver strong customer service and results; (6) reduce waste and defects leading to increased quality and simplified manual processes; (7) improved insight and consistency in reporting (i.e. Ethics, Safety, Office of Federal Contract Compliance Programs); (8) provide transparency into key talent areas to identify retention risk within critical areas and develop succession strategies; and (9) ensure core systems are stable and operational interruptions are minimized. The Company currently uses the SAP Human Capital Management ("HCM") module as a master source of employee data which feeds such information to other systems throughout the Company, including Human Resources and non-Human Resources systems.

However, vendor support for the SAP HCM module will be retiring at the end of 2025. The Workforce Connect – Talent Enablement project will implement the following SAP SuccessFactors modules: Employee Central, Succession Planning, Career Development, and Compensation. This project will ensure support of the following processes after the SAP HCM module retires: Core Human Resources Management, Hiring, Onboarding, Performance Management, Succession Planning, Compensation and Benefits, Leader and Employee Development, Technical Training, Talent Programs, Workforce Analytics, and Workforce Planning. The project scope includes: (1) implementing SAP SuccessFactors Employee Central, Succession Planning, Career Development, and Compensation modules; (2) retrofitting current SuccessFactors modules to support the integrated talent management suite; (3) providing mobile capabilities; (4) retiring the SAP HCM module; and (5) providing integrations as needed from SuccessFactors to SAP. Four alternatives were considered for this project:

(1) Maintain employee master data in the SAP HCM system, knowing that vendor support for HCM will be retiring at the end of 2025. This approach was not chosen as it poses a risk to system stability due to declining vendor support (such as maintenance, enhancements, and defect resolution) which could have Company-wide implications given the extent to which SAP HCM integrates with other systems throughout the Company and the number of functions and processes reliant on employee data.

(2) Explore alternate systems instead of SAP HCM for core Human Resources data and transactions. Consumers Energy uses 15 SAP modules, which are reliant on employee data from SAP HCM. Additionally, more than 40 other systems and applications are integrated with and dependent on the SAP HCM data. Migrating to a non-SAP Human Resources system would result in customization of technical integrations back to SAP and other systems currently integrated with SAP HCM. This approach was not selected, as migrating to a non-SAP core Human Resources system would incur significant re-work costs and would have Company-wide implications. For example, Company employees would need to be retrained and new technology support contracts would need to be negotiated at a higher cost.

(3) Replace the SuccessFactors solution with another talent management system. This option was not chosen since it would be costly to start over with a brand new talent management system, would result in significant organizational change management to support user adoption and loss of significant time and training invested in skilling up employees to use and maintain SuccessFactors, and would require retraining of the Human Resources Technology team as well as the majority of Human Resources employees who regularly use the current system in their day-to-day work.

(4) Expand the current Workforce Connect (SuccessFactors) solution with SAP's Employee Central product and configure additional SuccessFactors modules. This option is preferred as it minimizes impact and

customization to other existing Company-wide technical solutions and processes dependent on employee data and mitigates the risk of relying on the retiring SAP HCM system. Implementing SAP SuccessFactors Employee Central will enable standard, non-custom integration with on-premise SAP modules as well as seamless integration with current Workforce Connect (SuccessFactors) modules. Additionally, enhancing current modules and implementing the remaining SuccessFactors modules supports the overarching talent enablement plan.

Q. Is the Company planning projects that support the Corporate Services functions?

A. Yes. The Company is planning a talent enablement project that is critically important in allowing the Company's Human Resources area to support the gas business in a safe, effective, and efficient manner. The talent enablement project is part of an overarching talent enablement plan that includes both technology and non-technology efforts. The Workforce Connect – Talent Enablement technology project associated with the talent enablement plan is described above. The Career and Reward Framework project associated with this plan is described as follows:

- The **Career and Reward Framework** project will utilize an industry expert to develop and implement a framework that creates 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 Company's initiatives in the evolving utility industry. For example, as energy generation, distribution, and storage transforms, the Company will need a workforce skilled in renewable generation. 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 at scale, including upskilling current employees and adding 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 saves the expense and lost productivity associated with frequent recruiting and training.

Q. How does the Career and Reward Framework project benefit customers?

A. Consumers Energy has set out to build on its strong workplace culture by implementing a new career and reward framework for employees. A career framework helps employees define their role, expand their skill set, and develop their career consistent with the Company's initiatives. A reward framework supports efforts to compensate employees

fairly and competitively. Customers benefit from this through increased employee retention for continuity of knowledge and long-term customer relationships, reduction in costs associated with recruiting and onboarding new employees, positive customer interactions facilitated through strong employee engagement, and enhanced employee development to meet customer demands.

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 2017 gas A&G costs (excluding pension and benefits) the sixth lowest out of the 31 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-67 (KMG-11) for a 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.

Gas Uncollectible Expense

Q. What is included in the Company's gas uncollectible expense shown on Exhibit A-59 (KMG-3)?

A. Exhibit A-59 (KMG-3), page 2, column (b), includes the total write-offs of customer accounts receivable balances deemed uncollectible. This amount is reduced in column (c) by recoveries collected from customer accounts previously written off. Non-energy

related write-offs are also removed in column (e) from the net write-offs to arrive at net energy related uncollectible expense in column (f).

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 $13.3 million as shown on Exhibit A-59 (KMG-3), page 1. The test year uncollectible accounts expense is based on a three-year average Bad Debt Loss Ratio ("BDLR") of uncollectible accounts expense to gas service revenue for the years 2016 through 2018, as shown on Exhibit A-59 (KMG-3), page 2. This ratio is applied to the test year gas service revenue, plus Energy Waste Reduction surcharge revenue, to arrive at test year uncollectible accounts expense on Exhibit A-59 (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 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 gas rate case in Case No. U-20322.

Gas Injuries and Damages Expense

Q. Please describe Exhibit A-60 (KMG-4).

A. Exhibit A-60 (KMG-4) summarizes the Company's total 2014 through 2018 actual gas injuries and damages expense and projected injuries and damages expense through the 12 months ending September 30, 2021.

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 (up to a $500,000 insurance deductible per occurrence). 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 $1.6 million be included for the test year as shown on Exhibit A-60 (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-60 (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 2014 through 2018.

MGP Site Remediation and Direct Project Management Costs

Q. How did the Commission previously address environmental investigation and remediation expenditures at former MGP sites?

A. In Case No. U-10755, the Commission approved deferred accounting for these expenditures, with amortization over 10 years, beginning the year after expenditures are incurred. The approach adopted by the Commission envisioned that prudence reviews would occur in rate cases and that following a prudence review: (i) the amortization expense would be included in rates, and (ii) the deferred balance would be included in rate base and would earn a return at the authorized rate of return. The approach adopted by the Commission also provided for deferred accounting and amortization of third-party recoveries in excess of the costs of recovery over 10 years, the inclusion of the unamortized balance in rate base, and deferred tax accounting. In Case No. U-13000, the Commission upheld this accounting treatment.

Q. Please explain Exhibit A-61 (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 2018 and projected expenditures through December 31, 2019.

Q. Why are you including projected expenditures through December 31, 2019 and not through the projected test year ending September 30, 2021?

A. I am including projected expenditures through December 31, 2019 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-61 (KMG-5), page 1.

A. Line 2 shows the third-party insurance recoveries for the years 2005 through 2018 and projected recoveries through December 31, 2019. Lines 3 through 17 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 18 and acts as a credit to the amortization of expenditures identified in this case. Line 19 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-61 (KMG-5), page 1, line 19, is included in the direct testimony and Exhibit A-13 (JRC-52), Schedule C-6, of Company witness Jason R. Coker.

Q. Please explain Exhibit A-61 (KMG-5), page 1, line 20.

A. Line 20 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-57 (KMG-1).

Q. Please explain Exhibit A-61 (KMG-5), page 2, related to the rate base treatment of the MGP unamortized balance.

A. Exhibit A-61 (KMG-5), page 2, provides the net unamortized balance of actual deferred MGP remediation costs and third-party recoveries for the years 2005 through 2018 and projected balances for the year 2019. 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, 2020 and 12 months ending September 30, 2021. 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-61 (KMG-5), page 1; (iii) approve test year direct project management costs of $0.6 million as provided on Exhibit A-61 (KMG-5), page 1; and (iv) include the deferred net unamortized balance in the amount of $52.5 million in rate base as provided on Exhibit A-61 (KMG-5), page 2.

PART 2 – ACCOUNTING REQUESTS

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.

Deferred Capital Spending Recovery Accounting Request

Q. Does the implementation of a deferred capital spending recovery mechanism discussed in Company witness Jeffrey R. Parker's direct testimony require any specific accounting approvals?

A. Yes. The deferred capital spending recovery mechanism would require and result in deferred debits until the expense components in the mechanism can be fully collected. The Company requests approval to recognize regulatory assets, as needed, to record these deferred amounts.

Q. Would any outstanding regulatory asset associated with the deferred capital spending recovery mechanism accrue interest?

A. Yes. Any outstanding regulatory asset associated with this mechanism 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-62 (KMG-6), A-63 (KMG-7), and A-64 (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-65 (KMG-9) and A-66 (KMG-10), as described below.

Q. Please explain Exhibit A-62 (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-63 (KMG-7).

A. This exhibit summarizes costs billed to affiliated companies, page 1, and payments made to affiliated companies, page 2, for the year 2018.

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-64 (KMG-8), gas operations were favorably impacted by $626,618.

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-63 (KMG-7), page 2.

A. Services provided include officer services and professional services, such as accounting, engineering, finance, legal, 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 2018 is $3,102 as shown on Exhibit A-65 (KMG-9).

Q. Please explain Exhibit A-66 (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.

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-20650

DIRECT TESTIMONY

OF

KYLE P. JONES

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

Q. Please state your name and business address.

A. My name is Kyle P. Jones, and my business address is 311 East Michigan Avenue, Battle Creek, Michigan 49014.

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 Services.

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

A. I am responsible for all Fleet-based functions within Consumers Energy. This consists of Fleet Operations, Fleet Acquisition and Disposition, Licensing, Permitting, Regulatory (Federal, State, and Local), Technical Support and Training, and Strategy and Data Analytics.

Q. What is your formal educational experience?

A. I graduated from Kellogg Community College in 1993 with an associate degree in Applied Science - Industrial Engineering. In 1995, I also obtained an associate degree in Applied Science - Automotive Technology from Kellogg Community College. I have also completed numerous management courses, hold several leadership certifications, and I am also licensed as a certified Michigan Master Heavy Duty Technician with the State of Michigan.

Q. Would you please describe your previous work experience?

A. In 1992, I started my career as a Service Advisor for Battle Creek Ford. In 1994, I transitioned to working as a Diesel Mechanic at Wise International in Kalamazoo, Michigan. In 1997, I moved to Freightliner of Kalamazoo as a Service Manager.

In 2001, I started my career at Consumers Energy as a Fleet Field Leader for the Company's Pontiac location. In that position, I was responsible for all daily Fleet operations. In 2010, I was promoted to Senior Fleet Field Leader covering the West side of the state. In this role, I was responsible for the oversight of maintenance of more than 2000 Company-owned vehicles, equipment, and trailers. I was also responsible for providing supervision and support for 55 mechanics, 6 field leaders, and 6 administrative employees.

In 2011, I was promoted to the role of Fleet Regulatory and Technical Manager. In that role, I was responsible for ensuring that the Company's Fleet remained compliant with the Federal Motor Carrier Safety Regulations, the Michigan Vehicle Code, American National Standards Institute ("ANSI") standards as well as Occupational Safety and Health Administration ("OSHA") and Michigan Occupational Safety and Health Administration ("MIOSHA") regulations. Additionally, my responsibilities included the creation of training programs to ensure that more than 100 Company mechanics were properly trained to perform the vast array of vehicle maintenance activities for the Company's Fleet.

In 2013, I accepted the position of Fleet Business Relations Manager. In this role, I was responsible for aligning Fleet strategic plans with Gas and Electric Operations. This included ensuring that vehicle specifications and equipment requirements of the Company's Fleet vehicles being built were consistent with the operational and work needs of employees carrying out Company functions and customer service in the field. My responsibilities also included the analyses of vehicle performance and budgetary impacts to the Fleet. In 2018, I was promoted to Fleet Acquisition and Business Relations Manager. This role consisted of aligning operations requirements for all Fleet capital purchases along

with Fleet vehicle design, licensing, rentals, asset sales, and data management. In 2019, I accepted my current position in Fleet Services. In my current role as Director of Fleet Services, I am responsible for the supervision and oversight of 156 employees, which consists of: 112 mechanics, 14 administrative support staff, and 30 supervisors, analysts, and administrative support staff. I am also responsible for managing and maintaining over 7,000 units in our Fleet across 36 garages.

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

A. Yes. I am a board member of the Electric Utility Fleet Managers Council, and a member of The Midwest Energy Associates Fleet Utility conference.

Q. What has been your involvement in previous proceedings before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. I provided witness support in the Company's 2018 Electric Rate Case (Case No. U-20134) and the Company's 2018 Gas Rate Case (Case No. U-20322).

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:

- Describe the Fleet Services function and associated responsibilities;
- Describe Fleet Services' balanced three-pronged approach to delivering customer value;
- Describe and support the 2017 Utilimarc Vehicle Replacement report and the recommendations ("Utilimarc Report");
- Support the reasonableness and prudence of the capital expenditures for Fleet Services for the historical test year ended December 31, 2018; the bridge period beginning January 1, 2019, and ending September 30, 2020; and the projected test year ending September 30, 2021;

- Support reasonableness and prudence of the Operation and Maintenance ("O&M") expenses for Fleet Services for the historical test year ended December 31, 2018, the bridge period beginning January 1, 2019, and ending September 30, 2020, and the projected test year ending September 30, 2021; and

- Support reasonableness and prudence of the capital expenditures and O&M expenses for Telematics for Fleet Services.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-12 (KPJ-1)	Schedule B-5.10	Summary of Actual & Projected Gas and Common Capital Expenditures for the years 2018, 2019, 2020, and 12 months ending September 30, 2021;
Exhibit A-68 (KPJ-2)		Summary of Actual and Projected Fleet O&M Expenses for the years 2018, 2019, 2020, and 12 months ending September 30, 2021; and
Exhibit A-69 (KPJ-3)		Utilimarc Report.

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

A. Yes.

Q. Please briefly describe the exhibits you are sponsoring.

A. I am sponsoring: (i) Exhibit A-12 (KPJ-1), Schedule B-5.10, which is a Summary of Actual and Projected Fleet Capital Expenditures for the years 2018, 2019, 2020, and 12 months ending September 30, 2021; (ii) Exhibit A-68 (KPJ-2), which is a Summary of Actual and Projected Fleet O&M expenses for the years 2018, 2019, 2020, and 12 months ending September 30, 2021; and (iii) Exhibit A-69 (KPJ-3), which is a report prepared by Utilimarc. The Utilimarc Report presents the results of a study of the Company's existing Fleet and future Fleet needs, including findings and recommendations for investment

necessary to achieve and maintain a Fleet replacement strategy for the Company at a lower overall cost to customers.

Fleet Services Function and Responsibilities

Q. Please explain the Gas Operations Support function.

A. The 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 testimony and exhibits?

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

Q. Please explain the responsibilities of Fleet Services.

A. Fleet Services carries out all functions related to the acquisition and maintenance of Company-owned vehicles. Fleet Services is responsible for ensuring the safe operation of all vehicle equipment and trailers required to operate the functional areas of the business.

Q. Please explain the scope of Fleet Services' management responsibilities.

A. Fleet Services manages a Fleet of over 7,000 units through their first, second, and, in some cases, third lifecycle for use in daily operational work.

Q. Please explain what you mean by "lifecycle."

A. The lifecycle is the age at which a unit is prepared for replacement. The lifecycle is defined as a balance between maintenance cost, depreciation, and condition.

Q. What functions comprise the Fleet organization?

A. The Fleet organization consist of four groups which collaboratively work together to provide value to Gas Operations to service our customers. The four groups which make up Fleet Operations are Acquisition/Disposition, Fleet Maintenance, Fleet Regulatory & Technical, and Strategy & Data Analytics

Balanced Three-Pronged Approach to Delivering Customer Value

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 begin its day with zero Fleet impacts to service our customers efficiently in their efforts to meet; (i) Customer On Time Delivery ("COTD"); (ii) Vintage Service Replacement; (iii) Service On Time Commitment; (iv) Odor Response, etc.

Q. What is the overall approach used by Fleet Services in carrying out its responsibilities?

A. Fleet Services balances our approach by using three components – a quality component, a cost component, and a delivery component.

Q. Please explain the quality component of the approach utilized by Fleet Services?

A. The quality component of our approach ensures we are buying the highest quality trucks, trailers, and equipment at the lowest cost possible. Our other core quality metric is measuring whether we delay or impact Gas Operations' ability to begin each day to service our customers efficiently and execute the planned work without barriers or obstacles.

Q. Please explain the cost component of the approach utilized by Fleet Services.

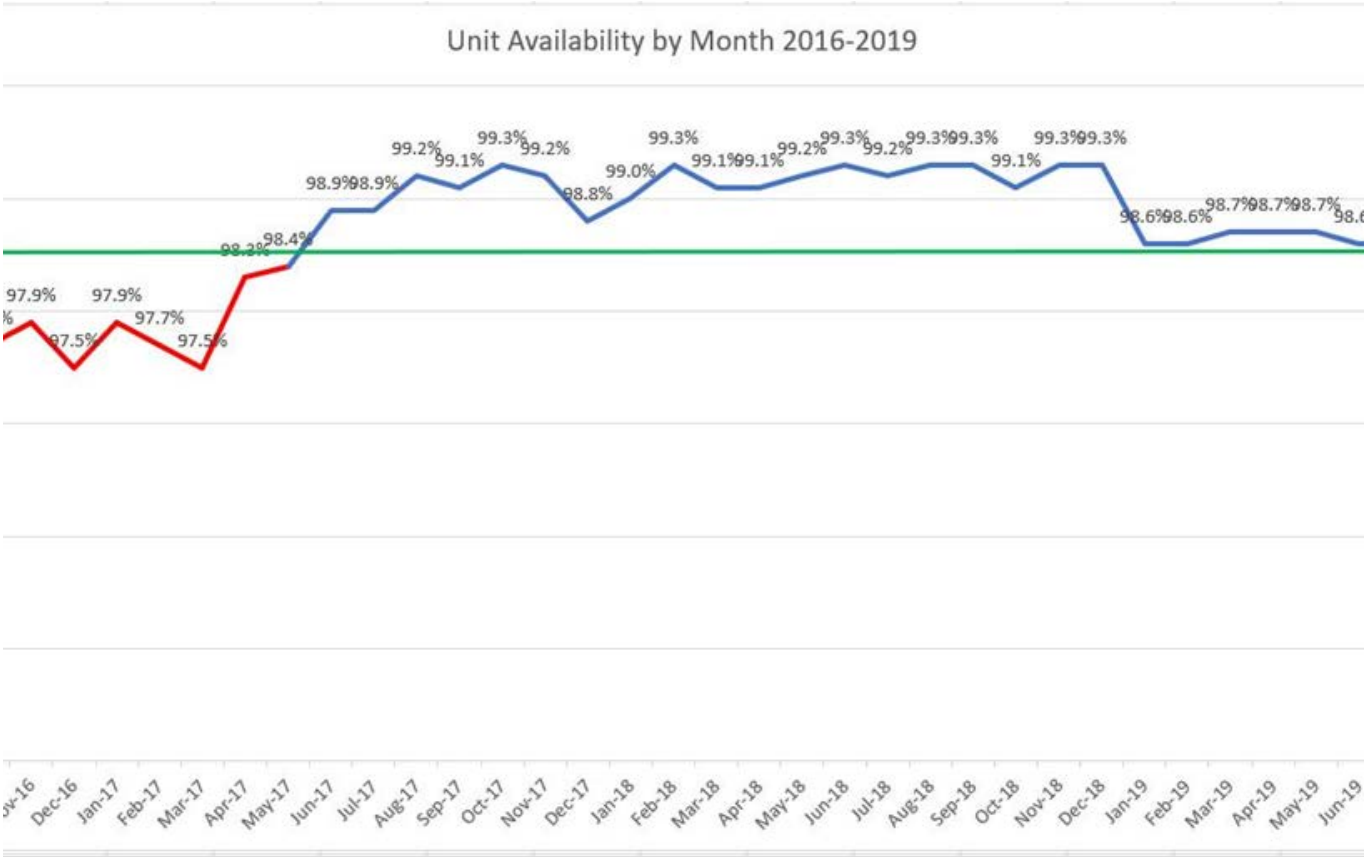
A. Fleet Services places an emphasis on managing overtime, outside services spend, and material cost in order to provide Gas Operations a regulatory compliant, safe, and efficient

Fleet to deliver on our promises to our customers. Additionally, Fleet partners with Gas Operations and our vendors in order to effectively execute our capital purchase plan.

Q. Please explain the delivery component of the approach utilized by Fleet Services.

A. For the delivery component of our approach, we measure critical unit availability in real-time across the state. Fleet began reporting Unit Availability in late 2016. See Chart 3 below that depicts unit availability from 2016 to 2019. The Unit availability, expressed as a percentage, has proven to be a critical metric to ensure our highest priority units are available for our crews to complete their daily work. Our plan for 2019 and 2020 is to maintain our focus on Unit Availability. Unit Availability is an output of total spend (cost) and predicts the level of impact on Gas Operations (quality). The goal is to balance the cost component against the level of unit availability to ensure zero start-of-day impacts to Gas Operations. By achieving zero Fleet-generated start-of-day impacts, Fleet Services provides value to Gas Operations by having the right unit at the right time to deliver on the commitment made to our customers. These commitments include COTD as well as leak request response. This is Fleet's commitment to maximize the value we provide to Gas Operations and ultimately to our external customers.

CHART 3 – Unit Availability Graph - Priority 1 & 2 Units



Utilimarc and the Utilimarc Report

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 Fleets which provided information to Fleets to help them understand ranking amongst peers. Utilimarc now works as a strategic partner with companies such as Consumers Energy, to assist Fleets with maximizing their value within the company through the use of data analytics, statistical analysis, and real-world industry experience (https://utilimarc.com/about-us/).

Q. What is the Company's experience with Utilimarc?

A. The Company has utilized Utilimarc for more than seven years for purposes of analyzing internal metrics and benchmarking our Fleet performance against other utilities.

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

A. Yes, benchmarking information is very useful; however, the Company now realizes that simply benchmarking the Company's Fleet performance against other utilities does not provide an accurate depiction of how Fleet impacts Electric and Gas operations. Thus, the Company turned to Utilimarc in 2017 to assist with analyzing Fleet's data to determine what drivers were necessary to make our Fleet more successful.

Q. How did the Company utilize Utilimarc?

A. The Company retained the services of Utilimarc to conduct a study of the Company's Fleet, utilizing our data and their industry knowledge to provide us with recommendations regarding future plans for Fleet Services.

Q. Please explain Exhibit A-69 (KPJ-3).

A. Exhibit A-69 (KPJ-3) is the Utilimarc report. This report was generated in 2017 when Fleet Services partnered with Utilimarc to determine what the appropriate lifecycle replacement plan would be for the Company's Fleet.

Q. Does the Utilimarc Report utilize Company data?

A. Yes. The Utilimarc Report, Exhibit A-69 (KPJ-3), utilizes the Company's data to determine the optimal lifecycle for the Fleet.

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

A. We learned that the Company's capital Fleet purchases were not reducing O&M spend. Most importantly, we learned that we have been reactively, rather than proactively,

investing in Fleet and, in continuing to do so, we can expect an increase in O&M costs. A discussion of Utilimarc's recommendations regarding the Company's Fleet capital and resulting O&M expenditures is discussed later in this testimony.

Q. Has the Company incorporated the recommendations set forth in the Utilimarc Report (Exhibit A-69 (KPJ-3))?

A. Yes, as will be demonstrated below, Exhibit A-12 (KPJ-1), Schedule B-5.10, and Exhibit A-68 (KPJ-2) incorporate the Utilimarc Report's proposed capital expenditures and O&M expenses.

Fleet Services Capital Funding

Q. What has been the Company's historical approach to capital funding for Fleet Services?

A. In previous years, Fleet's capital funding was maintained at $17.5 million. This amount was utilized to replace out-of-lifecycle vehicles, equipment, and trailers for all departments.

Q. How has the Company's previous investment strategy for capital funding affected the Company's Fleet?

A. The previous investments did not optimize for the age of the fleet or optimize the O&M spend. The fleet has continued to age and creates increasing O&M to maintain a safe and useful fleet for the operations teams to serve customers.

Q. Why did the Company create unequal historical investments between Electric Operations and Gas Operations Spend?

A. Funding was inadequate to optimize the age of the entire fleet; therefore, emergent needs of the Company, based on increases in the Company's workforce, as well as the state of

aging vehicles, determined where those funds were spent. This created a cycle constant "triage" scenario for Fleet to service both sides of the business which has negatively impacted the overall lifecycle of the Fleet. This impact, based on the previously-budgeted dollar amount, has resulted in a Fleet with an average age of over 8-years-old and, in some cases 12- to 15-years-old, and has also resulted in more than 1500 units out of 7000 being used beyond their lifecycles. Notably, units of this age experience much higher levels of maintenance problems. As a result, the constant "triage" of units for Fleet was necessary and persistent as aging units, experiencing maintenance problems at the end of any given day, had to be repaired throughout the night to make them operational and bring them back into service in time for them to serve customers the next morning. We began utilizing the Utilimarc data to identify the appropriate method to optimize the fleet and the O&M maintenance costs.

Q. How did the Utilimarc data help to develop a forward-looking plan for Fleet Services?

A. In 2017, our approach began to account for how we utilize our data in order to deliver value to all of the operational groups that Fleet supports. Fleet partnered with Operations to determine which units were down (non-operational) most frequently, causing missed critical dates to our customers. This information was then compared with the information of our lifecycle data. Additionally, in 2017, the Company commissioned Utilimarc to conduct a study of the Company's historic Fleet ownership and operational data. This study was intended to help the Company develop a Fleet replacement plan by analyzing our annual ownership and maintenance costs to determine the optimal time to replace units. Fleet Operations reviewed the Utilimarc Report, along with our own data, to develop a plan

to replace out-of-lifecycle units in a manner that addresses the lowest cost and highest quality to allow us to best serve our customers.

Q. Please describe the capital expenditures related to Fleet Services as shown on Exhibit A-12 (KPJ-1), Schedule B-5.10.

A. Exhibit A-12 (KPJ-1), Schedule B-5.10, includes Fleet Services Transportation Equipment and Other Equipment capital expenditure actuals for the 12 months ended December 31, 2018, projections for the 12 months ending December 31, 2019, projections for the 9 months and 21 months ending September 30, 2020, and projections for the 12 months ending September 30, 2021, which is the test year in this case. For the historical year, 12 months ended December 31, 2018, the Company incurred total Fleet Services capital expenditures in the amount of $23,609,000. The Company is projecting total Fleet Services capital expenditures to be $13,278,000 for the 12 months ending December 31, 2019, $27,769,000 for the 21 months ending September 30, 2020 (of which $14,491,000 is attributable to the 9-month period ending September 30, 2020); and $26,366,000 for the 12 months ending September 30, 2020, as set forth in Exhibit A-12 (KPJ-1), Schedule B-5.10, line 9, column (b); line 9, column (c); line 9, columns (d) and (e), and line 9, column (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, equipment, and trailers as part of the Company's Fleet Lifecycle Replacement Program that supports Operations.

Q. Please explain how the proposed spending levels for the bridge year and the projected test year ending September 30, 2021, were developed.

A. The proposed spending levels for the bridge year and test year are based upon the Gas Operations' capital investment plan of $19.1 million. The $21.921 million projected capital expenditure for the 12 months ending September 30, 2020, includes $21.217 million for transportation equipment (lifecycle replacement), plus $493,000 for transporation equipment (alternative fuel vehicles), plus $211,000 for fleet tools. This total amount is reflected in Exhibit A-12 (KPJ-1), Schedule B-5.10, line 18, column (c). Although the projected capital expenditures for the bridge year ending September 30, 2020, reflect $21.71 million, this amount incorporates the projected $19.1 million in capital investment in transportation equipment (for lifecyle replament and alternative fuel vehicles), and also includes additional spend from the last three months of 2019 for expenditures related to adjustments made to fleet purchases for changes such as delivery schedule changes. The $26.366 million projected capital expenditure for the test year ending September 30, 2021, includes $18.627 million for transportation equipment (lifecycle replacement), plus $493,000 for transportation (alternative fuel vehicles), totaling the projected capital investment of $19.1 million. It also includes $7.012 million for transporation equipment (Telematics), as will be addressed below, and $234,000 for fleet tools, which will also be discussed below. This total amount is reflected in Exhibit A-12 (KPJ-1), Schedule B-5.10, line 18, column (d). 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 utilized by Utilimarc in its recommendation.

Q. How did you determine the appropriate distribution of capital costs among the cost categories shown on Exhibit A-12 (KPJ-1), Schedule B-5.10.

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 we have 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. In order to do that, the Company calculated a five-year historical average of each of the Commission's prescribed cost categories from years 2014 to 2018 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 (KPJ-1), Schedule B-5.10.

Q. Can the cost categories presented in Exhibit A-12 (KPJ-1), Schedule B-5.10, 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. Generally, yes. It should be noted, however, that the contractor, labor, materials, business expenses, and other costs presented in Exhibit A-12 (KPJ-1), Schedule B-5.10, 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 only an estimate, but total values are good.

Q. How does the Company's request differ from previous rates cases?

A. For the projected test period ending September 30, 2021, Fleet Services is requesting a total capital expenditure amount of $26.366 million. This amount includes the Company's renewed request of $19.1 million to improve the lifecycle of the Gas Operations Fleet, $7.011 million for implementation of a new Telematics tracking system, and $234,000 for appropriate Fleet garage tooling and training.

Q. Why is the Company renewing its request for incremental capital for Fleet lifecycle?

A. The Company's historical Fleet lifecycle for our highest cost, largest, and most critical units is, on average, 12 to 15 years before unit replacement. Based on the study performed by Utilimarc, and comparing the outcome of the study with our own internal data, the Company has determined that the optimal lifecycle for Gas Operations Fleet asset replacement is between five and eight years, on average, depending on unit type

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. Below is a breakdown of the projected Fleet Services capital expenditures purchase plan of $19.1 million for the projected test year ending September 30, 2021. This plan is based on our analysis of out-of-lifecycle units. Nearly $15.627 million of this spend plan is allocated toward our most critical Gas Operations units. Additionally, the capital spend includes: contractor cost, business expenses, and other loadings/chargebacks incurred during the purchase of new units. The remaining $3.4 million in funding is allocated to the

purchase of trailers, forklifts, and engineering vehicles to support crews and support field leaders.

CHART 1 – Projected Fleet Services Capital Expenditures Purchase Plan

# of Units	Type of Unit	Total Acquisition Cost	
238	Crew Vehicles	$	15,860,340
38	Equipment	$	2,904,748
13	Trailers	$	341,500
289	**Grand Total**	**$**	**19,106,588**

Q. Why is $19.1 million of overall capital spending on Fleet Services required during the test year and what is the benefit to the customer?

A. Consistent spend levels will decrease the out-of-lifecycle units and improve the Company's overall lifecycle plan for the Fleet. As Exhibit A-68 (KPJ-2) indicates, a Fleet which is within the lifecycle model will ultimately require less maintenance which will provide value to our customers by reducing the overall O&M expense and having well working vehicles to perform the work needed for our customers on time. Decreased overall O&M spend will be dependent on consistently maintaining an optimal fleet age.

Q. How does the $19.1 million capital spend plan, year over year, benefit customers?

A. The Company's plan to establish a base Fleet purchase plan of $19.1 million for Gas Operations year over year benefits customers by incrementally moving to an appropriate Fleet lifecycle rather than our current approach which continues to increase O&M expenses. As illustrated in Chart 2 below, there are currently $46.5 million worth of units outside of the eight-year lifecycle, and in need of replacement. However, to replace those units ($46.5 million) while implementing a more consistent program for unit replacement ($19.1 million) for out-of-lifecycle units would result in a total cost of $65.62 million to immediately improve the Company's entire Gas Operations Fleet to an eight-year lifecycle

(or less) in the test year (2020-2021). The Company is not proposing such an approach, but is, instead, recommending a balanced approach which requires less capital and provides benefit to the customer by reducing O&M expenses each year.

CHART 2 – Remaining Gas Fleet Units out of Lifecycle

# of Units	Type of Unit	Total Acquisition Cost	Cost Per Unit
114	20's/22's Support Pick up Truck	$ 4,560,000	$ 40,000
71	23's Gas Service Van	$ 4,340,000	$ 61,127
5	27's Gas Mechanic Truck	$ 500,500	$ 100,100
140	28's/29's Support Pick up Trucks	$ 9,039,700	$ 64,569
2	39's Gas Commericial Industrial Mechanic	$ 248,750	$ 124,375
10	40's/42's Gas Crew Truck	$ 1,001,000	$ 100,100
5	41's Gas Welder Truck	$ 394,800	$ 78,960
48	44's Gas Distribution Crew Truck	$ 8,016,000	$ 167,000
7	45's Fleet Mechanic Service Truck	$ 700,700	$ 100,100
1	46's Hydro Vac Truck	$ 600,000	$ 600,000
6	54's Single Axle Dump Truck 5yd	$ 678,000	$ 113,000
6	57's Crane Truck	$ 1,461,000	$ 243,500
1	58's Prentice Loader	$ 425,000	$ 425,000
13	59's Stake Rack Truck All Purpose	$ 1,314,000	$ 101,077
1	67's Gas Crew Truck	$ 94,500	$ 94,500
3	83's Straight Truck	$ 424,300	$ 141,433
11	85's Semi Tractor	$ 1,705,000	$ 155,000
2	99's Medium Duty Test Truck	$ 239,500	$ 119,750
12	E10's Trencher Walk Beside	$ 1,240,000	$ 103,333
3	E11's Large Trencher	$ 324,000	$ 108,000
33	E20's/E21's/E22's/E23's/	$ 2,529,000	$ 76,636
13	E25's Tool Carrier	$ 455,000	$ 35,000
1	E28 Utility Tractor	$ 80,000	$ 80,000
5	E30's Dozer	$ 2,234,800	$ 446,960
2	E43's Air Compressor	$ 50,000	$ 25,000
19	E60's Forklift	$ 760,000	$ 40,000
2	E99's Personnel Carrier	$ 84,000	$ 42,000
81	Trailers	$ 2,589,000	$ 31,963
5	Trailer Dry Van	$ 125,500	$ 25,100
645		$ 46,547,750	

Q. Were other factors considered in the Company's approach to capital investments for Fleet?

A. Yes. Spending large sums of capital for Fleet in a single year proves to be counterproductive for the Company and customers. One of many challenges of a large spending plan is the difficulty in executing the purchase plan due to vendor availability. Large orders for vehicles which are equipped with specialized equipment requires time as vendors cannot turn around the size of such orders quickly. Another challenge in spending this sum of capital in a single year is the bubble created as a large number of Fleet units all age together. As this large bubble of units age together, they also experience maintenance

issues at the same time. This causes clusters of unpredictable O&M expenditures as the units age together and increases the likelihood of negatively impacting Gas Operations from servicing our customers. This bubble effect also creates the need to make larger rate relief requests every eight years as that large bubble of units age together and, in turn, have to be replaced together. This cycle of replacement results in an additional $65.62 million with compounding inflation year after year.

Q. How have you arrived at a forecasted plan of $19.1 million to avoid this bubble effect?

A. We utilized lifecycle analysis tools that we created, and then compared the results with Utilimarc replacement analytics results and recommendations. By comparing capital needed versus operating cost we have established that having a forecasted plan of $19.1 million annually will provide a consistent functional Fleet and enable us to predict and reduce volatility of the O&M expenses year after year.

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

A. As explained in other sections of this direct testimony, the other equipment includes Fleet garage tooling and other vehicle maintenance equipment required to repair and maintain new and old makes and models of vehicles.

Q. Why is this tooling and other maintenance equipment necessary?

A. Automotive and Equipment technology is advancing at a staggering rate, which is requiring new and additional tooling, along with software, to make the necessary repairs and adjustments to the Company's vehicles and equipment in an efficient manner.

Q. Can you explain the need for capital investment to support unit availability in light of the fact that unit availability is approaching 99%, as demonstrated in Chart 3 above?

A. The Company's ability to deliver unit availability occurs through increased O&M as we perform maintenance and repairs (the "triage" discussed above) on out-of-lifecycle vehicles to ensure their available at start-of-day for Operations. Additionally, we have mechanics work on afternoon and overnight shifts to ensure vehicles are repaired or, if the repair cannot be completed, another vehicle is transported to the location to eliminate any impacts to Operations. These efforts to drive zero impacts to Operations with an aging Fleet creates increased cost for the Fleet Organization.

Q. Why were the capital expenditure amounts of $24.5 million and $32.5 million evaluated by Utilimarc in its report?

A. The $17.5 million in annual historical capital expenditures were resulting in increased maintenance cost and creating a Fleet which was aging and had the potential to have negative impacts to Operations ability to serve our customers. We asked Utilimarc to create scenarios for different capital expenditure plans to better understand the impacts on the Fleet and our ability to serve Operations. The first scenario was $24.5 million, this scenario continued to show increased maintenance costs and an aging Fleet. The $32.5 million was another scenario which was based on previous years historical reviews of the Fleet in an attempt to balance the investment plan with the maintenance spend. This scenario resulted in increased maintenance cost and an aging Fleet as well.

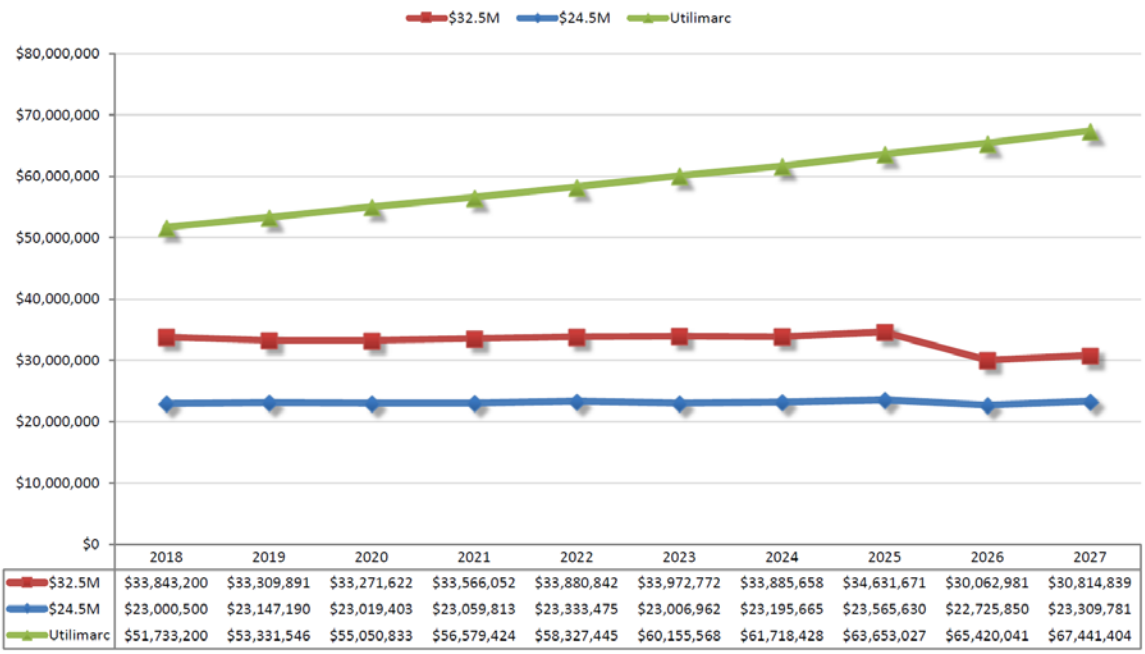
Q. Please summarize the annual capital investment recommended by Utilimarc for Fleet Services.

A. Chart 4 below illustrates the Annual Capital Investment to achieve an executable lifecycle plan for both Electric and Gas Operations using the following three capital spend plans: $32.5 million, $24.5 million, and the Utilimarc recommended spend. The Gas Operations portion of this spend is $19.1 million.

CHART 4 – Annual Capital Investment ($24 million vs. $51.7 million)

Annual Capital Investment

This graph shows the amount spent on replacement each year under each scenario.



	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
$32.5M	$33,843,200	$33,309,891	$33,271,622	$33,566,052	$33,880,842	$33,972,772	$33,885,658	$34,631,671	$30,062,981	$30,814,839
$24.5M	$23,000,500	$23,147,190	$23,019,403	$23,059,813	$23,333,475	$23,006,962	$23,195,665	$23,565,630	$22,725,850	$23,309,781
Utilimarc	$51,733,200	$53,331,546	$55,050,833	$56,579,424	$58,327,445	$60,155,568	$61,718,428	$63,653,027	$65,420,041	$67,441,404

Q. What is the basis for the Utilimarc's recommended increases year over year?

A. Based on market data, Utilimarc has added 3% for the expected inflation based on their analysis.

Q. Is the Company requesting the incremental inflationary increases recommended by Utilimarc?

A. No, we believe, with competitive pricing through negotiations with our vendors and suppliers, we can outpace the increase for inflation. Thus, the Company is only requesting the 2018 recommended amount of $19.1 million for Gas Operations.

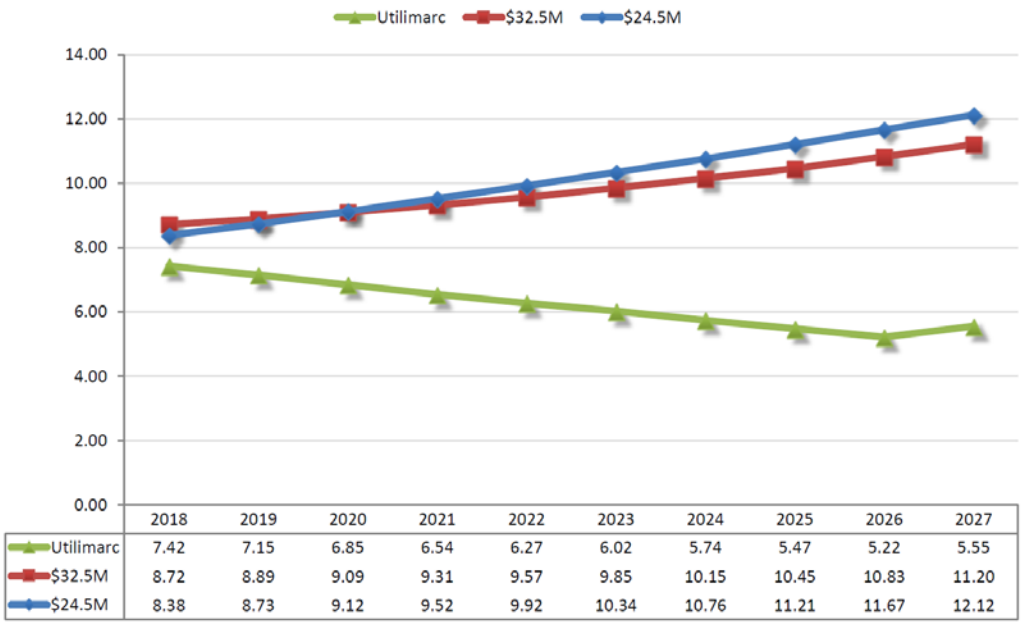
Q. Please explain how Utilimarc's recommended annual capital investment impacts the average age and maintenance cost of Fleet units.

A. Chart 5 below illustrates the impact of the age of the Company's Fleet when executing the recommended analysis performed by Utilimarc. By executing on the spending plan recommended by Utilimarc we can optimize our maintenance cost and the plan is forecasting to decrease the average age of the Fleet by 4% per year resulting in an average Fleet age of 6.02 years in 2023, and, based upon the projections, the average Fleet age will be 5.55 years, which is our targeted average age, in 2027. Additionally, by executing the Utilimarc plan consistently the cost avoidance in 2027 is estimated to be $14 million less in maintenance while sustaining our past performance of zero impacts to start-of-day for Operations.

CHART 5 – Average Age of Units ($24 million vs. $51.7 million)

Unit Average Age

This graph shows average unit age of fleet over the next six years. Under the Utilimarc Budget scenario unit average age goes from 7.42 to 5.55 by 2027. Unit average age goes from 8.38 to 12.12 under the $24.5M Budget scenario and from 8.72 to 11.20 under the $32.5M Budget scenario.



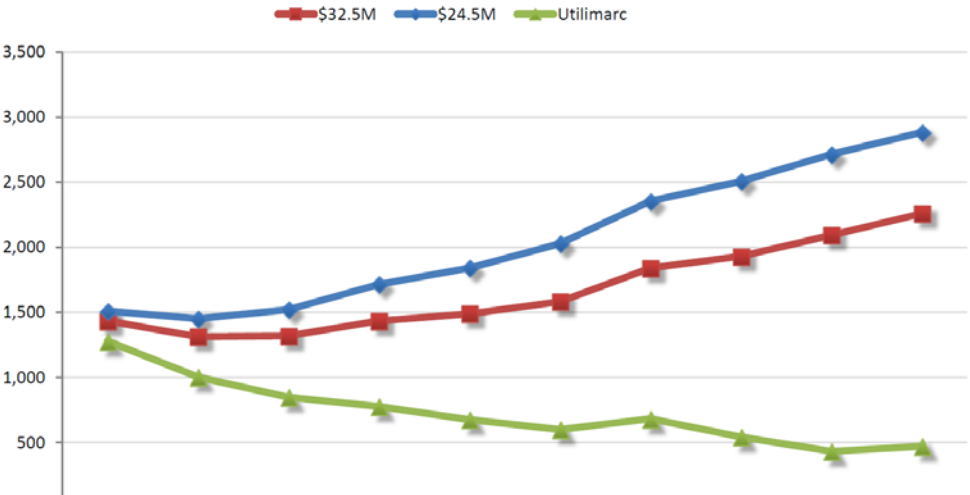
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Utilimarc	7.42	7.15	6.85	6.54	6.27	6.02	5.74	5.47	5.22	5.55
$32.5M	8.72	8.89	9.09	9.31	9.57	9.85	10.15	10.45	10.83	11.20
$24.5M	8.38	8.73	9.12	9.52	9.92	10.34	10.76	11.21	11.67	12.12

Q. Did Utilimarc analyze the spend plan, average age model, and lifecycle model?

A. Yes. Based on the Utilimarc analytics, utilizing Consumers Energy data, as demonstrated in Chart 6 below, the total number of out-of-lifecycle units would grow by 1,373 by 2027 when investing $24.5 million versus decreasing by 1,037 units by 2027 when investing $51.7 million. The lifecycle assumption in the chart for each year utilized the replacement age for each vehicle class which represents the lowest total annualized cost.

Units Out of Lifecycle

This graph shows the number of units outside the stated lifecycle for each scenario. The target value for this metric is close to zero. In the Utilimarc scenario the number of units out of lifecycle decrease from 1,279 to 472 by 2027. The number of units out of lifecycle increases from 1,509 to 2,882 in 2027 in the $24.5M Budget scenario and increases from 1,433 to 2,259 in 2027 in the $32.5M Budget Scenario.



	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
$32.5M	1,433	1,312	1,318	1,433	1,489	1,582	1,840	1,930	2,094	2,259
$24.5M	1,509	1,451	1,522	1,716	1,842	2,028	2,354	2,507	2,713	2,882
Utilimarc	1,279	1,003	849	777	676	601	682	543	432	472

Q. What does the Utilimarc analytics inform us regarding spend plan, average age model, and lifecycle model ultimately mean to the Company?

A. The lifecycle, average age, and spend plan models proposed by the Company in this case, as well as previous rate cases, which is based on the analytical models from Utilimarc, ensures each Fleet asset is fully utilized and disposed of before elevated O&M expenses are incurred in year seven to eight and beyond. This will optimize the O&M spend as well as optimize the residual values recovered at disposal.

Q. What other concerns does the Company have if the proposed capital expenditures amounts are not approved?

A. If the proposed capital expenditures are not approved, and the Company is unable to invest capital in its Fleet as recommended, the Company is concerned that there will be significant

missed opportunities of having the new technology offered by the Original Equipment Manufacturers ("OEM") to keep Fleet and Operations drivers safe at all times by preventing avoidable accidents using technology. The added safety features include lane departure, blind spot monitoring, front crash sensors with braking technology, adaptive cruise control, and many other driver safety benefits listed in the Chart 7 below. These safety features increase the average acquisition cost by $7,000 to $15,000 which, without the additional funding, negatively impacts the Fleet lifecycle and, in turn, causes O&M expenses to continue to rise, diminishing the value we deliver to Gas Operations to service our customers.

CHART 7 Safety Enhancements

Sedan Safety Enhancements		
Adaptive Cruise control		
Blind Spot Sensing		
Lane Departure		
360 Camera System		
Pre-Collision assist for Pedestrian	=	$14K
Adaptive Cruise control		
Front Crash Sensor		
Parking Assist		
All Wheel Drive		
Rain Sensing Wipers		

Pick-up Safety Enhancements		
Adaptive Cruise control		
Adaptive Steering		
360 Camera Sys		
Blindspot sensing	=	$7K
Front Crash Sensor		
Lane Departure		
Auto High Beam w/Rain Sensing		

Medium Duty Chassis Safety Enhancements		
Stability Control		
On Guard Collision		
Adaptive Cruise control	=	$15K
Lane Depature		
Disk Brakes		

Fleet Services O&M Funding

Q. Please describe Exhibit A-68 (KPJ-2).

A. Exhibit A-68 (KPJ-2) provides a summary of actual Fleet Services O&M expenses for the year 2018, and projected O&M expenses for 2019, 2020, and the test year, 12 months ending September 30, 2021.

Q. Please explain the calculated O&M expense for Fleet Services as displayed on Exhibit A-68 (KPJ-2), line 1.

A. The test year 12 months ending September 30, 2021 O&M expense for Fleet Services is $399,000 and is shown on Exhibit A-68 (KPJ-2), line 3, column (e). The test year expense was derived by using three months of the Company's 2020 outlook and nine months of the 2021 outlook from the Company's planning format. In 2018, the Company's Fleet Services O&M was $150,000, the 2019 projected expense is $278,000, and the 2020 projected expense is $343,000.

Q. What is included in Fleet Services O&M?

A. Fleet Services operations include O&M for repairing and maintaining vehicles utilized by Corporate Services. Corporate Services consist of corporate departments such as Engineering, Information Technology, Planning and Scheduling. Fleet Service costs in total, are captured as "responsibility" dollars then allocated or loaded onto Gas Operations work orders as Fleet loadings. Every work order that is completed using Fleet Services is "loaded" for Fleet costs. The loading baseline is labor, and then a percentage of cost is added to the work order and cleared from the Fleet cost centers. This is consistent throughout operational work orders. Those costs are not captured in my direct testimony because they reside in operational O&M and capital expenses. The portion of O&M expense included in Exhibit A-68 (KPJ-2) is the corporate direct charges. The $399,000 for the test year 12 months ending September 30, 2021 in O&M expense identified in Exhibit A-68 (KPJ-2) contains Fleet Services costs charged to Corporate Services for maintenance, repairs, fuel, and depreciation for vehicles assigned to corporate departments and corporate employees.

Q. Please explain your concerns regarding future O&M expenses if your requested capital expenditures amounts are not approved.

A. As discussed above, according to the study conducted by Utilimarc, the capital expenditures requested directly correspond to the expected O&M of the Company. The historical capital expenditure plans have created and will continue to create an increase in age of Fleet units, demand work orders and maintenance expense. The total anticipated projected increase in demand orders over the ten year period is 19% or a total of 92,000 orders. Additionally the anticipated maintenance cost is projected to increase by 21% over the ten-year period which results in an overall increase of $82 million. The concern of not approving the capital plan is that maintenance cost will continue to rise, and the condition of the Fleet will continue to decline. The challenge with not having the appropriate capital expenditure creates difficulties in maintaining the Fleet in a condition to provide optimal performance without increasing maintenance cost. Based on our data and that of Utilimarc, using their industry knowledge, when performing lifecycle analyses to optimize spending for our customers, the data indicates that the Company must increase replacement spend to provide the appropriate level of service to Gas Operations and customers.

Q. Why is an increase in O&M expenditures so important?

A. The Fleet has been reaching a tipping point due to Fleet growth and units beyond their lifecycles, which is causing O&M expense to continue escalating.

As the Utilimarc analytics indicates, demand work orders, annual maintenance cost, average age and lifecycles will continue to increase, resulting in higher O&M expense due to making major repairs to an out-of- lifecycle Fleet. This higher O&M expense will

ultimately elevate expenses to our customers. By increasing the capital spend plans, O&M expense is more predictable because the need to perform catastrophic repairs on out-of-lifecycle units is reduced.

Telematics as an Element of Capital and O&M

Q. The Company's capital and O&M exhibits related to Fleet reflect expenditures for "Telematics." Is this new? Please explain what this is.

A. Yes, this is a new request. 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. Does the Company's Fleet currently have a similar technology?

A. Currently our Fleet has two separate GPS tracking systems. The first system is Track-star, which was purchased by the Company in 2006, and the second system is Fleetilla, which is utilized on rental units and specialty equipment.

Q. What does Track-star do and why is the Company replacing it?

A. Track-star technology only provides a means of locating vehicles and providing simple information to identify if the engine is running and if the Power Take-Off ("PTO") is in operation. This technology was implemented to better schedule our vehicles and crews by providing visibility to their locations. Additionally, the passage of time, technological offerings from the manufacturers and vocational equipment, as well as the sunsetting of the 3G network has rendered the Track-star platform ineffective technology. Further, Track-star is no longer supporting upgrades to our platform, which has created the

necessity for Fleet to pursue other offerings with more up-to-date and advanced technologies.

Q. What does Fleetilla do and why is the Company replacing it?

A. Fleetilla is purely a tracking devise for latitude and longitude for our rental and specialty equipment for the purpose of locating and performing maintenance. This technology does not provide any additional functionality.

Q. Why did the Company choose Utilimarc Telematics as a replacement for Track-star?

A. Most all the Telematics companies offer the same inputs and outputs of the data; however, after seeking guidance from peers of other utilities, Fleet determined that the main ingredient to the success of Telematics is the level of service and support the Telematics company provides. Many companies provided insights into and comments regarding high implementation failure rates, poor data quality, generic solutions which did not fit utility industry needs and poor support after installation. Utilimarc's comprehensive data analysis has provided many Fleet teams with the tools, reporting, and dashboards necessary to effectively manage Fleet operations. In addition to Fleet analytics, Utilimarc also has the resources to resolve any of the data- or analytic-related needs quickly and professionally. Two significant reasons for using Utilimarc are that they: (i)specialize in utility fleets; and (ii) can integrate and overlay the vehicle information within the various platforms of Gas Operations to combine multiple data points which will deliver value added services to our customers.

Q. What are the main differences between Utilimarc Telematics and Track-star?

A. Utilimarc Telematics is more robust, and its technology is more advanced than the current Track-star system. The chart below represents a comparison which demonstrates the vast amount of data inputs which can be retrieved from using this newer technology.

CHART 8 - Telematics Comparison

Functionality of Technology	*Utilimarc Telematics (NEW)*	*Trackstar(CURRENT)*
Intergration to SAP	Yes	No
Integration to Work Order Mgmt System	Yes	No
Intergration to Infrastructure- Gas Information Systems & Mapping	Yes	No
Intergation to HR Systems	Yes	No
Intergration to OEM Chassis	Yes	No
Intergration to Vocational Equipment	Yes	No
Integration to WEX & Smartfill fuel reporting	Yes	No
Off road diesel tax recovery for non-road use benefit	Yes	No
GPS Location Latitude and Longitude	Yes	Yes
Accurate vehicle locations	Yes	Yes
Driver safety reporting	Yes	No
Street level routing - improved response time	Yes	No
Geofencing -Start and end of day reporting	Yes	No
Electronic DVIR (FMCSR)	Yes	No
Unit optimization	Yes	No
Idle mitigation	Yes	No
Preventative maintenance improvements	Yes	No
Predictive maintenance - repair information is submitted electronically	Yes	No
Vocation Reporting - Boom out of Stow, Air Compressor Operation	Yes	No
Warranty Cost Recovery	Yes	No
Data Interpreting	Yes	No
Benchmarking Supplementation	Yes	No

Q. Does the acquisition and implementation of Utilimarc Telematics impact the capital spend in this case versus the Company's last rate case?

A. In the 2018 Gas Rate Case application, Fleet Service requested a total capital expenditure of $19.34 million. This dollar amount was requested so that the Company could execute its lifecycle improvement plan and Fleet tooling purchases. In this filing, the Company has requested an increase of $7.011 million for the needed Telematics. Fleet services is continuing to ask for the same capital spend, ($19.34 million) to execute our lifecycle improvement plan and tooling purchases. The additional capital dollars ($7.011 million)

requested in this filing is to include the purchase and installation of Utilimarc Telematics for our Fleet units.

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 our 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 our operators of specific threats of violence. In 2018, there were 348 threats of violence to our operators. This technology has the ability to integrate geofencing with the threats of violence notifications to warn operators to help avoid operators being placed in harms 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 ("FMCSR"). 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 our customers. Having this ability to dispatch the nearest qualified crew to serve our customers results in lower expenses as well as increasing our 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 our 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 our 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 us 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 our drivers to change their behaviors on how much fuel is used for non-productive idle time. The reduced idle time also helps us achieve our environmental goals of reducing carbon. This technology offers engine fault codes and remote diagnostics as well. Having this insight to identify predicative maintenance trends prior to catastrophic repairs or extended downtime allows Fleet the ability to plan the repairs verses 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 our customers.

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

A. The productivity of the Telematics arises out of the ability to integrate and overlay onto many of our current systems. The integration allows us to view, on one central screen: (i) the location of crews; (ii) weather maps; (iii) street level routing; (iv) travel times for crews; (v) the qualifications of crew members; (vi) gas infrastructure mapping and systems; (vii) work orders assignments; (viii) amount of time at the jobsite; (ix) contractor locations; (x) bore crew locations; (xi) welder locations; (xii) MISS DIG requests and information; (xiii) damage notifications, and much more. The ability to collect all of these data points

in one place and on one screen will allow dispatchers the ability to analyze and provide a level of coordination of information we have never experienced. The output of this data will provide us with a lens to better understand how we can reduce non-premise time, eliminate waste in our day, and deliver world class performance to our customers.

Q. Can you quantify the economic benefits for customers by implementing Telematics?

A. A significant portion of the benefits in the chart below are based upon saving 45 minutes per day per crew member. A majority of the savings for Gas Operations will be achieved by dispatchers seeing the locations of the work, qualified crews, supporting crews (Boring Rig, Welders), MISS DIG tickets, and incoming damage notifications on one screen, versus the five different screens currently needed to obtain that information. Having the ability to overlay this information onto one screen diminishes the time and complexity of the decision-making process which will, in turn, allow for the optimization of crew resourcing, travel time and equipment placement. The productivity we anticipate to gain will avoid multiple trips and or truck rolls to our various job sites. The geofencing allows the leadership to track performance of crew arrival times to identify unnecessary stops as well as providing the visibility to the amount of time crews are at the job sites to monitor non-premise time. The investment required to implement this technology is $7.1 million; the savings and cost avoidance of implementing this technology (Telematics) is estimated at $6.9 million ($5.5 million Capital and $1.3 million O&M) for Gas Operations which will equate to lowering our overall expense for our customers. This project anticipates recapturing the investment and providing a positive return to our customers in less than two years.

CHART 9 - Telematics Savings

Description of Savings for Gas Operations					
Fuel Savings			***Capital***	***O&M***	***Total***
Fleet Fuel Savings - Idle Reduction- 10 Min Per Day- 5508 Veh/Equip		$	129,907	$ 32,477	$ 162,383
Fleet Fuel Savings - 5% Miles Reduction		$	250,365	$ 62,591	$ 312,956
Fleet Fuel Savings - Off Road Diesel Tax Recovery		$	221,950	$ 55,488	$ 277,438
Total Fleet Fuel Cost Benefit		**$**	**602,222**	**$ 150,555**	**$ 752,777**
Maintenance Savings			***Capital***	***O&M***	***Total***
Maintenance - Warranty Claims Recovery		$	130,177	$ 32,544	$ 162,721
Maintenance - 50% Reduction in Jump Starts		$	93,907	$ 23,477	$ 117,384
Maintenance - Predictive Maintenance - DTC Codes/Troubleshooting		$	208,310	$ 52,077	$ 280,105
Total Maintenance Cost Benefit		**$**	**432,394**	**$ 108,098**	**$ 540,492**
Gas Operations (Daily Time Savings)			***Capital***	***O&M***	***Total***
Gas Lineworker Time Savings Per Day- 45 Min Per Day-460 Employees @ $40 Per Hr. **This is done through Geo-Fencing specific locations to reduce wasted time existing the service center, gas station stops, returning to the service center early or multiple times per day and providing the optimal routes for the drivers to take to the job sites .Having visability to bore crews and welders will reduce wait times for crews performing work**	*45 Min Per Day, 460 Lineworkers @ $40 per hour*	$	2,870,400	$ 717,600	$ 3,588,000
Gas Service Worker Time Savings Per Day-12 Min Per Day-381 Employees @ $40 Per Hr **This is done through Geo-Fencing specific locations to reduce wasted time existing the service center, gas station stops, returning to the service center early or multiple times per day and providing the optimal routes for the drivers to take to the job sites**	*12 Min Per Day, 381 Lineworkers @ $40 per hour*	$	633,984	$ 158,496	$ 792,480
Total Daily Time Savings Cost Benefit		**$**	**3,504,384**	**$ 876,096**	**$ 4,380,480**
Rental Utilization			***Capital***	***O&M***	***Total***
Gas Ops- Rental Unit Utilization Reduction -	*10% of Annual Rental Cost Reduction*	$	964,969	$ 241,242	$ 1,206,211
Fleetilla Device Replacment		$	76,345	$ 19,086	$ 95,431
Grand Total Projected Savings			***Capital***	***O&M***	***Total***
		$	***5,580,313***	***$ 1,395,078***	***$ 6,975,391***

Q. Please describe the risk of the utilizing the current GPS tracking system?

A. The current Track-star system was selected as a corporate high impact risk due to a, "on classic support" system from our Track-star vendor. Currently version 5 is being utilized by the Company which has been unsupported by Track-star for approximately two years. The unsupported archaic technology only allows us to receive critical patches to maintain the solution but this version does not allow us to take advantage of software improvements required to satisfy key business requirements. Samples of the key business requirements have been included in the testimony and savings chart above.

Q. Are you addressing the entire Telematics project within this testimony?

A. No. This testimony is only addressing the Gas Operations portion of the Telematics project. The Company is planning on addressing the need for Telematics for Electric Operations within the electric rate case testimony.

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-20650

DIRECT TESTIMONY

OF

TIMOTHY K. JOYCE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

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. 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 Gas Management Services ("GMS"). I have divided my direct testimony into four parts:

(i) A description of the Company's GCS assets;

(ii) A description of functions within Gas Compression and Gas Storage and GMS;

(iii) A description of Operation and Maintenance ("O&M") expenses for Compression, GMS, Lost and Unaccounted for ("LAUF") and Company Use Gas for the years 2018 through the projected test year (October 1, 2020 through September 30, 2021). (**NOTE:** Storage O&M is addressed by Company witness Jared J. Martin.); and

(iv) A description of capital expenditures (including the Freedom Compressor Station ("Freedom") upgrade project) for the years 2018 through the projected test year for inclusion in the Company's rate base.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-70 (TKJ-1)	2018 – 12 Months Ending September 30, 2021 Gas Compression Storage and Gas Management Services O&M Expenses;

Exhibit A-71 (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, 2021;
Exhibit A-72 (TKJ-3)		Calculation of Gas Loss Percentage 2014 through 2019;
Exhibit A-73 (TKJ-4)		Calculation of Allowance for Gas Use and Losses for the Test Year 12 Months Ending September 30, 2021;
Exhibit A-12 (TKJ-5)	Schedule B-5.2	Projected Capital Expenditures Gas Compression and Gas Storage Summary of Actual & Projected Gas Capital Expenditures;
Exhibit A-74 (TKJ-6)		Storage Well Rehabilitation Detail;
Exhibit A-75 (TKJ-7)		Consumers Energy Company report titled "Ray Compressor Station Fire, Jan. 30, 2019" filed on April 5, 2019 in Case No. U-20463;
Exhibit A-76 (TKJ-8)		"Consumers Energy Company's Reply to the Commission Staff's Response and Stakeholder Comments" filed on May 30, 2019 in Case No. U-20463; and
Exhibit A-77 (TKJ-9)		"Consumers Energy Company's Ray Natural Gas Compressor Station Storage Field Injection Timeline & Facility Repair Update" filed on August 2, 2019 in MPSC Case No. U-20463.

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

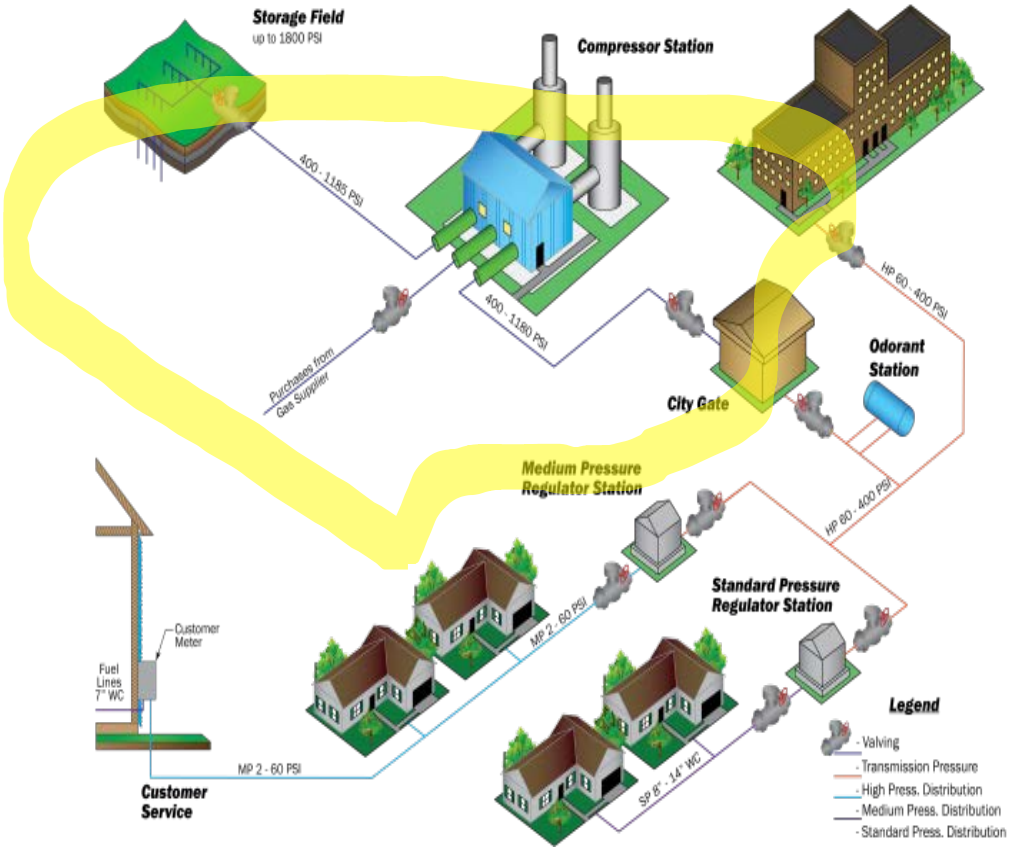
A. The first six exhibits listed above were prepared either by me or under my direction and supervision. Exhibits A-75 (TKJ-7), A-76 (TKJ-8), and A-77 (TKJ-9) were prepared by the Company and previously filed in Case No. U-20463 in connection with the event at

the Ray Natural Gas Compressor Station, and I am making them my exhibits in this case for purposes of my discussion of the event later in this direct testimony.

(i.) GCS ASSETS

Q. Please provide an overview of the Company's GCS assets.

A. The Company operates and maintains eight compressor stations, 15 storage fields, and 969 wells as of January 2019, throughout Michigan's Lower Peninsula. As of October 2019, the compression fleet is comprised of 49 natural gas-fired engines which generate 163,543 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 the next three years 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 150,940 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 (9 units)	Manchester, MI	14,500 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 (8 units)	Armada, MI	36,751 BHP
St. Clair (6 units)	Ira, MI	26,982 BHP
White Pigeon (10 units)	White Pigeon, MI	34,975 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, STORAGE, AND GMS

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 and to move gas from interstate pipeline sources onto the Company's transmission pipeline system and ultimately 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 conditions 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 will continue to be utilized to measure engine/compressor performance. The additional GFD metric will allow all compressor station and system equipment performance to be measured. Use of the new metric began in 2019.

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-2019.

Table 1: System ROR

Year	System ROR
2014	11.9%
2015*	7.8%
2016	10.7%
2017	14.8%
2018	15.0%
2019 YTD July	32.0%

*Consumers Energy's 2015 ROR was the lowest (best) ROR the Company has achieved in the history of using this metric.

Q. Why is ROR higher in 2019 than previous years?

A. ROR has increased, primarily due to three factors: intentional limited maintenance on assets that will be replaced as part of the Freedom upgrade project, the fire incident at the Ray Station that occurred in January 2019, and reliability challenges with our current fleet including the newer higher speed equipment.

Q. What is needed for the Company to be able to achieve and maintain its target performance?

A. To improve the compression fleet's ROR and, consequently, reduce downtime and overall maintenance costs, the Company will need to improve maintenance practices and then enhance funding to achieve more efficient preventative programs and eliminate costly reactive events.

Our current compression maintenance practices do not allow for analytics-based decision making or preventative and predictive maintenance. This is primarily due to the following:

- Compression currently operating on a break-fix cycle;
- Maintenance data storage (e.g., failure records, work orders, maintenance logs) being inconsistent; and
- Limited equipment condition data (e.g., temperature, in-flow pressure).

Funding to increase reliability of our compression fleet in support of a resilient and reliable gas system will begin in 2021.

Q. Does the Natural Gas Delivery Plan discuss gas compression assets?

A. Yes, gas compression is addressed in Section VI of the Company's Natural Gas Delivery Plan, which is provided as Exhibit A-36 (CCD-1) by Company witness Craig C. Degenfelder.

Q. Please describe the Company's objectives for gas compression assets.

A. 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. Thus, the proposed spending will address gas flow paths in Compression as well as other Statewide Energy Assessment factors like by-pass pipes and a new, additional dehy system to eliminate single failure points will significantly contribute to meeting the Company's objectives for more resilient (and safer) storage capacity as well as reduced operational risks.

In recent history, Consumers Energy has updated its Compression Fleet from 1940-1966 technology to modern and flexible units offering more options and higher efficiency. Post-launch reliability challenges are causing the Company to increase its preventative maintenance investments to leverage these new assets at significantly higher utilization rates. This will reduce risk during critical injection and withdrawal periods.

Improving the reliability and resiliency of the Company's compression fleet is a key priority for the future. Once improved compression reliability is achieved, the Company will annually evaluate compressor unit retirements to increase utilization rates. This will enable focused investments on the most critical units to optimize the Company's compression portfolio. In the near term, there are 11 compressor units being evaluated for retirement: five at Freedom, four at Muskegon River Compressor Station, and two at White Pigeon. Please refer to the Natural Gas Delivery Plan shown in Exhibit A-36 (CCD-1), Section VI, 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 has responsibility for the integrity, maintenance, and performance of the Company's 15 storage fields and 969 wells. This includes storage well maintenance and well logging and compliance with well integrity regulations. Further details about gas storage operations O&M expense are included in Company witness Martin'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.

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 adopted 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. Procedures governing operations, maintenance, integrity demonstration and verification, monitoring, threat and hazard identification, assessment, remediation, site security, emergency response and preparedness, and recordkeeping requirements of API RP 1171, sections 9, 10, and 11 were developed 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.

Q. Has PHMSA performed an audit of the Company storage system?

A. Yes. In August 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.

Q. What was the result of the audit?

A. A Detailed Action Plan was created 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 (as they come up in risk ranking) until the plan to discontinue operation of the field is executed. As a result, wells will be added 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 and will be added to future-year work scopes which will impact the average cost per well. A review of the wells rehabilitated in 2017 and 2018 is in progress and may require reconfiguration in order to comply with the recommendations.

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-72 (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 adjustment, not allowing the valve to

fully close. When storage field isolation valves are found to be not sealing, the valves are adjusted or repaired. During 2019, two leaking wellhead isolation valves were identified and repaired during well rehabilitation work at Lyon 29.

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 ~149 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 us 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 assess the retirement of at least one storage field at this time. Based on the outcome of this initial assessment, Consumers Energy will re-evaluate 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. With the remaining storage portfolio, Consumers Energy will retain the Ray Storage Field as a critical asset, and focus on increasing resiliency, while optimizing deliverability of the storage portfolio using tools at our disposal such as well rehabilitation.

Please refer to the Natural Gas Delivery Plan shown in Exhibit A-36 (CCD-1), Section VI, for further information on the Company's objectives for gas storage assets.

GMS

Q. Please describe the structure and primary functions of GMS.

A. GMS has 40 employees responsible for four major functions:

- Gas Control;
- Gas System and Operations Planning;
- Gas Supply; and
- Gas Transportation and Measurement.

The Gas Control department has 17 employees responsible for the centralized Gas Control Room operation, which monitors and controls the gas transmission system and 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, dispatch compression, and storage assets to ensure customer supply is met within the Transmission system's design limits, and monitor portions of the Distribution system. This department continually adapts to system conditions and varying customer demand. Much of the Company's customer demand is fed through the Company's city gates, which regulate the pressure and condition of the natural gas going into the Company's distribution system.

Gas System and Operations Planning has nine employees who are responsible for: transmission and storage capacity studies to support potential customer load inquiries; identifying prudent facility and operational improvements to meet changing supply and customer loads; compiling and supporting the reporting of operational data for other

required Company functions; assisting in the development of business cases for major system modifications related to the Company's gas transmission, storage, and compression system; the preparation of seasonal, monthly, and daily natural gas supply and storage dispatch plans; the coordination of the natural gas Gas Cost Recovery ("GCR") plan and GCR Reconciliation plan with the Company's operational plans to ensure customer load requirements will be met given the current operating conditions; as well as administering interconnect agreements with entities. This department also has responsibility for the long- and short-term planning of gas supply requirements.

The Gas Supply section has five employees who are responsible for obtaining reliable and reasonably priced gas supply for the Company's GCR or Sales customers and negotiating and administration of all the related gas supplier, transportation, and Asset Management contracts. In addition to tracking and forecasting the cost of gas sold and related inventory valuations; Gas Supply coordinates the gas purchase planning and regulatory filings related to GCR plans; and reconciliations.

The Gas Transportation and Measurement section has seven employees who are responsible for the management of the Company's Gas Customer Choice ("GCC") Program, including the preparation of required deliveries for GCC Suppliers (110 total) and monthly GCC remittance statements and annual reconciliations. It also has responsibility for the daily management of the gas transportation activity (there are about 500 transportation customers with about 3,500 associated meters) at the Company, including the daily balancing and confirmation of gas nominations and gas transportation contract administration. In addition, they are responsible for the preparation of the Gas Control Operations Summary and various internal and external reports, which make up

the foundation of volumetric accounting on the Company's gas transmission and storage system.

Additionally, the GMS department tracks the cost of gas; provides some regulatory reporting data; acts as witnesses and supports witnesses in other departments with various aspects of the Company's regulatory filings, including the GCR plan, the GCR Reconciliation plan, general Gas Rate Cases, and applications for a certificate of public convenience and necessity.

Q. What value do customers receive from the Company's GCS and GMS?

A. GCS and GMS 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 it allows 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>OPERATIONS, MAINTENANCE, AND COMPANY USE GAS</u>

<u>GCS AND GMS O&M EXPENSES</u>

Q. Please describe Exhibit A-70 (TKJ-1).

A. Exhibit A-70 (TKJ-1) identifies the 2018 – 12 Months Ending September 30, 2021, GCS and GMS O&M Expenses. Specifically:

- Column (a) identifies each O&M expense category;
- Column (b) identifies the Actual 2018 GCS and GMS O&M expense as $23,475,000;
- Column (c) identifies the Projected 2019 GCS and GMS O&M expense as $25,857,000;

- Column (d) identifies the Projected 2020 GCS and GMS O&M expense as $22,823,000;
- Column (e) identifies the Projected test year GCS and GMS O&M expense as $26,950,000;
- Line 1 identifies Base O&M expenses for 2018 through the test year of October 1, 2020 through September 30, 2021;
- Line 2 identifies Adjusted O&M expenses, which are expenses that are projected to change from past years or have been requested to be called out separately;
- Line 3 identifies Outside Services and are projected to decrease slightly from past years due to performing more maintenance with internal labor;
- Line 4 identifies Purchased Power which is projected to increase from past years; and
- Line 5 identifies Total O&M expenses for 2018 though the test year of October 1, 2020 through September 30, 2021.

Q. Please discuss the 2018 Actual O&M expenses incurred by the Company for GCS and GMS.

A. The 2018 Actual O&M expenses were taken from Consumers Energy's internal accounting records.

Q. Please explain how the 2019, 2020, and projected test year O&M expenses were calculated.

A. Consumers Energy tracks the history and future maintenance needs of each station and field. Once costs to operate and comply with the Michigan Gas Safety Code are prioritized, Business Services-Portfolio Planning, with the support and input from 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 GCS operations.

Q. Please discuss Base O&M costs.

A. Base O&M costs projected in Exhibit A-70 (TKJ-1) were developed by evaluating a unit's operating history and are broken into two categories – "labor" and "non-labor." Labor is the primary component and has a predictable increase. Because the Company has been in the natural gas business for more than 60 years, the Company has an excellent basis to make accurate forecasts. Non-labor expenses are also predictable and include items required to operate. These items include, but are not limited to: (i) fuel (diesel and gasoline) for equipment and vehicles; (ii) material; (iii) tools; (iv) cleaning supplies; (v) facilities; (vi) security; and (vii) road and grounds maintenance. Please note that Gas Storage expenses are addressed by Company witness Martin.

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 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-75 (TKJ-7), 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-76 (TKJ-8), "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-77 (TJK-9).

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 will be 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 were the Ray Fire Recovery efforts undertaken by the Company?

A. Repairs to the Ray facility are prioritized 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 can be filled prior to the start of the 2019-2020 heating season. A phased approach was used for the recovery work:

Phase	Description	Scope
1	Plant 3 equipment for injection operations	Glycol dehydration system, gas line heaters, and suction separator - includes major instrumentation and controls replacement, high-pressure large bore regulator/control valve rebuild, heat trace and insulation replacements, pressure safety and thermal relief valve replacements, misc. small bore valves and piping replacements
2	Plant 2 fuel gas system equipment	Glycol dehydration system, gas line heaters, and suction separator - includes major instrumentation and controls replacement, high-pressure large bore regulator/control valve rebuild, heat trace and insulation replacements, pressure safety and thermal relief valve replacements, misc. small bore valves and piping replacements
3	Plant 3 equipment for withdrawal operations	Glycol dehydration system, gas line heaters, and suction separator - includes major instrumentation and controls replacement, high-pressure large bore regulator/control valve rebuild, heat trace and insulation replacements, pressure safety and thermal relief valve replacements, misc. small bore valves and piping replacements
4	Plant 2 equipment injection operations	Throughput gas piping - large bore valve actuator repairs and control valve replacement, high-pressure large bore regulator/control valve rebuild, throughput gas major instrumentation, controls, and electric repairs, misc. small bore valves replacement
5	Plant 2 equipment for withdrawal operations	Dehydration system and line gas heaters - includes significant dehydration glycol process piping, instrument air, fuel gas, drain systems, instrumentation, controls, electric, heat trace, insulation, pressure safety and thermal relief valves, misc. small bore valves and piping
	Facilities	Assess damage and restore Plant 2 dehydration building, storeroom, and yard lighting

The Company focused on restoring the injection equipment at Plant 3 (Phase 1) first, because it maintains the highest compression capability, followed by the Plant 2 injection system equipment (Phase 4). The second priority was to repair the fuel gas equipment necessary to operate the Ray facility's emergency generator (Phase 2). The Company's third priority was to repair the equipment needed to withdraw gas from storage, beginning again with Plant 3 (Phase 3), then Plant 2 (Phase 5). Buildings in proximity to the Plant 3 blowdown vent and silencers were also damaged and required repairs (Facilities).

The Company also undertook a system-wide evaluation of blowdown methods and single-point failures at each of the Company's gas compressor stations, along with dispersion modeling of Ray Plants 2 and 3 discharge blowdowns. The analysis indicated that the circumstances that resulted in the Ray incident are not present at any other Consumers Energy facility. The Company will conduct precautionary dispersion modeling at additional locations as called for by its incident action plan. Results of this evaluation are detailed in "Consumers Energy Company's Compressor Station Blowdown Report & Ray Compressor Station Incident Action Plan", filed on September 3, 2019 in Case No. U-20463.

Q. Are there O&M and Capital costs included to address the Ray Station Event?

A. Yes. The Ray Fire Recovery efforts involves both Capital and O&M costs. O&M costs include 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. Table 2 outlines the O&M funding, included in Exhibit A-70 (TKJ-1), line 1, which are anticipated to occur prior to the test year.

Table 2: Ray Fire Restoration O&M Funding

		2018	Spent to Date 2019	JUL	AUG	SEP	OCT	NOV	DEC	2019	2020	OVERALL FORECAST
				Forecast	Forecast	Forecast	Forecast	Forecast	Forecast			
GC-94099	**Ray Fire Restoration O&M**	**-**	**1,486,150**	**715,217**	**1,458,235**	**934,906**	**626,910**	**367,223**	**401,289**	**5,989,930**	**200,000**	**6,189,930**
	Subtotal	**-**	**1,486,150**	**715,217**	**1,458,235**	**934,906**	**626,910**	**367,223**	**401,289**	**5,989,930**	**200,000**	**6,189,930**
	Phase 1	-	806,997	555,055	-	-	-	-	-	1,362,052	-	1,362,052
	Phase 2	-	183,000	65,162	-	-	-	-	-	248,162	-	248,162
	Phase 3	-	-	-	-	924,906	-	-	-	924,906	-	924,906
	Phase 4	-	-	-	435,405	-	-	-	-	435,405	-	435,405
	Phase 5	-	-	*50,000*	*75,000*	-	-	*314,719*	-	*439,719*	-	439,719
	Facilities	-	-	-	-	-	*195,015*	-	-	*195,015*	-	195,015
	Project Support / O&MC	-	*467,332*	*10,000*	*927,830*	*10,000*	*431,895*	*52,504*	*401,289*	*2,300,850*	*200,000*	2,500,850
	Detronics	-	*28,821*	*35,000*	*20,000*	-	-	-	-	*83,821*	-	83,821
	Loadings	-	-	-	-	-	-	-	-	-	-	-

Table 3 outlines the Capital funding, included in Exhibit A-12 (TKJ-5), Schedule B-5.2, page 2, line 7, which are also anticipated to occur prior to the test year.

Table 3: Ray Fire Restoration Capital Funding

		2018	Spent to Date 2019	JUL	AUG	SEP	OCT	NOV	DEC	2019	2020	OVERALL FORECAST
				Forecast	Forecast	Forecast	Forecast	Forecast	Forecast			
GC-00657	**Ray Fire Restoration Capital**	**-**	**5,129,821**	**3,420,209**	**775,836**	**277,217**	**1,350,668**	**660,476**	**(43,345)**	**11,570,883**	**484,009**	**12,054,892**
	Contingency	-	-	220,628	304,290	-	418,133	70,740	-	1,013,791	-	1,013,791
	Subtotal (without Contingency)	**-**	**5,129,821**	**3,199,581**	**471,546**	**277,217**	**932,535**	**589,736**	**(43,345)**	**10,557,092**	**484,009**	**11,041,101**
	Phase 1	-	1,783,238	(391,014)	-	-	-	-	-	1,392,224	-	1,392,224
	Phase 2	-	508,046	66,210	-	-	-	-	-	574,256	-	574,256
	Phase 3	-	450,605	906,590	656,454	(918,611)	-	-	-	1,095,037	-	1,095,037
	Phase 4	-	349,810	394,381	(435,405)	50,000	-	-	-	358,786	-	358,786
	Phase 5	-	*350,093*	*289,761*	*450,000*	*522,056*	*610,035*	*145,324*	-	*2,367,268*	-	2,367,268
	Facilities	-	-	-	-	-	-	-	-	-	-	-
	Project Support / O&MC	-	*821,101*	*1,394,083*	*(395,459)*	*486,700*	*64,043*	*251,664*	*(137,334)*	*2,484,799*	*325,700*	2,810,499
	Detronics	-	-	-	-	-	-	-	-	-	-	-
	Loadings	-	*866,929*	*539,571*	*195,956*	*137,072*	*258,457*	*192,748*	*93,989*	*2,284,722*	*158,309*	2,443,031
GC-00677	**Plant 3 Engine Mute Replacement**	**-**	**-**	**-**	**16,000**	**46,000**	**565,000**	**-**	**-**	**627,000**	**1,268,000**	**1,895,000**
	Engineering/Design	-	-	-	-	-	-	-	-	-	-	-
	Procurement	-	-	-	-	-	-	-	-	-	-	-
	Construction	-	-	-	16,000	46,000	565,000	-	-	627,000	880,000	1,507,000
	Internal	-	-	-	-	-	-	-	-	-	-	-
	Staffing	-	-	-	-	-	-	-	-	-	-	-
	Internal Services	-	-	-	-	-	-	-	-	-	-	-
	Loadings	-	-	-	-	-	-	-	-	-	-	-
	Contingency	-	-	-	-	-	-	-	-	-	388,000	388,000

Q. Please explain why the projected test year O&M expenses proposed in Exhibit A-70 (TKJ-1) are reasonable.

A. Base O&M costs are determined by operating history, and because these costs are relatively stable from year to year, accurate forecasting is achievable. This level of O&M expense allows the Company to provide reliable service by operating and maintaining equipment to meet customers' needs.

LAUF Gas

Q. Please explain LAUF gas as shown on Exhibit A-71 (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 expenses related to LAUF gas are based on a five-year average of actual LAUF volumes and the projected commodity cost of gas. Projected LAUF expenses can be found on Exhibit A-71 (TKJ-2). As shown on that exhibit (line 1, column (c)), the test year projected LAUF expense level is $6,936,000. The 2018 historical year amount was $26,629,000 as shown in Exhibit A-71 (TKJ-2), column (b).

Q. Please explain Exhibit A-71 (TKJ-2).

A. This exhibit identifies the projected changes from the historical 2018 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 by Company witness Eric T. Salsbury. 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-72 (TKJ-3).

A. This exhibit demonstrates the calculation of the most recent five-year average Gas Loss percentage (line 6, column (g)) of 1.27%. 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-73 (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 2.12%.

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 Michigan Public Service Commission ("MPSC" or the "Commission") 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-72 (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;

- 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.

Company Use Gas

Q. Please describe the Company Use Gas expenses shown on Exhibit A-71 (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 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-71 (TKJ-2), line 2, column (c), the Company Use Gas expense for the test year is projected to be $4,711,000. The calculation supporting this value can be found on Exhibit A-73 (TKJ-4).

Q. Why is there variability in the test year amounts for LAUF and Company Use Gas from the 2018 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 2018 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.) GCS CAPITAL EXPENDITURES

Q. What are the major drivers in determining capital expenditures for GCS?

A. The Company has invested significantly 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 adequate supply during peak periods. These system investments ensure continuous reliable service to customers during extreme demand weather conditions. In this filing, the Company seeks recovery of capital expenditures intended to complete the construction for the Freedom upgrade, and to comply with new regulations resulting from the PIPES Act and PHMSA IFR of 2016.

Q. Please describe Exhibit A-12 (TKJ-5), Schedule B-5.2.

A. This exhibit presents the capital expenditures for GCS from the year 2018 through the projected test year. The expenditures are grouped by: Freedom upgrade, Compression Sites, Storage Fields, Storage New Wells (line 15), Well Rehabilitation (line 16), Storage Pipeline Replacement (line 17), and Well Data Acquisition (line 18).

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 $146.2 million for 2018 (Actual), $147.8 million for the 12 months ending December 31, 2019 (Projected), $108.2 million for the 9 months ending September 30, 2020 (Projected), $256.0 million for the 21 months ending September 30, 2020 (Projected), and $116.6 million for the 12 months ending September 30, 2021 (Projected Test Year). The table below shows the Compression and Storage capital expenditures I am sponsoring in this docket.

Table 4: Compression and Storage Capital Expenditures

Line No.	(a) Program Description	(b) Historical 12 Mos Ended 12/31/2018	(c) Capital Expenditures Projected Bridge Year 12 Mos Ending 12/31/2019	(d) Projected Bridge Year 9 Mos Ending 9/30/2020	(e) Projected Bridge Year 21 Mos Ending 9/30/2020	(f) Projected Test Year 12 Mos Ending 9/30/2021
1	Freedom Upgrade Project	62,256	82,051	31,648	113,699	24,852
2	St Clair Upgrade Project	2,254	-	-	-	-
3	Compression	48,596	33,860	40,599	74,459	25,003
4	Storage	11,221	24,342	19,763	44,105	44,050
5	Well Rehabilitation	21,891	7,544	16,242	23,786	22,211
6	**Total Capital Expenditures**	**146,218**	**147,797**	**108,252**	**256,049**	**116,116**

Q. Please summarize the significant capital expenditures in 2018 ($146.2 million), bridge year ($256.0 million), and test year ($116.1 million) included on Exhibit A-12 (TKJ-5), Schedule B-5.2, page 1.

A. Exhibit A-12 (TKJ-5), Schedule B-5.2, page 2, lines 1 and 3, 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 3 are for projects that are separate from the upgrade project. In 2018, costs were incurred for suction filter separator installation and valve actuators. In 2019 through 2021, costs will be incurred for the upgrade project and tool purchases.

Q. Please identify the capital expenditures projected for the Muskegon River Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B-5.2, page 2, line 4, identifies the total capital expenditures for the Muskegon River Compression Station. In 2018, costs were incurred for unit overhauls, fuel gas valve replacement and thermal oxidizer stack replacement. In 2019 through 2021, examples of projected costs include: 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.

Q. Please identify the capital expenditures projected for the Northville Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B-5.2, page 2, line 5, identifies the total capital expenditures for the Northville Compression Station. In 2018, costs were incurred for the replacement of the back-up generator, and fire gate valve replacement. In 2019 through 2021, examples of projected costs include: completion of the back-up generator and fire gate valve replacements.

Q. Please identify the capital expenditures projected for the Overisel Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B-5.2, page 2, line 6, identifies the total capital expenditures for the Overisel Compression Station. In 2018, costs were incurred for dehydration system replacement, pressure regulating valve installation, and air compressor replacement. In 2019 through 2021, examples of projected costs include: valve replacements, replacement of the dehydration system, and turbocharger overhauls.

Q. Please identify the capital expenditures projected for the Ray Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B-5.2, page 2, line 7, identifies the total capital expenditures for the Ray facility. In 2018, costs were incurred for field scrubber installation and electrical system upgrades. In 2019 through 2021, examples of projected costs include: valve replacements, fire damage restoration, and early investment in a design study for an emergency flowpath to bypass around Ray.

Q. Are there Capital costs included to address the Ray Station Event?

A. Yes. Details about the incident and the capital costs are shown in Table 4 earlier in my direct testimony.

Q. Please identify the capital expenditures projected for the St. Clair Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B-5.2, page 2, line 8, identifies the total capital expenditures for the St. Clair Compression Station. In 2018, costs were incurred for valve replacements and turbine gas compressor overhaul. In 2019 through 2021, examples of projected costs include valve replacements and installation of an inlet filter separator.

Q. Please identity the capital expenditures projected for White Pigeon.

A. Exhibit A-12 (TKJ-5), Schedule B-5.2, page 2, line 9, identifies the total capital expenditures for White Pigeon. In 2018, costs were incurred for engine compressor re-builds and turbo overhauls. In 2019 through 2021, examples of projected costs include fire block valve actuator replacements, engine overhauls, and fire-eye system replacements.

Q. Please identify the capital expenditures projected for the Marion Storage Fields.

A. Exhibit A-12 (TKJ-5), Schedule B-5.2, page 2, line 10, identifies the total capital expenditures for the Marion Storage Fields. In 2018, costs were incurred for the McBain dehydration system replacement, engineering/preparation for new well drilling, and well rehabilitation. In 2019 through 2021, examples of projected costs include well rehabilitation and new well drilling.

Q. Please identify the capital expenditures projected for the Northville Storage Fields.

A. Exhibit A-12 (TKJ-5), Schedule B-5.2, page 2, line 11, identifies the total capital expenditures for the Northville Storage Fields. In 2018, costs were incurred for wellhead protection and engineering/preparation for new well drilling. In 2019 through 2021, an example of the projected costs include well rehabilitation, wellhead protection, and new well drilling.

Q. Please identify the capital expenditures that are planned for the Overisel Storage Fields.

A. Exhibit A-12 (TKJ-5), Schedule B-5.2, page 2, line 12, identifies the total capital expenditures for the Overisel Storage Fields. In 2018, costs were incurred for disposal well pumphouse replacement, well rehabilitation, and lateral replacement. In 2019 through 2021, examples of projected costs include disposal well secondary containment and walkway replacement, lateral replacement, well rehabilitation, and wellhead protection.

Q. Please identify the capital expenditures projected for the Ray Storage Fields.

A. Exhibit A-12 (TKJ-5), Schedule B-5.2, page 2, line 13, identifies the total capital expenditures for the Ray Storage Fields. In 2018, costs were incurred for well data acquisition system installation. In 2019 through 2021, examples of projected costs include completion of well data acquisition system installation, and installation of a brine disposal well.

Q. Please identify the capital expenditures projected for the St. Clair Storage Fields.

A. Exhibit A-12 (TKJ-5), Schedule B-5.2, page 2, line 14, identifies the total capital expenditures for the St. Clair Storage Fields. In 2018, costs were incurred for

observation wells hook up. In 2019 through 2021, examples of projected costs include a filter separator installation, well rehabilitation, and wellhead protection.

Q. Please identify the capital expenditures that are planned for Storage New Wells.

A. Exhibit A-12 (TKJ-5), Schedule B-5.2, page 2, line 15, identifies the total capital projected expenditures that are not tied to a specific site. In 2018 through 2020, this includes funding for the engineering, preparation, and drilling of new wells. These costs are budgeted for all storage fields in one common project based on historical trends and known future needs. Actual expenditures for 2018 will not be identified as "Storage New Wells" but instead will be represented within the site that ultimately adds the new well, replaces valves, or purchases capital tools. The table below outlines the timing and location of the Company's plan for drilling new wells.

Table 5: Proposed New Well Drilling Plan

Drill Year	Location	Field	New Well ID
2020	St. Clair	Ira	I-203
	Northville	Northville	N-303
2021	St. Clair	Lenox	L-201
	Marion	Winterfield	W-1003
2022	Marion	Cranberry	C-994
	Marion	Cranberry	C-995
	Marion	Cranberry	C-996

Q. Please identify the capital expenditures that are planned for Well Rehabilitation.

A. Exhibit A-12 (TKJ-5), Schedule B-5.2, page 2, line 16, identifies the total capital projected expenditures for the Company's Storage Well Rehabilitation Capital Program.

Exhibit A-74 (TKJ-6), Storage Well Rehabilitation Capital Program to Combine Rehabilitation with Logging, provides additional detail for this multi-year program that is in response to the federal minimum safety standards that are identified in API RP 1171, and which resulted from the PIPES Act and PHMSA IFR of 2016.

Q. Please provide more detail on the Well Rehabilitation Program.

A. The Well Rehabilitation Program will evaluate and reduce risk across our gas storage system and increase deliverability by rebuilding the gas wells at the Company's gas storage fields back to a like-new condition. The program also provides a baseline assessment for well integrity conditions during implementation to be used for risk assessment per requirement in API RP 1171.

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 10-year Well Logging 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, the well logging O&M will be required to maintain the desired 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-5.2, page 2, line 17, identifies the total capital projected expenditures that are not tied to a specific site. In 2019 through 2021, this includes funding for storage pipeline replacements. These costs are budgeted for all storage fields in one common project. Actual expenditures for 2018 are not identified as "Storage Pipeline Replacement" but instead will be represented within the site that ultimately has the pipeline replacement.

Q. Please provide more detail on the Storage Pipeline Replacement Program.

A. 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. To date, Consumers Energy has replaced 37.6 miles of LFERW pipe in the Winterfield, Cranberry, Northville, and Ira fields. There is approximately 8.78 miles of LFERW pipe left to replace in the storage fields.

For 2019, Consumers Energy has allocated $2.9 million of the EIRP budget to continue replacements, which funded the Winterfield Lateral 56S replacement project.

Table 6: Replacement of Storage Laterals in the EIRP

Year	Project WBS	Project Location	Project Name	Total Cost	Type of Pipe Replaced	Length of Pipe Replaced	Estimated Start	Estimated Completion
2016	GL-01621	Marion	MAR-Crnbry Lat 60W-60E Pipe Repl	$2,004,007	Pre-1970 LFERW Steel	7,633	4/4/16	11/1/16
2017	GL-01296	Marion	MAR-Wntrfld Lat 59 Pipe Repl	$2,580,634	Pre-1970 LFERW Steel	13,700	4/3/17	9/22/17
2018	GL-01321	Marion	MAR-Winterfield Lat 57N	$975,225	Pre-1970 LFERW Steel	3,000	4/2/18	9/7/18
2018	GL-01320	Marion	MAR-Winterfield Lat 57S	$965,916	Pre-1970 LFERW Steel	4,386	4/2/18	9/7/18
2019 Forecast	GL-01299	Marion	MAR-Winterfield Lat 56 S	$2,664,000	Pre-1970 LFERW Steel	4,280	8/1/19	9/30/19

Starting in 2018, the Company began a program to address the well lines 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.

Beginning in 2020, the Company will be consolidating the EIRP storage lateral replacements into the Storage Pipeline Replacement Program. All well line piping will be tracked under the Transmission Integrity Management Program ("TIMP"), following 49 CFR 192 Subpart O, for risks and consequences of failures. Replacement of these well lines and laterals contributes to safety of our crews and the public, deliverability, resilience, and integrity of our system.

Table 7: Projected Pipeline Replacement Schedule

Year	Project WBS	Project Location	Project Name	Total Cost
2020	GS-00384	Overisel	OVS- Overisel Lat 6	$7,040,000
2021	GL-02553	Overisel	OVS- Overisel Lat 7E	$5,000,000
2021	TBD	Overisel	OVS- Overisel Lat 7W	$8,500,000
2021	TBD	Marion	MAR-Winterfield Lat 54N/54N 8B	$9,200,000
2021	TBD	St Clair	STC- Lenox Lateral	$2,664,000
2021	TBD	Overisel	OVS- Overisel Lat 2	$3,447,000
2021	TBD	Overisel	OVS- Salem Lat 1	$1,547,000
2021	GL-01319	Marion	MAR-Winterfield Lat 56 N	$1,724,000

Q. Please identify the capital expenditures that are planned for Well Data Acquisition.

A. Exhibit A-12 (TKJ-5), Schedule B-5.2, page 2, line 18, identifies the total capital projected expenditures that are not tied to a specific site. In 2019 through 2021, this includes funding for well data acquisition. These costs are budgeted for all storage fields in one common project. Actual expenditures for 2018 are not identified as "Well Data Acquisition" but instead will be represented within the site that ultimately has the data acquisition equipment installed.

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 preventative and mitigative measure and reduce risk. 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.

Instrument communication testing was performed in 2018 in Ray storage field wells to ensure pressure communication between transmitters to confirm the mesh network communication works properly. Additional work is being performed in 2019 on approximately 12 Ray wells, with the work on the remaining 65 Ray wells expected to be completed in 2020. 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 most likely 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-5.2, page 2, line 1.

A. Exhibit A-12 (TKJ-5), Schedule B-5.2, page 2, line 1, identify 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 $62.3 million for 2018 (Actual); as provided in column (b), line 1, of Exhibit A-12 (TKJ-5), Schedule B-5.2, page 2; $82.1 million for 2019 (Projected), as provided in column (c), line 1, of Exhibit A-12 (TKJ-5), Schedule B-5.2, page 2; $31.6 million for the nine months ending on September 30, 2020 (Projected), as provided in column (d), line 1, of Exhibit A-12 (TKJ-5), Schedule B-5.2, page 2; $113.7 million for the 21 months ending on September 30, 2020 (Projected), as provided in column (e), line 1, of Exhibit A-12 (TKJ-5), Schedule B-5.2, page 2; and

$24.9 million for the test year ending September 30, 2020 (Projected), as provided in column (f), line 1, of Exhibit A-12 (TKJ-5), Schedule B-5.2, 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-5.2, 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 2020, and the 12 months ending September 30, 2021, costs will be incurred for engineering, procurement of new compressor engines, a new transformer, valves, and the balance of equipment, site preparation, construction of a new compressor and auxiliary buildings, and construction of the equipment.

Q. What is the projected annual investment for the overall Freedom upgrade project?

A. The projected annual spend 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, as engineering is completed, and as major contracts are awarded.

Anticipated Spend (Millions)	
2016	$16.8 (actual)
2017	$30.2 (actual)
2018	$62.3(actual)
2019	$82.1
2020	$40.0
2021	$22.0
2022	$1.0-6.6
Total	$254.4 - 260.0

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 old 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	On schedule
Phase 2 move Phase 1 compressors to permanent location	October 2021	On schedule
Demolition of Plant 1 and 2, and site restoration, complete	November 2022	On schedule

Q. What is the operating state of Freedom now that Phase 1 is complete with two new compressors installed?

A. With the completion of Phase 1, Freedom has the seven existing compressors in Plants 1 and 2, as well as the two new compressors installed in a temporary location. The two new compressors installed in the temporary location will mitigate potential short-term reliability concerns with the existing units until Phase 2 is complete. 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 reduce this probability to a level lower than 75%. Phase 1 provides back-up horsepower to offset such an occurrence. It also provides 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) and primary workhorse in the station suffered a significant failure and is 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 YTD Aug	20.5%

An ROR between 4% and 5% is needed to meet a 95% probability of meeting station reliability target; and

(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. Since 2005, annual throughput has almost doubled from about 42 Bcf in 2005 to a peak of about 78 Bcf in 2016. The percentage of Freedom's portion of the supply to the total system supply has also doubled from about 12% to about 24% of total system supply. 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. It now operates nine compressor units, seven of these units were installed in 1948, plus the two Phase 1 units. 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 eight 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, which is the proposed project, consisted of installing five new large units, two of which are 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. As mentioned previously in this direct testimony, 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. In the futures market, the benefit provided by taking advantage of summer prices over winter prices is about $0.20 to 0.30/dth on average out to 2030. In 2016,

average summer New York Mercantile Exchange natural gas Henry Hub prices were about $0.72/dth less expensive than average winter natural gas prices.

Q. Will the Freedom upgrade project improve reliability?

A. Yes. The Freedom upgrade project will not only replace the existing old compressors, pumping capacity will increase station horsepower from 10,400 BHP to 18,750 BHP and provide for new valves, gas conditioning and separators, and emergency generators will be installed. 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.

Q. Does this complete your direct testimony?

A. Yes. My direct testimony describes the Company's GCS and GMS operations as they correlate to our request for rate relief. The four areas of my direct testimony address the range of services provided by: (i) our compressor stations, storage fields, and wells, and (ii) 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 being a part of a 10-year plan to make the gas system safer and more reliable while continuing to be affordable and cleaner though 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-20650

DIRECT TESTIMONY

OF

ERIC J. KEATON

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

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 was promoted to Principal Rate Analyst 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, and U-20322.

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 2018 Historical Year Revenues;
Exhibit A-5 (EJK-3)	Schedule E-2	2018 Historical Year Consumption and Customer Counts;
Exhibit A-5 (EJK-4)	Schedule E-3	2018 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 2018 Historic Actuals to 12 Months Ending September 2021 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 2018?

A. Our weather adjusted cycle deliveries for 2018 totaled approximately 303.8 Bcf, compared to our budgeted cycle deliveries of approximately 303.3 Bcf, or within 0.2% 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 2018 operating revenue based on the actual customer and gas delivery levels for the historical year.

A. The 2018 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 2018 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, and U-20322. 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%.

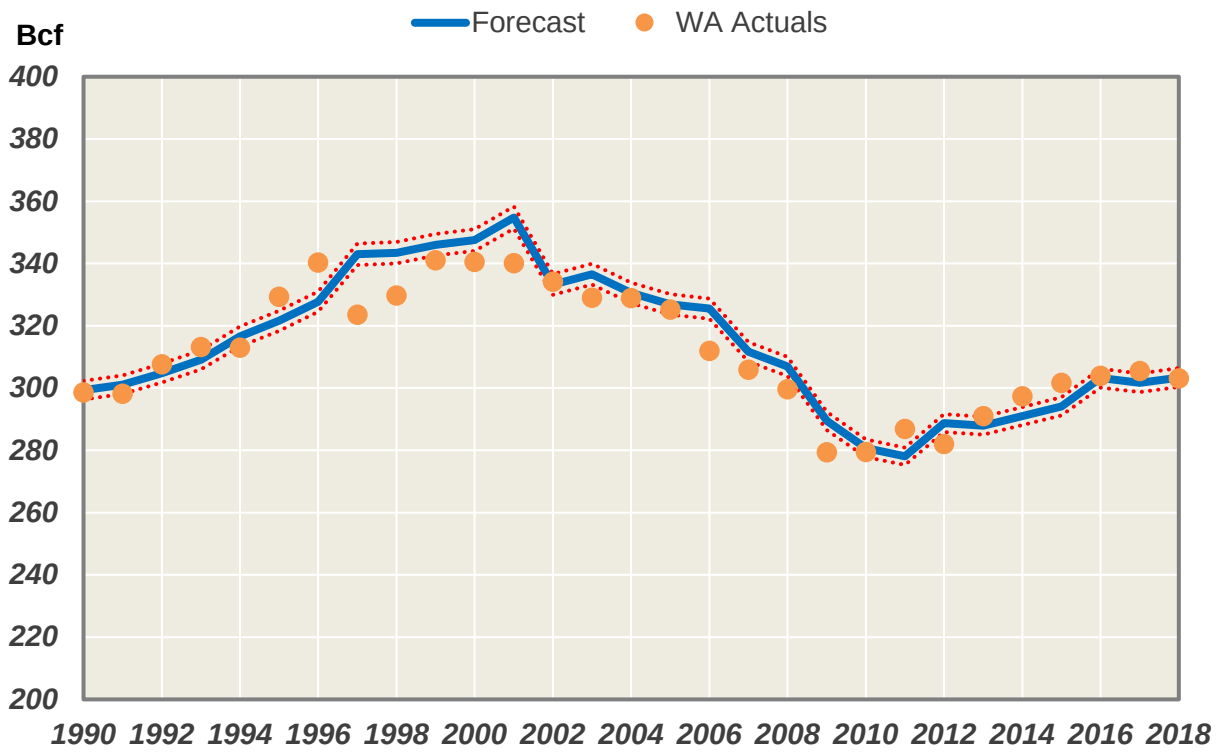
Q. Please explain the criteria used when considering the t-statistics and p-values associated with the model coefficients.

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 2012 through 2018 is 5 Bcf and the MAPE is only 1.4%.



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

A. Total calendar deliveries are projected to remain near historic weather normal levels of 303 Bcf in 2018 through the test year. Over the next five years, total deliveries are projected to increase by 0.17% per annum to 306 Bcf by 2023. However, the growth or loss in gas deliveries is not symmetric across all classes. The total and class level gas delivery annual forecasts for 2019 through 2023 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 2021 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 2018 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 1.3% from 1,775,619 in 2018 to 1,798,601 in the 12 months ending September 2021 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 2018 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 81,000 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 2018 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 2018 historical year to the 12 months ending September 2021 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-20650

DIRECT TESTIMONY

OF

SRIKANTH MADDIPATI

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

Q. Please state your name and business address.

A. My name is Srikanth Maddipati, 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 Treasurer and Vice President of Investor Relations.

Q. What are your current responsibilities?

A. I am responsible for managing corporate liquidity, financing, and treasury operations, and maintaining relationships with the banking community, rating agencies, investors, and research analysts. As a part of my role, I am responsible for raising the financial capital required by the Company including revolving credit facilities, long-term debt capital, and equity capital. In order to carry out my responsibilities, I maintain constant interaction 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 a Bachelor of Science Degree in Computer Engineering from the University of Michigan in 2004 and, concurrently, completed my Master of Science Degree in Engineering with a specialization in Signal Processing. I received a Master of Business Administration Degree ("MBA") from the Ross School of Business at the University of Michigan in 2008, where I focused on Finance and Accounting.

Q. What positions did you hold prior to your present position?

A. I began my career in 2004 as an engineer in the Advanced Information Systems Division of General Dynamics where I developed quantitative models for a number of Department of Defense related programs. After receiving my MBA in 2008, I joined Goldman Sachs in New York as an Associate in the Financial Institutions Group. In this role, I developed financial models to value both public and private companies and executed financing transactions for companies across a number of markets including equity, investment grade and high yield debt, preferred equity, and syndicated bank loans. I developed cost of capital analyses, financing and liquidity plans, and strategic alternatives for corporate boards, management teams, and investors during a time of extreme uncertainty and financial stress in the United States and global markets (2008 and 2009). In 2011, I joined the Private Equity Group in Goldman Sachs' Asset Management Division and was promoted to Vice President in 2012. As part of this group, I analyzed and recommended investments in a wide variety of industries and assets including power and energy assets. As part of my investment recommendation, I analyzed the capital structure and required rates of returns for securities across the entire capital structure (equity, debt, and hybrid). In 2014, I joined CMS Energy Corporation ("CMS Energy") and Consumers Energy as Assistant Treasurer, and I was promoted to Treasurer in 2016.

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

A. Yes. I have provided testimony on cost of capital in several cases including Case Nos. U-20322, U-20134, U-18424, U-18322, and U-18124. I have also provided testimony in the Company's integrated resource plan, Case No. U-20165, on the Company's financial

compensation mechanism. In addition, I have provided support to Dhenuvakonda Rao, who served as the Company's witness covering capital structure and cost of capital in several past electric and gas rate cases before the Commission including Case Nos. U-17990 and U-17882.

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 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:

- **I. SUMMARY OF RECOMMENDATIONS**
- **II. DEVELOPMENT OF ROE RECOMMENDATION**
  - **A. Importance of ROE and Financial Strength**
  - **B. General Principles**
  - **C. Summary of ROE Results**
  - **D. Qualitative Equity Cost Rate Considerations**
    1. **Investor and Rating Agency Expectations and View of Regulatory Environment**
    2. **Interest Rates**
       - **a. Long-Term Interest Rates**
       - **b. Short-Term Interest Rates**
    3. **ROE Trends**
    4. **Economic Outlook And Uncertainty**
    5. **Capital Investment**
  - **E. Quantitative Equity Cost Rate Analyses**
    1. **Selection of Proxy Companies**
    2. **Empirical Capital Asset Pricing Model Analysis**
    3. **Projected Risk Premium Analysis**
    4. **Comparable Earnings Analysis**
    5. **DCF Analysis**

III. DISCUSSION OF EMPLOYEE INCENTIVE COMPENSATION PLAN FINANCIAL INCENTIVES

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring:

Exhibit A-14 (SM-1)	Schedule D-5	Cost of Common Shareholders' Equity;
Exhibit A-78 (SM-2)		Goldman Sachs Economics Research Report – September 18, 2019;
Exhibit A-79 (SM-3)		ROE and Equity Relationship;
Exhibit A-80 (SM-4)		John D. Quackenbush Testimony before FERC;
Exhibit A-81 (SM-5)		FERC Notice of Inquiry;
Exhibit A-82 (SM-6)		PPUC Decision;
Exhibit A-83 (SM-7)		S&P Global RRA Regulatory Focus Report – October 17, 2019;
Exhibit A-84 (SM-8)		UBS Regulatory Report;
Exhibit A-85 (SM-9)		Fama and French: *"The Cross-Section of Expected Stock Returns"*;
Exhibit A-86 (SM-10)		Fama and French: *"The CAPM is Wanted, Dead or Alive"*;
Exhibit A-87 (SM-11)		Financial Times: *"The time has come for the CAPM to RIP"*;
Exhibit A-88 (SM-12)		Chartoff, Mayo, and Smith: "*The Case Against the Use of the Capital Asset Pricing Model in Public Utility Ratemaking*";
Exhibit A-89 (SM-13)		Chretien and Coggins: "*Cost of Equity for Energy Utilities: Beyond the CAPM*";
Exhibit A-90 (SM-14)		FERC Opinion No. 531-B;
Exhibit A-91 (SM-15)		Federal Reserve: "*The Equity Risk Premium: A Review of Models*";

Exhibit A-92 (SM-16)	Brattle Group: "*Estimating the Cost of Equity for Regulated Companies*";
Exhibit A-93 (SM-17)	Mississippi Public Service Commission Rate Schedule (Mississippi Power);
Exhibit A-94 (SM-18)	Alberta Utility Commission, Decision 20622-D01-2016 (Extract);
Exhibit A-95 (SM-19)	Value Line: "*Using Beta*";
Exhibit A-96 (SM-20)	FERC Opinion No. 551;
Exhibit A-97 (SM-21)	Gordon and Shapiro: "*Capital Equipment Analysis*"; and
Exhibit A-98 (SM-22)	Additional Cost of Common Shareholders' Equity Analyses.

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

A. Exhibits A-14 (SM-1), Schedule D-5, A-79 (SM-3), and A-98 (SM-22) were prepared under my direction and supervision. My 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 are you recommending for Consumers Energy's gas business?

A. Based on my qualitative and quantitative analyses, I believe a reasonable ROE range for Consumers Energy's gas business is 10.00% - 11.00%. While the analyses support a higher recommendation, because the Commission has a preference for adjustments to be limited to reasonable movements, and given the recommended equity ratio of 52.5% provided by Company witness Marc R. Bleckman, I recommend the Commission set an ROE at 10.5% at this time, which is the middle of recommended range. Alternatively, if the Commission elects to maintain an ROE of 9.9%, the Company would propose an

equity ratio of 53.94% which is still below that of peers. I have arrived at this recommendation after considering 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 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 your recommended ROE compare to your current authorized ROE?

A. The current ROE authorized by the Commission for Consumers Energy's gas business is 9.9%, which was established in the Commission's Final Order in Case No. U-20322 and is below the bottom of my recommended reasonable range. Given the capital structure recommended by Company witness Bleckman, I recommend an ROE of at least 10.5% which is 60 basis points higher than the current authorized 9.9% ROE.

Q. Discuss why you believe the Commission should increase the ROE, given they recently lowered it in Case No. U-20322?

A. The Commission's Order in Case No. U-20322 noted, as part of its rationale for a lower authorized ROE, that "[n]ationally, ROEs are trending downward." MPSC Case No. U-20322, September 26, 2019 Order, page 71. Importantly, ROEs and equity ratios are linked, as I will outline in my testimony. Thus, while national ROEs may have trended downward, the Commission should note that national equity ratios have trended upward. As discussed by Mr. Bleckman in his direct testimony, the average equity ratio for the

Company's peer group is 56.0% (see Exhibit A-25 (MRB-10)), which is meaningfully higher than what is 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% and approve an equity ratio of 53.94%.

My 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, I believe such an outcome could be partially mitigated with a corresponding increase in the authorized equity ratio.

II. DEVELOPMENT OF ROE RECOMMENDATION

A. Importance of ROE and Financial Strength

Q. Discuss the importance of financial strength for a utility, including Consumers Energy.

A. Our nearly 1.8 million natural gas customers count on us to provide natural gas to heat their homes, businesses, schools, and communities. Our 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 gas 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. Our customers and the state of Michigan are not well served if our ability to meet these obligations is either subject to significant

uncertainty or contingent on the instant state of the capital markets. Temporary market conditions can be disjointed and, as such, it would not be in the best interest of customers to be completely reliant upon them. It is tempting to assume that markets will remain robust and capital will always be accessible. Markets, however, can and do deteriorate quickly as evidenced during the Great Recession. A recent example occurred in mid-September of this year (2019) when short-term interest rates spiked up to the 10% area, requiring the Federal Reserve to inject significant liquidity into the markets to help return interest rate levels back to moderate ranges. This dislocation is captured in the Goldman Sachs Economics Research Report from September 18, 2019, Exhibit A-78 (SM-2), which provides, in part:

> Dollar funding rates surged at the start of the week, with overnight GC repo spiking to highs of 10% intraday on Tuesday. These rate levels were higher than those observed over 2018 year-end, leading to concerns about the Fed losing control of short-term rates. Even the policy rate, fed funds, rose sharply, by 11bp on Monday to set at 2.25%, the top of its target range. On Tuesday, the Fed offered dealers up to $75bn in repurchase operations, and followed this with another temporary Open Market Operation (OMO) this morning of similar magnitudes. Even with the Fed's intervention, fed funds effective set at 2.3% for Tuesday, above the target range. Today's operation resulted in a take-up of the full $75bn amount, and we suspect the Fed may have to increase the size further or offer term repo. [Emphasis added.][1]

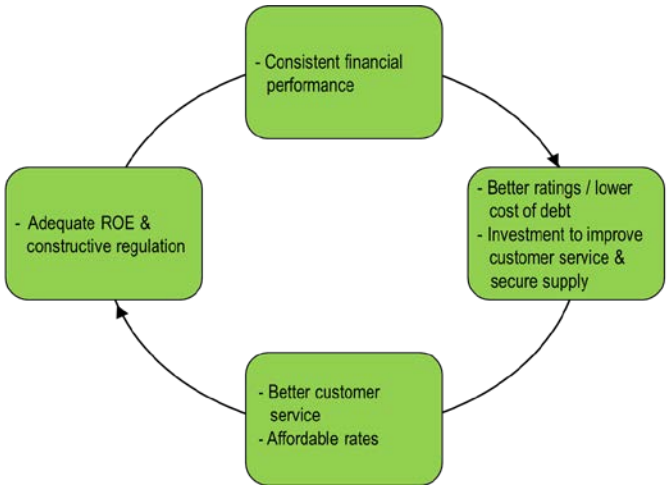
Further, on an ongoing basis, the capital markets have seen volatility and dislocations driven by social media messages surrounding trade negotiations with a number of different Unites States trade partners.

[1] See Exhibit A-78 (SM-2), page 1.

As such, 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, from robust to more capital constrained conditions as well. In my experience, for businesses faced with financing and investing decisions that were not regulated and lacked an obligation to serve, it was not uncommon for major investments to be deferred or canceled in response to tightening market conditions or shifts in economic cycles. Our customers, however, would not be well served by such a strategy, particularly market conditions resulting in the need to adjust work on major projects, such as delaying installation of new gas services, halting replacement of old pipelines, or halting construction of new pipelines.

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 gas infrastructure. As the chart demonstrates, attractive ROEs are important and, in part, contribute to delivering consistent financial performance. This occurs because the equity 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. In fact, higher ROEs are associated with higher customer satisfaction. Utilities with customer satisfaction in the top quartile have ROEs that are 50 basis points higher than those in the bottom quartile,[2] demonstrating that a reasonable ROE is not only important for investors, but delivers value to customers as well. This reinforces 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.

[2] J.D. Power's report, *How Customer Satisfaction Drives Return on Equity for Regulated Electric Utilities*, https://www.jdpower.com/sites/default/files/How%20Customer%20Satisfaction%20Drives%20Return%20On%20Equity%20for%20Regulated%20Electric%20Utilities%20White%20Paper.pdf

Q. Discuss the role ROE has in capital allocation.

A. Capital is finite. As such, not all projects or investments can be funded, and the management team of a utility must decide which investments are most beneficial to customers and investors and should, therefore, be ultimately 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 private enterprise to make an investment decision. 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 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 of that view.

Q. Does your 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. Every 10 basis point increase, relative to the currently authorized ROE of 9.9%, would represent less than a 0.2% gross impact to customer bills; thus, on average, my recommended ROE would increase the average residential customer bill by $0.48 per month. I emphasize the impact on a "gross" basis because the stated ROE sensitivity may be partially offset by lower debt costs and improved access to capital markets given the aforementioned benefits of the "virtuous cycle." While the Company

certainly 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, I believe an ROE and equity ratio consistent with my recommendation ensures the continuation of the "virtuous cycle" and is in the best interest of the customers we serve.

B. General Principles

Q. What are the general principles in setting a fair rate of return?

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 I have provided and discuss in my direct testimony.

Q. To support the principles reflected in *Hope* and *Bluefield,* what methodology did you employ for setting a fair rate of return?

A. I performed several analyses to determine a reasonable ROE. I performed an analysis of the ROE and equity ratio that would support the Company's long-term Funds from Operation ("FFO")-to-Debt and credit. I also employed several quantitative models to determine a return for investments having commensurate risk.

Q. Why did you employ multiple methodologies and analyses for this case?

A. An ROE and equity ratio that support the Company's credit may not be commensurate with investments of similar risks and vice versa; therefore, my analysis looks at both the impact to credit and similar investments. Furthermore, determining an ROE for an investment of commensurate risk is not an exact science, and any methodology utilized is based on assumptions and inputs that may be less than certain. I, therefore, utilized multiple methodologies, because each of these methods individually will often produce a range of values as illustrated by Exhibit A-14 (SM-1), Schedule D-5, page 11, and results of these quantitative models often make assumptions that do not necessarily fully reflect the returns that investors require, given current economic and financial conditions. Thus, the application of multiple methods, 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.

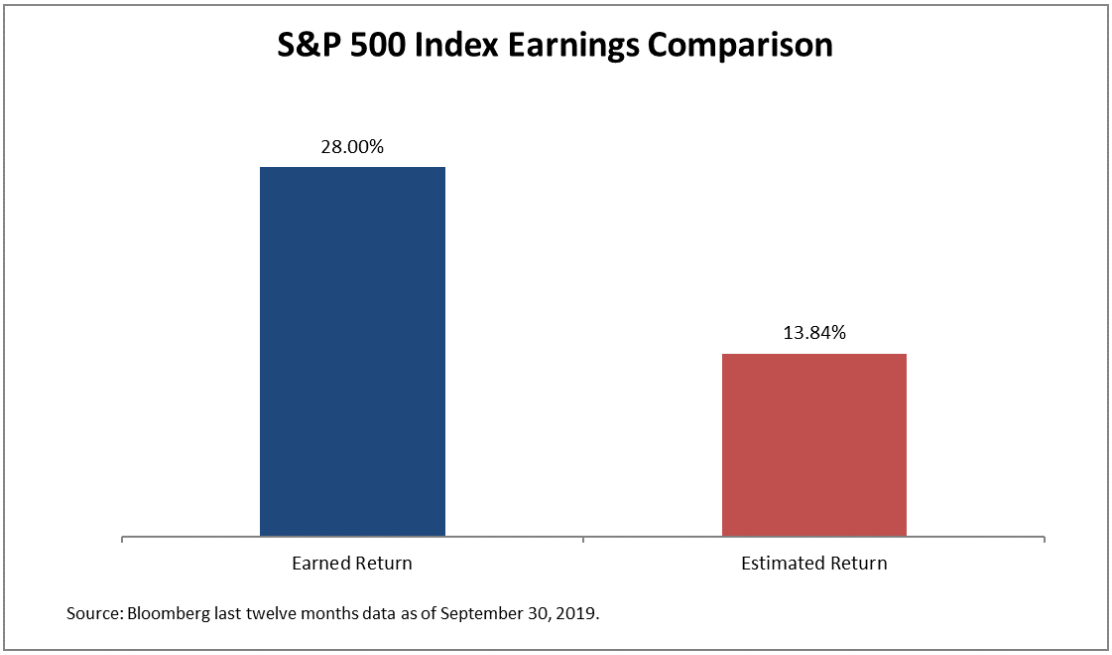
A. Each of the standard quantitative models assumes that economic conditions are relatively stable and that current market inputs are reflective of their long-term outlook. That

assumption may not be true in current market conditions mainly because of the unprecedented amount of central bank intervention and impacts of the Tax Cuts and Jobs Act ("TCJA" or "Tax Reform") on the economy and credit quality of utilities observed during the last several years.

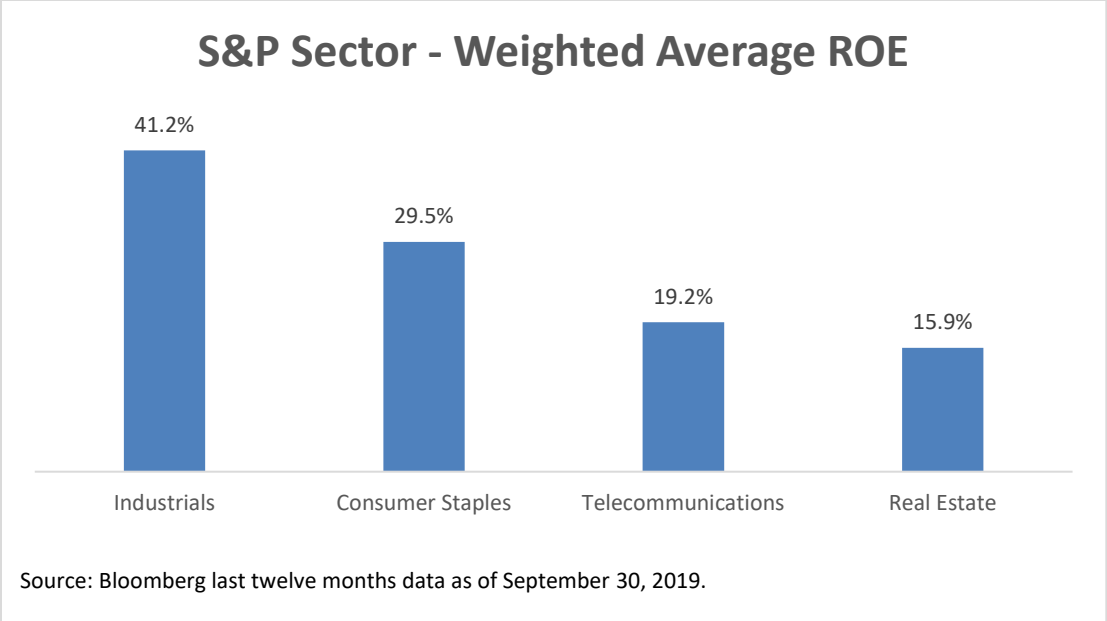
Q. What are the estimates produced by quantitative models representing?

A. Each of the quantitative models I 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 be greater than the required rate of return. This point is best illustrated by considering the average earned return of the Standard and Poors ("S&P") 500 index.[3] In the last 12 months, the market earned an ROE that is 14.2% higher than that implied by standard model estimates.

[3] Data provided by Bloomberg, as of September 30, 2019. 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 the S&P sectors and the earned return of each. It demonstrates that investors may be able to realize competitive or better returns in other investments with commensurate risk, and the utility sector is competing with each of them for investment dollars.



Source: Bloomberg last twelve months data as of September 30, 2019.

C. Summary of ROE Results

Q. Can you summarize your findings regarding Consumers Energy's cost of common equity?

A. The results of my analyses are displayed in Exhibit A-14 (SM-1), Schedule D-5, page 11, and summarized in the chart below. While I believe the methodologies and inputs used in my analyses are supported by academic literature and regularly used by regulatory witnesses across the country, I replicated the MPSC Staff's ("Staff") methodology in the Company's most recent gas rate case (Case No. U-20322). Two of three methodologies regularly employed by Staff result in estimates that exceed 10.0% and are greater than my recommended 10.5%. Only the DCF analysis provided a lower result but the analysis also provided a wide-range of results. Furthermore, as noted by other regulators given capital market conditions – in particular the low-yields on bonds, including U.S. Treasury bonds – there is less confidence that the DCF provides a risk-appropriate ROE, as required by Hope and Bluefield.

Summary of ROE Estimates

	Company ROE Estimate	Case No. U-20322 Staff Methodology ROE Estimate
Projected CAPM		10.60%
Projected Risk Premium ECAPM	10.71%	
Projected Risk Premium	11.25% - 12.01%	10.97% - 11.34%
Analyst Consensus DCF	6.68% - 10.02%	5.96% - 11.65%
Comparable Earnings	10.73%	
Recommended Range	**10.00% - 11.00%**	

Based on my analyses and consideration of factors I discuss below, I have concluded that an appropriate ROE range for Consumers Energy's gas business for the test year is 10.00% - 11.00%. The significant need to update the Company's and the state's energy infrastructure would suggest an ROE at the top end or even above the ranges shown in my analysis. My recommended ROE is 10.5% which is at the center of my reasonable ROE range. I recognize the Commission recently authorized an ROE of 9.9% and may view an increase of 60 basis points to be dramatic, but in order to maintain the credit health of the Company as it pursues significant infrastructure improvements, I believe that they should consider this ROE in conjunction with the recommend equity ratio proposed by Mr. Bleckman. If the Commission believes 60 basis points in ROE is too dramatic, then a higher equity ratio than requested would be a reasonable compromise, which is also discussed in the direct testimony of Company witness Bleckman.

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. 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 in 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 *Regulated Electric and Gas Utilities Rating Methodology* for Moody's Investor Services ("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." 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.

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 as the Vice President of Investor Relations and Treasurer, I have had many conversations with investors and rating agencies, and though they recognize the general strength of Michigan's regulatory construct and legislative framework, several have expressed concerns regarding authorized ROEs and a resulting perceived deterioration in Michigan's regulatory environment. While one case or decision may not instantly shift investor views, a sequence of cases overtime can create disappointment among investors. In fact, analysts noted the Commission's lower ROE in the Company's electric rate case (Case No. U-18322) as a concern, with one analyst highlighting "ROE creep" as an area of concern. 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 most recent 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.

Q. How do you think that investors will view your proposed ROE?

A. I believe investors would consider an authorized ROE of 10.5% together with an equity ratio of 52.50%; the legislative impacts of 2008 PA 286 ("PA 286"), 2016 PA 341 ("PA 341"), 2012 PA 342 ("PA 342"); and other regulatory adjustment mechanisms proposed by the Company, to be commensurate with the risks involved in investing in Consumers Energy.

Q. Have you 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 increases, by four months, the time between filing a rate case and implementation of any rate increases. Overall, I do not believe this aspect of the legislation reduces the risk faced by equity investors in the utility.

Q. Have rating agencies commented on the impact of Tax Reform?

A. Yes. Each of the agencies published reports on Tax Reform, and their respective titles highlighted the credit challenges faced by utilities considering Tax Reform:

> *U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound.* [S&P, January 24, 2018];
>
> *Tax Reform Creates Near-Term Credit Pressure for Regulated Utilities and Holding Companies.* [Fitch Ratings, Inc. ("Fitch"), January 24, 2018]; and
>
> *Tax reform is credit negative for sector, but impact varies by company*. [Moody's, January 24, 2018.]

Given the impact of Tax Reform, Moody's initially revised the outlook of 24 utilities to "negative" and continued in June 2018 by revising its outlook for the entire U.S. regulated electric and gas utility sector from "stable" to "negative." Moody's has downgraded the outlook and credit of numerous holding and utility companies, specifically citing Tax Reform's negative effect on company credit metrics as a main driver, if not the primary driver, for the ratings action. While Consumers Energy has not yet been put on negative watch, the inaction by ratings agencies has been predicated on the current constructive regulatory environment in Michigan, and the *expectation* that the Commission will consider the impacts of Tax Reform on credit.

Q. Have the rating agencies commented on any Michigan utilities?

A. Yes. As discussed in Mr. Bleckman's testimony and shown in Exhibit A-137 (MRB-13), 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:

> The 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.]

The Commission should note this action was taken *despite* recognition of a credit supportive regulatory environment and *despite* an authorized ROE of 10.0% and a 52% equity ratio.

Q. Are there ways to mitigate the credit risks imposed by TCJA?

A. Yes. In particular, the regulatory response will play a critical factor in mitigating these credit risks and the credit rating agencies have specifically identified ROE and equity ratio as key tools for mitigating this impact as noted in the following excerpts from Moody's and Fitch:

> [M]ost utilities will attempt to manage the negative financial implications of tax reform through regulatory channels…They could <u>propose to increase equity layer in rates or level of the authorized return on equity. In these cases, a cooperative regulatory relationship matters most for a given utility.</u> [Moody's, January 24, 2018. (Emphasis added.)]

> Regulatory Support Key to Mitigating Downward Migration in Ratings…many tools could be employed, including <u>increase in authorized equity ratio and/or return on equity.</u> [Fitch, January 24, 2018. (Emphasis added.)]

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. Two key factors that help determine this ratio are the Company's ROE and equity ratio. Exhibit A-79 (SM-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. As Exhibit A-79 (SM-3) also illustrates, reducing either ROE or equity ratio on a stand-alone basis results in a corresponding deterioration of the FFO-to-Debt ratio. Further, movement of the ROE and equity ratio pair from 10.5%/52.5% to the Company's 9.9%/52.05%, as determined in the September 26, 2019 Order in Case No. U-20322, would result in a further deterioration of 94 basis points in the resultant FFO-to-Debt ratio.

Q. Do you believe an ROE/equity ratio pair of 10.50%/52.50% supports the Company's current credit rating?

A. No. The methodology I've proposed most closely aligns with Moody's methodology and, as I have 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. Moody's noted in their most recent credit opinion that a factor that could lead to a downgrade is a "deterioration in financial metrics such as CFO pre-WC to debt falling below 20%"; therefore, I believe an ROE or equity ratio higher than currently recommended by the Company would be justified. However, I recognize the Commission has recently lowered the ROE to 9.9% and may be hesitant to reverse course

and raise the ROE by 60 basis points. If the Commission believes an ROE of 9.9% is more appropriate, then a higher equity ratio would be warranted.

Q. Please summarize your conclusions regarding investor and credit rating agency expectations.

A. Based on my interactions with investors and the rating agencies, I conclude that they view the authorized ROE as a critical metric provided by the Commission 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. <u>Interest Rates</u>

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 I will discuss below.

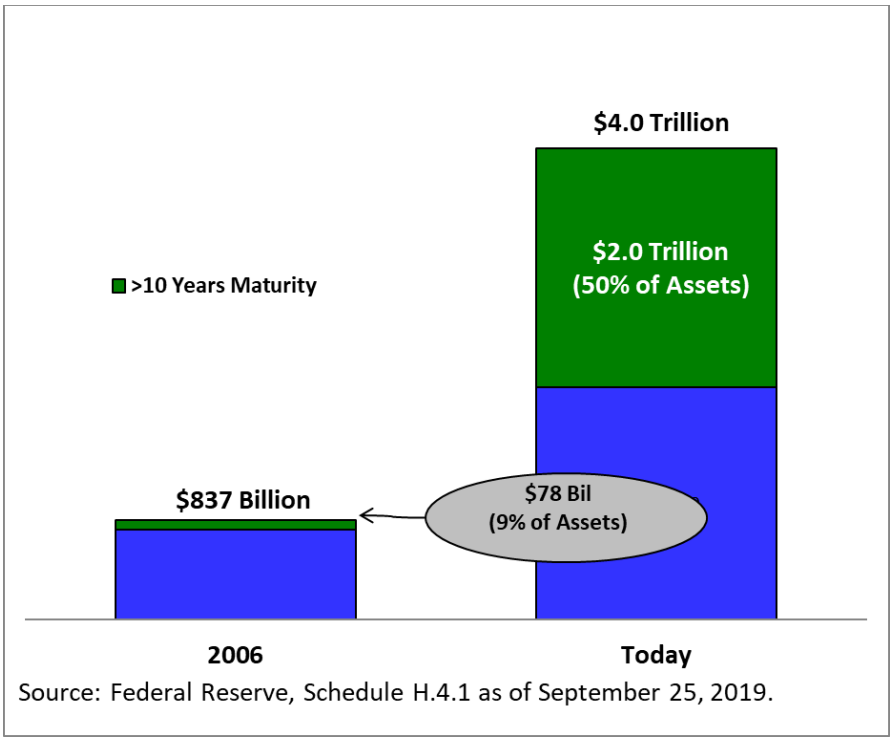
a. Long-Term Interest Rates

Q. What is your assessment of current long-term interest rates?

A. Long-term interest rates have been, and continue to be, held 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 the size of the Federal Reserve's balance sheet increasing, the duration of the assets being held have 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 lowering long-term interest rates per the Federal Reserve's policy.



Source: Federal Reserve, Schedule H.4.1 as of September 25, 2019.

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 largely kept interest rates artificially low as developed countries continue to experience tepid growth. This has resulted in 37% of all developed country sovereign debt, over $15 trillion, having negative yields[4]. Furthermore, 96% of debt for developed sovereign bonds has a yield below that of the 30-year United States Treasury. These drastic actions by central banks have made the rates offered by long-term United States Treasuries appear attractive on a relative basis, which has increased demand. However, as I 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

[4] Data provided by Bloomberg, as of September 30, 2019. See workpapers for support data and summary.[5] See Consumers Energy 2019 Third Quarter 10-Q, page 19.

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 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. Based on my extensive experience and conversations with utility investors, and in particular Consumers Energy investors, it is clear that investors' expectations for investment returns do not simply decrease because of extraordinary intervention by central banks to lower rates.

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 starting in late 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%, 198 basis points higher than the current case annual cost of 3.97%.

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. In fact, the Company's improved credit ratings over the past several years, resulting in lower long-term debt rates, 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 improved credit ratings and financial stability, could justify a lower ROE?

A. No. Such a belief confuses the risk faced by bond investors with the risk faced by equity investors, which are important to differentiate. As stated above, the Company's improved credit ratings and lower interest rates lead to a lower cost of debt, which decreases the overall cost of capital, and this benefit is passed on to customers. Exhibit A-14 (SM-1), Schedule D-5, page 6, demonstrates how increased credit ratings save customers $89 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 as investors seek safe havens for their investments

but, would necessitate a higher ROE for stocks to compensate for the additional risk;

- Equity risk premiums 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 direct testimony before the Federal Energy Regulatory Commission ("FERC"), the former chairman of the MPSC, John D. Quackenbush, cited anomalous market conditions and advocated ROEs in the high end of the zone of reasonableness. See Exhibit A-80 (SM-4).

Q. Has any other regulator commented on the impact of low interest rates and ROE?

A. Yes. FERC issued a March 21, 2019 Notice of Inquiry ("NOI") to seek information on how it should modify its methodology regarding ROE for utilities under its jurisdiction. See Exhibit A-81 (SM-5). In particular, FERC notes that:

> Since the financial crisis of 2008-2009, the Commission has grappled with whether the DCF model continues to produce ROEs for public utilities consistent with the *Hope* and *Bluefield* capital attraction standards. In both Opinion Nos. 531 and 551, the Commission concluded that the capital market conditions prevailing after the financial crisis—in particular, the low yields on bonds, including U.S. Treasury bonds—rendered the Commission less confident that a mechanical application of the midpoint of the DCF-produced zone of reasonableness would provide a risk-appropriate ROE, as required by Hope and Bluefield. [FERC NOI, pages 13-14.]

In a 2012 decision for PPL Electric Utilities, the Pennsylvania Public Utility Commission ("PPUC") recognized that market conditions may have caused certain models to understate the cost of equity. In particular, the PPUC historically relied solely on the Discounted Cash Flow ("DCF") model but gave weight to other methodologies:

> This suggests that, while properly computed in the abstract, the DCF-only results understate the current cost of equity for PPL and that consideration should be given to the CAPM and RP ("Risk Premium") evidence in determining the appropriate range of reasonableness. [See Exhibit A-82 (SM-6), page 81.]

Decisions such as this by regulators highlight the fact that quantitative models provide output estimates that need to be scrutinized based on market conditions.

Q. How did you address the limitations of mechanical application of quantitative models in your 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. I addressed the limitations of various models by employing multiple methodologies, using projections for market inputs (risk-free rates, dividends, and risk premiums) and using my judgement based on conversations with the investment community. Furthermore, my analysis includes a methodology for calculating the impact on credit metrics for both ROE and equity ratio.

b. Short-Term Interest Rates

Q. What is your opinion of how interest rates will 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. This process began in December 2015 with the Federal Reserve's first rise in interest rates in nearly a decade and continued with nine total rate hikes before reversing course and, once again, lowering rates twice, starting in August of 2019. It is important to understand 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 your 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 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. Therefore, it is important to keep these circumstances in mind in setting the cost of equity for utilities. My quantitative analysis takes this critical factor into consideration.

3. ROE Trends

Q. What are the trends for authorized ROEs around the country?

A. There is no accurate or complete source for the national ROE trends. Databases such as S&P Global Regulatory Research Associates ("RRA") attempt to do so but are incomplete. They do not include alternative regulatory jurisdictions (Alabama, Georgia), ROEs set outside of general rate cases (California), cases where ROEs are settled/unstated, and jurisdictions that have separate riders (Wisconsin, Iowa, Virginia), all of which tend to support higher ROE values. I have continued to make the case that the RRA database underestimates national average data, as numerous jurisdictions with strong regulatory frameworks that have constructive ROEs are not reflected in the RRA database.

The Commission, in its September 26, 2019 Order in Case No. U-20322, seemed to be persuaded that the trend in ROEs nationally have been downward. This appears to be based on evidence presented by Staff and Intervenors, who continue to rely heavily on the RRA database. While I still believe the Commission should not rely on flawed data, it is worth noting that the RRA Regulatory Focus from October 17, 2019 cites increases to both ROE and equity ratio through the first three quarters of 2019 compared to 2018 and 2017. See Exhibit A-83 (SM-7).

Even more pertinent, however, is that the same report highlights a simultaneous increase in authorized equity ratios and notes "equity ratios have generally increased over the last 15 years." If the Commission is persuaded that ROEs trended downward based on the data from RRA, then I believe the Commission should also consider that equity ratios have, in fact, trended upward.

Q. What is the interplay between regulatory environments and ROEs?

A. UBS produces an annual report that ranks U.S. states and Canadian provinces according to the quality of their regulatory environments. The 2019 UBS report shows that states with a regulatory environment in the top two quartiles earned ROEs, on average, of 11.5% and 10.0%, respectively, while states in the bottom two quartiles earned ROEs, on average, of 9.8% and 9.6%, respectively. The UBS report shown in Exhibit A-84 (SM-8) demonstrates that there is a clear, positive relationship between the quality of the regulatory environment and ROE. Analysts, in turn, recognize this 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.

4. Economic Outlook and Uncertainty

Q. Did you consider the current state of the economy in performing your ROE analysis?

A. Yes. Several of the inputs to my analysis included market observations that are impacted by the current state of the United States economy. In addition to the United States economic outlook, the global economy factors into investor considerations because of the ripple effects on the United States economy and the integrated nature of global financial markets. The Company makes long-term investments in infrastructure to serve our customers, but markets can and do face significant dislocations from time to time. The most recent example of which is the Federal Reserve's recent injection of cash which was needed to stabilize volatility in the repurchase market which I mentioned earlier. 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.

5. Capital Investment

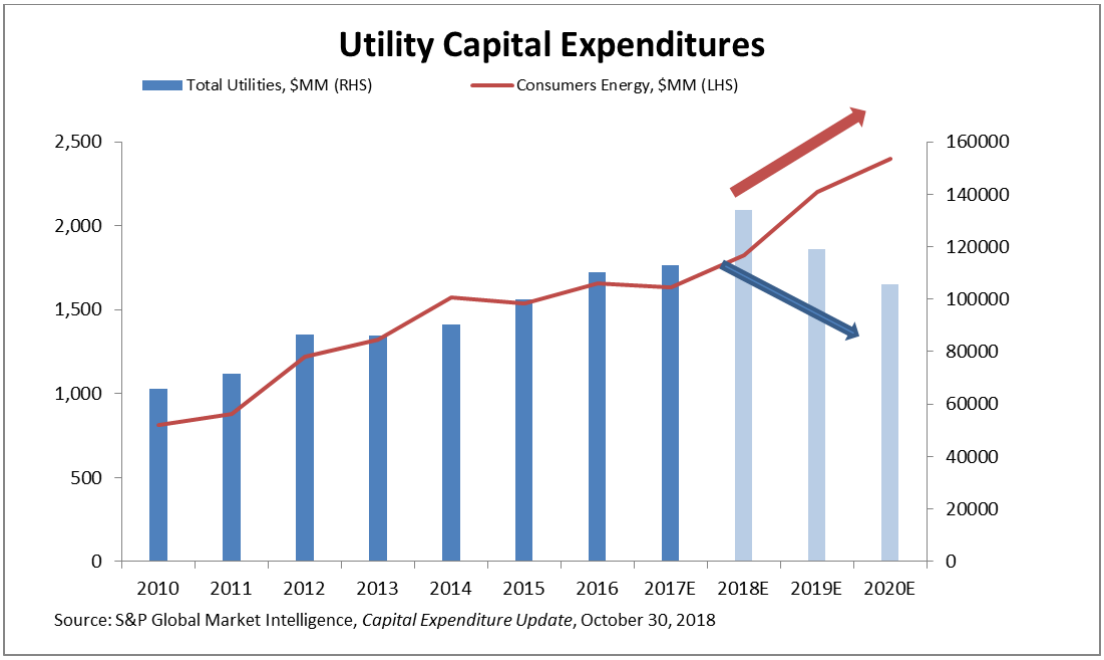
Q. Does the Company's significant capital investment program impact the appropriate ROE determined in this case?

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. Over the next five years, the Company plans to invest approximately $11.8 billion on a total company basis, $5 billion of which is earmarked for gas infrastructure investment.[5] 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 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 our cost of capital or hinder the Company's ability to access capital, 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 Market Intelligence* ("S&P Global") as well as historical and projected capital expenditures for Consumers Energy.

[5] See Consumers Energy 2019 Third Quarter 10-Q, page 19.



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. 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 10.5%, 60 basis points higher than is currently authorized, is within the range of reasonable returns, as I will demonstrate through my quantitative analysis, and would also send an important signal to investors that management is not investing in a company or state that has a declining regulatory environment.

E. Quantitative Equity Cost Rate Analyses

1. Selection of Proxy Companies

Q. Why did you select a group of proxy companies to perform your 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 you chose your proxy group of companies.

A. The focus of this case is on Consumers Energy's gas operations. My initial selection criteria were selected to identify gas utility companies that are publicly traded and for which public data is available. I utilized the *S&P Global* published data set, formerly referred to as *SNL Financial*, to select my initial proxy group. In order to be included in the proxy group, the operating company had to be classified as a gas utility in the *S&P Global* database. This criteria eliminates companies that do not have sufficiently significant gas operations. Secondly, the company must have a market capitalization greater than $1 billion and less than $25 billion. This filter excludes both the very small as well as the extremely large ends of the size spectrum of utility companies, thereby focusing on similarly-sized companies in the relative range of Consumers Energy's gas business. Further, 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-85 (SM-9). In addition, the company had to: (i) be headquartered in the United States; (ii) currently not be a recent merger target or be 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; (iii) be currently paying common stock dividends; and (iv) have bonds rated at or above a minimum investment grade of Baa3 by Moody's and BBB- by S&P. These criteria resulted in a proxy group of 13 companies. The list of the proxy group companies, the selection criteria, and the data supporting inclusion is set forth on Exhibit A-14 (SM-1), Schedule D-5, page 1.

Q. Why did you utilize the *S&P Global* data set to filter your proxy group rather than additional sources that had been referenced by the Company in past years?

A. The Company had previously utilized additional sources to filter the proxy group, to include AUS monthly reports. The AUS monthly data set was previously used to determine the classification of the business, but unfortunately, the service was discontinued as of September 2016. Because the same AUS data is no longer available, I made the determination to move completely to the *S&P Global* data set for proxy selection.

Q. How does your proxy group differ from the most recent gas rate case?

A. My proxy group in Case No. U-20322 was the same except it also included New Jersey Resources. S&P discontinued ratings coverage for New Jersey Resources in May of 2019. As a result, the company no longer meets the investment grade ratings criteria (iv), outlined above and was, therefore, excluded from my proxy group.

Q. Which companies did you exclude due to merger or restructuring issues?

A. As in Case No. U-20322 both Vectren Corporation and SCANA Corporation were excluded from the analysis. Vectren Corporation was excluded due the recent acquisition of the company by CenterPoint Energy, which was announced in April of 2018. SCANA Corporation was also excluded due to its recent acquisition by Dominion Energy.

2. Empirical Capital Asset Pricing Model Analyses

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. The principal assumption of the CAPM (and ECAPM) is that the expected return on an asset is related to risk – that is, risk taking is rewarded with appropriate returns. The CAPM and ECAPM state that the expected rate of return on an investment is equal to a risk-free rate of return plus a risk premium. 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 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. Would you give more specific detail to the theory underlying CAPM?

A. Yes. 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 base risk-free rate, which is traditionally seen as the income return available from investing in United States Government Treasury securities. 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 formula of CAPM is expressed as:

Equation (1): $K_e = R_f + F + B \times (R_p)$

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:

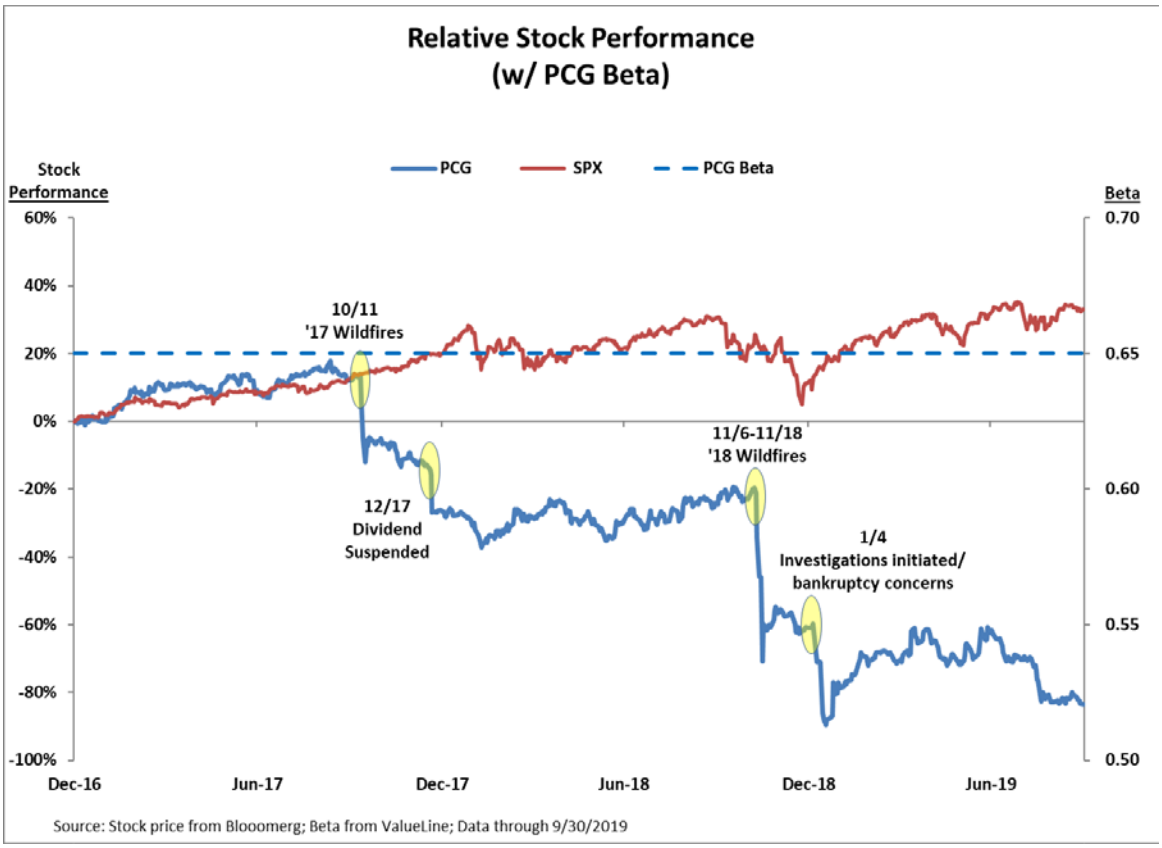
- Fama and French: "*The CAPM is Wanted, Dead or Alive,*" (Exhibit A-86 (SM-10));
- Tony Tassell: *"The time has come for the CAPM to RIP," Financial Times,* (Exhibit A-87 (SM-11));
- Chartoff, Mayo, and Smith: "*The Case Against the Use of the Capital Asset Pricing Model in Public Utility Ratemaking,"* (Exhibit A-88 (SM-12));
- Chretien and Coggins: "*Cost of Equity for Energy Utilities: Beyond the CAPM,*" (Exhibit A-89 (SM-13)); and
- Robert Morin: "*New Regulatory Finance."*

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 our proxy group as shown on Exhibit A-14 (SM-1), Schedule D-5, page 2, are typically less than 1.00. 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. Utilities are interest rate sensitive and exposed to regulatory risk, neither of which is captured by the traditional CAPM analysis.

Q. Can you provide 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 look at Pacific Gas and Electric Company ("PG&E"). The chart below shows PG&E's stock price over the course of the past two years 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 has exemplified heightened risks over the period as the stock performance has underperformed both the UTY index as well as the S&P 500 index over the course of this time. The stock has 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 remains at 0.65 today. This clearly shows that utility beta does not fully capture the entire risk faced by the underlying company, even when those risks threaten the viability of the company itself.



Q. How did you address these shortcomings?

A. In previous cases before the Commission, I had performed and relied upon a CAPM analysis, but given the voluminous evidence that the CAPM methodology understates the required rate of return for utilities I did not rely on it in forming my recommended ROE range in this case. While I performed the CAPM analysis for reference (Exhibit A-98 (SM-22), page 1), reliance upon it is not appropriate. In order to adjust for the shortcomings of the CAPM model I used the ECAPM analysis.

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 (1a): $K_e = R_f + \alpha + F + B \times (R_p - \alpha)$

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 values did you assume for the components of this analysis?

A. Except for alpha, which is not a component of the CAPM formula, I used the same values as the CAPM. For alpha, I used 1.5%, 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 does not fully address the shortcomings of CAPM. Without the use of adjusted beta and long-term risk-free rates, the alpha adjustment would need to be higher than my 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 (SM-1), Schedule D-5, page 2. The Projected Risk Premium ECAPM ROEs are displayed in column (h) and show the average ROE for my proxy group is 10.71% and ranges from a minimum of 9.10% to a maximum of 13.37%.

Q. What is the source of your market risk premium?

A. Since the equity risk premium may be fundamentally higher in different market conditions, analysis must use market periods which mirror the conditions in the current environment in order to best approximate the current equity risk premium. I estimated a

projected market risk premium based on the expected market return of the S&P 500 Index and subtracted the expected yield of the 30-year U.S. Treasuries during the projected test year. I calculated the expected market return 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 1.97% and long-term EPS growth estimate of 11.87% resulted in a sum expected market return of 13.84% as of September 30, 2019. Subtracting the expected 30-year U.S. Treasury yield of 2.87% for the test period results in an estimated market risk premium of 10.97% 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 my 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 I have applied to calculate the forward-looking market risk premium, referencing both the S&P 500 Index as well as the 30-year U.S. Treasury bond yields. See Exhibit A-90 (SM-14), at paragraphs 109-111.

Q. Did any other analyses support your projected estimate?

A. Yes. I have also provided four additional equity risk premium estimates which are supportive of the resulting 10.97% value I utilize in my 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; (iii) equity risk premiums from Federal Reserve research; and (iv) the Staff calculated estimate in Case No. U-20359.

The first two utilize Roger Ibbotson's *2018 Stocks, Bonds, Bills, and Inflation (SBBI) Yearbook.* In Exhibit A-14 (SM-1), Schedule D-5, page 7, lines 56 and 58, I focus the calculations on the low interest rate periods of 2011 through 2018, and from the low interest rate periods of 1942 through 1951 and 2011 through 2018 on line 58. 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 9.02% and 12.73%, respectively.

The third estimate relies upon a recently published report by the Federal Reserve, *The Equity Risk Premium: A Review of Models*, Exhibit A-91 (SM-15) which indicates that equity risk premiums in low interest rate environments are much higher – 12%. The fourth estimate is taken from the direct testimony of Staff witness Kirk D. Megginson in Case No. U-20359 on October 17, 2019[6]. Staff estimated the risk premium to be 12.10%, which is higher than my estimate in this case. Each of these estimates are shown in the

[6] Direct testimony and exhibits of Kirk D. Megginson, Michigan PSC Case No. U-20359 (October 17, 2019), page 16.

following table and each is supportive of my projected estimate. The average is 45 basis points in excess of the 10.97% estimate I have applied in my analysis.

Equity Risk Premium	
Risk Premium During Most Recent Low Interest Rates (2011-2018)	9.02%
Risk Premium During Federal Reserve Action (1942-1951 and 2011-2018)	12.73%
Federal Reserve Research	12.00%
Staff Estimate in MPSC Case No. U-20359	12.10%
Average	**11.42%**

Q. Is it appropriate to use the average from 1926 to 2018 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 current risk-free rates requires estimating a current equity risk premium as I do in my primary calculation.

Q. How did you arrive at the projected risk-free rates?

A. As in the past, I calculated the test year risk-free rate by utilizing an average of Blue Chip and Global Insight 30-year U.S. Treasury Bond yield estimates. According to the September 2019 edition of Global Insight's United States Economic Outlook, the average yield on 30-year United States Treasury Bonds for the test year is projected to be 2.98%. The estimate for 30-year United States Treasury Bonds from the September 2019 Blue Chip Financial Forecast for the test year is 2.75%. The average of the two results in an estimate of 2.87%.

Q. Why did you choose to use longer dated bonds?

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 did you use for purposes of your ECAPM analysis?

A. I used the values of beta calculated by Value Line. Value Line computes historical betas using data over the last five years and adjusts this historical beta using the method prescribed by Marshall E. Blume to make it an expected beta. Value Line betas are used in ECAPM analyses, and the values of beta for my proxy group of companies are found on Exhibit A-14 (SM-1), Schedule D-5, page 2. The average current beta for my proxy group is 0.67.

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. Can you point toward third-party support for the use of ECAPM?

A. Yes. As discussed earlier in my direct testimony, the CAPM has several deficiencies which impact utilities in particular. There are numerous academic articles that have discussed the shortcomings of CAPM. I relied mainly on the simple adjustments formulated by Dr. Morin to correct these deficiencies. 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-92

(SM-16), pages 15-20) reinforce my opinion of 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-89 (SM-13) 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 my 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 my analysis is not only supported and logical, but necessary in setting a fair ROE.

Q. Beyond academic literature, are you able to provide examples of applications of your ECAPM analysis?

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. I have included the rate schedule from Mississippi Power showing the use of ECAPM with a Value Line adjusted beta. Please refer to Exhibit A-93 (SM-17), page 24;

(ii) The ECAPM approach has been relied on by the Staff of the Maryland Public Service Commission. For example, Staff 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"[7];

(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[8];

(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 CAPM analysis by flattening the risk-return relationship,"[9] 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[10];

(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[11];

(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

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[7] Direct testimony and exhibits of Julie McKenna, Maryland PSC Case No. 9299 (October 12, 2012), page 9.
[8] Regulatory Commission of Alaska, Order No. P-97-004(151) (Nov. 27, 2002), page 145.
[9] Proceeding No. 13AL-0067G, answer testimony and exhibits of Scott England (July 31, 2013), page 47.
[10] 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 Cause No. PUD 201800140, responsive testimony of Marlon F. Griffing, Ph.D, (April 22, 2019), pages 41-43.
[11] https://www.revenue.state.mn.us/sites/default/files/2019-05/Caprate_Rate_Report.pdf

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-94 (SM-18).

While not an exhaustive list of examples, the use of ECAPM in these regulatory proceedings demonstrates that it is neither new nor novel.

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 said:

> 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-95 (SM-19) that the Value Line calculation for beta uses historical data, and the adjustment prescribed by Marshall Blume does not incorporate the effects captured in ECAPM. Therefore, the use of Value Line adjusted betas is very much consistent with the application of ECAPM.

Q. Has the MPSC commented on the use of the ECAPM?

A. No. The Commission did not address this matter in Case No. U-20322. The Administrative Law Judge ("ALJ") in Case No. U-20322 seemed to be persuaded by Staff and intervenor contention that the use of adjusted betas is not appropriate with the ECAPM (MPSC Case No. U-20322, Proposal For Decision ("PFD"), page 119). This issue, however, was not specifically addressed by the Commission in its September 26, 2019 Order.

Q. What did the ALJ in Case No. U-20322 overlook in his PFD as it relates to the Company's use of ECAPM?

A. Although 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 short-comings of CAPM and make ECAPM unnecessary, this is simply untrue as is demonstrated by other practitioners who use ECAPM with both long-term Treasury Rates and Value Line beta. Further, in the same literature, Dr. Morin notes that the empirical evidence on the appropriate range of the alpha factor is higher than the 1% - 2% alpha adjustment I have proposed. Dr. Morin specifically states in *New Regulatory Finance,*

> An alpha adjustment of **1%-2% is somewhat lower than that estimated empirically**. 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 **some** 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, the past claims made by Staff are based on a misreading and/or misquoting of the literature of the very author upon which Staff has relied.

Furthermore, in the academic literature the "*Cost of Equity for Energy Utilities: Beyond the CAPM*" (Exhibit A-89 (SM-13)) 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-89 (SM-13), page 19].

Q. Should the ALJ's PFD in Case No. U-20322 as it relates to the discussion of ECAPM be considered in this case?

A. No. The PFD in Case No. U-20322 is not representative of the Commission's decision. The Commission did not address this matter in the final Order and, as such, the conclusions of a past PFD, that were not adopted by the Commission, should not be considered persuasive authority in this current case. The Commission and ALJ should base their judgment on the evidence presented in the current case, which includes numerous academic and regulatory citations. Staff and other intervenors should be required to provide third-party, independent support if they continue to maintain that adjusted betas are not appropriate with the ECAPM.

3. Projected Risk Premium Analysis

Q. Please describe the risk premium analysis that you 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 you calculated the future utility bond yield.

A. To determine the future yield of utility bonds I added (i) the risk-free rate, and (ii) the bond spread over United States Treasury Bonds. The applied risk-free rate in the Projected Risk Premium Analysis is the projected long-term government bond return of 2.87%, which was developed in the ECAPM analysis and is supported in Exhibit A-14 (SM-1), Schedule D-5, page 2. I performed the risk premium analysis calculations separately for each of the bond rating spreads from A to BBB.

Q. Please discuss how you determined the risk premium relative to utility bonds.

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 (SM-1), Schedule D-5, page 8, column (j), shows that gas utility common stocks have an average historical risk premium of 3.90% (line 66) over the yields of A-rated utility bonds. However, an article published by the Federal Reserve, Exhibit A-91 (SM-15), 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 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."[12]

To adjust for the fact that risk premiums are higher when interest rates are low, I calculated the risk premium since the Federal Reserve began its recent accommodative period (2011 to 2018) when interest rates were held artificially low. During this period gas utility common stocks had an average risk premium of 7.27% over the yields of A-rated utility bonds. See Exhibit A-14 (SM-1), Schedule D-5, page 8, line 67.

However, in Case No. U-20322 Staff disagreed with my use of historical data to project the risk premium in the current low interest rate environment. Instead, Staff calculated a projected risk premium by using the risk premium calculated in the ECAPM analysis multiplied by the beta of the proxy group. While I disagree with Staff's criticism, applying Staff's methodology from Case No. U-20322 would result in a risk premium of 7.48%, 21 basis points higher than my estimate, as shown in Exhibit A-14 (SM-1), Schedule D-5, page 3.

Q. What is the result of the risk premium analysis you calculated?

A. My Projected Risk Premium analysis shows that the average ROE is 11.52% and ranges from a minimum of 11.25% to a maximum of 12.01%. These results are shown in Exhibit A-14 (SM-1), Schedule D-5, page 3.

[12] Direct Testimony of Joseph E. Ufolla, MPSC Case No. U-20479 (September 27, 2019), page 36.

Q. Has Staff performed a projected risk premium analysis in the past?

A. Yes. In Case No. U-20322, Staff performed a projected analysis that calculated a risk premium for the proxy group as well as a forecasted CAPM ROE and projected risk premium. While one should not conclude that I am endorsing Staff's methodology in its entirety, I have calculated the analysis performed by Staff in that case in order to minimize disagreements in this case. I have included the analysis as part of Exhibit A-14 (SM-1), Schedule D-5, page 3. Applying Staff's methodology results in an ROE range of 10.97% to 11.34%, which is supportive of my analysis and overall recommended range.

4. <u>Comparable Earnings Analysis</u>

Q. Briefly describe the comparable earnings analysis method.

A. Under this method, I analyzed projected ROEs for the proxy group. 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 (SM-1), Schedule D-5, page 5, shows the results for the group of proxy companies by year for the 2022 through 2024 period. The average projected earned ROE for the proxy group is 10.73%.

Q. Why have you included this method as part of your 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.

5. DCF Analysis

Q. Briefly describe the 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 (2): $K_e = (D_1 / P_0) + g + F$

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 (SM-1), Schedule D-5, page 4.

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 (3): $P_0 = D_1/(1+K_e)^1 + D_2/(1+K_e)^2 + \ldots + D_n/(1+K_e)^n + P_n/(1+K_e)^n$

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 (2) 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 you calculated the dividend yield.

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. I used an average of 30 daily closing stock prices covering the period August 19, 2019 through September 30, 2019.

Q. How did you determine the dividend yield for each of the proxy companies?

A. For each of the proxy companies, I first determined the average closing stock price for the period identified above. This provided an estimate of P_0. Then, I obtained the latest annual dividend amount and divided the annualized dividend 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, I adjusted the current dividend yield 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 (SM-1), Schedule D-5, page 4.

Q. How did you determine the growth rate for the DCF calculations?

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 I used analyst projections for dividends over the next three years to estimate dividend growth. In addition to analyst dividend growth, company management will often provide guidance for projected growth, and I therefore performed two methods of analysis: 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 I disagree with the assertions that have been made, I have calculated both methods, and I have only considered the analyst guidance DCF methodology in forming my recommended ROE range in this case. For reference, the company guidance DCF can be seen in Exhibit A-98 (SM-22), page 4.

Q. Why do you utilize dividend growth instead of earnings growth 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.

I have included this paper as Exhibit A-97 (SM-21), 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 your DCF cost of equity analyses for the proxy companies?

A. Exhibit A-14 (SM-1), Schedule D-5, page 4, shows the results for my group of proxy companies. Proxy group company returns for the Analyst Consensus DCF ROE have a wide range from 6.68% to 10.02% with an average return of 8.44%.

Q. Why did you calculate a company guidance DCF in addition to analyst estimates?

A. The DCF model works well if we are able to determine a single "long-term" (i.e., perpetual) growth rate. I used the mid-point of company guidance for growth since this encapsulates a single "long-term" growth rate. Analyst estimates often tend to focus on the near-term (i.e., growth rates for the next year or two years) instead of the long-term growth rate required for the model. This results in understating true investor-required returns in the current environment, where investors may accept lower growth in the near term but expect higher growth in the long term. Furthermore, different analysts may determine the basis for growth differently (i.e., excluding transitory effects such as one-time losses or gains); therefore, using Company guidance provides a more consistent and potentially more accurate approach to convey a single long-term growth expectation. Exhibit A-78 (SM-2), page 2, shows the results for my group of proxy companies. The returns for the Company Guidance DCF ROE also have a wide range from 6.67% to 13.68% with an average return of 9.14%. However, as stated above, while I performed the analysis, and I think it can be informative, I did not explicitly rely upon the company guidance DCF to form my recommendation in this case.

Q. Did you perform any additional DCF analysis?

A. Yes. My DCF analysis was performed using dividend growth estimates from analysts while Staff in recent years has continued to show a preference to utilize earnings guidance. 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, I have included one in Exhibit A-98 (SM-22), page 3. An application utilizing earnings growth for a DCF should also apply earnings yield rather than dividend yield in the calculation, and my supporting analysis shows this as well. This application results in an average estimated ROE of 9.75%, a full 131 basis point increase over the dividend growth DCF I have included in my analysis.

Q. Does the result of your DCF analysis fully reflect the cost of equity required for utilities?

A. No, it does not. As highlighted by FERC, the reliability of the DCF, considering the low yields on bonds, including U.S. Treasury bonds, provides less confidence than a mechanical application of the DCF and produces 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, using an ROE of 8.44% and the Company's recommended equity ratio of 52.5% would result in an FFO-to-Debt of 17.5%, which would further deteriorate the Company's credit.

The DCF analysis has four companies with ROEs less than 8% and one Company less than 7%. No commission in the country has authorized an ROE less than 8%, let

alone 7%. This highlights why regulators such as FERC have had concern with relying so heavily on the DCF model. I do not believe that the average output of the DCF analysis, which is below the national average ROE as reported in the RRA report, would 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 Company assets and income. The Commission has already noted in Case No. U-20322 that an ROE of 9.65% is too low[13] and, because the results of the DCF clearly underestimates the required ROE, my ROE recommendation considers more heavily the results of the ECAPM, Risk Premium, and Comparable Earnings analyses.

III. DISCUSSION OF EMPLOYEE INCENTIVE COMPENSATION PLAN FINANCIAL INCENTIVES

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 Employee Incentive Compensation Plan ("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 gas bills as highlighted above and helps to provide customers with better service. As I stated earlier, a virtuous cycle is created by constructive regulation, which creates a financially

[13] MPSC Case No. U-20322, September 26, 2019 Order, page 72.

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") plays 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 (SM-1), Schedule D-5, page 6, the Company has saved ratepayers $89 million 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.

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-20650

DIRECT TESTIMONY

OF

JARED J. MARTIN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

Q. Please state your name and business address.

A. My name is Jared J. Martin, and my business address is 530 West Willow Street, Lansing, Michigan 48909.

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 Operations Systems.

Q. Please describe your educational background and work experience.

A. I earned a Bachelor of Science in Mechanical Engineering from Michigan State University and later earned a Master of Business Administration from Wayne State University. I have held my current position as Manager of Gas Operations Systems for Consumers Energy since December 2016. My prior positions at Consumers Energy include Manager of Financial Management Controls, Manager of Distribution Planning and Scheduling, and Director of Economic Portfolio Management.

Q. What are your responsibilities as Manager of Gas Operations Systems?

A. I am responsible for co-managing the field workforce completing the Enhanced Infrastructure Replacement Program ("EIRP") and Vintage Services Replacement ("VSR") Program. This includes all gas distribution pipeline replacement work that meet the criteria for the programs. The workforce is seasonal in nature.

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

A. I am a licensed Professional Engineer in the state of Michigan and belong to both the Michigan and National Society of Professional Engineers.

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, 2021. My direct testimony also supports certain Gas Distribution capital investments through September 30, 2021. My direct testimony is divided into four parts: (i) Gas Operations O&M expenses; (ii) Gas Operations capital expenditures; (iii) Information Technology ("IT") projects; and (iv) 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-101 (JJM-1)	Summary of Actual & Projected Gas Operations Division O&M Expenses - For the Years 2018, 2019, 2020 and Test Year 12 Months Ending September 30, 2021;
Exhibit A-102 (JJM-2)	Summary of Actual & Projected Operations Maintenance & Metering O&M Expenses - For the Years 2018, 2019, 2020 and Test Year 12 Months Ending September 30, 2021;
Exhibit A-103 (JJM-3)	Summary of Actual & Projected Field Operations Services O&M Expenses - For the Years 2018, 2019, 2020 and Test Year 12 Months Ending September 30, 2021;

Exhibit A-104 (JJM-4)		Summary of Actual & Projected Other Gas Operations O&M Expense - For the Years 2018, 2019, 2020 and Test Year 12 Months Ending September 30, 2021;
Exhibit A- 12 (JJM-5)	Schedule B-5.6	Projected Capital Expenditures, Distribution Plant, Summary of Actual & Projected Gas and Common Capital Expenditures;
Exhibit A- 105 (JJM-6)		Actual & Projected Gas Capital Expenditures - Material Condition Program;
Exhibit A-106 (JJM-7)		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 or supervision?

A. Yes.

GAS OPERATIONS O&M EXPENSES

Q. How has the Company projected its Gas Operations Division O&M expenses for the test year 12 months ending September 30, 2021?

A. The Company has identified its O&M expenses for the test year 12 months ending September 30, 2021 that are necessary to meet public safety and customer service requirements.

Q. Please summarize your direct testimony pertaining to the Gas Operations O&M expenses.

A. The total Gas Operations Division O&M projected expense for the test year is $114,270,000 and is set forth on Exhibit A-101 (JJM-1), line 7, column (e). The total test year projected O&M expenses for the Company's Gas Operations Division are separated on Exhibit A-101 (JJM-1), lines 1 through 6. Line 1 is the Gas Operations Maintenance

and Metering O&M expenses. Line 2 represents the O&M expenses associated with Field Operations Services. Line 3 represents the Compliance and Controls O&M expenses. Line 4 represents the Planning and Scheduling O&M expenses. Line 5 represents the Gas Operations Performance O&M expenses. Line 6 represents the Gas Operations Management O&M expenses.

Q. Please explain the source of the 2018 actual and derivation of the projected test year O&M expenses for the Gas Operations expenses shown on Exhibit A-101 (JJM-1).

A. The 2018 actual O&M expense amount of $103,890,000 for Gas Operations O&M are 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. The 12 months ending September 30, 2021, expense levels for the Gas Operations Division O&M 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, on-going 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. What are the major O&M programs that are managed within the Gas Operations Division?

A. The six major O&M programs within the Gas Operations Division are as follows:

1. Operations, Maintenance, and Metering;
2. Field Operations;
3. Compliance and Controls;
4. Planning and Scheduling;
5. Operations Performance; and
6. Operations Management.

Operations, Maintenance, and Metering

Q. Please describe the O&M expenses related to the Operations, Maintenance, and Metering sub-programs shown on Exhibit A-102 (JJM-2).

A. The Operations, Maintenance and Metering sub-programs include a number of customer demand programs related to the front-line operations of the gas service and 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 Program.

A. Operations and Maintenance - Distribution Program includes multiple activities that keep the gas flowing to customers' homes. Work activities related to the condition of Company assets include non-leak maintenance activities such as repairing or replacing lockwings to allow emergency shut-offs, installing water pump-drips on the standard (low) pressure system to alleviate water infiltration and freezing of lines, and property restoration after underground work is performed. This program also includes site checking personnel that ensure customer locations are ready for work, which improves on-time delivery. These site checking personnel pre-check customer job sites for underground facility staking, sewer lead locations, grading, hydro vacuum excavation, and temporary traffic control requirements. Gas mains and services alterations for customer requested work (such as 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. Finally, this program also includes reinforcing prior repairs on steel mains by installing a welded reinforcement over a bolted split sleeve, which extends the life of the repair.

Q. What is the basis for determining the $7,838,000 of projected O&M expenses in the test year 12 months ending September 30, 2021 for this program?

A. Projected spending in this program is less than the 2018 expense and is primarily driven by expected hours of employee labor to complete the work. The expenses for this program are needed for material condition emergent and non-leak maintenance. In 2018, the $8,241,000 expense amount in this program included a large non-leak maintenance project within an apartment complex that will not recur in the test year. Also, the Company has reduced the labor hours in the program as a result of improvements in processes related to gas alterations and relocations.

Q. Please describe the O&M expenses related to the Operations and Maintenance – Pipeline Program.

A. The Operations and Maintenance – Pipeline Program includes expenses related to inspection of transmission pipelines, valves, operators, and associated internal inspection tool launchers and receivers (pigging). Other expenses include vehicle and foot patrol of pipelines, third-party staking (MISS DIG), and construction oversight to prevent damage to the facility as well as leak survey. Program funding also includes necessary maintenance of valves sites, buildings, fencing, and security systems and structures. This program ensures public safety by maintaining the integrity of the Company's gas transmission pipeline system through inspection of all critical assets and the repair of those assets to ensure proper operating conditions. One key example is line patrols where, based on class location, the Company patrols the system, from one to four times per year, investigating for new dwellings, leaks, and third-party activity. As part of these line patrols, the Company takes appropriate actions to repair and/or remediate in

compliance with the Michigan Gas Safety Standards ("MGSS") (MGSS 192.705, 192.706, 192.613, 192.935). This program also includes the inspection and maintenance of gas quality equipment to protect pressure regulation and customer metering equipment.

Q. What is the basis for determining the $3,476,000 of projected O&M expenses in the test year 12 months ending September 30, 2021 for this program?

A. Projected spending in this 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 Right-of-Way ("ROW") encroachment resolutions, and direct allocation of miscellaneous expenses are projected based on historical trends and anticipated needs. The below table provides a detailed breakdown of anticipated Operations and Maintenance – Pipeline Program expenses in the test year compared with the 2018 actual amount.

Transmission Pipeline Projection Breakdown by Activity Type		
Work Type	**2018 Actual**	**Test Year (2021)**
Code Inspections	$812,000.00	$1,054,000.00
Facilities Locating for Third Parties (MISS DIG)	$772,000.00	$949,000.00
Demand Maintenance	$505,000.00	$558,000.00
Allocation of Miscellaneous Expenses	$409,000.00	$412,000.00
Restoration/ROW Encroachment Resolutions	$0.00	$298,000.00
Preventative Maintenance	$103,000.00	$129,000.00
Operations	$69,000.00	$76,000.00
Total Program	$2,670,000.00	$3,476,000.00

Code Inspections pertains to performing MGSS and Michigan Department of Environment, Great Lakes, and Energy ("EGLE") code inspections associated with pipeline valves, pipe, and associated assets and primarily consist of Company employee labor and ancillary material costs. Projected labor hour allocations are based on historical

time to perform required maintenance, but also include 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. The transmission pipeline system contains approximately 2,300 valves and the projected test year expense adds two hours to the maintenance plan per asset spread over three years, increasing the annual expense amount by $153,000. The three-year cycle will allow all assets to have the correct and comprehensive inspection once per three years, which is more consistent with manufacturers' recommendations and is expected to prevent some of the repairs currently required in absence of the three-year cycle. Additional projected labor hours also include maintenance related to investments providing system and customer benefits such as Remote Control Valves ("RCV"), which are sponsored by Company witness Chad L. Alley. 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 $19,000 annually. Additionally, $60,000 is required above the 2018 actual amount due to three MGSS required pipeline maintenance cleaning pig runs that were completed under the Pipeline Integrity Program. These maintenance pig runs were

required as part of the preparation for internal inspection tools that occur every seven years versus the MGSS requirement to clean them annually. The maintenance pigging portion of the program accounts for six maintenance pig runs total during 2021, which are three more than in 2018, and which are required as part of the Transmission Integrity Management Program.

The Facilities Locating for Third Parties (MISS DIG) portion of the program is primarily comprised of labor hours required to evaluate, locate and stake, and oversee third-party activities near transmission pipelines. The projected expense is comprised of historical data, trends. There has been a steady increase over the last four years 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 increasing trend and expected 2019 hours (9,500), it is anticipated that demand for third-party locating responses will grow (see below table).

MISS DIG Tickets and Associated Hours

Year (Jan-Dec)	Orders	Hours
2014	6,080	3,642
2015	7,499	4,291
2016	12,538	6,119
2017	14,440	7,000
2018	18,412	8,327
Trend 2019	21,275	9,500
Trend 2020	24,436	10,708
Trend 2021	27,596	11,915

The Demand Maintenance portion of the program accounts for labor, material, and contractor supported activities to address pipeline assets that require repair due to performance during annual inspections, outages, or other activities. These types of repairs are typically related to valves, cathodic protection test stations, rectifiers, liquid

collection equipment, pipeline markers, metering equipment, communication equipment, calibration equipment, pipe coating, sites and facilities, leaks, ROW access, third-party damage, and snow plowing. Increases in projected expense for this area over 2018 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.

The Allocation of Miscellaneous Expense portion of the program is comprised of labor, internal departmental chargebacks, and materials not associated with a work order and spread over departmental needs. Such 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. Projected amounts are based on historical spend increasing only for inflation.

The Restoration/ROW Encroachment Resolutions portion of the program is primarily comprised of contractor and property owner settlement payments necessary to remove the public safety risk associated with existing and anticipated encroachments to Company pipelines. Existing encroachments and prevention of future encroachments are a high priority to increase pipeline and public safety from third-party activities. Encroachment resolution also ensures access to Consumers Energy's easements and ROWs for MGSS-required inspections and repairs that are both emergent and non-emergent. There are over 170 documented encroachments on the Transmission Pipeline system as of August 2019.

Pipeline Preventative Maintenance pertains to performing proactive and necessary inspections that do not fall under code requirements but are necessary for maintaining system operations safely, reliably, and predictably on behalf of customers. Such inspections include instrument calibration, launcher and receiver inspections, two maintenance pig runs not required by MGSS (but necessary based on operational history of solids and liquid buildup), vehicle safety inspections, general safety inspections, and liquid drip collections. Additionally, Preventative Maintenance includes labor hours and material costs to maintain site access and conditions, such as access drive and site stone, grass and weed spraying and mowing, and fence condition. Projected expense is set at the historical amount without increase beyond inflation.

The Operations portion of the program is primarily comprised of labor necessary to address the general operations of the Transmission Pipeline Operations workforce. This includes general housekeeping, site maintenance, and other general functions not associated with any inspection or other activity. The projected expense is set based on historical amounts without increase beyond inflation.

Q. Please describe the O&M expenses related to the Operations and Maintenance Regulation Distribution Program.

A. The Regulation Distribution 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 inspection and maintenance and repairs of these facilities. The 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

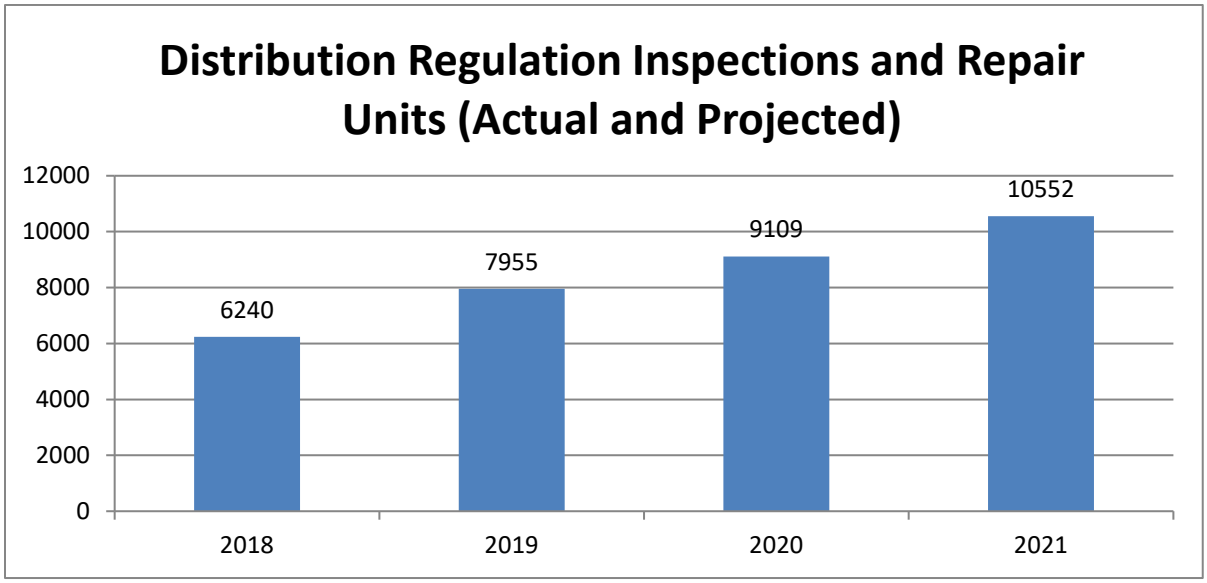
planned outages or emergencies is also included in this program and is critical for system operations and public safety. The Regulation Distribution Program is responsible for the statewide inspection, maintenance, and repair of:

- 728 Distribution Regulation Stations;
- 1,324 1-inch and larger high-pressure regulation stands;
- 92 Odorant Injection Facilities; and
- 2,035 Designated pipeline valves.

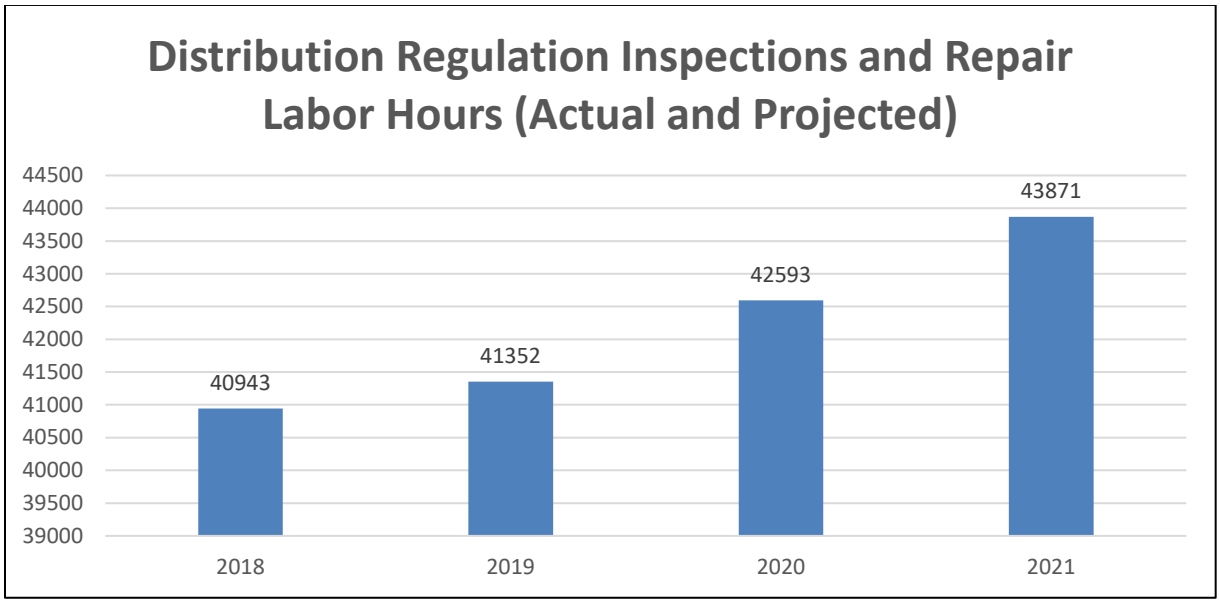
Q. What is the basis for determining the $7,267,000 of projected O&M expenses in the test year 12 months ending September 30, 2021 for this program?

A. In order 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 Alley. 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 2018 actual amount and is needed to continue to provide natural gas to customers. Examples include: Supervisory Control and Data Acquisition ("SCADA") communication components, transducers, catalytic heaters, gas pipeline filter separators and 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. By 2020, 44% of the current gas mechanics will be 60 years and older. Thus, a regulation

apprenticeship program is planned 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. However, as these are new employees, it is planned that Reasonable Expectancies ("RE") for individual job and task completion will increase for the test year until experience levels allow for more stable time on jobs.



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 labor costs over the next two years.

Q. Please describe the O&M expenses related to the Measurement and Regulation Transmission Program.

A. The Measurement and Regulation Transmission Program is primarily responsible for gas measurement, pressure control, and gas quality for the Company's transmission system, which feed the distribution system as well. This includes third-party supplies and metering to meet Sarbanes Oxley ("SOX") requirements as well as lost and unaccounted fuel custody requirements. This 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. Other expenses include vehicles, maintenance equipment, utility bills, regulatory permits, and general cost to maintain city gate sites, buildings, fencing, and security. This program ensures the safety and compliance of Company gas transmission and distribution pipeline systems through inspection and repair of all critical assets to meet federal, state, and local agencies' regulatory requirements.

Q. What is the basis for determining the $3,629,000 of projected O&M expenses in the test year 12 months ending September 30, 2021 for this program?

A. Much of the work in this program is driven by field worker labor hours. Each activity includes a forecasted number of units and associated expected amount of time to complete the unit. The units multiplied by the time to complete, along with anticipated labor rates, accounts for much of the cost projection.

Transmission Measurement and Regulation Projection Breakdown by Work Type	
Work Type	**Test Year**
Code Inspections	$1,098,750.00
Preventative Maintenance	$219,750.00
Demand Maintenance	$1,190,500.00
Operations	$215,750.00
Direct Allocation of Miscellaneous Expenses	$666,750.00
Lead Abatement Program	$237,500.00
Total Program 2021	$3,629,000.00

The projection for Code Inspections is calculated based on 7,486 maintenance units needed to meet the criteria of regulatory code inspections, which have increased from 6,984 units in 2018. This 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 SOX controls. The projected amount primarily consists of Company employee labor hours, services, and necessary material costs. Labor hour allocations 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. These inspections can include piping, regulators, transducers, SCADA, valves, operators, emergency shut down devices, separators, heaters, meters, and odorizers. 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). Fugitive emissions testing is a new Environmental Protection Agency requirement adding a $35,000 annual cost. Inspection units have increased 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 to meet multiple station outputs to meet customer demands. The code inspection activities are driven to meet safety and compliance 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 pertains to performing 525 proactive and necessary inspections that do not fall under the code requirements but are necessary for maintaining the system operations safely, reliably, and predictably, which have increased from 334 units in 2018. 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 monthly operations, 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 condition-based needs.

The Demand Maintenance projected expense accounts for labor, material, and contractor supported activities to perform 993 repair units on Measurement and Regulation assets, which have decreased from 1,193 units in 2018. 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 all alarms generated from gas control requiring investigations including RTU communications failures. The additional efforts focused on Code Inspections as well as Preventative Maintenance have resulted in a reduced number of Demand Maintenance units due to equipment failures and ultimately increasing the safety and reliability of the system.

The Operations portion of the program is primarily comprised of labor necessary to operate 303 units to address the general operations of the Transmission Measurement and Regulation Operations workforce, which have increased from 265 in 2018. 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 projection is comprised of labor, materials, and services not associated with a work order. These costs include travel and meal charges, Company laboratory labor for equipment calibration, storeroom stock and non-stock material, heater glycols, valve grease, equipment rental charges, storage space rental, purchase power, SCADA cellular bills, repair parts, outside services, contractors, buildings, testing in laboratory services, and parts and materials to support system operations and code work. This portion of the program also includes actions needed to comply with governmental agencies and local ordinances. Costs here are projected based on historical spend.

Lead Abatement is part of a five-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. 28 sites have been abated during the period 2016 through 2018, leaving nine 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 2018 as part of the program.

Q. Please describe the O&M expenses related to the Odor Response Program.

A. This program provides for constant response to odor calls and other emergencies including initial response to third-party damages. The Michigan Public Service Commission ("MPSC" or the "Commission") monitors Company performance on response times with a targeted average annual response of 30 minutes and with less than 1.3% 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 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 program cover the O&M portion of the final resolutions. The O&M portion is based on a historic 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. In the 2018, the O&M percentage

was 70%, and in the test year the percentage projected is 74.3%. The higher O&M percentage in the test year is based on the increased number of leaks found on the gas system and the need to complete additional immediate repairs as opposed to asset replacements. This is consistent with the Company's efforts to reduce overall leaks on the system in the near term, prior to the long-term positive impact of the Natural Gas Delivery Plan. The Natural Gas Delivery Plan is sponsored by Company witness Craig C. Degenfelder as Exhibit A-36 (CCD-1).

Q. What is the basis for determining the $6,459,000 of projected O&M expenses in the test year 12 months ending September 30, 2021 for this program?

A. The Odor Response Program consists of labor costs that are based on the RE to complete each work activity along with known labor rates for the personnel completing the activity. New activities such as new leak investigation standard (six house check) and the increase in the O&M percentage are causing the total costs to increase slightly from the historical year. The new Leak Investigation Standard provides a more thorough leak investigation. The new standard requires 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 RE was increased in the test year from .65 (65% of one hour) in 2018 to .70 due to this change.

This program is based on 58,136 units which includes odor response and CO calls. The test year assumes 74.3% of the total odor response units will be O&M instead of the historical year actual of 70% O&M.

	Historical Year	Test Year
Units	54,743	58,136
% O&M	70.0%	74.3%
RE	0.65	0.7
Total Cost	$5,265,000	$6,459,000

Q. Please describe the O&M expenses related to the Leak Repair and Survey Program.

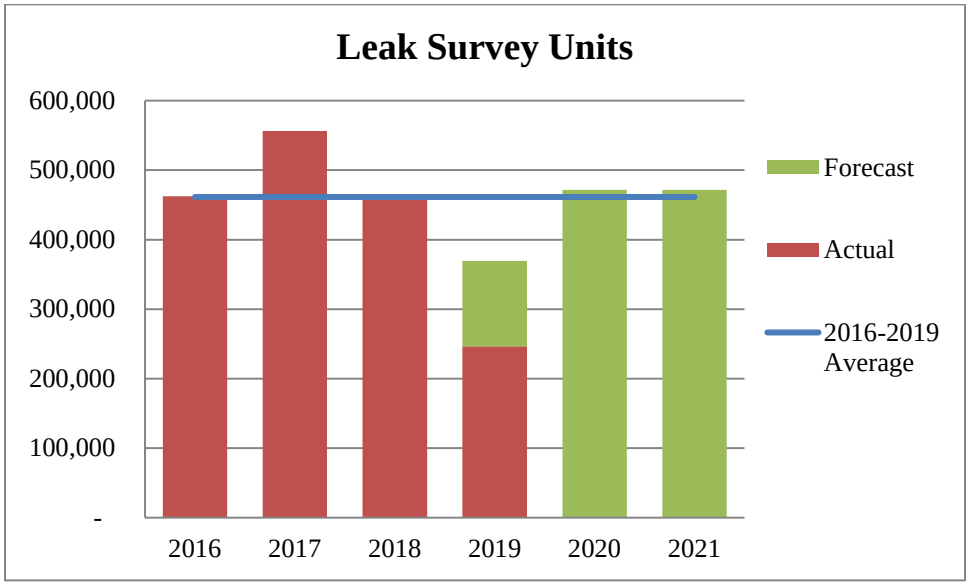
A. The Leak Repair and Survey Program includes Company labor and contractor services for annual mobile and walking leak surveys and classification of leaks on mains, services, and meter stands called in by customers or found during leak survey activity. The program also includes leak repairs to mains, services, and meter stands, including installation of leak repair fittings and clamps, tightening of fittings and clamps, partial service replacement, and rebuild of meter installations. This work is on the Company's distribution system and helps to ensure public safety.

Q. What is the basis for determining the $20,271,000 of projected O&M expenses in the test year 12 months ending September 30, 2021 for this program?

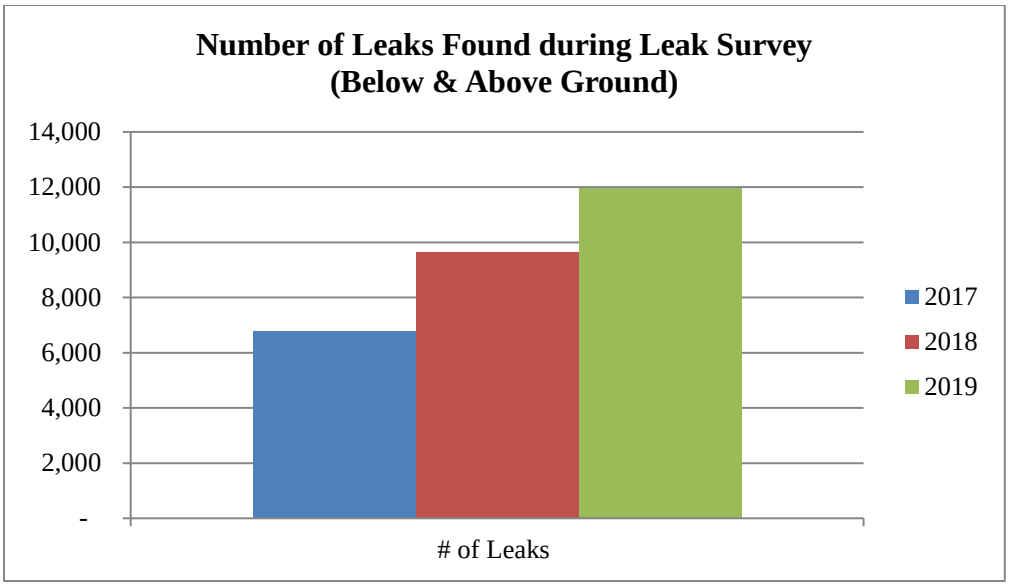
A. The projected expense in this program is primarily driven by leak survey requirements, leaks found during leak survey, current actionable leaks, and leaks requiring repair. Leak survey is compliance driven per MGSS 192.481, 192.557, 192.613, 192.705, 192.706, 192.721, 192.723, and 192.935, which require line patrol and leak survey frequency for mains, services, and customer-owned gas systems. The frequency of leak survey is determined by the survey type:

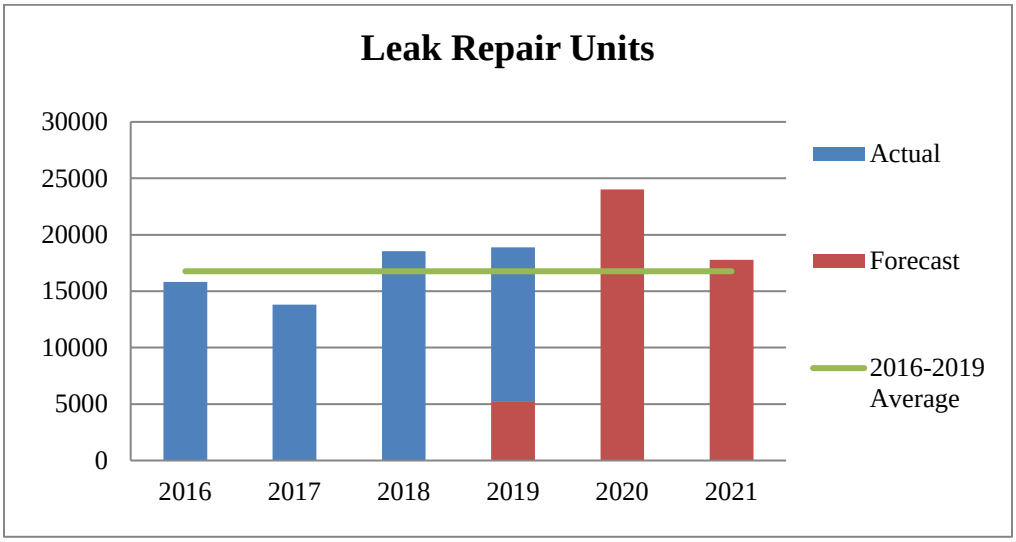
- Scheduled leak surveys — Required on a quarterly, semiannual, annual, three-year, or five-year basis;
- Non-scheduled leak surveys — Required on an as-needed basis;

- Contracted Customer-Owned Gas System Leak Surveys — Varies per contract; and
- Discretionary leak surveys — Performed on an as-needed basis.



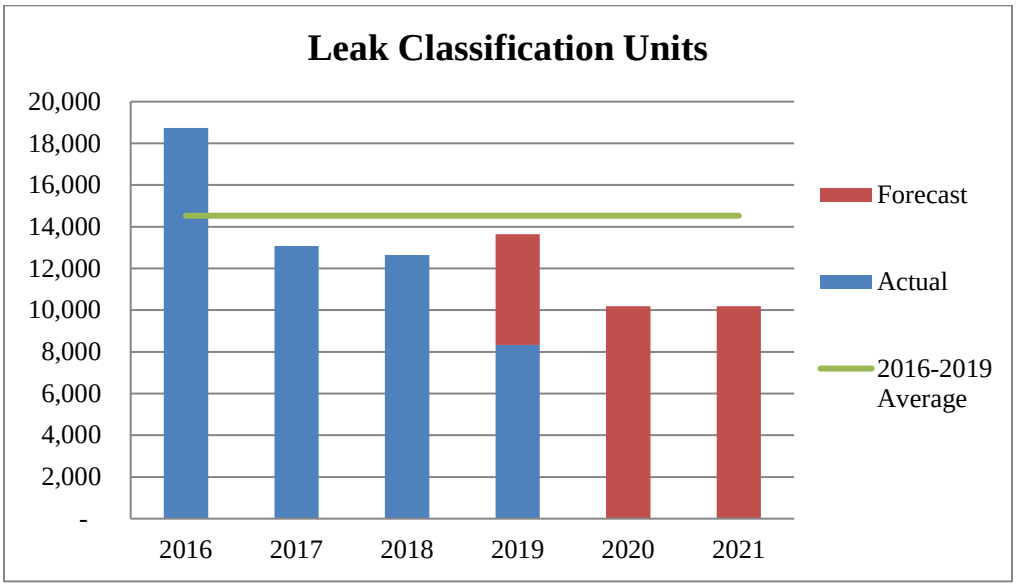
Leak Survey for the test year is forecasted to be similar to 2016 and 2018 with approximately 460,000 units. This is based on the code required schedule and frequency of the gas facilities to be surveyed. The Company has seen an increase in the number of leaks found by annual survey. In 2017, 6,775 leaks were found, compared to 9,646 in 2018, and 11,954 through August 2019. This indicates that the system is deteriorating more quickly than in prior years. The increase in leaks found drives increased required leak repairs.





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. Due to the higher than average leak found rate in 2019, the Company must repair a larger number of leaks in 2020 and 2021 compared to the 3-year average of 2016 through 2019 due to code requirements. In addition, as discussed in the direct testimony of Company witness Jeffrey R. Parker, the Company is increasing investment in its capital replacement

program that focuses on gas services with existing leaks. The repair and replacement programs will moderate leaks prior to the implementation of the Company's Natural Gas Delivery Plan. By repairing and/or replacing more leaking gas services, less re-classifications of leaks will be required, which is depicted in the chart below.



The table below shows a comparison of the units between 2018 and the test year.

	2018	Test Year
Survey Units	457,641	471,763
Classification Units	12,650	10,191
Repair Units	18,556	16,807
Total Cost	**$ 16,087,691**	**$ 20,271,009**

Despite the decrease in classification units and repair units from 2018 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 substantial shift from service repairs to main repairs. This is based on leaks that have been identified through 2019. The below table shows this projection.

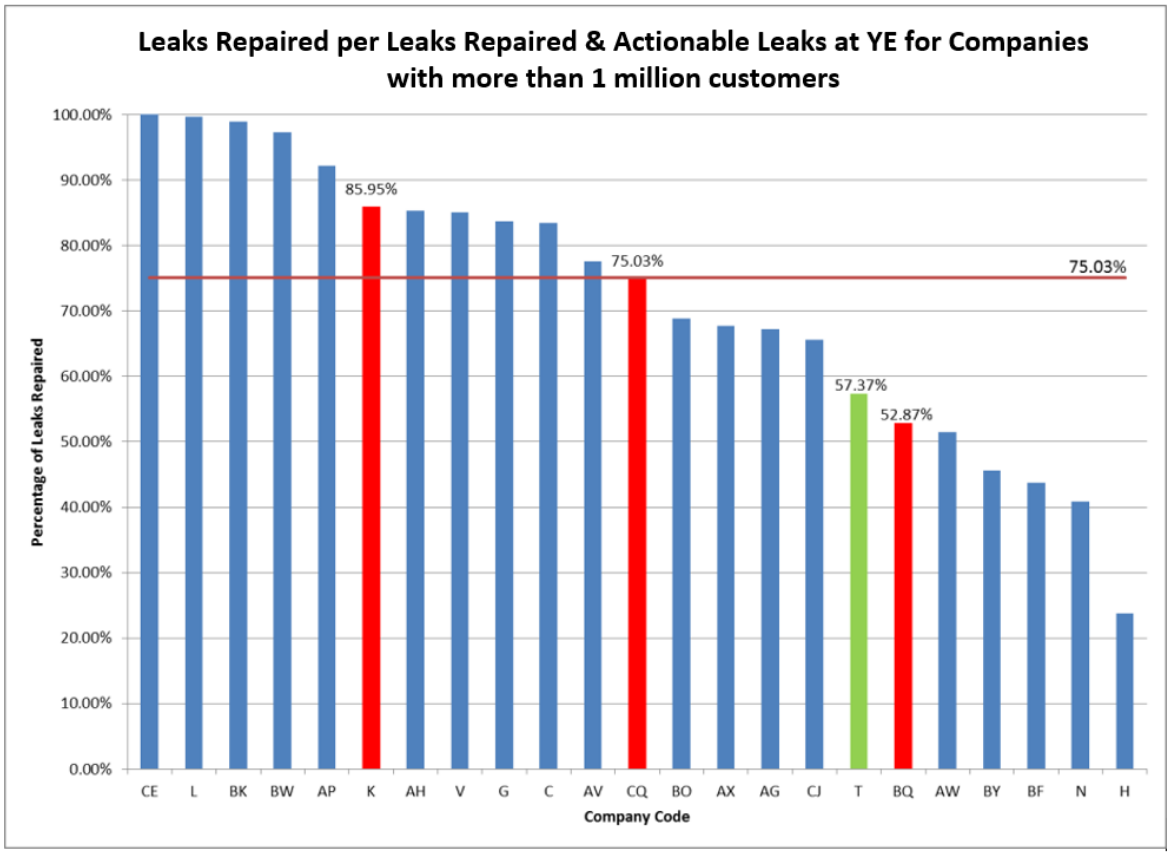
Units	2018	Test Year	RE (hrs)
Leak Repairs - Mtr Stands & Regs	14,104	12,661	2.1
Leak Repairs - Services	3,804	2,450	5.8
Leak Repair Main	648	1,696	30.0

As shown, the 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 the total cost of the program to increase.

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 57.37% as of April 22, 2019, which is the bottom of the third quartile. Based on benchmarked data, the Company is seeking to position itself more favorably with peers who have demonstrated best practices for managing leaks on their gas systems, which drives improved system integrity and public safety.



The additional leak repairs planned for 2020 and 2021 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 is 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 in 2020 and 2021, there will be fewer actionable leaks compared to prior years (2017 and 2018). However, the Company will still carry a backlog of actionable leaks, although reduced,

out of 2019 and into future years. The Natural Gas Delivery Plan will address long term system integrity.

Q. Please describe the O&M expenses related to the Staking Program.

A. The Staking Program involves Company labor and contractor services for the staking and locating of the Company's gas pipeline facilities in response to MISS DIG staking requests. This program minimizes damage to the Company's system and works to ensure public safety and deliverability.

Q. What is the basis for determining the $8,227,000 of projected O&M expenses in the test year 12 months ending September 30, 2021 for this program?

A. Spending in this program is primarily driven by staking request volume and units. The table below shows the increase in staking volumes realized in 2019 year to date compared to 2018. The majority of staking is completed by a vendor and billed based on contractual unit costs. An anticipated 3% volume and cost increase is included in the test year projection based on market rates for this work.

	2018	**2019**	**2020**	**2021**
$	6.753M Actual	8.186M	8.021M	8.227M
Total Units	231,000 tickets through July 370,000 tickets – full year	280,000 tickets (21% increase in volume YTD through July)	+3% - standard increase planned	+3% - standard increase planned

MISS DIG data shows a continuous growth in staking ticket requests for the entire state of Michigan:

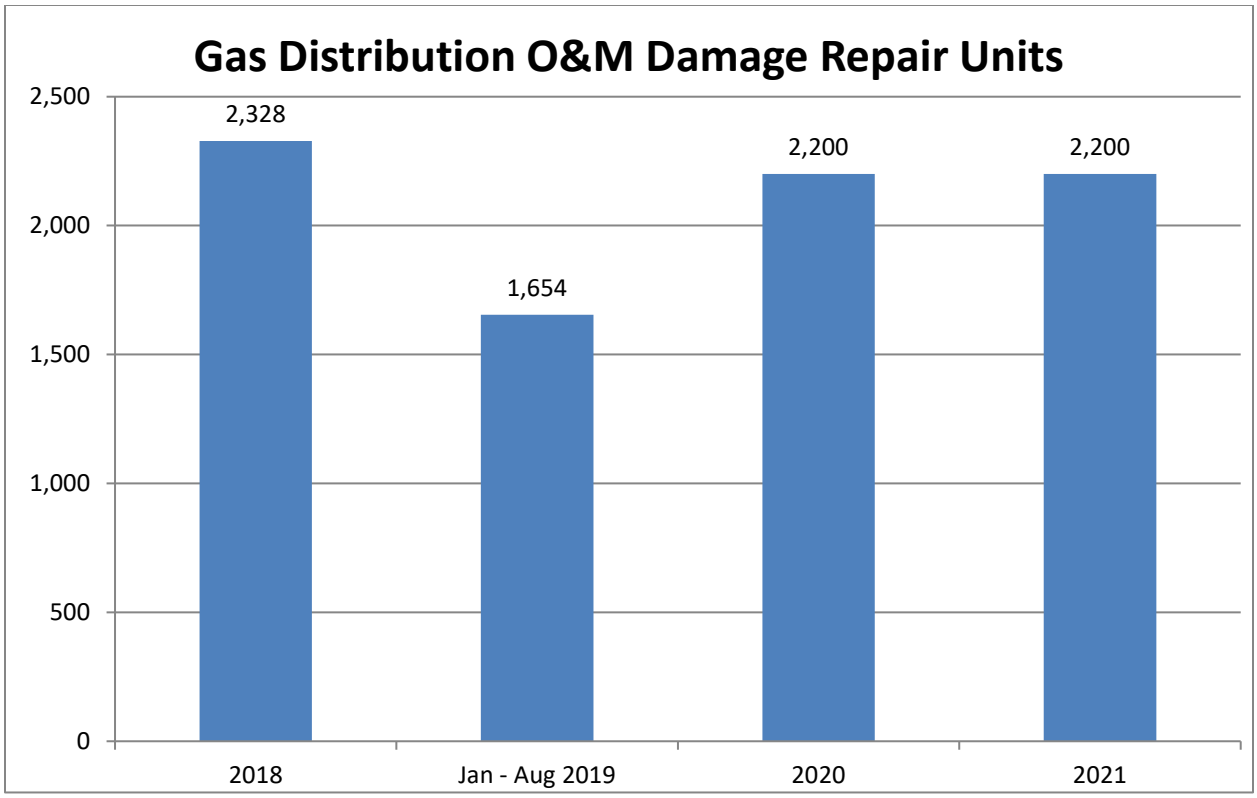
Growth by Year	
2015 to 2016	5.9%
2016 to 2017	7.2%
2017 to 2018	5.8%
2018 to 2019 YTD + Forecast	12.7%
2019 YTD + Forecast to 2020 Forecast	4.1%

Q. Please describe the O&M expenses related to the Damage Repair Program.

A. The Damage Repair Program involves repairing gas mains, services, and meter installations from damages by third parties (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.

Q. What is the basis for determining the $1,289,000 of projected O&M expenses in the test year 12 months ending September 30, 2021 for this program?

A. Spending in this 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. The table below shows both historical and projected damage counts for 2018 through 2021.



As seen in the table, 2019 (through August) is showing a damage rate that is likely to result in a similar count of repairs as 2018. Through PSO efforts, damage repairs are projected to be slightly lower in 2020 and 2021. These efforts are meant to reduce costs for the damage repair portion of this program. Offsetting these cost reductions is 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 individual homeowners. The Company has determined not to bill homeowners that 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 increasing from 2018 through the test year given the lower collection for damages.

Q. Please describe the O&M expenses related to the Customer Requested Services Program.

A. This 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. This work is primarily emergent. The Company has seen a 13.7% increase in this type of work over the historical year.

- 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 new 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. Troubleshooting RE's are trending higher than the historical year RE (2021 RE =.49 vs 2018 RE= .39), which included removals and installation of the gas communication modules.

Q. What is the basis for determining the $16,697,000 of O&M expenses in the test year 12 months ending September 30, 2021 as requested for this program?

A. The costs of the program are primarily being driven by Company field worker labor. In addition, the program covers costs for materials, costs associated to capital work (i.e. relights), and contractors/vendors (contractors used in general investigations for no-gas or low pressure), and minor miscellaneous expenses. Labor costs are based on the RE to complete each work activity along with known labor rates for the personnel completing the activity. New activities (i.e. AMI/AMR troubleshooting), an increase in Customer and Company Requested Service activities (demand work), and increases in labor rates are resulting in the total program projected costs to increase from the historical year.

	Historical Year - 2018		***Test Year***	
Cost	**$15,885,000**		**$16,697,000**	
	Units	**RE**	**Units**	**RE**
Meter Work	79,617	0.45	77,294	0.45
Cust & CE Req	48,388	0.63	56,042	0.63
Trans Reads	27,326	0.15	31,668	0.15
Charts & Insp	11,686	0.95	11,686	0.95
Routines	33,369	0.59	28,951	0.59
Smart Meter Work	10,914	0.39	6,684	0.49
Program Total	**211,300**		**212,325**	

Q. Please describe the Meter First Set Credits Program.

A. The Meter First Set Credits Program offsets the initial labor costs to install a newly purchased 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.

Q. What is the basis for determining the $6,921,000 projected O&M credit in the test year 12 months ending September 30, 2021?

A. This offset is primarily driven by the purchase of new gas meters. The credit is calculated monthly based on the standard labor rate of employees performing the work, the vehicle loading rate, and the associated costs such as travel time an employee spends performing that 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. 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 non-premise time an employee spends performing that 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 gas meters purchased. 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 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 is able to adjust the orders as actual inventories are observed.

The annual dollar amount of the cost of removal credits is directly tied to the number of units of gas meters retired from service during the year. Actual and projected amounts for 2018 through September 30, 2021 are shown in the table below:

$(000)	2018 Actual	2019 Projected	2020 Projected	12 Months Ending September 30th 2021
Units Purchased	62,312	67,023	62,425	62,991
1st Set Credits	$ (4,957)	$ (5,015)	$ (5,065)	$ (5,141)
Units Retired	50,654	50,654	50,654	50,654
Cost of Removal Credits	$ (1,680)	$ (1,785)	$ (1,780)	$ (1,780)

Q. Please describe the O&M expenses related to the ROW Clearing Program.

A. The ROW Clearing Program expenses are for needed clearing and vegetation management for the Company's nearly 2,500 miles of gas transmission pipeline. While the Company has recently performed minimum clearing necessary to complete inspections, repairs, and replacement of pipe and limited demand clearing for emergent work, clearing for gas transmission lines has not recently occurred at a cyclical program level. The projected test year amount of $1,827,000 will permit the clearing of approximately 350 miles of transmission line ROW per year. This will place the gas transmission system on an approximate seven-year clearing cycle to optimize resources needed to maintain the ROW and prevent the growth of large trees that would require

hand cutting. A seven-year cycle is similar to the Company's electric lines ROW Clearing schedule and will allow the Company to create a sustainable vegetation management plan and implement the use of herbicides to minimize growth of woody vegetation and promote growth of grassy vegetation. Reducing the presence of woody vegetation on the ROW will reduce the requirement for hand cutting and is expected to reduce long-term unit cost per mile for ROW Clearing. The current "Demand Maintenance" approach results in a reduced clearing width (15 to 30 feet) over the pipeline. The projected program will allow the transmission ROW to be maintained at full ROW width within the identified clearance cycle which will increase awareness and make encroachments on the ROW more visible. The duration of seven years represents the minimum clearing needed to permit aerial and ground inspections of ROWs.

Q. What is the basis for determining the $1,827,000 of projected O&M expenses in the test year 12 months ending September 30, 2021 for this program?

A. The projected expense in this program is primarily driven by mileage cleared. In 2018, the Company spent $1,095,000 on ROW vegetation clearing, which allowed for 352 miles to be cleared but not at full ROW width. In Case No. U-20322, the Company projected to increase the funding in this program to implement a vegetation management program with a seven-year clearing cycle. In that case, MPSC Staff ("Staff") proposed and the Company agreed to certain reporting requirements, with modifications. The first report is to be provided to Staff no later than April 30, 2021 following the first full year of plan implementation in 2020. Performing this work will increase ROW awareness for the public, increase visibility of encroachments in the ROW, and ultimately increase public and employee safety.

Q. Please describe the O&M expenses related to the Meter Reading Program.

A. The Meter Reading Program includes Company employee labor, business expenses (such as mileage reimbursement and training), and technology expenses 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 utilizing AMR equipped vehicles on scheduled routes; (2) the automated collection of meter indexes utilizing the Company's AMI meters; and (3) 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. During the month of September 2019, the Company achieved an overall monthly gas meter read rate of 99.62% and a year-to-date gas meter read rate of 99.28%. The meter reading results for the month of September for the various processes utilized by the Company are as follows:

	Meters Available	Meters Read	Meter Read Rate
Gas AMR	1,067,781	1,065,806	99.82%
Gas AMI	628,806	627,596	99.81%
Manual Gas Reads	24,069	20,676	85.90%

The program also includes the Meter Reading Support team, which monitors performance by tracking and reporting various performance indicators, completes meter reading route optimization, identifies specific meter reading system issues, troubleshoots system issues, and manages the Consecutive Estimates Program. The Consecutive Estimates Program 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 to resolve meter access issues.

The Meter Reading Program also includes technology expenses in the form of meter reading system upgrades, hardware and software (including associated maintenance fees), navigation subscriptions, and technical support services.

The Meter Reading Program is managed jointly for the Company's electric and gas operations. As a result, the total meter reading costs are allocated between electric and gas. The average Gas/Electric allocation for the test year ending September 30, 2021 is projected to be 25% Electric and 75% Gas; in 2018 the allocation was split 15% Electric and 85% Gas. The difference between the 2018 actual and projected test year electric and gas allocation considers the completion of the installation of AMR technology during 2019. In 2018 by year end, 795,193 meters were available to be read by AMR technology. In 2019 by year end, 1,137,308 meters will be available to be read by AMR technology.

Q. What is the basis for determining the $6,097,000 of projected O&M expenses in the test year 12 months ending September 30, 2021 for this program?

A. Spending in this 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, 2021 test year projected expense of $6.1 million is less than the 2018 actual expense of approximately $10.5 million, as shown on Exhibit A-102 (JJM-2), page 2, line 12. Reduction in Meter Reading 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, 2021, the number of gas meter reader operating employees is projected to be 39 employees. These employees will navigate AMR mobile collection vehicles and continue to manually read approximately 26,106 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	
Description	**Manually Read Meters Count**
Legacy Not Cut Over	8,966
Legacy Opt Out Not Cut Over	7,504
Total Legacy Not Cut Over	16,470
GCM AMR Not Cut Over	7,533
GCM AMR Opt Out Not Cut Over	78
GCM AMR Rates Ineligible	825
GCM AMI Not Cut Over	1,105
GCM AMI Opt Out Not Cut Over	10
GCM AMI Rates Ineligible	85
Total Smart Not Cut Over	9,636
Grand Total Not Cut Over	26,106

Q. Please describe the O&M expenses related to the Meter Technology and Management System Support Program.

A. The Meter Technology and Management System Support 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.

Q. What is the basis for determining the $1,408,000 of projected O&M expenses in the test year 12 months ending September 30, 2021 for this program?

A. This 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 Metering Technology Center began processing gas communication modules that are integrated with meters. This implementation has resulted in a slight increase in both labor and expenses. Each 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.

Q. Please describe the O&M expenses related to the Smart Energy Metering Technology Center Program.

A. The Smart Energy Metering Technology Center Program includes: (i) the gas portion of expenses related to software maintenance for gas communications modules installed on locations in which the module communicates data through the electric meter; (ii) the gas portion of the cellular communication expenses allocated to gas communication modules that pass data through the electric meter; (iii) hardware and software maintenance for belt clip radios which are used by Company employees to program gas communication modules; and (iv) 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.

Q. What is the basis for determining the $729,000 of projected O&M expenses in the test year 12 months ending September 30, 2021 for this 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. In 2018, the AMI program was still in deployment and the number of gas meters with AMI modules installed was continuing to increase. 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, the software maintenance expense per unit increases 3% per year.

Q. Please describe the O&M expenses related to the Gas Storage Program.

A. This program involves the maintenance and operation of gas storage wells, gathering lines, conditioning equipment, access roads, valve sites, fencing, and security. This program includes well maintenance, integrity management, and code compliance requirements. It also includes maintenance, integrity monitoring, and code compliance of the following: regulators and relief valves, surface and subsurface safety valves, isolation valves, fluid separators, fluid disposal systems, and lateral and main line piping.

Q. What is the basis for determining the $6,285,000.00 of projected O&M expenses in the test year 12 months ending September 30, 2021 for this program?

A. The projected expense for this program is historically based and is primarily driven by known units (labor hours) for the following activities: compliance inspections, maintenance inspections, operating the gas storage facilities to meet gas flow deliverability needs, and third-party damage prevention (such as locate/stake, crossings, and contractor oversight) to ensure public safety, code compliance, maintenance of critical assets, and operation of facilities to deliver gas across the state. Cost projections for the test year are similar to the 2018 historical year amount of $6,306,000. A breakdown of the projected costs by work type is included in the table below.

Test Year Gas Storage Expense Breakdown by Type	
Work Type	**12 Months Ending Sept 30, 2021**
Code Inspections	$ 324,633.00
Facilities Locating for Third Parties (MISS DIG)	$ 284,523.00
Demand/Preventative/Compliance Maintenance	$ 2,238,748.00
Operations	$ 3,437,591.00
Total Program for Test Year	$ 6,285,495.00

Compliance and maintenance 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. Maintenance activities include pigging activities, corrosion prevention through chemical treatment, dehydrator and separator preventative maintenance, valve and operator inspection and repair, access road maintenance, ROW maintenance for storage lateral pipelines and mainlines, line patrol, and leak survey to ensure deliverability and public safety.

Operation and integrity work includes the following: pressure survey for reservoir inventory verification, wellhead pressure monitoring to ensure public safety and deliverability, pipeline integrity verification, configuring fields for injection/withdraw cycles, and routine inspection of assets during winter operations.

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 access facilities, and equipment and system failures requiring intervention to maintain public safety and deliverability of gas supply.

Gas Operations Field Operations

Q. Regarding the Gas Field Operations sub-programs shown on Exhibit A-103 (JJM-3), please describe the O&M expenses related to the Training Program.

A. The Training Program includes training for the 1,250 gas field operations employees, including OQ training, in accordance with applicable regulations. Examples of training provided under this program include equipment operator, pipe joining, valve inspection and maintenance, and pressure control (regulation). Safety training is also included in this program. Since 2015, the Company has improved its employee safety performance

in gas field operations every year. These employees receive an average of 100 hours of 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.

Q. What is the basis for determining the $7,134,000 of projected O&M expenses in the test year 12 months ending September 30, 2021 for this program?

A. Spending in this 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. For the test year ending September 30, 2021, that is projected to equate to approximately 100,000 hours. This is similar to the 2018 historical year level, but also includes some inflationary pressures.

Q. Please describe the O&M expenses related to the Tools Program.

A. The Tools 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.

Q. What is the basis for determining the $1,975,000 of projected O&M expenses in the test year 12 months ending September 30, 2021 for this program?

A. The projected expense for this program is based on historical levels as well as any known work plan needs for the test year period. 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 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. Please describe the O&M expenses related to the Field Operations Expense Program.

A. The Field Operations Expense Program includes operating employee expenses, telephone/computer chargebacks, environmental fees, gas pipeline user fees, transmission flight operations (aerial surveys), and other miscellaneous expenses.

Q. What is the basis for determining the $3,511,000 of projected O&M expenses in the test year 12 months ending September 30, 2021 for this program?

A. The projected test year expense in this program is based on historical spend levels as well as any known work plan needs for the test year period. Primary drivers for this 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.

Q. Please describe the Direct and Indirect Labor Variant O&M Expense.

A. The Direct and Indirect Labor Variation expense supports the difference between what the Company pays operating employees and what work orders calculate the labor to be, 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 area.

Q. Please describe the O&M expenses related to the Supervision and Administration Program.

A. The Supervision and Administration 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 $6,130,000 of projected O&M expenses in the test year 12 months ending September 30, 2021 for this program?

A. The projected expense in this program is primarily driven by labor and expenses. Inflation was 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 Smart Energy Operations Center ("SEOC") Program.

A. 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 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.

Q. What is the basis for determining the $243,000 of projected O&M expenses in the test year 12 months ending September 30, 2021 for this program?

A. The projected program expense represents labor and expenses for personnel required to maintain the reliability of the electric and gas smart metering devices. Monitoring the reliability of the gas devices is less complex, requiring approximately 20% of the SEOC total resource time, which equals $243,000 in the test year.

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.

Q. What is the basis for determining the $3,024,000 of projected O&M expenses in the test year 12 months ending September 30, 2021 for this program?

A. Approximately 75% of the expense in this program is the technical training required to ensure the field employees are fully skilled and qualified to complete the work. This includes initial training for newly hired employees, as well as more advanced training for higher skilled employees. Along with technical training, expenses here cover 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 has experienced an elevated level of employees transferring out in 2018 and 2019 as a higher number of employees have moved to new positions within the Company. Along with this employee movement, a considerable amount of hiring and training is planned for 2020 and 2021, 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 in 2020 and 2021 compared to 2018. 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 500 to 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 cost breakdown for the projected test year is shown in the below table.

EIRP O&M	Test Year
EIRP Training	1,927,818
Salaries	514,563
Expenses	225,154
Tools	146,138
Training Expenses (i.e. travel)	61,513
Facilities	148,814
TOTAL	3,024,000

Gas Operations Compliance and Controls

Q. Please describe the O&M expenses related to the Compliance and Controls O&M Program shown on Exhibit A-104 (JJM-4).

A. The Compliance and Controls Program represents a new department within the Consumers Energy Operations organization beginning in 2019. Compliance and Controls includes the following functions:

- Management of the Company's operational compliance 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.

- 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 management 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.

- OQ program management to ensure the Company's field workforce is qualified to perform its work obligations on the gas system. This also utilizes technology and standardization to achieve compliance with regulatory requirements.

- Contractor oversight and management for construction contractors performing work on the behalf of the Company on the gas system.

Q. What is the basis for determining the $1,741,000 of projected O&M expenses in the test year 12 months ending September 30, 2021 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 to manage and be responsible for audits, assessments, and verification that the Company OQ Program is being followed. The program gains insights from industry best practices in order to inform Company implementation of processes for compliance requirements. Third-party consultants also verify adherence to operational compliance and effectiveness in verifying corrective actions. This program requires technology to support records integrity for controls, audits, and corrective and preventative action completion.

Gas Operations Planning and Scheduling

Q. Please describe the O&M expenses related to the Scheduling and Dispatch and Resource Planning and Closeout programs.

A. The Scheduling and Dispatch Program includes the labor and expenses for personnel who are responsible for efficiency and consistency in statewide planning, scheduling, and dispatching of long- and short-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. The

Resource Planning and Closeout Program 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.

Q. What is the basis for determining the $2,817,000 for Scheduling and Dispatch and the $295,000 for Resource Planning and Closeout of projected O&M expenses in the test year 12 months ending September 30, 2021 for these programs?

A. The projected expense in these programs is primarily driven by customer requested demand, including short cycle demand such as emergency and service calls in addition to longer cycle demand such as new or modified gas services. Response to this customer demand requires appropriate levels of personnel to plan, schedule, and closeout the associated field work. This program includes the labor costs and expenses for this personnel. The 2018 actual spend in these areas reflected robust economic and construction activity throughout Consumers Energy's service territory in addition to increased gas reliability and integrity investment. Robust demand is expected to continue in the test year at levels higher than the 2018 historical year. The Company projects costs for personnel labor and expenses to meet customer demand to increase modestly through 2021 as a result of volume and inflationary increases.

Q. Please describe the O&M expenses related to the Contract Administration Program.

A. Contract Administration conducts bidding, contracting, and field administrative support of contracted maintenance and construction operations to ensure that the Company is effectively utilizing its contractors.

Q. What is the basis for determining the $247,000 of projected O&M expenses in the test year 12 months ending September 30, 2021?

A. Spending in Contract Administration is primarily driven by economic and construction activity throughout Consumers Energy's service territory and increased gas reliability and integrity investment. The expense consists entirely of the personnel labor and expenses for the contract administrative functions, which are projected to increase slightly through 2021 because of projected inflation and economic activity.

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 that improve efficiency and quality to 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. These objectives 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 $1,378,000 of projected O&M expenses in the test year 12 months ending September 30, 2021 for this program?

A. The Gas Operations team includes experts in data analytics, data science, lean operating systems, process engineering and documentation and 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 2018 to the test year is primarily driven by inflationary increases for the personnel labor, and includes restructuring in 2019 that increased the focus on gas.

Gas Operations Management

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 cleanup, asbestos assessments and removal, and environmental spills testing and cleanup.

Q. What is the basis for determining the $1,200,000 of projected O&M expenses in the test year 12 months ending September 30, 2021 for this program?

A. The projected test year increase from 2018 actual expense is the result of an additional management position and increased supply chain costs.

GAS OPERATIONS CAPITAL EXPENDITURES

Q. Please describe the Company's projections of capital expenditures for Gas Operations you are sponsoring.

A. As shown on Exhibit A-12 (JJM-5), Schedule B-5.6, the Gas Operations capital expenditures I am sponsoring were $143,424,000 in 2018 and are projected to be $123,482,000 in 2019; $84,915,000 for the nine months ending September 30, 2020; and $192,787,000 for the 12 months ending September 30, 2021, as set forth on this exhibit on line 3.

These projections are based upon the requirements for meeting customer reliability, ensuring public safety and compliance, and maintaining system deliverability.

Q. What are the major programs within the Gas Operations capital expenditures that you are sponsoring.

A. The major programs, as shown on Exhibit A-12 (JJM-5), Schedule B-5.6, are:

- EIRP – Distribution; and
- VSR.

Q. Have you included contingency costs in the capital expenditures you are sponsoring?

A. No, I have not.

Q. Does the Natural Gas Delivery Plan discuss gas distribution assets?

A. Yes, it does. Please refer to the Natural Gas Delivery Plan shown in Exhibit A-36 (CCD-1), Section VIII, for further information,

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; and
- Replacement of approximately 100 miles of transmission pipeline located in high consequence areas and transmission pipelines operated on the Distribution System.

Q. Please describe the progress of the EIRP.

A. The EIRP was created in response to the Gas Distribution Integrity Management Program to address the replacement of the Company's lowest performing Distribution main pipe, replacement of approximately 100 miles of high-pressure steel TOD pipe, and replacement of approximately 70 miles of Transmission and Storage pipe. The lowest performing distribution pipe segments include copper, Xtrube, bare steel, T&C steel, oxyacetylene welded steel, unprotected steel, wrought iron, and cast iron. Other programs, like Asset Relocation – Civic Improvement and Material Condition

Non-Modeled, also eliminate these mains. These programs are sponsored by Company witness Parker. 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 utilizes a risk model to optimize the investment to eliminate the highest risk gas mains first, which influences the miles retired of any given material in a single year. The current 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 157.3 of 580.0 miles by the EIRP through 12/31/2018, retiring an average of 22.5 miles a year for the period 2012 through 2018. At the historic average rate of retirement, it will take an additional 17 years to eliminate cast iron main;
- Wrought iron main – Eliminated 4.7 of 21.6 miles by the EIRP through 12/31/2018, retiring an average of 0.7 miles a year for the period 2012 through 2018. At the historic average rate of retirement, it will take an additional 25 years to eliminate wrought iron main;
- Bare steel main (including oxyacetylene welded bare steel) – Eliminated 121.8 of 1,033.4 miles by the EIRP through 12/31/2018, retiring an average of 17.4 miles a year for the period 2012 through 2018. At the historic average rate of retirement, it will take an additional 49 years to eliminate bare steel main; and
- T&C main – Eliminated 70.6 of 1,061.7 miles by the EIRP Program through 12/31/2018, retiring an average of 10.1 miles a year for the period 2012 through 2018. At the average rate of retirement, it will take an additional 93 years to eliminate threaded & coupled main.

At the current pace of retirements and annual spending level, the Company will not achieve completion of the EIRP in the originally planned 25-year program term.

See the table below for a summary of pipe replacement each year by the EIRP Program and the associated program capital spend.

MILES OF EIRP CLASSIFIED MAIN PIPE REPLACED BY YEAR												
PIPE TYPE:	Miles of Pipe by Pipe Type in EIRP Program Scope	EIRP 2012 Actuals [1]	EIRP 2013 Actuals [1]	EIRP 2014 Actuals [1]	EIRP 2015 Actuals [1]	EIRP 2016 Actuals [1]	EIRP 2017 Actuals [1]	EIRP 2018 Actuals [1]		Cumulative EIRP Retired as of 12/31/18 [1]	Estimated Cumulative Retired by Other Programs as of 12/31/18	Est. Miles Remaining as of 12/31/18
TOTAL:	2,869.2	28.4	61.9	56.3	77.9	70.1	63.4	44.5		401.8	159.1	2,308.3
Cast Iron	580.0	5.3	29.9	28.7	32.9	23.1	24.0	13.3		157.3	38.0	384.7
Bare Steel	1,033.4	5.0	16.9	12.9	25.1	25.8	21.7	15.1		121.8	64.4	847.2
Threaded & Coupled	1,061.7	1.0	6.0	10.3	11.0	17.1	14.2	11.2		70.6	55.2	935.9
Wrought Iron	21.6	0.0	0.2	0.8	2.7	0.3	0.8	0.0		4.7	0.4	16.5
X-trube	0.9	0.0	0.9	0.0	0.0	0.0	0.0	0.0		0.9	0.0	0.0
Copper	1.6	0.0	0.2	0.0	0.0	0.4	0.0	0.0		0.6	1.0	0.0
TOD	100.0	0.0	0.0	0.0	3.8	1.0	0.0	3.6		8.4	0.0	91.6
LFERW	70.0	17.0	8.0	3.6	2.5	2.5	2.6	1.4		37.5	0.0	32.5
Additional Pipe Replacement:												
Plastic [2]		0.2	1.4	0.9	1.9	0.6	1.5	1.2		7.6		
Coated & Wrapped [2]		1.1	10.7	11.3	11.2	12.9	13.3	8.7		66.7		

EIRP CAPITAL SPEND BY YEAR ($ MILLIONS) [3]										
EIRP Distribution	$14.7	$49.6	$57.2	$82.5	$79.6	$81.1	$86.8		$451.6	
EIRP T&S	$41.7	$20.1	$10.2	$3.5	$2.7	$2.6	$2.0		$82.8	
Total	$56.3	$69.7	$67.4	$86.1	$82.3	$83.7	$88.8		$534.4	

Notes:

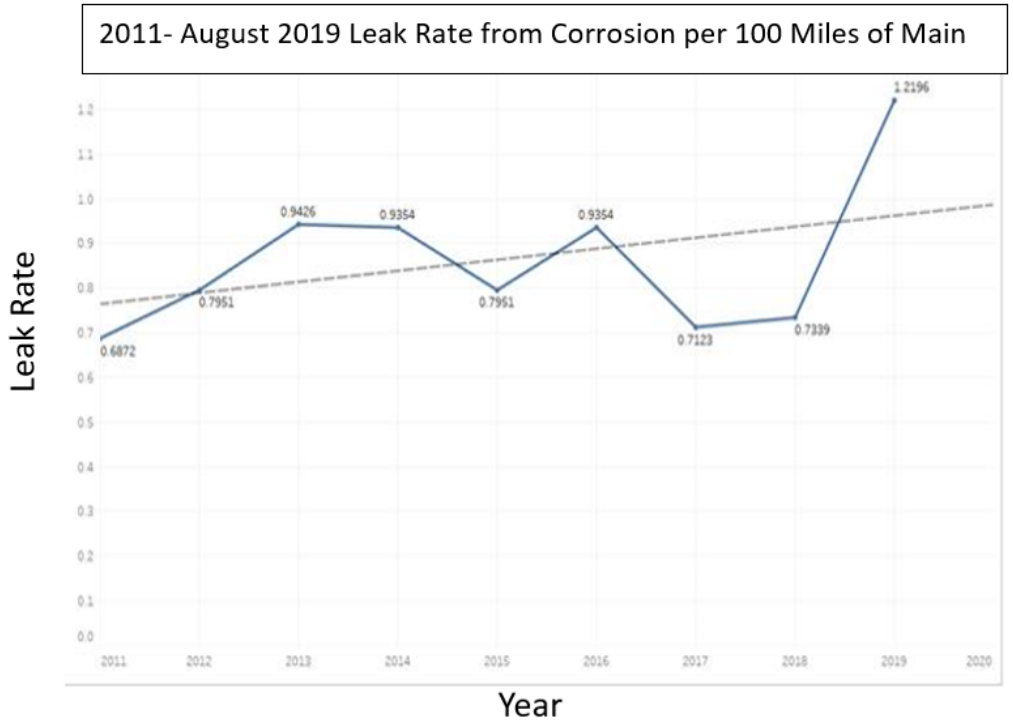
1 Does not include miles of EIRP pipe type that were replaced as part of other programs like Civic Improvement or Emergent CE Initiated.

2 It is necessary to replace some coated and wrapped and plastic pipe as part of EIRP projects due to the configuration of the system, project constructability c code 3 condition, but coated and wrapped and plastic are not an EIRP targeted pipe type.

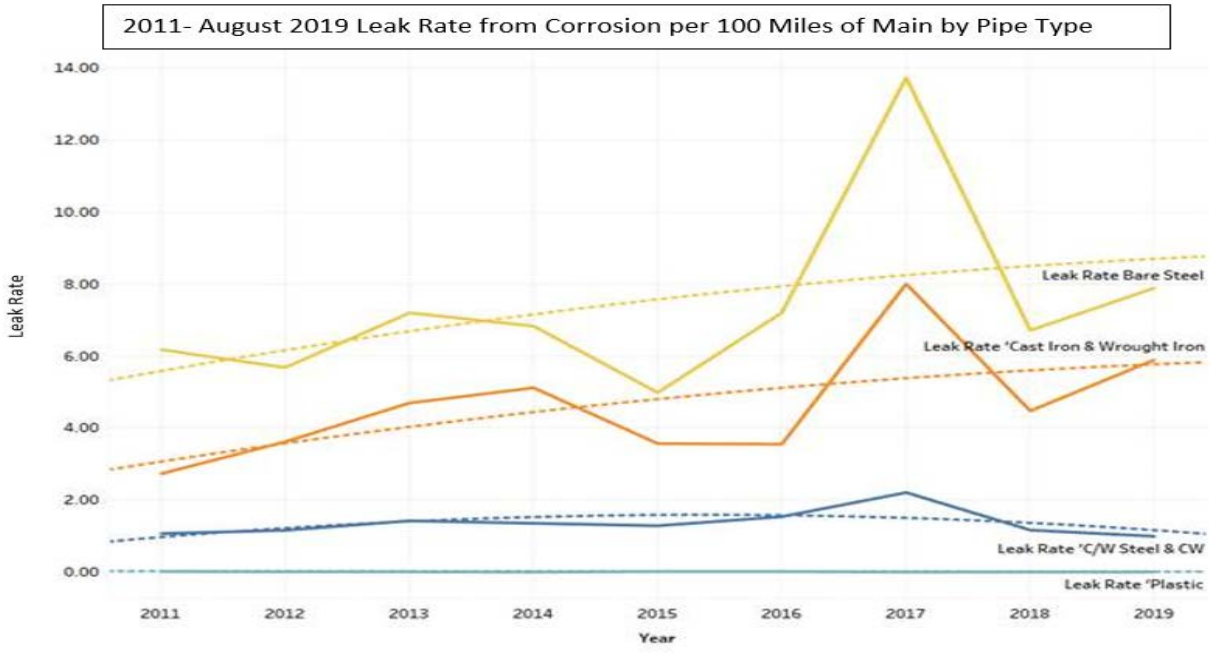
3 Capital spend from EIRP Annual Performace Reports

Q. Why is the Company seeking to increase the capital spending level and the miles of main being replaced from the level approved in Case No. U-20322?

A. The EIRP investment is to ensure the safety and reliability of the Company's gas distribution system for the Company's customers and the general public. Gas leaks caused by corrosion on this material, in particular cast iron, have seen a sharp increase in recent years. Most apparent is the increase seen year-to-date in 2019. This is illustrated in the chart below, which shows the leak rate per 100 miles of Distribution main pipe.



The following chart shows the leak rate per 100 miles by material for all pipe types in the distribution system excluding copper main, which has now been completely retired.



Q. Is the EIRP effective in preventing leaks?

A. Yes. A recent analysis shows that there have been 0 gas leaks found on any pipe installed under the EIRP from 2015 to 2018. The Company utilizes a Geospatial Information System ("GIS") system for project planning purposes. These project boundaries can be superimposed over the asset information in the Company's GIS system. All EIRP projects from 2015 through 2018 were overlaid on the Company's leak history layer in GIS, and any leaks within a project boundary were selected for further review. By reviewing these leaks, the Company determined that none of the leaks occurred after the EIRP asset replacement.

Q. How many miles of distribution main and associated services does the Company plan to replace for the projected $161 million investment for the test year?

A. The Company prepares its estimates and forecast based on calendar years running from January 1 through December 31. For the test year of October 1, 2020 through September 30, 2021 the Company combined a forecast for the three months of 2020 and a prorated 2021 forecast for the nine months of 2021.

- The Company's forecast for the calendar year 2020 includes 75 miles of main installation and 9,662 associated services. This includes 3 high-pressure steel projects representing 4 miles and 67 services, 31 distribution pipe segment projects for 37 miles and 5,269 services, and 5 pilot grid projects (as more fully described in my testimony below) for 34 miles and 4,326 services.

- The Company's forecast for the calendar year 2021 includes 161 miles of main installation and 17,272 associated services. This includes 4 miles of high-pressure steel pipe installation and 7 grid projects (as more fully described in my testimony below) for 157 miles and 17,272 associated services.

- While total miles and services are subject to final project designs and construction schedule, based on the current forecast the test year is estimated to include approximately 153 miles of main installation and 17,175 associated services.

Q. The Commission's September 26, 2019 Order in Case No. U-20322 adopted a targeted retired per-mile average cost for non-TOD main of $913,000. Are your projections based on this average cost per mile retired?

A. No. The Company's projections do not represent the cost of $913,000 per mile retired on non-TOD/high pressure steel main pipe for multiple reasons.

- The Company does not estimate project cost based on retired miles. Project cost estimates are based on miles of pipe installed and consider many factors as described more fully in my testimony below.

- The Company's 2020 non-TOD/high pressure steel project plan for the EIRP Program includes a mix of 31 pipe segment projects that will utilize historical construction practices and 5 pilot projects that will utilize a modified grid approach for construction. While the Company anticipates cost reductions from utilizing the grid approach, this only represents a portion of the 2020 project work. The 2020 segment pipe projects are forecasted to have costs similar to 2018 non-TOD/high pressure steel projects with an average cost per mile of $1.29 million (based on a simple average of consolidated project cost divided by forecasted miles to be installed). Additionally, the pilot grid projects will be constructed using a different approach than the Company has used historically, so the Company has no direct historic reference of actual cost to use for estimating these projects. The pilot grid projects include anticipated savings based on improvements to reduce the cost per mile for the EIRP Program work. Considering these anticipated savings, the 2020 pilot grid project work is currently forecasted to be $0.951 million per mile.

- The Company's 2021 non-TOD/high pressure steel project plan for the EIRP Program includes 7 grid projects. Based on the conceptual information currently available and anticipated cost reductions from utilization of the grid approach, the 2021 grid project work is currently forecasted to be $0.917 million per mile.

The Company plans to use the 2020 pilot grid projects to learn and refine the grid approach to become more efficient and drive to lower cost for project work in 2021 and future years. The Company proposes to use the information gained in transitioning to the grid approach to further refine the appropriate expected unit cost per mile for this work that considers actual results and specific factors that influence the installed cost per mile.

This change in approach will not only help reduce unit costs but also provide increased value to customers by decreasing risk on the gas distribution system.

Q. Has the Company experienced new cost drivers since the inception of the EIRP in 2012?

A. Yes. The Company has incurred additional costs in completing the EIRP project work due to multiple factors since the beginning of the program in 2012. Some of the primary drivers of these additional costs are as follows:

- 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 cross-bores 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. Now, locating of customer sewer service lines has been added to 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.

- Cross bore inspections – This work helps ensure that Company Gas facilities were not installed through sewer lines or other utilities while using horizontal directional drilling pipe installation techniques. Given the potential risk with cross bores, the Company is inspecting for them after construction work is completed (though all other underground facilities are now being located and marked) to ensure public safety, which is adding to costs.

These factors have contributed to the Company experiencing an increase in the average cost per mile of pipe installed since the inception of the program.

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 cost and requirements;
  - Suburban projects – Mostly residential and some commercial services, moderate hard surface with potential for installation under sidewalks or streets, moderate traffic control and safety services cost, low to moderate obstacles in the ground (other service provider wires, pipes, etc.), moderate permitting cost and number of requirements;
  - Urban projects – Commercial and residential buildings and services, significant hard surface requiring installation under sidewalks and streets, high traffic control and safety services cost, high obstacles in the ground (other service provider wires, pipes, etc.), moderate to high permitting cost and number of requirements; and
  - Inner city projects – Buildings and commercial services, significant hard surface requiring installation under sidewalks and streets, high traffic control and safety services cost, significant obstacles in the ground (other service provider wires, pipes, etc.), high permitting costs and number of requirements.
- Number of associated services – The average number of services to be renewed with the installed main is a significant driver of project cost, as every service renewal requires material and labor time and contributes to the required support services needed for a project (such as sewer locates, hydrovac excavation, aggregates, and soft and hard surface restoration). A project with 50 services per mile will contribute less cost related to service renewals than a project with 100 services per mile. Additional considerations 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. The table below provides data on services worked on through the EIRP Program for 2016 through 2018 and a forecast of 2019 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 the table below does not include pipe miles installed or services related to high pressure steel TOD projects.

EIRP Services by Location and Year:

Year/Location		SW	NE	SE	Total
2016	**Total**	**1,637**	**2,209**	**6,079**	**9,925**
	Renewals	1,125	1,654	4,574	**7,353**
	Tie-overs	510	410	1,503	**2,423**
	Retired	2	145	2	**149**
	Miles Main Installed	18.62	18.8	42.1	**79.5**
	Total Renewals/Mile	60	88	109	**92**
	Total Services/Mile	88	118	144	**125**
2017	**Total**	**867**	**1,307**	**5,099**	**7,273**
	Renewals	574	1,085	4,616	**6,275**
	Tie-overs	293	185	482	**960**
	Retired	0	37	1	**38**
	Miles Main Installed	12.0	16.2	42.8	**71.1**
	Total Renewals/Mile	48	67	108	**88**
	Total Services/Mile	72	80	119	**102**
2018	**Total**	**649**	**1,411**	**2,563**	**4,623**
	Renewals	540	1,184	2,245	**3,969**
	Tie-overs	109	148	307	**564**
	Retired	0	79	11	**90**
	Miles Main Installed	9.8	15.2	22.4	**47.4**
	Total Renewals/Mile	55	78	100	**84**
	Total Services/Mile	66	93	114	**97**
2019 Forecast	**Total**	**652**	**1,052**	**3,252**	**4,956**
	Renewals	414	805	2,584	**3,803**
	Tie-overs	238	247	668	**1,153**
	Retired				**0**
	Miles Main Installed	8.3	11.4	29.1	**48.8**
	Total Renewals/Mile	50	71	89	**78**
	Total Services/Mile	78	92	112	**101**
TOTAL SERVICES		**3,805**	**5,979**	**16,993**	**26,777**
TOTAL MILES		**48.7**	**61.7**	**136.5**	**246.8**
AVERAGE RENEWALS/MILE		**54**	**77**	**103**	**87**
AVERAGE SERVICES/MILE		**78**	**97**	**125**	**108**

- 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. The table below provides data on the feet of pipe installed through the EIRP Program for the years 2016 through 2018 and a forecast for 2019.

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
2016	377,745	28,110	13,889					3,073	4,683	**427,500**
2017	344,644	44,231	11,768	3,231	700			225		**404,799**
2018	195,527	25,216	30,939	2	129		10,057	546	16,685	**279,101**
2019 Forecast	186,928	31,969	32,967	1,486	347		7,995			**261,692**
TOTAL	**1,104,844**	**129,526**	**89,563**	**4,719**	**1,176**	**0**	**18,052**	**3,844**	**21,368**	**1,373,092**

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
2016	88.4%	6.6%	3.2%					0.7%	1.1%	**100%**
2017	85.1%	10.9%	2.9%	0.8%	0.2%			0.1%		**100%**
2018	70.1%	9.0%	11.1%	0.0%	0.0%		3.6%	0.2%	6.0%	**100%**
2019 Forecast	71.4%	12.2%	12.6%	0.6%	0.1%		3.1%			**100%**
TOTAL	**80.5%**	**9.4%**	**6.5%**	**0.3%**	**0.1%**	**0.0%**	**1.3%**	**0.3%**	**1.6%**	**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/premise), 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 main 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).

Q. Please describe what measures the Company is taking to improve the cost per mile performance.

A. The Company plans to modify its approach for project selection and execution to a grid approach, which transitions from selecting a higher number of smaller size projects focused on high risk segments of pipe, to selection of projects based on the highest average risk concentration of pipe in a defined geographic area. This change will result in significantly larger project sizes, with a typical grid project expected to retire approximately 15 to 25 miles of vintage main pipe compared to the 2017 and 2018 two-year average EIRP distribution plastic pipe retirement project size of 1.74 miles. These average figures do not include EIRP high pressure steel/TOD project miles retired. This change is expected to provide multiple benefits, including productivity improvements, cost reductions, improved long term coordination with local communities on their planned project work, and reduced impact to customers over the life of the program. Additional information on the grid approach is discussed in the Company's Natural Gas Delivery Plan.

Q. Will the methodology for project risk selection change in moving to the grid approach?

A. Yes. The Company will still use risk prioritization software to identify the highest risk gas mains for replacement. The major difference with the grid approach is that these

highest risk segments will be the seed for each grid project, and the project will be expanded to encompass approximately 20 miles of total vintage pipe adjacent to the seed segment. In addition to the vintage gas main replacement, the Company will be replacing all vintage services within the grid as well. Those vintage services that are attached to vintage main will be replaced with the main project. Any vintage services not connected to vintage main within the grid will be replaced under the Proactive Vintage Service Program. Utilizing this approach will still prioritize replacement by risk while allowing the Company to be more efficient by eliminating the travel between projects.

Q. Will the grid approach provide cost synergies for the replacement of vintage main distribution pipe and services?

A. Yes. The grid approach provides multiple benefits and allows for the creation of economies of scale. Some of these customer benefits include the following:

- Fewer project locations – The historic approach resulted in a higher number of smaller projects compared to the grid approach plan to have a smaller number of larger projects. Benefits include:
  - Real estate rights cost – Need for fewer number of project laydown yards to store materials and equipment;
  - Survey cost – Reduced number of survey locations and efficiencies from focus on fewer and larger projects; and
  - Equipment cost – Each project requires certain minimum amount of equipment to perform the required work. An example is bore machines. While it is typically necessary to have one or more bore machines at each smaller project, a larger grid project might only require two or three total bore machines (while the project scope is several orders larger than this) and be able to utilize equipment more efficiently and cost effectively.
- Improved efficiency – The grid approach is focused on completing all the vintage pipe and service work in an identified geographic area. The historic approach has resulted in projects being completed for a section of pipe in one year and then returning to complete a nearby project only a few streets over a year or few years later. In addition, the historic approach may result in

prioritizing work for a Vintage Services project in a year and then have an EIRP project in the same area a year or few years later.

- Increased productivity – The grid approach will reduce the amount of project mobilization and demobilization travel time and cost each year, allowing for construction crews to use that time for productive project work.

- Improved coordination with local communities – Longer term planning and communication on fewer and larger projects will allow for improved coordination of local public works projects and plans. This provides the opportunity to explore cost savings opportunities with local municipalities.

Q. What is the Company's planned timing for implementing the grid approach?

A. The Company is planning to conduct 5 pilot projects using the grid approach in 2020 with plans to fully use this approach in 2021 and after. The 2020 pilot projects will be at a smaller scale (2 miles to 12 miles of expected main retirement compared to a historical average of 1.74 miles) and provide the opportunity to gain experience with the grid approach and implement learnings and improvements prior to full utilization of this approach in 2021.

Q. Please highlight the customer benefits of accelerating the vintage main distribution pipe and services replacement.

A. Expected customer benefits of accelerating the EIRP 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;

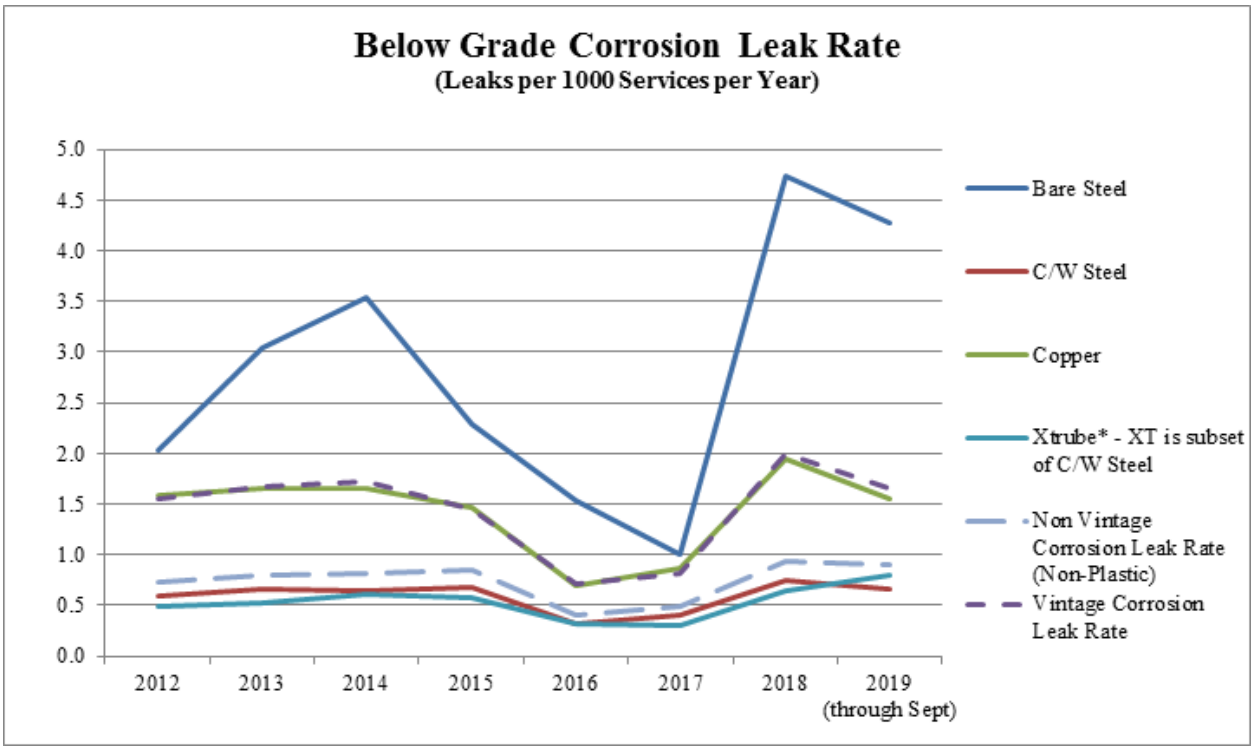
- Reduced O&M costs; and

- 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, 2018, the Company has replaced 401.8 miles of high-risk transmission, storage, and distribution pipe through the EIRP, including 157.3 miles of cast iron and nearly 27,000 services replaced and retired through 2018 to improve reliability and customer safety.

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. The chart 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:



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 vintage service replacements.

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.

There are approximately 1,100 vintage services in these four soil areas statewide, with approximately half of these completed in the 2019 proactive vintage service plan and remainder in 2020. 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 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 vintage service replacements will be charged to each of these individual programs.

- Utilizing the grid approach, the Company will also proactively replace VSRs – those that are not connected to a vintage main facility that will be replaced under the EIRP – within the grids targeted by the EIRP. 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 2,100 proactive vintage services. The costs for these vintage service replacements will be charged to the VSR Program.

For 2021, there are a total of 3,150 services that do not fall within a grid containing vintage main facilities, and therefore would not be prioritized in the grid approach. To achieve the annual replacement goal of 10,250, and to complete the program in the timeframe outlined in the Natural Gas Delivery Plan, the Company will also need to proactively replace these VSRs that are outside of the vintage main grids. 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 vintage service replacements.

Q. How many services will be replaced under the VSR Program?

A. As of year-end 2018, there are approximately 157,000 vintage services remaining on the Consumers Energy gas system. The Company's VSR Program included the replacement of 9,383 proactive vintage services in 2018. In 2019, the Company will replace 6,250 proactive vintage services. In 2020 the Company intends to perform 6,250 proactive VSR replacements, and in 2021 the Company intends to perform

5,250 proactive VSR replacements. Additionally, 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.

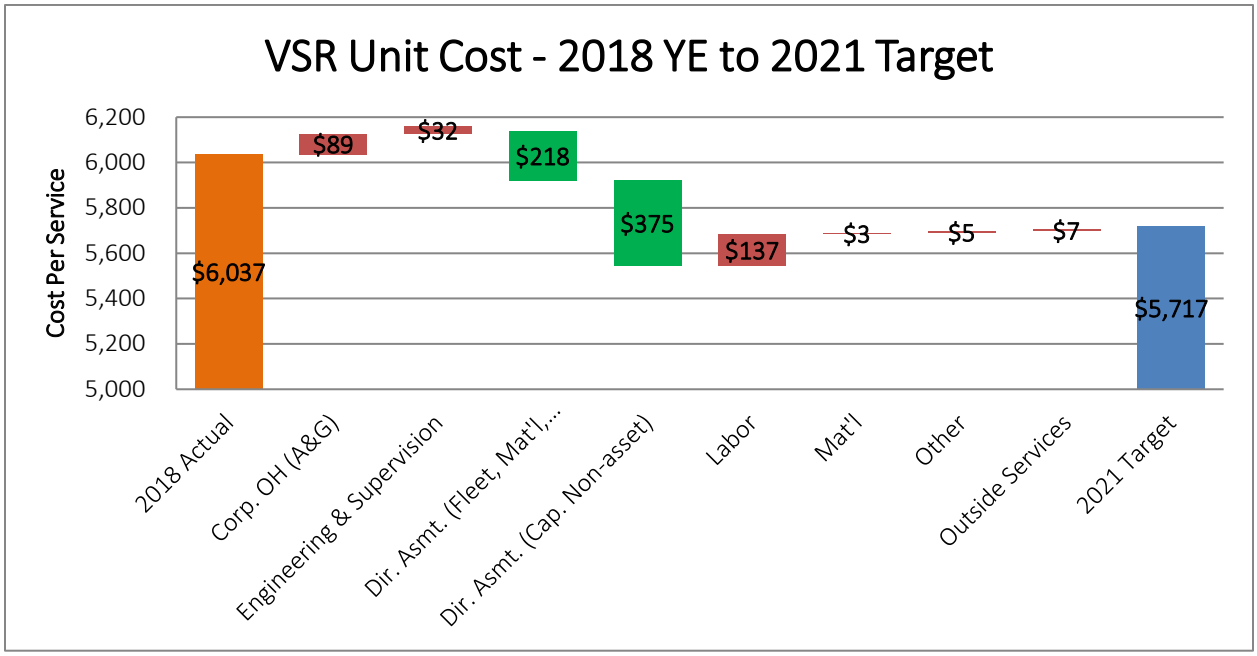
As shown in Exhibit A-12 (JJM-5), Schedule B-5.6, line 2, the historical VSR Program expenditures were $56,635,000 for the year 2018 and are projected to be $40,500,000 in 2019, $32,177,000 for the 9 months ending September 30, 2020, and $31,427,000 in the 12 months ending September 30, 2021.

The projected costs are based on an estimated cost per VSR of $6,480 for 2019, $6,169 for 2020, and $5,717 for 2021. The 2018 actual cost per VSR was $6,037.

Q. Please explain the derivation of the service replacement unit cost under the VSR Program projected in this filing?

A. The 2018 cost per unit of $6,037 is the actual cost per unit experienced in that year. The 2019 unit cost is the forecasted unit cost of $6,480, which considers actual and projected remaining costs in 2019. In 2020, the Company expects to slightly reduce the unit cost based on efficiency gains in labor and equipment utilization. The expected decrease in unit cost from 2020 to 2021 is largely due to the Company utilizing the grid approach discussed above. Given the nature of this approach, the Company expects efficiency

gains that will result in improved service replacement unit costs. Furthermore, the Company is continuing to manage contractor outside services costs such as hydrovac excavation to reduce overall unit costs. These unit costs are based on actual unit costs with the program since its inception in 2017. The below waterfall chart shows both cost drivers (increases) and efficiency gains (reductions) from the historical year to 2021.



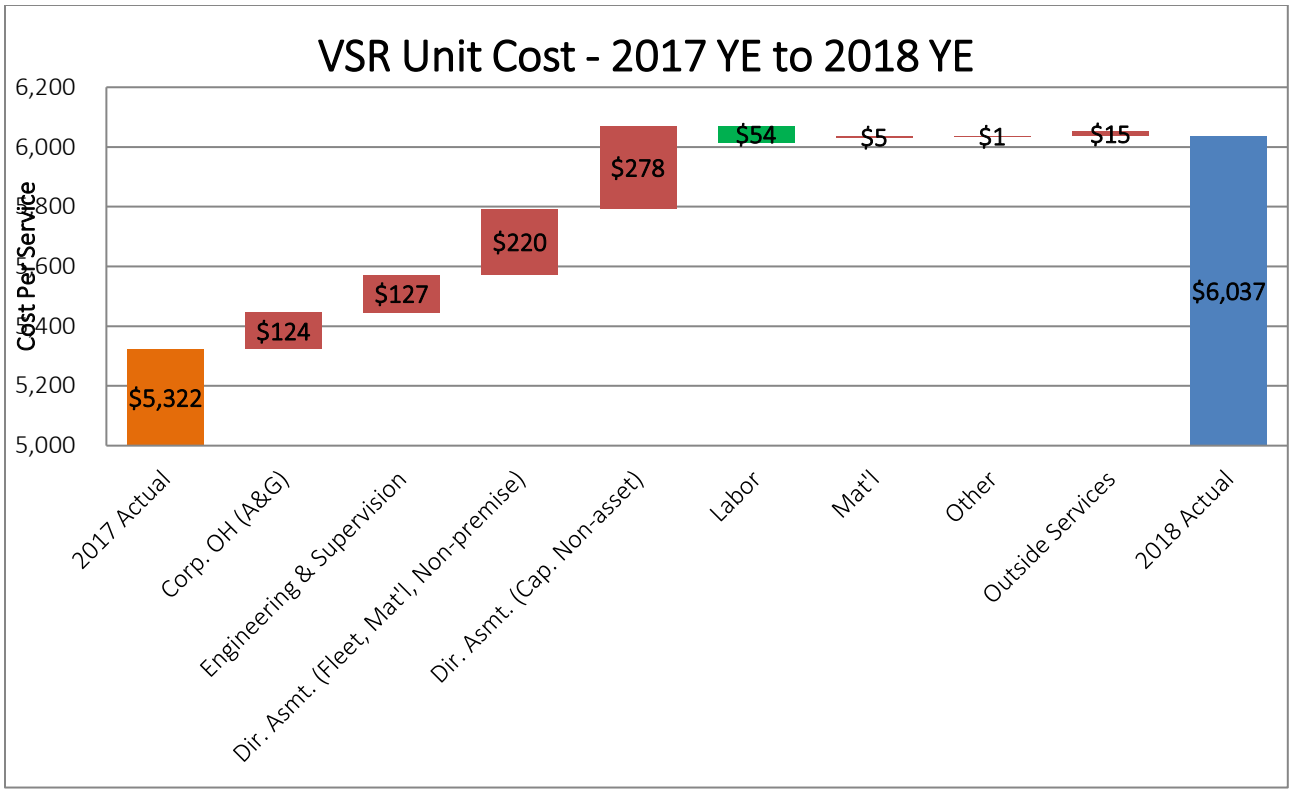
Q. How is the grid approach expected to reduce unit costs for Vintage Service Replacements?

A. As discussed, the Company expects to achieve cost synergies through higher volume projects and planning of the grids with reduced mobilization and sharing of resources. In 2020, the expected unit cost is $6,169 and in 2021 it is $5,717. Targeted unit completion is 6,250 and 5,250 respectively for the VSR proactive program. Accounting for all gas facility replacement programs, total vintage services (copper, bare steel, and unknown material) replacement targets are 9,250 in 2020 and 10,250 in 2021.

Q. The Commission's September 26, 2019 Order in Case No. U-20322 approved VSR expenditures based on a per unit cost of $3,875. Is this the unit cost the Company is projecting in this rate case?

A. No. The unit cost projected in this case is based on actual historical dollars spent in the program. The Company initially targeted a per unit cost in the VSR Program of $3,875 in its Case No. U-18424 projections. However, this estimated unit cost was based upon limited experience encompassing a small sample size, for the month of June 2017, of services eliminated in this type of program.

Since that time, the Company has gained additional experience with VSRs, has incurred actual costs for VSRs, and has experienced increases in various contractor support costs (outside services) associated with the location of underground utility infrastructure, as well as welding, hydrovac, traffic control, and property restoration costs. These supporting activities are required in order to perform work in a manner that is safe to customers and construction crews and should be reflected in the cost projections for the VSR Program. More current actual unit costs also fully reflect the inclusion of vehicle and equipment depreciation in the Company's fleet chargebacks assessed to VSR. The waterfall chart below shows the unit cost for VSRs for the full year of 2017 to be $5,322 (not $3,875). It shows the largest cost drivers that resulted in the actual unit cost of $6,037 for 2018.



The Company manages the VSR Program with a standard approach for planning the field work of the program, displaying progress, and managing costs. Through regular operation reviews, program progress is reviewed and problem solving, and course corrections are performed on a consistent basis. In addition, labor hours, outside service expenses, and unit costs are tracked to provide visibility and allow for efficiency.

Q. Can you provide additional detail on the contracted support services used for the VSR?

A. Yes. In 2018, the Company incurred approximately $15.1 million in contracted support services costs for the VSR Program. The major components of these costs can be seen in the table below.

	2017		2018		2019 *	
Total Proactive Services	6,307		9,383		4,464	
Description	$ (millions)	$/unit	$ (millions)	$/unit	$ (millions)	$/unit
Welding	3.215	510	5.275	562	2.73	612
HydroVac	0.878	139	3.121	333	1.036	232
Sewer Locating	1.589	252	2.456	262	1.458	327
Restoration (soft & hard)	1.229	195	1.874	200	1.014	227
Traffic Control	0.225	36	0.864	92	0.499	112
Aggregate	0.303	48	0.679	72	0.402	90
All Other	0.511	81	0.811	86	0.434	97
Total	7.950	1,261	15.080	1,607	7.573	1,696
* 2019 Data is through Sept. 30						

Q. Is the use of contracted services unique to the VSR Program?

A. No. The Company would utilize these contracted services for Material Condition Non-Modeled or Material Condition Renewals program work, although less frequently than the VSR Program. These types of contracted services are also utilized on EIRP Distribution projects, but the costs of the contracted services are generally charged to an associated EIRP gas main work order, not to individual service work orders. As explained below, because the VSR Program is exclusively services, it is not practical to directly allocate all charges to each individual service order. Since there are no gas main work orders in the VSR Program, the Company accumulates these contracted support costs in separate internal orders. The internal order costs are then allocated to individual service replacement work orders through an indirect capital non-labor loading. This loading has a unique loading rate for VSR, which can change on a monthly basis in order to allocate the actual costs incurred over the service replacements charged during a specific month. Because these contractor support costs are charged directly to main

construction work orders in the EIRP Distribution Program, the EIRP Distribution service installation orders would not include these contracted support costs. As a result, the Company experiences a higher unit cost in the VSR Program than it would experience in other Material Condition programs. The selection of these vendors occurs through the Company's competitive bid process to ensure quality and fair pricing.

Q. Have actual fleet cost changes occurred that also make the 2017 unit cost estimates obsolete?

A. Yes. During the second half of 2017, as identified in Case No. U-18424, the Company revised the accounting for the depreciation of vehicles and equipment used by Company operating, maintenance, and construction crews so that those costs no longer are charged to depreciation expense, but instead are charged to work performed by Company crews. This change reduces overall depreciation expense, and effectively transfers those costs to Company work orders which increased unit costs in distribution capital programs. This is estimated to increase the total VSR Program costs by approximately $4 million per year. For all of the reasons discussed above, the initial 2017 unit cost estimate of $3,875 for VSR is no longer a reasonable estimate of current and future program costs.

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 gas distribution system for its customers?

A. Yes. Company witness Christopher J. Varvatos 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. Varvatos. The projects and the benefits of the projects which will provide customer benefits for the areas which I am sponsoring are described below:

- The **EIRP Technology Enablement** project requires $1,159,499 in capital and $345,628 in O&M. This project will implement an electronic work management solution that will enable EIRP 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 project will add value by: (1) improving visibility to work locations of crews and job status updates in real time; (2) reducing field time and increasing flexibility of assignments of intra-day work adjustments; (3) standardizing employee time tracking; (4) reducing closeout time by reducing data entry; (5) eliminating efforts to hand off paper copies of work orders for emergent jobs; (6) reducing billing processing lag time for customers through direct updates on electronic forms; and (7) improving customer satisfaction with more timely meter installation dates. The scope of the project includes: (1) implementing an electronic work management solution for the EIRP; (2) enabling EIRP employees to assign, manage, and field complete work orders; and (3) developing the interfaces for management of the EIRP 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. The location and time tracking portions would need integration for proper job time cards and viewing the crew location for safety response. Lastly, a method of work assignment and dispatch would need to be developed.

- The **Field Contractor Work Management Technology Enablement** project requires $644,413 in capital and $66,331 in O&M. This project will provide the ability to electronically manage contractor work, increasing accuracy and timeliness of information processing for field work deliverables. This project will create new opportunities to measure and optimize field work processes that support customer on-time delivery 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; (4) improving material management; (5) making it easier to move emergent work to contractors, which will better meet customer commitments and balance workload; and (6) enabling real time updates to work order information, increasing data accuracy and reducing invoice reconciliation time. The project scope includes: (1) meeting with stakeholders to identify

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 new technology and processes. The alternatives considered include: (1) continuing with the current paper-based process; (2) using the current Company mobile application; (3) using off-platform options such as Service Bench; and (4) providing Company-funded field devices to get contractors on a common technology platform. These alternatives were not chosen because: (1) this approach does not allow for the timely, data-driven work management metrics required to improve servie to customers; (2) this solution is not expected to receive long term investment by the vendor and the mobile application would require more upfront investment than the proposed option; (3) to ensure contractors leverage the benefits and integrations with the existing Service Suite platform, the chosen option is preferred; and (4) 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 risk of loss of control of information security and corporate assets. The ABB Service Suite hybrid solution was chosen because it uses existing well-developed Service Suite functionality while leveraging cloud-based, BYOD capability to move short-term and long-term contractors from paper processes to the established, standard work management system.

- The **Gas Measurement, Regulation, Pipeline, and Storage ("MRPS") Field Work Management Enablement** project requires $1,057,879 in capital and $22,976 in O&M. This project is to move gas MRPS work orders from the current paper process to an electronic solution that includes work management, compliance scheduling and tracking, and mobile dispatch and work completion functions. The project will add value by: (1) increasing efficiency of order entry and management reporting; (2) maintaining key compliance records without depending on paper processes and records; (3) improving productivity by eliminating records management through paper binders; (4) reducing risk of MPSC non-compliances; (5) reducing risk to gas storage assets and adherence to standards by enabling a monthly well monitoring program that ensures accurate and timely data capture for identification and mitigation of asset risk, analysis, and data trending; and (6) increasing visibility to asset health. The project scope includes: (1) SAP updates to enable gas MRPS work processes; (2) evaluation and conversion of up to 300 paper forms (75 for compliance work, 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) training Company employees in the new tool. Alternatives considered were: (1) utilize an SAP module to migrate field work orders to an electronic platform; and (2) continue manual paper-based process currently used by the gas MRPS work force. 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 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 provides work management scheduling capabilities and real time validation of field work order forms.

- The **Work Management Scheduling Analytics and Reporting** project requires $321,372 in capital and $57,636 in O&M. This project will implement a solution capable of scheduling long cycle, maintenance, and emergent work. This will combine data from the several excel spreadsheets that are used today to allow single views of all the information needed to effectively produce the various schedules and provide reporting. The project will add value by providing: (1) accurate schedules tied to productivity, reducing waste, and shrinking the work backlog across work types (emergent, customer requested, project, and compliance); (2) enhanced quality and integrity of scheduling process through reduction in manual scheduling steps and hours spent developing route sheets; (3) time saved from manual entry to be reallocated to better schedule analysis and alignment across disciplines, decreasing risk of missing code work and being in non-compliance; (4) improved transparency into whether the weekly schedule is meeting business objectives such as: financial scenarios, compliance requirements, and first time completion; and (5) increased employee engagement by having a quality product to schedule, while being able to focus on priority and execution of work versus workarounds to meet daily scheduling needs. The project scope includes: (1) implementing a streamlined scheduling process across Operations; and (2) implementing associated analytics and reporting. Two alternatives were considered for this project: (1) Purchase disconnected software products. This option was not chosen due to a risk of increased costs as well as it contains solutions that provide overlapping functions with existing solutions or will not meet base requirements. (2) Automating manual data movement across systems through Robotic Process Automation. This option was not chosen because it will not meet base requirements and does not provide desired insights. The option to purchase the SAP Multi Resource Scheduling module was selected as it will minimize ongoing support costs, meets base requirements, and will provide increased transparency into scheduling.

- The **Field Mapping and Graphics** project requires $475,140 in capital and $9,216 in O&M. This project will implement a replacement system for the mobile field mapping and data collection software (“ArcPad”) that can search

and view facility map data, view work order designs, and create work order as-built construction drawings in the field. This will make it possible to consolidate field graphics functionality into an efficient process while implementing a current and supported application and retiring the unsupported ArcPad solution. 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 resulting from current system limitations; (4) enabling the adoption of the GIS standard; and (5) allowing for growth of functionality and capabilities to make more 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, and the ability to search by address; (3) producing the ability to view pre-construction work order designs in a new GIS format; and (4) enabling the creation of as-built construction drawings in GIS format for assigned work orders. Three alternatives were explored and determined non-viable for the project: (1) Continue to maintain 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 through the use of static, oudated data; or require the creation of as-built construction drawings on paper documents. (2) Use the existing Mobile Information Management System ("MIMS") mapping solution for facility maps portion and use other existing applications that have rudimentary drawing capabilities, like Adobe or Snagit, for creating as-built construction drawings. This option was not selected because it would introduce significant cost because of the complexity and customization to integrate the applications. Also, this alternative would forfeit the already-established user experience and application integration achieved with the proposed MIMS solution. (3) Rebuild ArcPad from the ground up. This option is not advisable as existing industry solutions are available at a much lower cost with much less risk. Implementing the new field mapping and graphics software will consolidate field graphics functionality into an efficient process and provide a current, supported solution.

- The **One Call Ticket Risk Analysis Model for Damage Prevention** project requires $192,960 in capital and $48,374 in O&M. This project implements a risk analysis and data analytics program that identifies the riskiest excavation tickets, utilizing current one-call ticket data, damage history, and incorporating asset information from the GIS to focus damage prevention resources and activities on locate requests with the highest risk. Completion of this project will provide value to both the Company and its customers by providing safety improvements and risk mitigation through: (1) implementation of automated screening daily one call tickets to enable decisions that mitigate damages and support proactive communication;

(2) creation of a risk analysis model to identify and prioritize the highest risk tickets; (3) creation of detailed data analytics for high risk tickets and actual damages to identify root cause or systemic issues; (4) mitigation of damage prevention risk and prevented damages, which results in fewer root cause investigations, facility repairs, lost service to customers, collection efforts, legal expenses, and regulatory reporting, and results in better public relations. Fewer damages result in reduced potential for serious injuries and property damage for customers. The customer directly and indirectly benefits from this implementation by reducing disruptions to service, reducing planned work interruptions for emergent work, and reducing public safety risk through proactive damage prevention measures. Together with improved business process, risk analysis, monitoring, and proactive communication safe digging practices with highest risk excavators, damages can be reduced. The project scope includes: (1) vendor application hosting, maintenance, and support of one or more instances of the Cloud-based platform; (2) a solution to provide gas and electric asset information from the GIS databases for use within the vendor platform as either extracts (FTP or emailed files) on a regular interval (i.e., quarterly, monthly) or through integration with the GIS platform; (3) ongoing and historical ticket locate data to vendor software through either an email format, web service, or integration; (4) copies of ongoing and historical excavation damage records that occurred on any of the locate requests provided above by either a spreadsheet or web service; and (5) a damage risk statistical model that calculates risk scores based on multiple factors to produce outputs of a daily summary of highest risk tickets, reports, and web access to the customer portal for detailed risk assessment data. Alternatives considered include: (1) augmenting existing damage prevention staff to manually perform daily risk analysis on one call tickets; (2) developing an in-house, custom solution with significant consulting; and (3) deferring risk model implementation to a future year. The first alternative was not selected because it would require a significant increase in resources to perform the work. It is estimated that each ticket analysis would take 15 minutes, resulting in an additional 50 full time resources (15 minutes/ticket*445,000 tickets/year = 111,250 hours/year = 50 full time resources = approx. $5M in labor and overheads). The second alternative was not selected because the estimated capital investment would exceed a commercial vendor solution. The third alternative was not selected because it continues to defer value realization and does not provide a timely response to mitigate safety risk. The option of implementing a cloud-based solution was chosen because it implements a solution that has been tested in the industry with success, provides an ongoing support model through a subscription-based application, and provides a path to deliver faster business value through damage reductions.

Gas City Facility

Q. Is the Company planning any training enhancements in support of ensuring a trained and competent workforce available to work on the gas pipeline?

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 students 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 the gas pipeline.

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 does this by allowing students to learn in a classroom and then perform tasks in a neighborhood that includes 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.

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 not 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 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 light ups – Appliance light ups 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 allow employees 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 that understands 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 utilized 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. The cost for the Gas City facility is sponsored by Company witness LaTina D. Saba.

Q. Please describe Exhibit A-106 (JJM-7).

A. Exhibit A-106 (JJM-7), in accordance with Attachment 11 to the filing requirements prescribed in Case No. U-18238, provides the variances in the capital program amounts for the distribution programs which I am sponsoring to the Company's most recent general rate case, Case No. U-20322.

Q. Can you explain why columns (d), (e), and (f) of Exhibit A-106 (JJM-7), do not contain any data?

A. Yes, the information for column (d), the "Actual Spending in the Test Year," cannot be completed as the test year in Case No. U-20322, which was the 12 months ending September 30, 2020, is a time period that has yet to transpire as of the filing of this case. Since there is no data to display in column (d), the information for columns (e) and (f), which seek information concerning the variances from (c) and (d), cannot be completed at this time.

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, Planning and Scheduling, Operations Performance, and Operations Management, as well as capital investments in EIRP and VSRs, 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.

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-20650

DIRECT TESTIMONY

OF

STEVEN Q. MCLEAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

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 Experience Regulatory Strategy, Reporting and Quality in the Clean Energy Products 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 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.

Q. What are your responsibilities as the Director of Customer Experience Regulatory Strategy, Reporting and Quality?

A. In this position I am responsible for coordinating the regulatory filing, reporting, and quality processes associated with the Company's Energy Waste Reduction Plans, Renewable Energy Voluntary Green Pricing programs, and residential Demand Response ("DR") programs. In addition, I am responsible for supporting all Customer Experience related expenses and capital investments in gas and electric general rate cases.

Q. Have you previously testified before the MPSC?

A. Yes. I have testified before the MPSC in numerous general rate cases, Gas Cost Recovery cases, Energy Waste Reduction cases, and other miscellaneous proceedings on behalf of the MPSC Staff and SEMCO.

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

A. The purpose of my direct testimony is to describe Customer Experience & Operations ("CX&O") and how the work performed within this organization benefits the Company's residential and business natural gas customers today and into the future. As part of my direct testimony I will also address the Operations and Maintenance ("O&M") expenses, capital investment, and corresponding revenues associated with executing this work in the test year ending September 2021. Additionally, in response to the Statewide Energy Assessment, my testimony will propose two new Gas DR pilots that are a component of the Company's Natural Gas Delivery Plan. These pilots will 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. Please describe CX&O.

A. In short, CX&O comprises four areas that collectively define the experience customers have when interacting with the Company. These include: (i) using established data-analysis techniques to understand, communicate, and engage with the Company's natural gas customers in an impactful way (Customer Analytics and Outreach); (ii) connecting with natural gas customers in the channel (phone, text, and email) they prefer today, while enhancing the Company's digital resources in response to growing customer feedback that they prefer "self-serving" through digital channels (Customer Interactions); (iii) providing customers accurate, timely energy bills and consistent payment processes (Billing and Payment); (iv) providing enhanced energy products and services to customers beyond those offered by the regulated utility (Customer Programs). While I will describe each of these areas in turn, it is through the collective efforts of these areas that (i) cost savings will be realized; and (ii) customers will decide whether they were satisfied when interacting with the Company.

Q. How is customer satisfaction measured by the Company?

A. Historically the Company relied on J.D. Power as the primary measure of customer satisfaction. While the J.D. Power results still provide valuable quarterly feedback from customers, the Company realized it needed a real-time measure of its performance to keep pace with customer expectations. As such, the Company is using the Customer Experience Index ("CXi") score developed by Forrester, along with customer feedback through

J.D. Power and internal customer research, to improve its agility in responding to customer feedback.

Q. Please describe the CXi score and why the Company is using it as the primary metric for measuring customer experience.

A. The CXi score is a common customer experience survey framework that measures the customer perception of an interaction. The framework consists of three questions: How well did the Company meet your needs? Was it easy? Was it enjoyable? Through these three simple questions, the Company gains insight into a more complete picture of the overall customer experience and can use near real-time feedback to prioritize and focus its work as part of improving its interaction with customers without waiting for quarterly J.D. Power results to see if an initiative has worked. As an example of how CXi is used, assume a customer is in the process of moving and wants to schedule a move-in and create an account online. The customer locates the online application but for some reason cannot make the update and receives a message to call a customer service representative who makes the proper arrangements in quick fashion. In this scenario the Company would have met the customer's need of updating the account, but it was not easy. As another example, assume that a customer calls to report a gas leak and is immediately sent a text with a link that allows the customer to see a picture of the assigned crew leader, track the crew's arrival on a map, and use the information checklist to ensure the customer's family is safe. The crew arrives as expected and secures the leak. In this scenario the Company met the customer's need, made it easy for the customer to report and track progress of the work, and provided information on what steps should be taken to keep everyone safe.

Q. Is the Company proposing to use the CXi across all "touchpoints" with customers?

A. Yes, the Company has created a standard system for tracking and reporting the CXi scores across its call centers (phone and Interactive Voice Response systems) and digital interactions with customers. As part of this process, the Company also continually refines its measurement of the CXi scores to ensure it is accurately capturing customer sentiments across all channels.

Q. Please describe the Company's CX&O focus.

A. Historically, there has not been a significant emphasis on being a "retailer" for customers. However, given the changes in customer behavior and the Company's desire to be a cleaner and leaner utility, the Company needed to change how it interacts with customers. The Company is transforming its service methodology in accordance with the changing behaviors and needs of customers. This includes introducing enhanced clean energy products to meet the needs of customers and the environment. The CX&O strives to make interactions fast and simple for customers in order to encourage them to choose the Company's clean energy products in the future. This framework includes success metrics and long-term technology and program offerings that the Company must implement to meet these objectives.

Figure 1

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-12 (SQM-1)	Schedule B-5.9	Projected Capital Expenditures Customer Experience & Operations Summary of Actual & Projected and Common Capital Expenditures;
Exhibit A-107 (SQM-2)		Projected Customer Experience and Operations O&M Expenses & Revenues Summary;
Exhibit A-108 (SQM-3)		Customer Experience and Operations IT Project Summary; and
Exhibit A-109 (SQM-4)		Residential and C&I Gas Demand Response Pilots.

Q. Please describe Exhibit A-12 (SQM-1), Schedule B-5.9.

A. Exhibit A-12 (SQM-1), Schedule B-5.9 details the capital expenditures related to work within the CX&O organization, which total $8.1 million, $500,000 of which is to support gas DR pilots, from the bridge year through the test year ending September 30, 2021.

Q. Please describe Exhibit A-107 (SQM-2).

A. Exhibit A-107 (SQM-2) details the O&M expenses related to work within the CX&O organization, which total $120.2 million for the test year ending September 30, 2021. Exhibit A-107 (SQM-2) also includes $91 million of revenues from the Customer Programs. These revenues are used to offset the Company's test year revenue requirement, and can be found as part of the other revenues included in Company witness Jason R. Coker's Exhibit A-13 (JRC-49), Schedule C-3.

Q. Please describe Exhibit A-108 (SQM-3).

A. Exhibit A-108 (SQM-3) describes the Information Technology ("IT") projects supporting the CX&O organization along with a summary of the corresponding test year capital and O&M costs contained in the exhibits of the Company's IT witness Christopher J. Varvatos.

Q. Please describe Exhibit A-109 (SQM-4).

A. Exhibit A-109 (SQM-4) provides detail regarding the capital and O&M projections for the proposed gas DR pilots.

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

A. Yes.

Q. Please discuss any changes to the structure of the organization since the Company filed its last natural gas rate case.

A. There have been no major changes to the structure of the CX&O organization in 2018 or 2019. There has been some minor shifting of responsibilities both within the CX&O organization and other organizations within Consumers Energy which I will describe later in my testimony.

Q. Please provide a summary of the projected CX&O expenses and capital investment.

A. CX&O is projecting $120.2 million in O&M expense for the test year ending September 2021. This amount comprises $55.9 million of O&M for Analytics and Outreach, Customer Interactions, Billing and Payment, and gas DR, plus $64.3 million as part of the Company's non-regulated services (Customer Programs). As an offset to the revenue requirement, CX&O is also including $91 million of revenues from the non-regulated services, resulting in a benefit to customers of $26.7 million in reduced revenue requirements when subtracting Customer Programs' revenues from expenses. The CX&O O&M expenses are provided at Exhibit A-107 (SQM-2). The Company is also projecting $8.1 million in capital investment for the bridge year though the test year to support the CX&O infrastructure development initiatives described below and outlined in Exhibit A-12 (SQM-1), Schedule B-5.9.

I. ANALYTICS AND OUTREACH

Q. Please provide an overview of the Analytics and Outreach area and any structure changes since Case No. U-20322.

A. The Analytics and Outreach work is performed by two separate teams and can be broken into four major categories: (i) Customer Research; (ii) Data and Analytics; (iii) Customer

Experience Design; and (iv) Operational Communications. In the Case No. U-20322 filing, Analytics and Outreach included the Communications and Outreach function which develops the strategy, media buying, and creative material to communicate with customers on topics such as safety, improvements in the natural gas system in customers' communities, and assistance programs to help customers manage their bills. This function has been consolidated into the Corporate Communications organization. In addition, operational communications have been moved from the Corporate Communications organization to Analytics and Outreach as part of a new team dedicated to Customer Experience Design and Operational Communications. To effectively perform in the Analytics and Outreach functions, the Company is projecting $7.4 million of O&M expenses for the test year ending September 2021, as shown on Exhibit A-107 (SQM-2), page 2. This represents an increase in O&M expenses of $2.4 million from the $5.0 million expended in 2018. The $2.4 million O&M increase is mostly related to several projects which will increase the Company's ability to understand, serve, and communicate with customers. These projects are discussed in greater detail below. To complete these projects, the Company is also projecting $6.5 million of capital expenditures through the test year, as shown on A-12 (SQM-1), Schedule B-5.9. I will discuss the four major functions of Analytics and Outreach, and related projects, in two separate sections: (i) Customer Analytics; and (ii) Customer Experience Design and Operational Communications.

A. Customer Analytics

Q. Please provide an overview of Customer Analytics.

A. Customer Analytics is the business process of creating relationships with and satisfying customers. Consumers Energy is focused on better understanding its customers, being more predictive about their needs, and becoming more personalized in the customer experiences they have with Consumers Energy, including:

- **What programs to offer**: Use of primary and secondary customer research to understand and inform the experiences, utility programs, and services to develop;
- **Who to target**: Develop advanced analytics models to identify target customers based on demographic/firmographic data, customer insights, and other customer specific attributes; and
- **How to engage customers**: Develop customer engagement that is outside-in focused, meaning it is built with the customer needs first, based on feedback received, to meet the needs of customers, based on specific customer preferences.

The expected results of these efforts are reduced costs and increased efficiencies for both the customer and the Company.

Q. Please describe the type of work performed in Customer Analytics.

A. Much of this work can be categorized into two areas of focus: (i) customer research; and (ii) customer analytics. The Company is undertaking several projects which will increase customer feedback and develop advanced analytics models to improve the Company's ability to serve customers. Projected test year O&M expense for these projects that contribute to the increase over 2018 actual amounts is approximately $0.4 million and included in Exhibit A-107 (SQM-2), page 2. And to support the critical work of customer analytics, the Company is projecting $3.5 million in capital investment which is included

in A-12 (SQM-1), Schedule B-5.9. Table 1 below details these Customer Analytics projects.

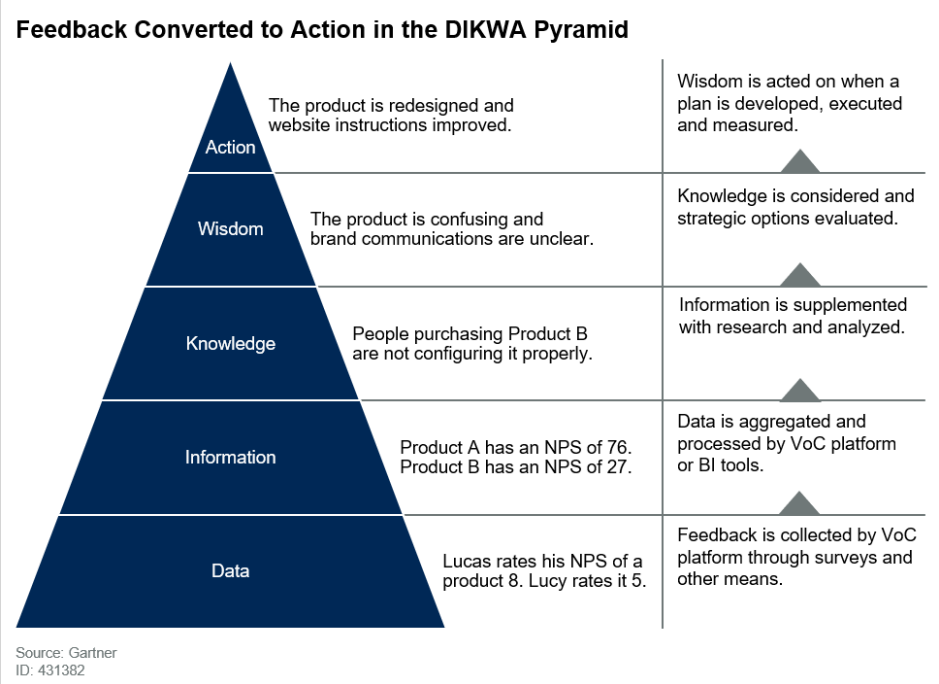
Table 1 – Analytics & Outreach Investments
($ in Dollars)

Category	Description	O&M	Capital
CUSTOMER RESEARCH		$131,688	$330,000
A. Voice of the Customer	A new technology platform and process to manage and integrate customer research, customer feedback, and customer comments into one Voice of the Customer solution. This solution will enable a more holistic view of the customer, their needs and service expectations. The data and insights derived from this will improve the outreach outcomes when promoting utility products and services, as well as improve the contact center experience.	$131,688	$330,000
CUSTOMER DATA & ANALYTICS		$304,001	$3,055,064
B. Advanced Analytics Hub	Measuring the impact of communications, outreach, and engagement on utility products and services and overall customer experience. This includes being able to predict the next best service to offer a customer based on their past engagement, measuring the effectiveness of communication messages and channels to individual segments, and determining the return on investment (increased customer satisfaction, digital adoption that offsets contact center expenses, enrollment in customer programs, etc.) of communications and outreach campaigns.	$42,875	$632,780
C. Customer Relationship Management ("CRM")	CRM technologies support the ability to identify and manage customer relationships, in person or virtually. CRM software provides functionality to companies in four segments: customer service, digital interactions, sales, and marketing.	$261,126	$2,422,284
Total		**$435,689**	**$3,385,028**

Q. Please describe the Voice of the Customer ("VoC") technology platform and process?

A. Advancements in customer technology and customer expectations are continuing to shift the energy industry landscape. Customer data and feedback such as surveys, social media comments, and conversations with contact center representatives are generated through customers' interactions with various teams within the Company. This data and feedback is reviewed daily by operational teams to identify issues, customer pain points, and opportunities to improve the overall customer experience. Using this data and feedback has helped the Company reduce over 1 million calls from our contact center since 2017 as well as reduce formal complaints more than 20% since 2017. However, the Company does not currently have the ability to integrate all of the customer data and feedback received from the various channels at a customer record level. The dispersed nature of the data limits the Company's ability to effectively incorporate customer feedback and continue to reduce calls and formal complaints. This new VoC technology platform will bring all of the data and feedback together allowing the Company to better understand customers' feedback across any and all channels leading to better customer understanding and engagement. This new platform provides a foundation for the Company to obtain and organize essential customer data necessary to address existing issues and create innovative, differentiated experiences. Below is an illustration of how customer feedback, or the VoC data, is used to improve an experience, the communications, and the customer outcomes.

Figure 2



VoC will provide increased visibility into customer expectations and experiences. This will allow the Company to better collect information from customer interactions and analyze it to identify the best opportunities and area of focus which will have the greatest impact on improved customer service.

Using information from leading research firms such as Gartner's and Forester, the Company will develop best practices, identify surveys and research needs, obtain the right data to produce the necessary analysis, and provide the customer information that the customer needs and values. The Company's VoC efforts will drive key aspects of a good customer experience management program to improve the Company's service to customers. VoC will:

- **Improve Customer Experience** – VoC data is used to fuel a collaborative process to improve the end-to-end customer journey. Data is used by cross-functional Customer Experience ("CX") teams to understand the needs of customers and the Company's success in meeting those needs. Key

considerations include drivers of customer satisfaction and dissatisfaction, as well as the financial impact of improved satisfaction, loyalty, and advocacy;

- **Close the Loop** – VoC data is used to drive granular action at a customer-by-customer level. Individual customer responses are evaluated for targeted action, typically when a customer expresses strong dissatisfaction or satisfaction;

- **Improve Customer Activation** – VoC data is used to support efforts to gain a single view of the customer and execute strategies that deliver greater engagement. Customer feedback can be combined with operational and other data and used to drive personalization and other customer activation strategies; and

- **Uncover Risks** – VoC data is used to listen, identify, and act early on potentially costly risks. Customer survey and listening data can be monitored to uncover issues that might grow into damaging problems, such as data or security risks.

Customer Analytics and VoC technologies were the biggest investments for CX improvement projects in 2018 and are expected to increase in 2019.

Forrester has also identified the role that VoC has in the Company's CX maturity. The table below identifies the competency and the outcomes the Company expects from this VoC platform:

Figure 3

Discipline	Relationship to VoC
Research	Insights about customer attitudes and behaviors help guide qualitative research efforts that produce tools like personas, customer journey maps, and CX ecosystem maps.
Prioritization	VoC programs guide organizations on where to focus by identifying what is most important to the customers' experience and the business' success.
Design	The ultimate design of an experience flows from the organization's CX vision and the insights from its research discipline, which are both influenced by data from the VoC program.
Enablement	The VoC program helps organizations tune technology, processes, and procedures for employees and partners, ensuring that the actions those people take deliver customer value. This is because it provides managers with a way to collect customer observations on the health of the journey.
Measurement	Through surveys, VoC programs capture the solicited, structured data that provides metrics for customer experience measurement programs.
Culture	Customer stories and verbatims gathered by the VoC program can bring the customer experience to life and help create a customer-centric culture.

144031 Source: Forrester Research, Inc. Unauthorized reproduction, citation, or distribution prohibited.

Q. Are you aware of other regulated utilities investing in customer research?

A. Yes, utilities across the county are investing in research to better understand the voice of their customers. The Company has spoken directly with two utilities that have successfully implemented VoC utility technology platforms:

- Southern California Edison leverages a VoC system to present customer feedback to their operations employees, driving actionable insights for those employees to improve the customer experience. Since implementing in 2017, they have found the system allows for more real-time feedback from customers with transactional experiences driving quicker action internally. As a result, their Net Promoter Score ("NPS"), which measures how likely customers are to recommend a company to a friend for transactions, improved approximately 10 points one year after implementation; and

- Duke Energy is also using a VoC system to identify opportunities to improve customer satisfaction, quantify and validate opportunities with operational measures, and develop recommendations to enhance the customer experience.

Q. Please describe the customer data and analytics projects.

A. The Company is projecting costs to continue to build an advanced analytics hub and implement a new CRM technology platform. These efforts are foundational in order to offer the right customer experience, to the right customer, in the right channel, at the right time. Salesforce's study[1] on customer expectations concluded that:

- 84% of customers say being treated like a person, not a number is very important;

- 70% of customers say understanding how they use products and services is very important;

- 59% of customers say tailored engagement based on past interactions is very important;

- Customers are twice as likely to view personalized offers as important versus unimportant; and

[1] Source: Salesforce, "Customer Expectations Hit All-Time Highs" https://www.salesforce.com/research/customer-expectations/

- 67% of customers say their standards for good experiences are higher than ever.

The Company recognizes this shift in customer expectations and is expanding the role of data and analytics in order to better understand the complexity of data, the number of variables to be analyzed, the types of analysis, and the speed of the analysis required to produce better outcomes for customers.

It is not enough for the Company to merely know the consumption patterns of customers, the way customers pay their bill, and the demographic (or firmographic for businesses) data. Customers expect the Company to understand their needs and the impact of their behaviors on their bill, and to provide personalized recommendations for what to do next.

This requires the Company's analytics capabilities to evolve from descriptive analytics – understanding what happened historically – to predictive analytics – being able to predict what will happen next. These more advanced analytics capabilities include propensity modeling, machine learning, and artificial intelligence.

These analytics support actionable recommendations for which utility products and services are right for a specific customer segment. This may include customer recommendations such as paying a bill a certain way, changing to a different rate that is better suited for their energy needs, and alerting customers to higher consumption patterns that may yield a higher bill and then tailoring actions to help them reduce their bill.

Additionally, these analytics will provide insights into which communications and customer touchpoints are driving the greatest customer benefit. An example of this is the insight these capabilities are producing for the Summer Time of Use rate pilot outreach. The Company is able to assess which communication channels and which frequency level of communicating drives favorable customer outcomes for each customer segment (such

as low income and seniors). The Company will be able to predict with greater accuracy the communication types and costs necessary by segment to ensure customer communications are efficient and effective.

The CRM technology platform will ensure that the data is accessible to those within the Company that need to access the information. The Company currently does not have an enterprise CRM solution focusing on customer and marketing analytics. This limits the Company's ability to efficiently identify products and programs for customers. CRM is a technology for managing all relationships and interactions with customers. This technology platform connects customer care, account management, customer activation, and customer acquisition for products and services. This will permit anyone in the Company that needs to (and has access rights) to view the complete customer relationship including what has been offered to them, service issues, programs they are engaged in, and usage patterns. Customers may be contacting the Company on a range of different platforms including phone, email, or social media — asking questions, following up on orders, or contacting the Company about an issue. Without a common platform for customer interactions, communications can be missed or lost in the flood of information — leading to a slow or unsatisfactory response.

The CRM solution will permit the Company to integrate with existing software solutions to create a Companywide tool for supporting customer relations. The Company will be able to compare marketing data with customers' energy usage and other datasets, which the Company expects to lead to improved programs and increased customer enrollment in Company programs. The project is expected to add the following value:

- Program Enrollment Growth;
    - Increased effective customer communication;

- Increased program enrollments, such as in Energy Waste Reduction, DR, and Home and Industrial products; and
- Increased customer activation through campaign automation.

- Operational Efficiency and Productivity Improvements;
  - Decreased customer acquisition cost into programs;
  - Enhanced visibility and optimization of campaign spend;
  - Decreased program administration cost;
  - Decreased data entry time;
  - Decreased data extraction and manipulation time; and
  - Decreased report creation and maintenance time.
- Cost optimization through system consolidation of siloed CRM instances; and
- External vendor costs reduction.

Q. Can you provide an example where the Company would have experienced an operational benefit from a CRM?

A. Yes. On January 30, 2019, Consumers Energy experienced a fire at the Ray Natural Gas Compressor Station disrupting a significant supply source for the Company's system. The fire, combined with exceptionally cold weather, led to a natural gas supply shortage on the Company's system. During this shortage Consumers Energy did not have a tool to quickly and systematically identify and communicate to customers impacted by the Company's curtailment directive due to lack of integrated contact information and the presence of some inaccurate contact information. The CRM platform will provide accurate and integrated customer contact data which would enable the Company to inform and prepare customers for impeding major events or emergencies in a systematic manner. This will significantly reduce the likelihood of a communications situation similar to the one faced by the Company on January 30, 2019.

Q. Are there other examples of how a CRM can benefit the Company?

A. Yes. It recently came to the Company's attention that some customers are receiving excessive communications over a short period of time. This is the result of a lack of comprehensive information regarding customer communications to any individual customer. A CRM will provide accurate and integrated information regarding customer communications which will allow the Company to limit and target communications to provide customers with the information they need without overwhelming them.

Q. What is the scope of the CRM Project?

A. The project includes implementation of modules for Account Management, Sales Life-Cycle Management, Product and Program Management, Marketing and Campaign Management, Centralized eligibility and enrollments, Service Quality Management, Partner Management, Consolidated Preference Center, and Common Platform. The project will maintain customer information related to their account and activity, maintain process flow for programs enrollment and services, and maintain an inventory of programs they have participated in; integrate with the Company's existing Supply Chain product (SAP); identify and maintain campaigns for various customer segments across all channels, maintain eligibility and business rules for programs, maintain and manage customer contacts related to issues, maintain partner inventory/roster including metrics, maintain all customer preferences for communications, notifications, and alerts within a single repository, and include the ability to connect/integrate with a number of third-party applications and internet of things.

Q. Has the Company evaluated alternatives to the CRM Project?

A. Yes. The alternatives include: (1) hiring additional staff to complete data retrieval, consolidation, and updates for each customer interaction, thereby requiring additional cost of 10 new employees' salary and benefits; (2) customizing (build your own) internal applications to hold additional data including integration points, datastores, modification of business processes, and increased maintenance costs; and (3) continuing with the current process, which will continue to create waste and additional costs, leading to a reduction in customer experience and fewer opportunities for enrollment in utility products and services. These options were less cost effective than implementing a CRM because they would require the Company to add additional employees, increase maintenance cost, or continue to face the risk of system-wide issues when errors occur.

Q. Are you aware of other utilities investing in analytics and CRM technology?

A. Yes, utilities across the country are investing in improved analytics capabilities and CRM technology to better understand customer opportunities and deliver a better customer experience. A few examples include:

- San Diego Gas & Electric Company launched its Customer Information System project in 2017 and subsequently discussed the program with Consumers Energy. They recognized that evolving market and customer demands are driving immediate needs in their analytics and technology capability. Some of those demands included:
  - Customers expect an experience comparable to top retailers;
  - On-demand service through the digital channel of the customers' choice;
  - Personalized communications and offers;
  - Exponential increase in data volume;
  - Expanding customer choice and options; and
  - Complex rates and programs introduced at rapid pace.

- Examples of some of the benefits that they realized are stated in Figure 4.

Figure 4

Customer Benefits		**Operational Benefits**	
Previous State:	**Future State:**	**Previous State:**	**Future State:**
Complex interactions with utility Customer experience across platforms and channels can be siloed Lengthy time to implement new products and services Limited personalized recommendations	Simplified interactions with utility Communicate with utility through any channel consistently Quickly implement programs and customer options Tailored customer experience	Manually intensive back office processes Static customer engagement processes Inflexible, customized systems	Automated / streamlined modern processes Personalized and more efficient processes Agile, configurable vendor products

- According to SAP, other relevant utilities in North America leveraging their CRM platforms include Duke, Sempra, Southern California Edison, Southwest Gas, First Energy, Navajo Tribal, Florida Power and Light, Centrepoint Energy, Puget Sound Energy, and Hawaiian Electric.

Utilities that have implemented a CRM technology platform have indicated that they realized the same benefits and outcomes, such as:

- Decreased customer-acquisition costs by approximately 20% through integrated data, insight driven customer outreach, and activation into operational and demand side programs;
- Increased number of customer activation campaigns by approximately 10%;
- Increased program enrollment by approximately 25% as a result of more prospects converting to demand side program enrollments;

- Decreased program administration costs by approximately 50% through consolidation of multiple solutions and integration of disparate data silos with a streamlined application process;

- Reduced system maintenance costs by approximately 25% through avoided costs of maintaining older, end-of-life applications, software licenses, and system decommissioning; and

- Reduced time to market for new programs by approximately 15% with advanced analytics and product lifecycle management.

B. Customer Experience Design and Operational Communications

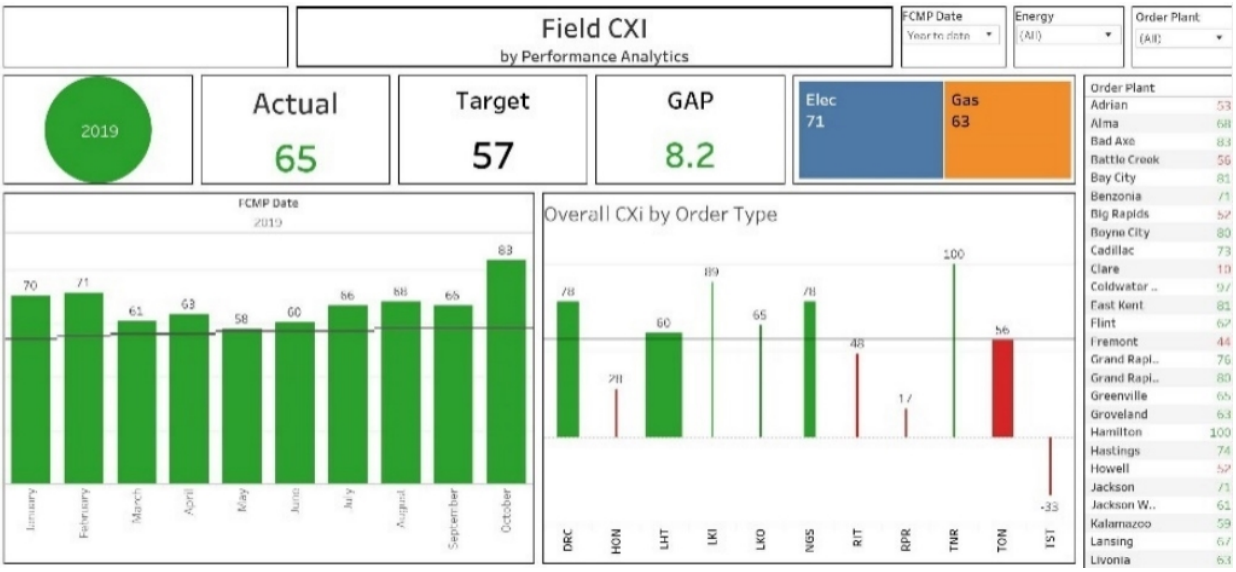
Q. Please describe the functions of the CX Design and Operational Communications area.

A. This area has three core responsibilities for the Company:

(1) **Experience Design Services** – Identify and remove customer interaction pain points and demonstrate customer centricity by making processes more efficient, modifying business rules, and creating user-friendly interactions. This team applies leading customer-centric practices, such as design thinking, iterative design, co-creation, and journey mapping to better understand customer needs and quickly identify and test potential solutions. These services are provided by Experience Managers who are responsible for strategic end-to-end interactions and prioritization of customer value improvement initiatives and who serve as customer advocates for design and implementation of approved projects.

An example of this role is the Field Experience Manager who is responsible for improving customer interactions across various field services through improvements in people, process, and technology.

Figure 5



The Experience Managers introduce customer satisfaction metrics into various processes and direct attention to improvements that will drive efficiencies and help realize service improvements. Figure 5 illustrates some of the field service satisfaction metrics introduced in 2019. Additional Field CXi tracking is planned to expand into forestry, gas line replacement, and metro projects in 2020.

The Experience Manager also identifies and designs transformational improvement opportunities by using proven design practices that identify core problems and create ground-up solutions that achieve project goals. One of many examples is a gas leak experience, which includes the customer event of recognizing a gas smell, reporting the problem, and having the situation resolved. The design process includes joint interviews with internal stakeholders and customers. Input from all parties results in solutions that address the needs of all parties, followed by rapid cycles of prototypes and testing. In this example, a working prototype of a new process and technology application was designed in one month and is ready for development. The implementation of this project is detailed below within the Service Tracker project.

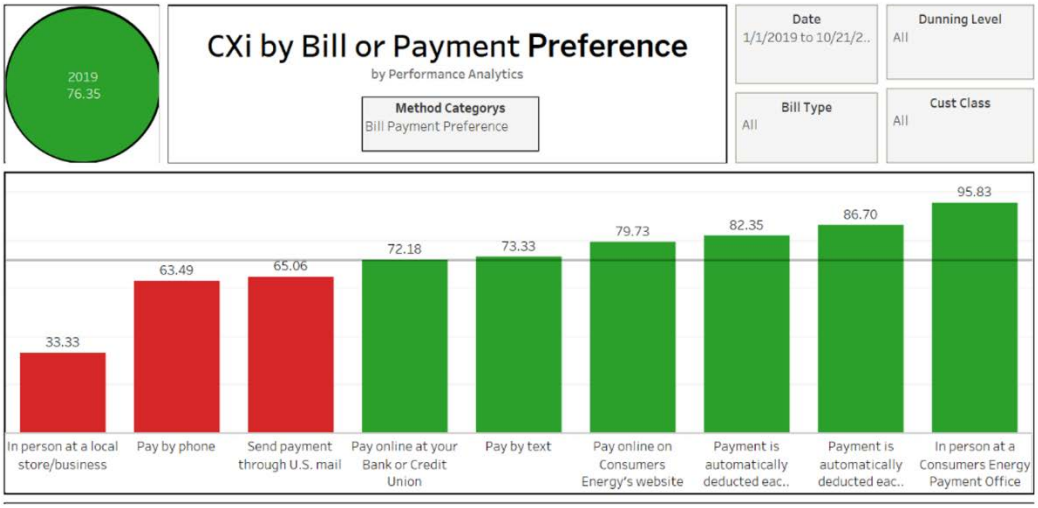
(2) **Product Managers** - Responsible for the operational quality and continuous improvement of established products and services. These individuals monitor, proactively test, and manage improvements to products and tools such as the Interval Web Portal, Budget Plan, and multiple payment options. This helps ensure that customer products and services are operating as designed and with maximum efficiency, continue to meet customer needs and expectations, and stay current against industry performance benchmarks.

This team is critical to ensuring problems are identified early and resolved quickly, often before customers are aware an issue exists.

The payment product owner role, for example, makes sure that all customer payment options are working as intended on a daily basis. This role researches areas for improvement, designs and tests new solutions, and assumes a leadership role to implement approved projects. This role is also Chairperson of a Payment Council within the Company, which includes participants from Treasury, Finance, Billing Services, and Operational teams. The Council recently sponsored a cross-discipline project to improve the process of payment refunds, resulting in improved customer satisfaction, reduction of 3,500 calls annually, labor efficiencies estimated at 2,000 hours annually, and an annual cost reduction of $9,000 in bank fees.

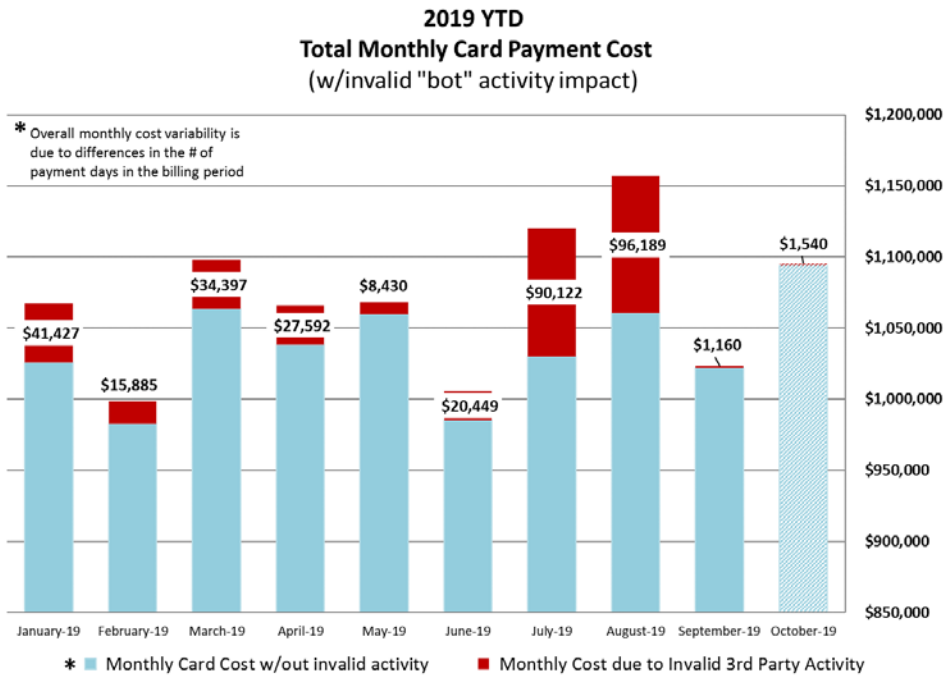
While the Payment role has been in place longer than some of the others and is unique to the area of specialty, the nature of the work is indicative of the overall role of the Product Owner team.

Figure 6



The Payment Product Owner tracks satisfaction and feedback by payment type (see Figure 6) and leads investigation of satisfaction issues across all payment options to identify opportunities for improvement. The Payment Product Owner advocates for improvement projects and plays a leadership role in the design and implementation of such initiatives. Current initiatives include pursuit of a "no fee" payment policy and priority projects detailed within the Customer Payment Program testimony below.

Figure 7



The Payment Product Owner investigates payment activity that violates terms and conditions and leads intervention activities. The Payment Product Owner recently identified a surge of unauthorized payments and led actions to interrupt the activity. This activity and the related expenses are illustrated in Figure 7. The Payment Product Owner documents payment behavior trends and forecasts future shifts in payment behavior to ensure the Company is prepared to provide payment services that customers expect in the future. The Payment Product Owner also implements the Customer Payment Strategy, which is detailed later in my testimony.

The Payment Product Owner manages payment budget and vendors, monitors compliance to payment processes, and investigates customer and operational issues that involve the vendor network.

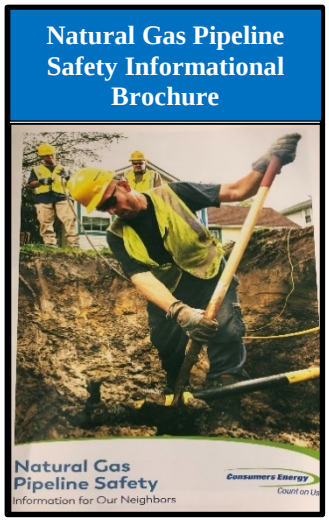
(3) **Operational Communications** - Manages turn-key communication standards and solutions for ongoing customer-facing utility operations. This includes identifying customer expectations, designing and testing communication solutions, documenting and socializing standards, and implementation across key operations. Examples of solutions developed and implemented during 2019 include extreme weather/high bill communications, outage communications, and gas safety.

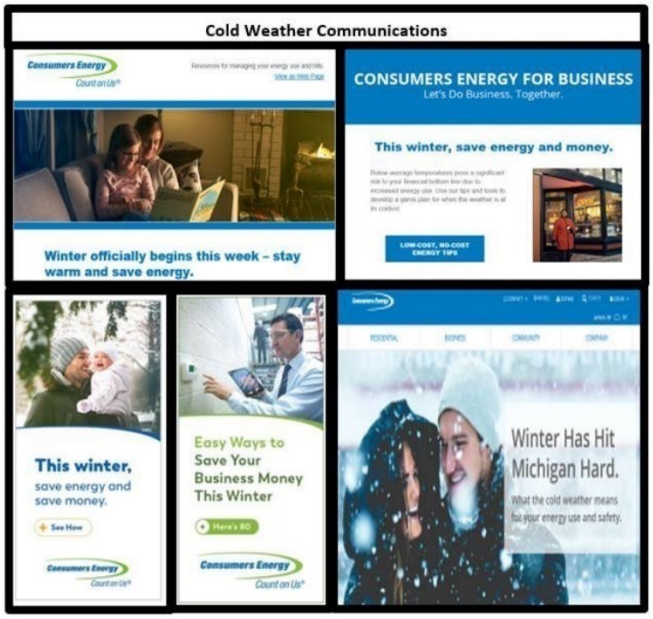
Operational Communications work often involves close coordination with Experience Managers when designing new processes and with Product

Owners for execution, or improvement of, existing communications. In the case of extreme weather/high bill communications, a standard process that was recently implemented includes monitoring weather and resulting billing patterns to activate communications that have been proven over the last year to help inform and educate customers in advance of receiving higher bills associated with seasonal weather changes and temperature extremes. This helps customers avoid surprises by offering advance notice with options to help control energy expenses. This simple process mitigates potential customer complaints and negative public sentiment, and operational impacts that are otherwise experienced during these times. In the 2018-2019 cold weather season, the Company communicated within 9 channels ranging from email to social media, garnering 80 million impressions and resulting in 819 fewer informal complaints and 808 fewer formal complaints when compared to the previous year.

Together, the Experience Design and Operational Communications team plays a critical role in ensuring the Company understands what customers want and expect, prioritizing needs and project opportunities to deliver the most value possible, and leading the design, build, and implementation of customer-centric initiatives to achieve sustainable, long-term operational and customer satisfaction results. To continue improvement in these services to customers, the Company is projecting an increase above the 2018 historical period of $1.9 million in test year O&M expenses, which is included in the Analytics and Outreach total on Exhibit A-107 (SQM-2), page 2. This increase is mostly related to the projects discussed later in this section of my testimony, but also includes a small inflationary increase. Additionally, the Company is projecting $3.1 million of capital expenditures through the test year related to Customer Experience Design and Operational Communications projects, which is included in the Analytics and Outreach total on A-12 (SQM-1), Schedule B-5.9, page 2. Figure 8 shows examples of the types of communications that provide customers with information on topics that can impact their usage. Providing these communications within multiple channels (mail, email, social media) is necessary and important for customer satisfaction and understanding of Company operations.

Figure 8 –Customer Communications



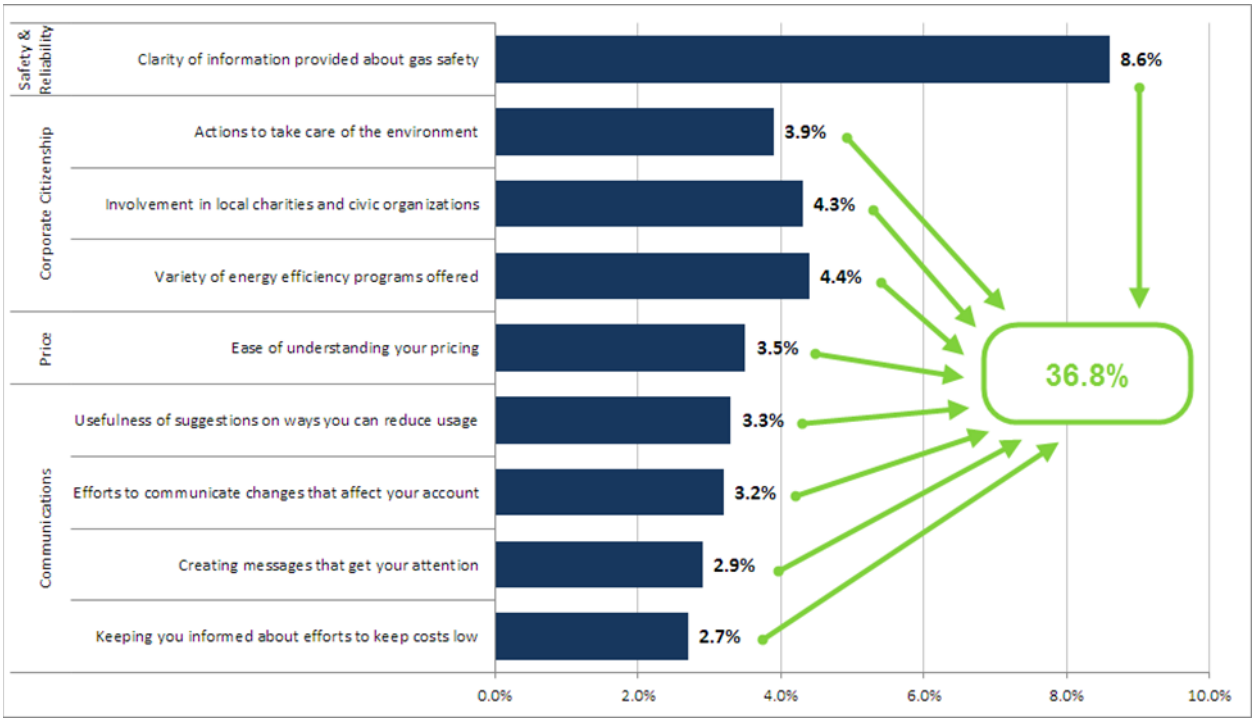


Q. How interested are customers in receiving communications about their gas service?

A. J.D. Power calculates a weight for various service attributes identified as important to customers as part of the quarterly survey. The greater the weight assigned, the greater importance customers place on the attribute. Based on these weights, communication is

roughly 37% of customer satisfaction. Figure 9 provides the customer satisfaction weights attributed to customer communication.

Figure 9 – Natural Gas Customer Satisfaction from Communications



Q. Is the Company projecting additional funding in this case to support the proposed work in the test year for Experience Design and Operations communication and outreach projects?

A. Yes. In support of improving customer experiences and satisfaction, the Company is projecting $1.6 million in test year O&M expense for projects that contribute to the projected increase over 2018 actual amounts. The Company also projects $3.1 million of capital through the test year. These customer experience improvement and communication related projects are detailed in Table 2 below. Customer feedback is integral within the design and implementation of new offerings and products and the Company will continue to solicit customer feedback using focus groups and facilitated user testing sessions.

Table 2 – Customer Experience & Communication Projects

Project	Description	O&M	Capital
Online Communication and Service Enhancements		$1,161,300	$3,087,000
Online Work Scheduling	This project will provide the ability for customers to be able to self-serve in making an appointment for work, eliminating the need for them to call to schedule.	$14,700	$980,000
Service Tracker	This project provides greater transparency into the status of work orders (gas leak, service connection/turn on, etc.) from initiation to completion. It is designed to provide customers timely and accurate updates, including work order status and identification of arrival of field worker at the service location.	$147,000	$1,960,000
Operational Communications Automation	This will allow the Company to automate the sending of communications to customers within key operational experiences.	$245,000	$0
Alert Upgrades	System upgrades to the existing alert platform will provide direct control and additional flexibility that allow faster and more accurate notification tools. It will also allow the creation of new alerts to improve customer communications, including provision of notifications for past-due and dunning communications.	$754,600	$147,000
Promotion of Self Services		$483,875	$0

Move In/Move Out Initiative	The purpose of this is to work with local real estate agents, builders, customers, and communities to educate and engage with the Company's improved online customer move in/move out process.	$238,875	$0
Rate and Product Experience Design	An evaluation and redesign of how the company is explaining rates and associated product choices to make it easier for customers to understand and choose from existing options to best meet their needs.	$245,000	$0
Total		**$1,645,178**	**$3,087,000**

Q. Please describe the Online Communication and Service Enhancements.

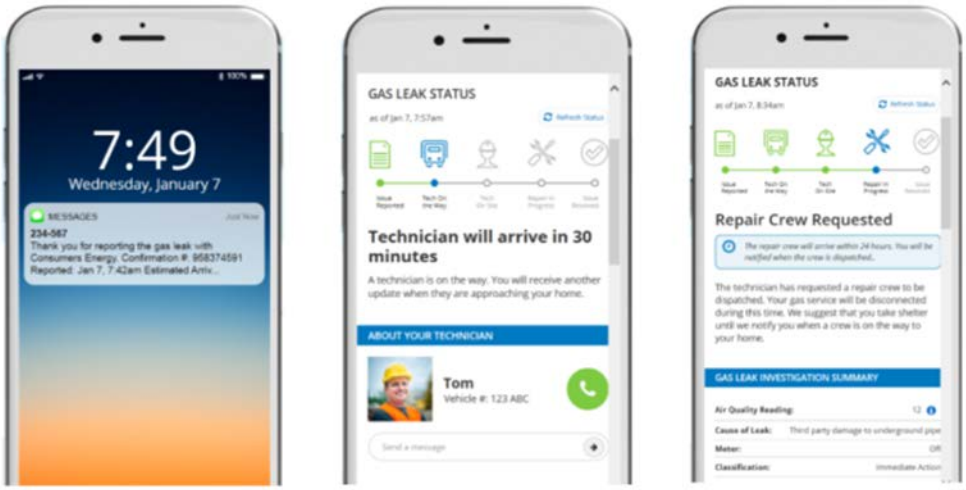
A. The Company is seeking to adopt a version upgrade to the platform used to manage customer alerts. This new platform will provide new features, including:

- Ability to update alert messages real-time vs. relying on the vendor, also giving the ability to quickly and easily test different versions of messaging with customers; and
- Natural language processing and machine learning to allow the system more flexibility in processing more than a few keywords. Currently, 33% of inbound text messages from customers fail because they contain something other than a keyword. This enhanced ability would create a more seamless customer experience and decrease the number of manual interventions and calls.

This will also allow the Company to introduce new past-due (dunning) billing status notifications using the existing platform. In 2018, the Company sent over 1.6 million disconnect notices and received 205,000 calls related to these notices. Currently, dunning and associated payment status is only available by calling a live agent during business hours, which often creates hardship and an unnecessary barrier for customers who are experiencing difficulty.

The Company will also develop and implement its mobile gas services application which will provide customers with improved communications following a utility service request, including the ability to track the Company's response. In 2018, the Company received over 140,000 requests from customers requesting utility work. Recognizing customers' needs for frequent status updates regarding these requests, the Company would like to implement a gas service application that will allow customers to not only request service or report a gas leak, but also provide them with safety information and instructions on what to do next. In addition, customers will see which crew will be responding, when they will arrive, and important contact information. The tracker will be hosted on the Company's website and will be mobile responsive, also allowing for customers to receive updates via text and email. Likewise, the crew will receive immediate notes on what the customer reported and how to contact the customer if needed. This application, shown in Figure 10 below, will reinforce safety messages, improve customer confidence, and reduce follow-up calls to the contact center. Furthermore, the Company will use these alerts to proactively address any billing questions that may arise due to extreme weather, such as a colder-than-normal month, or a longer-than-normal billing period.

Figure 10 – Example of Service Tracking Application



Q. Please describe the promotion of self-services.

A. Although more and more customers are accustomed to using the internet to buy merchandise or pay bills online, many customers are still not familiar with the online self-service features offered by the Company. The Company has identified two services that have great potential for improvement in digital participation, which are expected to improve customer satisfaction and reduce costs.

The first digital growth opportunity is when customers are moving. Customers initiate over 900,000 moving-related interactions with the Company on an annual basis, only one-third of which are successfully completed online. Reasons for this limited self-service completion rate fall into two categories. The first category is simply technology related. There are many customer-use cases (such as a pending balance, or an overlap in moving dates) that self-service functionality does not yet address, thus requiring the customer to call an agent during business hours. Improvements to a few of these conditions during 2019 resulted in a 10% increase in online self-service completions. Company witness Christopher J. Varvatos sponsors the $850,000 in capital and $86,000 in

O&M for two separate projects to complete the changes necessary to improve the technology-related issues to increase self-service completion rates for moving-related interactions. The second category is customer behavior. Many title companies and real estate agents specifically tell their customers to call Consumers Energy (and other utilities) to update their service. Thus, a key component to increasing online self-service is a communications and educational effort for these companies about convenient online self-service options that are available to Consumers Energy customers. In addition, there is publicly available moving information that can be used effectively to address these customers directly. The Company is seeking to test and implement a communications campaign to educate those who are moving, and those companies that have significant influence on customers who are moving, to help increase self-service adoption. Communications and data testing will provide reliable insights into how to maximize the effectiveness of these communications at increasing self-service adoption, reducing phone calls, and ultimately delivering a better moving experience.

As to the rate and product experience design, the Company is planning to complete an evaluation and redesign of how the Company presents rates and options to customers to make it easier for customers to understand and choose the options that are right for them.

Q. When does the Company expect to see the cost savings from implementing and promoting its self-services?

A. At this time the Company projects to see modest cost savings beginning in 2021. Over the coming years, however, the Company is expecting much greater savings as it increases the number of customers taking advantage of electronic billing by 5% per year and reduces the

number of customer calls to a call center representative by 7% per year, which is expected to result in approximately $200,000 per year in savings once achieved.

Q. Is the Company projecting any test year IT project funding related to the Customer Experience Design work described above?

A. Yes. Company witness Varvatos is sponsoring test year IT costs that include $3,240,418 of capital and $602,682 of O&M expenses for four IT projects that support the Customer Experience Design work. Collectively these IT projects are related to updates to comply with regulatory billing changes, improve billing functionality, and improve customer satisfaction. These projects also improve the self-service relocation technical issues discussed above. I have briefly described each of these IT projects, and provided the corresponding expenses, in Table 3 below. A more complete description of each project is provided as part of Exhibit A-108 (SQM-3).

Table 3 – Customer Experience Design IT Projects
($ in Dollars)

IT Project	Description	Expenses	
		Capital	O&M
A. Bill Design and Delivery Transformation	The Bill Design and Delivery Transformation project will execute a bill redesign for all rates and program combinations, including necessary software replacements and a flexible print and delivery outsourcing initiative.	$1,732,507	$358,148
B. Move In/Move Out Digital Redesign	This Move In-Move Out project will allow Move In and Move Out web pages to be better supported on mobile devices.	$367,753	$17,856

C. Business Customer Interval Web Portal	The Business Customer Interval Web Portal project will develop a new Interval Web Platform (IWP) for Business Customers to provide the customers insight into their energy usage.	$209,201	$105,266
D. On-Bill Financing Project	The On-Bill Financing Project will enable product purchases (both margin and Energy Efficiency, Demand Response) by customers utilizing on-bill financing.	$444,474	$53,423
E. Move In Move Out 3.0	The Move In Move Out Version (MIMO) 3.0 effort will update and re-design the customer experience to remove barriers and increase ease for customers who desire self-service in the MIMO experience.	$486,483	$67,6989
Total		**$**3,240,418	**$** 602,682

III. CUSTOMER INTERACTIONS

Q. Please provide an overview of Customer Interactions.

A. Customer Interactions is responsible for using the research, analytics, and customer experience design work described above to interact with the Company's customers through the various channels (such as digital, phone, mail) customers choose. This work includes the following five main areas of focus: (i) Digital Customer Experience, (ii) Customer Contact Center, (iii) Business Customer Care, (iv) Field Payment Channels and Claims, and (v) Credit and Assistance. To effectively perform in these five areas, the Company is projecting $23.9 million of O&M expenses for the test year ending September 2021. As

shown on Exhibit A-107 (SQM-2), page 3, this represents a decrease in O&M expenses of $0.8 million from the $24.7 million expended in 2018. The Company is also projecting $0.04 million of capital for a project that will automate address changes for customers, eliminating 8,000 manual address changes annually. The capital is included on A-12 (SQM-1), Schedule B-5.9.

A. Digital Customer Experience

Q. Please provide an overview of Digital Customer Experience ("DCE").

A. DCE is responsible for the operation and continuous improvement of the Company's customer-facing digital applications, including the website and self-service functionality. Operationally, the DCE team collects over 3,000 points of customer feedback every month, which drives the team's priorities in three simultaneous work cycles: (i) website changes the team can make itself using available configuration tools; (ii) managing the solution design, development, and launch of monthly releases to add new features or modify website user flows; and (iii) leading major technology projects that add new functionality or modify business rules to better serve customers. In addition, this team is responsible for managing the Company's online account management and self-service capabilities, website analytics, two-way alert communications, mobile device usability, and website content development.

Q. What types of transactions do customers complete on the digital channel?

A. The most common reasons customers use the Company's website is 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, or Energy Waste

Reduction rebates. In January through June 2019, the website averaged over 170,000 web transactions per month, a 51% increase from 2018.

Q. How successful are online services for customers?

A. Of the 27 million website sessions in 2018, the Company received customer feedback that 80% of the time (21 million web sessions in 2018) customers can accomplish their goal online. The other 20% of the time (6 million sessions in 2018) customers cannot accomplish their goal online, primarily due to missing information or technology limitations. In addition, 18% of customers who call the Company indicate they tried to address their question online before calling. By investing in its digital applications, the Company plans to address these gaps, thereby reducing the future number of calls received, lowering transaction costs, and improving customer experience.

Q. Please explain why the Company is continuing to invest in the digital channel.

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. For instance, approximately 89% of United States adults are using the Internet, 77% have access to Internet-enabled mobile devices, and 57% are using their devices for online banking transactions. In addition, survey results from Accenture's 2016 New Energy Consumer Research indicate that:

- 92% of consumers would be more satisfied if their energy provider could personalize their overall customer experience;
- Digitally engaged consumers are more satisfied with their energy provider (77% vs 64%) and are more likely to trust their provider on advice regarding energy optimization and data protection;
- 89% believe it is important to have a seamless customer experience with their energy provider across all digital and non-digital channels. 83% report it would negatively impact satisfaction if the energy provider was unable to deliver such,

and 77% would be discouraged from signing up for additional products and services; and

- Forrester Research reports that 79% of customers prefer self-service over traditional channels such as phone and email.

More and more customers are choosing to conduct business online – such as banking, paying bills, and making purchases. Between 2016 and year-end 2018, the Company experienced a 79% annual increase in website sessions and a 69% increase in the number of unique users per month. Further, the Company supported more than 27 million website sessions through 2018 and sent more than 9 million phone, email, and text alerts to customers. The projected expense in this case will assist the Company with (i) addressing performance gaps and (ii) keeping pace with the changes in how customers prefer to interact with the Company.

Moreover, the Company expects these investments to improve customer satisfaction and ultimately reduce costs through lower on-line transaction costs of $0.11 versus agent-assisted costs of $8.78 per live agent call.

Q. Is the Company projecting any test year IT project costs related to the DCE?

A. Yes. Company witness Varvatos is sponsoring test year IT costs that include $2,033,383 of capital and $286,238 of O&M expenses for four IT projects that support the DCE work described above. Collectively these IT projects will improve the Company's ability to serve customers within the channel of their choice, namely, the mobile channel, and improve the experience of customers in completing self-service transactions within that channel. Although the purpose of these investments is primarily related to increases in digital tool functionality in response to customer feedback, the Company projects roughly $0.7 million in future O&M expense savings related to operational efficiency beginning in 2022. These IT projects are described briefly, with the corresponding expenses, in Table 4

below. A more complete description of each project is provided as part of Exhibit A-108 (SQM-3).

Table 4 – Digital Customer Experience IT Projects
($ in Dollars)

IT Project	Description	Expenses	
		Capital	**O&M**
F. Dashboard Redesign	The current online dashboard is not structured to provide customers the information they need immediately upon logging in at a glance. Observed user behavior indicates that customers struggle with the dashboard load time and locating information that is meaningful to them. This redesign will improve that process.	$840,730	$63,623
G. Website Redesign	In order to deliver an effective customer experience and serve customers more robustly within the mobile channel, the Consumers Energy's mobile website needs to be optimized to improve customer experiences in outage, billing and payment, and move in/move out.	$1,058,992	$167,854
H. Cross-Channel Analytics	Improved ability to understand and address customer pain points in self-service processes through use of enhanced speech analytics and customer experience tools.	$0	$40,800
I. Data Lake Entry	Migrating all Customer Operations data to the data lake will save costs by reducing now manual efforts to collect, consolidate, and analyze data.	$133,661	$13,961
Total		**$**2,033,383	**$**286,238

B. 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 2018, call center representatives answered 4.2 million customer calls, a decrease of nearly 400,000 calls from the previous year. Likewise, the automated phone system (or interactive voice

response ("IVR") system) addressed 8.5 million calls during 2018. To continue this work the Company is projecting $13.9 million of O&M expenses for the test year ending September 2021. As shown on Exhibit A-107 (SQM-2), page 3, this represents a decrease in O&M expenses of $0.8 million from the $14.7 million expended in 2018. This decrease in operating expense has been achieved through reducing call defects, while striving to maintain the Company's Average Speed of Answer ("ASA") at 66 seconds during the test year and to deliver the quality that customers experience when they contact the Company via the Customer Contact Center.

Q. Please explain why the Company is planning to maintain the ASA at 66 seconds.

A. The Company is committed to an excellent customer experience across all its service channels. Recognizing that customers would prefer spending their time doing something other than waiting for a call center representative, the Company is planning to maintain its internal and external resources in the call center at current staffing levels and to maintain its ASA at 66 seconds.

Q. Is the Company projecting any test year IT project costs to support the work proposed by the Customer Contact Center?

A. Yes. Company witness Varvatos is sponsoring test year IT costs that include $751,899 of capital and $61,000 of O&M expenses for the Voxai Survey Tool and the Landlord Small Business Portal IT projects presented in the table below. The Voxai Survey Tool project will implement an immediate post-interaction customer survey tool to allow real-time feedback and data regarding the customer's experience with the Company's IVR or live contact center. Currently, a third-party vendor is utilized to perform surveys via a live agent two days post-interaction. Engaging a real-time survey tool to gather feedback from

customers will not only improve the timing and accuracy of data, but will also improve the cost for generating this critical feedback. The Landlord Small Business Portal project will modernize the existing Portal to reflect current usability standards and allow for increased adoption of digital services by landlords and management companies. Table 5 provides a summary of these projects and more complete descriptions are provided as part of Exhibit A-108 (SQM-3).

Table 5 – Customer Contact Center IT Projects
($ in Dollars)

IT Project	Description	Expenses	
		Capital	O&M
J. Voxai Survey Tool	Provides for real time surveys and data collection from higher volumes of customers to drive better feedback and faster resolution of customer concerns.	$55,296	$3,060
K. Landlord Small Business Portal	Modernizing the Landlord portal will increase adoption and utilization of digital services by landlords and management companies thus reducing cost through reduction in contact center support and resources.	$696,603	$57,611
Total		**$**751,899	$60,671

C. Business Customer Care

Q. Please provide an overview of Business Customer Care.

A. Business Customer Care ("BCC") works directly with the Company's commercial and industrial 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 116,000 customers, which equates to 216,000 contract

accounts. This represents $2.6 billion in revenue, which is approximately 46% of 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 $2.7 million of O&M expenses for the test year ending September 2021. As shown in Exhibit A-107 (SQM-2), page 3, this represents an increase in O&M expenses of $0.3 million from the $2.4 million expended in 2018. The primary drivers of this increase from 2018 are inflation, work performed to improve the Company's ability to curtail customers when necessary, and increased communication to natural gas business customers of Company programs and services that will assist them in their operations.

Q. What work has the BCC team performed to improve the ability to curtail customers?

A. Beginning early in 2019, the Company created a Gas Curtailment Report identifying commercial and industrial customers by usage level so the Company can quickly contact these customers for curtailment in the event of a future emergency. Simultaneously, the Company conducted a mail campaign requesting contact information for commercial and industrial customers. To date the Company has received over 2,000 responses and will continue to work to obtain additional contact information. Using the CRM and operational communication projects discussed earlier in my testimony, the Company will be able to develop programs to automatically call and text these customers during a future emergency. Going forward, the Company will continue to review the curtailment procedures to assure they are up to date. In addition, the Company plans to annually confirm contact information and run test events to assure Company personnel are fully prepared.

Q. Is the Company projecting any test year IT project costs to support the Business Customer Care proposals in this proceeding?

A. Yes. Company witness Varvatos is sponsoring test year IT costs that include $68,194 of capital and $49,311 of O&M expenses for the Large Customer Rate Tool IT project that supports the BCC work described above. This project will improve the Company's rate design functionality and the Company's response to business customer rate information requests. This project will provide value to both the Company and its customers by: (1) automating the intensive, manual processes that account managers utilize in working with large businesses to ensure they are on the best possible rate; and (2) improving functionality to better assist large business customers with evaluating different rate options. A more complete description of this project is provided as part of Exhibit A-108 (SQM-3).

D. <u>Field Payment Channels and Claims</u>

Q. Please provide an overview of Field Payment Channels and Claims.

A. Field Payment Channels and Claims is responsible for operating the Company's 14 Direct Payment Offices, investigating theft, and resolving claims of damage to Company and customer property. Twelve of the fourteen payment offices are located within existing Company facilities, making them a cost-effective option for customers to pay their bills in person. Without these options, customer that do not have electronic means of paying their bill, i.e. credit card or bank accounts, would be forced to utilize third-party agencies to pay their utility bill, incurring a service charge in addition to their energy bill. In 2018, the payment offices served 1,007,415 customers and collected $212,400,000 in electric, natural gas, and combination customer payments. 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. This is a channel that customers continue to choose, especially within these vulnerable customer segments.

The Damage Claims and Loss area investigates and resolves incidents where damage was caused either to the Company's or a customer's property. In 2018, this area resolved 911 claims of damage to customer property in the amount of $1.1 million and recovered $1 million in damages caused to the Company's property by others. To continue this work, the Company projects $1.8 million of O&M expenses for the test year ending September 2021. As shown on Exhibit A-107 (SQM-2), page 3, this represents an increase in O&M expenses of $0.3 million from the $1.5 million expended in 2018 due to inflation and the conversion of long-term contractors to full-time employees in 2018.

The theft investigation team provides a critical service of investigating and finding energy theft within the Company's communities. Stopping this theft is important both for maintaining the safety and integrity of the Company's system, as well as reducing lost gas and keeping costs lower for customers. In 2018, the theft team created a theft analytics tool that enables them to utilize millions of pieces of customer information to create use cases that can help to identify instances of theft in the community. Throughout this year, the team will continue to expand the uses and workings of the tool to include more data to help refine those use cases, as well as create a tool that will help identify theft on the commercial side of the business.

Q. Is the Company projecting any test year IT project costs to support the Field Payment Channels and Claims proposals in this proceeding?

A. Yes. Company witness Varvatos is sponsoring test year IT costs that include $103,707 of capital and $50,917 of O&M expenses for the Commercial Theft project. This project will allow the Company to more effectively identify and reduce theft by Commercial customers using smart meter data and algorithms. A more complete description of the project is provided as part of Exhibit A-108 (SQM-3).

E. Credit and Assistance

Q. Please provide an overview of Credit and Assistance.

A. Credit and Assistance addresses customer accounts that are past due or involved in bankruptcy. Employees within this area manage the collections cycle, beginning with issuing a notice to customers through visiting their premises to disconnect service. Additionally, this group manages contracts with outside collection agencies to recover payments from customers with outstanding balances. In 2018, the Company recovered $17.8 million of previously written-off customer balances. Recovery of these payments directly offset the uncollectible expense discussed in the testimony of Company witness Karen M. Gaston.

This team is also 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, this program has obtained $18.3 million of assistance requested through the Michigan Energy Assistance Program. 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 2018, the CARE program was able to secure $35.5 million in assistance on behalf of the Company's most vulnerable customers. To continue these efforts, the Company is projecting $2.63 million in O&M expenses for the test year ending September 2021. As shown on Exhibit A-107 (SQM-2), page 3, this request represents a slight decrease in expenses of $0.03 million from the $2.66 million expended in the 2018 historical year.

F. Billing and Payment

Q. Please provide an overview of Billing and Payment.

A. Billing and Payment is responsible for using customer feedback collected as part of the analytics research and various interactions to ensure: (i) customer payment processes are consistent and simple; (ii) monthly energy bills are accurate and easy to comprehend; and (iii) customers receive their bills in a timely fashion. The work in this area primarily falls into the following three areas: (i) Customer Payment Program; (ii) Customer Billing; and (iii) Business Support. To effectively perform in these three areas the Company is projecting $20.6 million of O&M expenses for the test year ending September 2021. As shown on Exhibit A-107 (SQM-2), page 4, this represents an increase in O&M expenses of $2.5 million from the $18.1 million expended in 2018.

1. Customer Payment Program

Q. Please describe the Customer Payment Strategy.

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 focus on removing payment difficulties, providing payment options that customers expect, and ensuring all customers have the same easy payment experience

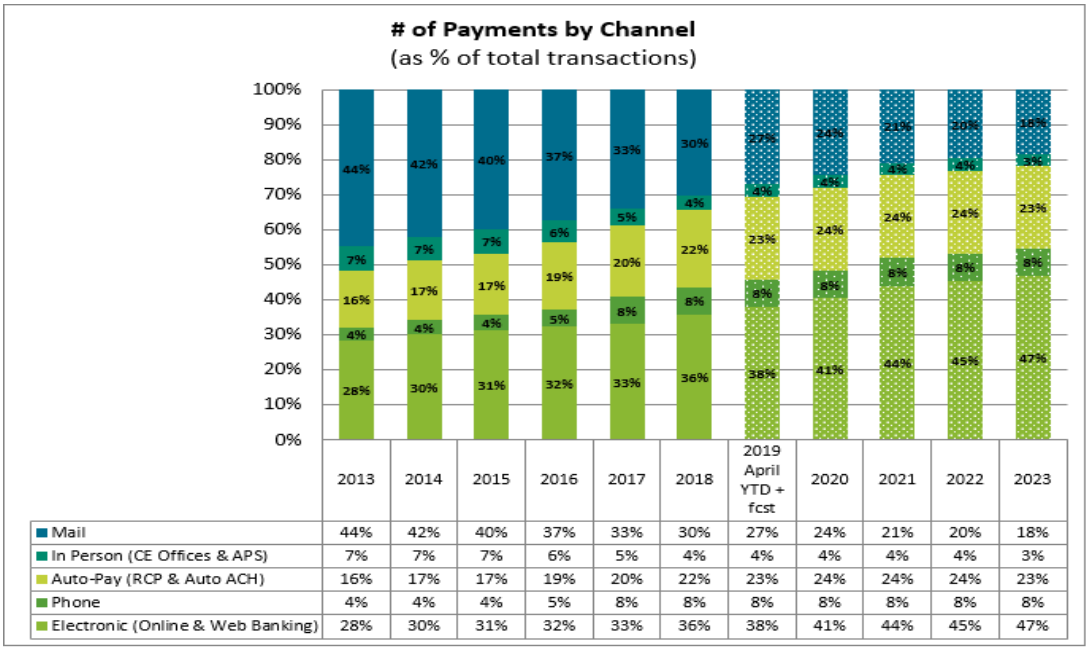
regardless of how they choose to pay their bill. This has resulted in a significant improvement in customer satisfaction and reduction of payment-related calls and complaints. The Company continues to make it a priority to accommodate customer preferences with simple and consistent payment options.

Operating costs of customer payments continue to evolve with changes in customer behaviors. As such, the Company is projecting $8.7 million in test year O&M expenses shown on Exhibit A-107 (SQM-2), page 4. This represents a $2.1 million increase from the $6.5 million expended in 2018. The increased expense is attributed to: i) the continued increase in customer use of credit cards to make a payment; and ii) several projects to improve customer payment options which are discussed in greater detail later in this section of my testimony. Figures 11a through 11c show the trends and forecasts for customer payment behaviors showing increasing credit card payments and the associated costs to the Company for customer payments.

Q. Have customer payment behaviors changed in recent years?

A. Yes. As illustrated in Figure 11a below, the biggest change in payment behavior is the shift away from mail to electronic payments. From 2013, payments by mail have fallen from 44% to 30% of total payments in 2018, while electronic payments have increased from 28% to 36% for the same period. The Company expects the trend of increasing electronic payments to continue into the foreseeable future with credit cards as the main driver. The below figure illustrates the growth of electronic payment methods, including credit cards, over time.

Figure 11a – Historical and Forecasted Customer Payment Mix

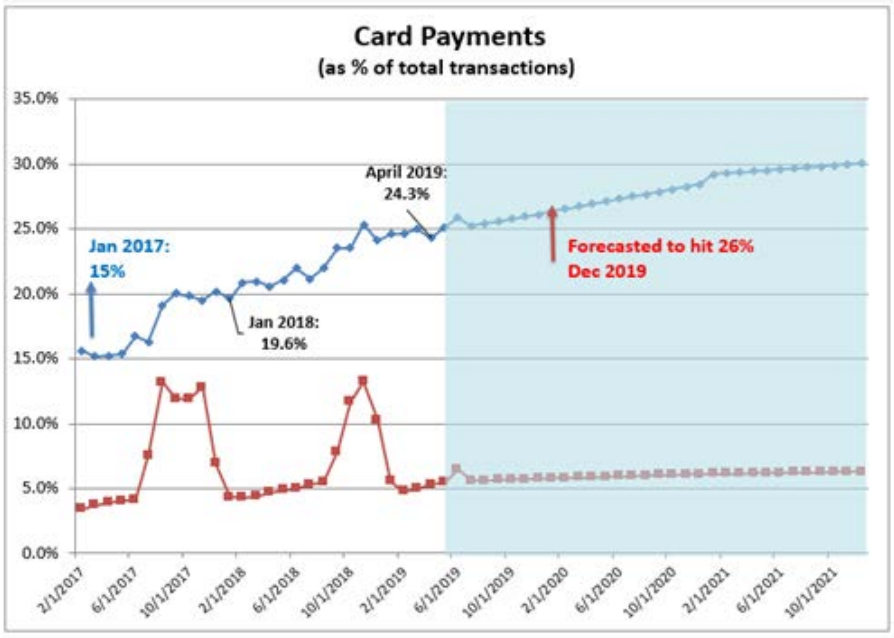


	2013	2014	2015	2016	2017	2018	2019 April YTD + fcst	2020	2021	2022	2023
Mail	44%	42%	40%	37%	33%	30%	27%	24%	21%	20%	18%
In Person (CE Offices & APS)	7%	7%	7%	6%	5%	4%	4%	4%	4%	4%	3%
Auto-Pay (RCP & Auto ACH)	16%	17%	17%	19%	20%	22%	23%	24%	24%	24%	23%
Phone	4%	4%	4%	5%	8%	8%	8%	8%	8%	8%	8%
Electronic (Online & Web Banking)	28%	30%	31%	32%	33%	36%	38%	41%	44%	45%	47%

Q. Has the Company seen a corresponding increase in credit card payments?

A. Yes. Following the Company's decision to remove credit card payment fees in January of 2017 there has been a steady rise in credit card usage. As illustrated in Figure 12b below, use of credit cards as a percent of total transactions has increased from 15% in January of 2017 to approximately 24% in 2018. Credit card use is expected to account for 26% of customer payments (residential and business) by December 31, 2019.

Figure 11b – Projected Increase in Customer Card Payments



Q. How have the increasing credit card payments impacted customer payment program expenses?

A. As illustrated in Figure 12c below, the total O&M expense related to credit card payments has steadily increased as the number of payments has increased. In 2018, the expense was $5.7 million, and the Company expects it to grow to $7.4 million in 2020.

Figure 11c - Illustrates 2017-2020 (forecasted) credit card payment activity and costs

Description	2017	2018	2019	2020
Credit Card Payments	5.2M	7.2M	8M	9.2M
Credit Card Payment % of Total	20.2%	24.1%	26.1%	28.5%
Total Cost of Credit Card Payments	$4.4M	$5.7M	$6.8M	$7.4M

Q. Is the Company projecting additional funding in this case to support the proposed work in the test year for Customer Payment Program projects?

A. Yes. The Company is undertaking several projects listed in the below Table that continue evolution of payment options necessary to keep pace with changing customer expectations and realization of payment-related business objectives. They will provide the flexible options that customers expect, continue to drive use of electronic billing, and eliminate utility payment fees that create confusion and frustration, especially among our most vulnerable customers.

Table 6 – Customer Experience & Communication Projects

Project	Description	O&M	Capital
Secure PDF	This project will add a new ebill delivery and payment option known as Secure PDF.	$14,700	$980,000
Authorized Pay Station Fee Removal	This will remove the last remaining customer payment fee, which is $1.75 for use of third-party payment centers.	$937,370	$0
Payment Extension	Language modifications to online and IVR user flows will make the payment "grace period" more apparent and value-add to customers with good payment histories. This is expected to improve customer understanding regarding the Company's payment terms.	$7,350	$49,000

Automated Clearinghouse ("ACH") Incentive Plan Rollout	With use of emerging analytic capability, the Company is better understanding how specific customer groups are paying bills and identifying opportunities to educate and offer high value options. This initiative will help decrease overall payment expenses by educating customers on electronic payment methods other than credit cards.	$245,000	$0
In Person Network Expansion	This expands the network of third-party locations customers have available to pay a bill statewide. This provides customers with more flexible payment choices, especially in rural areas.	$14,700	$122,500
Total		**$1,219,120**	**$1,151,500**

Q. Please describe the Customer Payment Program projects.

A. As the largest and most frequent touch point with customers at over 32 million customer payments made annually, the Company recognizes the significance that continued improvements and simplifications to payment processes can have for customers. These projects have been selected to keep pace with changing customer expectations and to help achieve payment-related business objectives:

- **Secure PDF:** This project encompasses the design and launch of an all-new electronic billing and payment option that allows customers to pay a bill directly from a .pdf attachment in a Company email. The customer can view the bill and receive any relevant messages from the Company, but save time by avoiding the need to log into a Company or bank website. Secure PDF is especially appealing to large business customers with consolidated accounts who must log in to each using unique authentication to pay their bills. While the Company has made great strides at improving ebill participation from 34% in 2018 to a projected 36% in 2019, secure PDF is recognized to be a necessary addition for the Company to achieve or exceed the target of 40%.

- **Payment Extension:** It is unnecessary for customers who are in good standing and have consistently made on-time payments to be communicated with in a fashion that implies otherwise. As such, the Company would like to change the "one size fits all" messages to customers who are late on a payment. Call Center agents frequently make use of the Company's five-day grace period to accommodate customer requests or concerns about on-time payments, but this messaging is absent from the IVR and website. Making these changes is expected to improve important customer perceptions of "time to pay" and overall perception of friendly payment options. It is also expected to help reduce unnecessary phone contacts associated with this topic.

- **ACH Incentive Plan:** Given the payment transaction costs resulting from growth of consumer credit card use, the Company is proposing a pilot to learn how the Company can effectively promote increased use of lower-cost ACH payments without using financial incentives. The Company understands, however, that each customer is unique and may be reluctant to change in the absence of a compelling reason. To address this, the Company will use the customer data and analytics, described in the Customer Analytics section of my direct testimony, to design messages that speak to the benefits most relevant to each customer – such as being environmentally friendly, enhanced security, or overall convenience. By using customer data and emerging Company analytic capability, the Company is planning to educate customers on electronic payment methods other than credit cards and shift payment choices away from this transaction without reducing customer satisfaction.

- **In-Person Network Expansion:** The existing in-person payment network consists of 430 agents that process 600,000 payments annually including Wal-Mart, Kroger, and K-Mart. Over 100 K-Mart locations have closed in recent years leaving only 12 total walk-in pay stations in rural communities in northern Michigan north of Saginaw. The Company is proposing to expand its network of retail establishments that can accept customer payments. The proposed expansion adds 1,850 new agents including 7-11, Dollar General, CVS, and Speedway that offer expanded hours of service and vast demographic coverage. Customers would pay with a unique barcode that contains account information which differs from the existing pay agent structure. Addition of the "In-Lane" channel would increase walk in agents north of Saginaw by 90%. A pilot is proposed in the northern region to gauge customer feedback and feasibility of expanded network and barcode presentment.

The Company is also proposing to no longer pass along to customers the $1.75 service charge for making a payment at third-party establishments, which are often the most convenient payment options for our rural customers. This easily implemented change aligns with no-fee credit card payments and positions the Company to promote unilateral

"no fee" payments at any time. Beyond the additional convenience and consistency this creates, it is an important evolution of the Company's payment strategy for two reasons: (i) billing consolidators that many customers use (knowingly or not) can be very expensive to use and have potential to be confused as payment fees imposed by the Company; and (ii) utility scams that threaten power shut-off and immediate payments continue to hit residential and business customers alike. Removing fees – and promoting that Consumers Energy does not charge fees to pay and will never demand an immediate payment to avoid being shut off - is a positive message that can help build reputational credibility and heighten awareness that requirements such as these are not associated with the Company and are not authentic.

2. <u>Customer Billing</u>

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 (digital and paper) before they are sent to customers. As part of the exceptions process, this area may contact customers to gather additional information or to inform them of a potential billing issue, correct the bill through a billing adjustment process, or re-read the meter as part of a validation process. Through rigorous continuous improvement efforts to provide an accurate bill every time to customers, the Customer Billing team has continued to optimize their processes and technology to aid in the review of billing exceptions. In 2018, Customer Billing saw a 30% reduction in the number of inaccurate bills, from approximately 344,000 in 2017 to approximately 240,000 in 2018. Ensuring that customers receive the right bill every time is critical. To continue this work, the Company is projecting $3.5 million of O&M expenses for the test year

ending September 2021. As shown on Exhibit A-107 (SQM-2), page 4, this represents an inflation increase in O&M expenses of $0.6 million from the $2.9 million expended in 2018.

3. Business Support

Q. Please provide an overview of Business Support

A. Business Support is responsible for stationery, forms, and postage related to the Company's billing and dunning processes along with other support related activities. In 2019, the Company mailed over 23 million paper bills and over 3 million dunning notices to customers. As illustrated in Figure 12, the number of customer bills mailed has declined by 2.9 million during 2019 as a result of deliberate efforts to increase electronic billing participation. This savings has been offset by an increase of $0.6 million for additional dunning notices mailed during the year in an effort to reduce past-due balances. The net result is a projected decrease of $329,400 in 2019 from 2018. The Company is projecting $8.5 million of O&M expenses for the test year ending September 2021 to continue supporting activities associated with billing, dunning communications, and support services. As shown on Exhibit A-107 (SQM-2), page 4, this represents a $0.3 million decrease of O&M expenses from the amount expended in 2018.

Figure 12

	2018	2019 projected	2020 projected
# Customer Bills	26.5M	23.6M	23.5M
# Dunning Notices	2.7M	3.3M	3.5M
O&M Expense	$8.7M	$8.3M	$8.4M

IV. CUSTOMER PROGRAMS

Q. Please provide an overview of Customer Programs.

A. For more than 25 years, Consumers Energy has been assisting residential, commercial, and industrial customers to solve energy-related problems. The Company began providing these services as a means of addressing customer concerns, assisting underserved demographics, maintaining high customer satisfaction, and ultimately reducing revenue requirements for customer rates. Consumers Energy's ability to provide "value added product and services" not only benefits the utility and its customers, but also third-party contractors. The non-regulated programs use third-party contractors to perform a significant amount of the work. In doing so, the Company provides significant value to contractors by providing marketing and sales, billing, and taking on the risk of non-payment associated with their revenue stream. Customer Programs includes $91 million in revenue and $64.3 million of expenses from the Company's non-regulated services (Home and Industrial Energy Products) and Compressed Natural Gas ("CNG") Stations, resulting in a net benefit of $26.7 million in reduced revenue requirements.

Q. Please describe the Home Energy Products.

A. Home Energy Products consists of the Company's non-regulated Appliance Service Plan ("ASP"), appliance repair, and Allconnect services. 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, per the contract Terms and Conditions. Customers primarily enroll in ASP to avoid unexpected costly repairs, or replacement, of home

appliances. This program benefits customers by reducing the risk of potentially expensive and unexpected repair costs. As an example of how the program works, consider that a new variable speed blower motor on a modern furnace can cost over $1,000 and can create significant financial impact to the customer should it need replacement compared to a $19.99 monthly fee for coverage under the ASP program. Currently nearly 180,000 customers utilize the ASP program, making it the Company's most popular value-added service. This program covers nearly one million appliances and the team completes approximately 140,000 service repair orders per year.

Customers may also elect to utilize the Appliance Repair and Tune-ups service whereby the Company provides repairs, based on time and material, to Heating, Ventilation, and Air Conditioning ("HVAC"), water heaters, and 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 provides a single point of contact to assist customers with transferring cable, internet, and waste management services. After the utility account move is complete, the agent asks if the customer would like to speak to an Allconnect representative to set up other household services related to the move. The Company receives a commission from Allconnect for customers who agree to speak with an Allconnect representative and sign up for those services as part of the moving process. The profits from both the Company's 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 $78.5 million, expenses of $54 million, and net margin of $24.5 million to be used to offset net revenue requirements, shown on Exhibit A-107 (SQM-2), page 6, for the test year ending September 2021.

Q. Please explain why Home Energy Product profits (revenues less expenses) are projected to decrease from the 2018 level.

A. The Company's ASP repair expenses are increasing due to the complexity of newer appliances and increased cost of parts and labor. This increased complexity of newer appliances requires additional training of service personnel and use of more expensive materials (electronics and refrigerant) to complete repairs. Additionally, the program is covering more parts under its terms and conditions to increase customer satisfaction and provide additional value. 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. The Company also experienced significant impacts on total program costs related to the colder-than-normal winter and warmer-than-normal summer of 2018, which led to a higher-than-normal number of HVAC repairs. To reflect the higher expenses, the Company recently increased its subscription fees. Overall, the ASP program's total number of customers has remained relatively flat using traditional marketing methods and sales channels. The Company has not significantly modified the ASP marketing program in the last decade and has allocated resources and dollars to address this concern. The Company is planning new marketing research and sales campaigns to help drive future enrollments. The costs associated with the market research and sales campaigns are also contributing to a reduction in overall margin for the ASP program.

Q. Please describe the Industrial Energy Products.

A. Industrial Energy Products consist of the Company's Virtual Energy Engineer ("VEE") service, On Site Energy Engineers ("OSEE"), Gas Transportation and Storage ("Gas T&S"), Engineering Technical Services, and Laboratory Services.

The VEE service provides business customers with a virtual energy management solution that evaluates the "health" of their facilities and process controls through a single user interface dashboard which can include specific sub-metering. A vital component of the VEE service is the availability of certified energy managers to assist business customers with routine facility improvements identified through centralized monitoring, analytics, and virtual site assessments.

For large industrial customers requiring frequent and specialized engineering management services, the Company offers OSEEs. The OSEE service provides business customers with an assigned certified energy manager to manage complex energy projects at their facility similar to a site utility manager. The customer, for a fee, receives a dedicated person to assist in behind-the-meter electric and gas analytics, diagnosis, and project management as needed by the customer.

In addition to the engineering management services provided through VEE and OSEE, the Company also offers two engineering construction services. The first is a Gas T&S service to assist large gas suppliers interconnected with the Company's Gas T&S infrastructure with planned maintenance, emergent repair, and construction services.

The second is Engineering Technical Services to provide business customers with construction services beyond the meter. These services include construction and project management services, material sales, electrical equipment repairs and preventative

maintenance, billing services, generator installation, energy tax audits and consulting services, and power quality projects. These services are requested by the customer and competitively bid. All installation work is completed by a network of third-party contractors that perform the work on behalf of the Company.

Laboratory Services is a technical service provided to customers requiring calibration and instrumentation services, metallurgy, analytical chemistry, and nondestructive testing.

The Company is projecting Industrial Energy Product revenue of approximately $11.1 million, expenses of $9.5 million, and net margin of $1.6 million to be used to offset net revenue requirements, shown on Exhibit A-107 (SQM-2), page 6, for the test year ending September 2021.

Q. Please describe the CNG Stations.

A. In 2016, the Company opened its first CNG fueling station in Livonia, giving customers in Southeast Michigan an alternative to gasoline and diesel. In 2019, the Company opened its second CNG station near Flint. With the addition of the new station, the Company projects operating expenses will increase from $0.1 million in 2018 to $0.8 million in the test year, and revenues to increase from $0.2 million to $1.4 million with a net margin of $0.6 million Both the expenses and revenues from these stations are shown on Exhibit A-107 (SQM-2), page 6.

V. PILOTS

Q: Is the Company proposing any Pilots?

A: Yes, the Company is proposing two Gas DR pilots – one for Residential customers and one for Commercial and Industrial ("C&I") customers. Both the Residential and C&I pilots

will be modeled after the electric DR programs currently offered to customers. The Company is projecting $4.0 million in test year O&M and $0.5 million in capital for the Gas DR pilots. See Exhibits A-12 (SQM-1), Schedule B-5.9, page 2, and A-107 (SQM-2), page 5. Differences between projected and actual costs will be reconciled as part of the Company's annual DR Reconciliation proceeding.

Q. Please describe the purpose of the Gas DR pilots.

A. As requested in the Statewide Energy Assessment, and as part of the Company's Natural Gas Delivery Plan, Consumers Energy is initiating Gas DR pilots that will incentivize Residential and C&I customers to reduce their gas consumption during times of peak system demand or abnormal system conditions in Winter 2020/2021. The pilots could add 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 resilience. The purpose of the pilots is to: (i) understand and assess the design and potential of the offering; (ii) assess the financial opportunity to potentially avoid or defer capital infrastructure costs; and (iii) evaluate customers' receptiveness to the offering. Please refer to the Natural Gas Delivery Plan, Exhibit A-36 (CCD-1), Section XI, for further information

Q: Please describe the residential gas DR pilot being proposed.

A. The Residential pilot will be a Bring Your Own Device ("BYOD") Smart Thermostat program. The Company is proposing that the pilot would run during the winter of 2020/2021 and would initially target 3,000 customers who have a gas furnace and a Wi-Fi enabled smart thermostat. The program would use cloud-based software deployed through the customer's Wi-Fi thermostat to reduce the heating load during demand response events.

The projected cost of developing and implementing this pilot is $3.0 million in O&M during the test year.

Q: Please describe the C&I gas DR pilots being proposed.

A. The C&I pilots will incentivize customers to provide net reductions of natural gas during pilot events. Two programs will be developed, one for large C&I customers and a second for small to medium C&I customers.

For the large customer C&I program, each customer would contract for a specified load (Mcf) reduction during events for the program year of December 1 through February 28. The customer contract would set forth the program parameters, including the program period, timing and frequency of events, minimum advanced notification time, primary contacts to receive event notifications, how performance will be calculated, rules regarding non-performance, and the compensation the customer will receive for the reduction provided.

For the small to medium pilot program, the Company will offer a BYOD C&I gas DR pilot similar to the residential BYOD pilot described above. Customers will have their usage adjusted through control of their compatible Wi-Fi enabled thermostat. The Company will be targeting up to 450 business customers to participate in this pilot. The projected cost of developing and implementing both components of the C&I Gas DR pilot is $1.0 million in O&M and $0.5 million capital investment.

Q: Please describe how gas DR will be deployed.

A: The Company is planning on calling up to 10 DR events during the Gas DR season and may call events to test customer acceptance, even if weather and supply conditions would not warrant load curtailment. These pilot events under varying conditions will provide the

Company with the information necessary to design a cost-effective Gas DR program going forward.

Q: Does the Company plan to pursue geo-targeting for gas DR?

A: Yes. The Company understands that geo-targeting capabilities will be important to increasing the value of gas DR long term. While the pilots being proposed do not include a geo-targeting component, the Company intends to explore geo-targeting in future pilot phases.

Q: **Is the Company requesting a financial incentive for the gas DR pilots at this time?**

A: Not at this time; however, the Company recommends convening a working group to explore an appropriate financial incentive for implementing a Gas DR Program in order to encourage the building and usage of gas DR in Michigan.

VI. SUMMARY

Q. Please summarize your direct testimony.

A. The Company projects $120.2 million in test year O&M expenses and $8.1 million in capital expenditures to support the work within the CX&O organizations, including $500,000 in capital and $4.0 million of O&M to support a gas DR pilot. Exhibit A-107 (SQM-2) details the O&M expenses related to this work for the test year ending September 30, 2021. Exhibit A-107 (SQM-2) also includes $91 million of revenues from Customer Programs. These revenues are used to offset the Company's test year revenue requirement and are part of the other revenues included in Exhibit A-13 (JRC-49), Schedule C-3. In addition, the Company is projecting $6.2 million in capital and $1.0 million in O&M expenses associated with IT projects supporting the work in the CX&O organizations for

the test year. A list of these projects is presented in Exhibit A-108 (SQM-3). Additional detail regarding the Company's gas DR pilot is presented in Exhibit A-109 (SQM-4).

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 distribution of natural gas and for other relief.	)))))	Case No. U-20650

DIRECT TESTIMONY

OF

KAREN J. MILES

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

Q. Please state your name and business address.

A. My name is Karen J. Miles, 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 state your educational background.

A. I graduated from Huntington University at Huntington, Indiana, in May 1984, with a Bachelor of Science degree in Business Management and Accounting. In addition, I have attended a number of courses on utility ratemaking, tax accounting, Microsoft Office software, and business writing.

Q. What is your business experience?

A. I have been employed by Consumers Energy since 1987. From April 1987 through April 1989, I worked in the Internal Audit Department where my duties involved Inventory, Pension, and Electronic Data Processing audits and business analysis. I joined the Tax Department in April 1989 as an Associate Accountant where my responsibilities included tax compliance, tax research, and tax accounting. In 1993, I was promoted to Tax Analyst II. In 1997, I was promoted to General Tax Analyst where my responsibilities included preparing data and tax footnotes used in Michigan Public Service Commission ("MPSC" or the "Commission") and Federal Energy Regulatory Commission reports; preparing federal, state, and local tax returns; and forecasting for quarterly income tax payments. In July 2004, I joined the Rates and Regulation Department as a General Rate Analyst where my primary focus was preparation of gas

cost-of-service studies. I became a General Rate Analyst II in May 2005, joined the Rate Administration Section within the Rates and Regulation Department in August 2012, and became a Senior Rate Analyst I in August 2017. My primary responsibilities are tariff filings for Gas Cost Recovery ("GCR") and Power Supply Cost Recovery ("PSCR") proceedings, including for general gas rate case proceedings, developing tariff exhibits, preparing rate and monthly bill comparisons, and successfully implementing tariff changes based on orders from the MPSC.

Q. Have you previously testified or supported witnesses in any proceedings before the MPSC?

A. Yes, I have sponsored proposed tariff changes in Consumers Energy's general gas rate cases in Case Nos. U-17882, U-18124, U-18424, and U-20322. I also sponsored proposed tariff changes in the Company's Voluntary Large Customer Renewable Energy Pilot Program in Case No. U-18351. I was also lead support and prepared gas cost-of-service studies in the Company's general gas rate cases in Case Nos. U-15190, U-15506, U-15986, U-16418, and U-16855 for the cost-of-service witness. In addition, I was lead support for all tariff changes for the pricing witness in the Company's general gas rate case, Case No. U-17643, and for the tariff witness in two of the Company's general electric rate cases, Case Nos. U-17990 and U-20134.

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

A. In my direct testimony, I will identify and support all proposed changes to the Company's gas tariffs, including all price changes as provided to me by Company witness Alex M. Gast.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-110 (KJM-1)		Summary of Tariff Changes; and
Exhibit A-16 (KJM-2)	Schedule F-5	Proposed Gas 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-110 (KJM-1).

A. Exhibit A-110 (KJM-1) provides a summary and explanation of the tariff changes proposed for the Company's Gas Rate Book.

Q. Please describe Exhibit A-16 (KJM-2), Schedule F-5.

A. Exhibit A-16 (KJM-2), Schedule F-5, provides proposed tariff sheets which detail, in redlined format, all proposed tariff language changes and all price changes, proposed by Company witness Gast, to the Company's Gas Rate Book.

Q. On Tariff Sheet Nos. C-7.00 through C-18.00, please explain the updates to Curtailment of Gas Service.

A. The Company is proposing to update Rule C3.1, Definitions; Rule C3.2, Curtailment of Gas Service for Gas Supply Deficiency; and Rule C3.3, Curtailment of Gas Service During an Emergency, with more current and readily available information and to make the tariff easier to understand and implement. No changes were made to the overarching policy related to Curtailment.

Q. Please explain the reason for the updates to Curtailment of Gas Service.

A. The Company utilized the curtailment tariff process for the first time during an emergency situation in January 2019. This event provided the Company with actual

experience of, and unique perspectives in, implementing the tariff process for curtailment of gas service. As a result, the Company is proposing to revise the curtailment process to reflect those recent experiences and new perspectives.

Q. On Tariff Sheet Nos. C-33.00 and D-5.00, please explain the proposed updates.

A. In an effort to reduce the number of bills that reflect a higher than average number of days of natural gas consumption, the Company has added additional billing dates to the billing calendar. The additional billing dates limit the time available to calculate and review the monthly GCR Factor within the current requirement of filing the updated GCR Factor 15 days prior to the start of the bill month. Therefore, to ensure there is sufficient time to calculate, approve, and submit the actual monthly GCR Factor prior to the start of the bill month, the Company is proposing to change Rule C7.1, D.(1), General Conditions, to provide the Company with 5 additional calendar days to complete the GCR Factor calculation and review process. This change would allow the Company to file the revised GCR factor 10 days prior to the start of the bill month and is consistent with the filing requirements for the monthly electric PSCR Factor.

Q. Please explain the proposed carrying cost and discount rate changes in regard to the CAP on Tariff Sheet No. C-40.00.

A. On Tariff Sheet No. C-40.00, the Company is proposing to change the carrying cost rate to 9.27% and the discount rate to 7.40%. This change is further detailed in Company witness Gast's Exhibit A-56 (AMG-7).

Q. Please explain the proposed language updates to the Low Income Assistance Credit ("LIAC") on Tariff Sheet No. D-10.00.

A. Tariff Sheet No. D-10.00 incorporates the Company's Consumers Affordable Resource for Energy into the LIAC to provide vulnerable customers assistance in paying their gas utility bills. Tariff Sheet No. D-10.00 also eliminates portions of the existing LIAC eligibility criteria in an effort to improve the administration of the credit to customers.

Q. Please explain the changes on Tariff Sheet Nos. D-10.00, D-12.00, D-13.00, D-14.00, E-8.00, and E-10.00.

A. Tariff sheet Nos. D-10.00, D-12.00, D-13.00, D-14.00, E-8.00, and E-10.00 reflect the price changes proposed in the direct testimony of Company witness Gast.

Q. On Tariff Sheet No. E-4.00, please explain the proposed changes pertaining to the Heating Value language.

A. The Company is proposing to remove the Heating Value exception for Hanover 19 TMS on Tariff Sheet No. E-4.00 because Hanover 19 TMS LLC is no longer in business. In addition, the Company is proposing to clarify the Heating Value regarding applicable base pressure and temperature.

Q. Please explain the proposed changes to the Allowance for Use and Loss percentage on Tariff Sheet No. E-4.00.

A. The Company is proposing to change the percent of Allowance for Use and Loss as discussed in detail in the direct testimony of Company witness Timothy K. Joyce.

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-20650

DIRECT TESTIMONY

OF

JEFFREY R. PARKER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

Q. Please state your name and business address.

A. My name is Jeffrey R. Parker, and my business address is 530 West Willow Street, Lansing, Michigan 48909.

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 Director of Gas Distribution Engineering Planning - West.

Q. What are your responsibilities as Director of Gas Distribution Engineering Planning – West?

A. I partner with the Director of Gas Distribution Engineering Planning – East to direct the team of local Gas System Engineers and Engineering Technical Analysts. Together we are responsible for the engineering and asset planning of the Company's natural gas distribution system and overall execution of the plan to deliver those system enhancement projects to customers. I lead the development and execution of plans to maintain, upgrade, and expand the gas distribution system that provides safe, reliable, and affordable gas service to the Company's 1.8 million natural gas customers. In doing so, we look to optimize the configuration of the system. I oversee gas distribution system risk modeling, and coordinate selection of the projects undertaken annually for the Enhanced Infrastructure Replacement Program ("EIRP") and the Vintage Service Replacement ("VSR") Program. In addition, I have responsibilities for working with municipal agencies to coordinate gas distribution facility work in conjunction with their road, sewer, water, and other municipal infrastructure upgrades. Also, our team is responsible for working with large industrial customers on requested upgrades to their natural gas services and

requests for new service. Lastly, the Gas Distribution Engineering Planning team has responsibility for the permitting of gas distribution projects across the state.

Q. What other relevant experience do you have?

A. I have been in the Director of Gas Distribution Engineering Planning – West position since 2014. I have also served the Company as a Distribution Project Manager, Gas System Engineer, and Compliance Assurance Manager. As a Distribution Project Manager, I was responsible for budget and forecasting of large gas distribution projects in the Lansing, Jackson, and Kalamazoo regions of the state. During my four years as a Gas System Engineer, I was the asset owner for the gas distribution system in southwest Michigan, responsible for all gas distribution main replacement and system augmentation projects. This involved work with a wide variety of stakeholders, from residential to industrial customers, to municipalities, to the Michigan Economic Development Corporation ("MEDC"). Our team performed all scoping, engineering design, and project support for gas main upgrades; coordination of the Company's facility locations for road improvement projects; and technical review of new business and customer attachment program installations. In this role, I also oversaw the annual leak survey and regulation inspection programs for southwest Michigan. The Compliance Assurance Manager role involved understanding the state and federal codes related to gas safety, developing a process for and performing internal self-assessments of the Company's compliance with those codes, and leading any corrective actions deemed necessary by those self-assessments. I have worked in gas distribution engineering for 12 of the 15 years I have been with the Company.

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

A. Yes. I represent the Company at the American Gas Association ("AGA") by serving on the Steering Committee for the Distribution Best Practices Committee, responsible for benchmarking performance among participating AGA distribution companies. I also represent Consumers Energy on two sub-committees of the Michigan Infrastructure Council – one working on developing a Project Portal and another working on creating an index of industry standard terms to aid in project coordination across all road right-of-way stakeholders.

Q. What is your formal educational experience?

A. I graduated from the University of Michigan with a Bachelor of Science in Mechanical Engineering in April of 2004. I also completed a master's degree in Business Administration through the Indiana University Kelley School of Business in May of 2008.

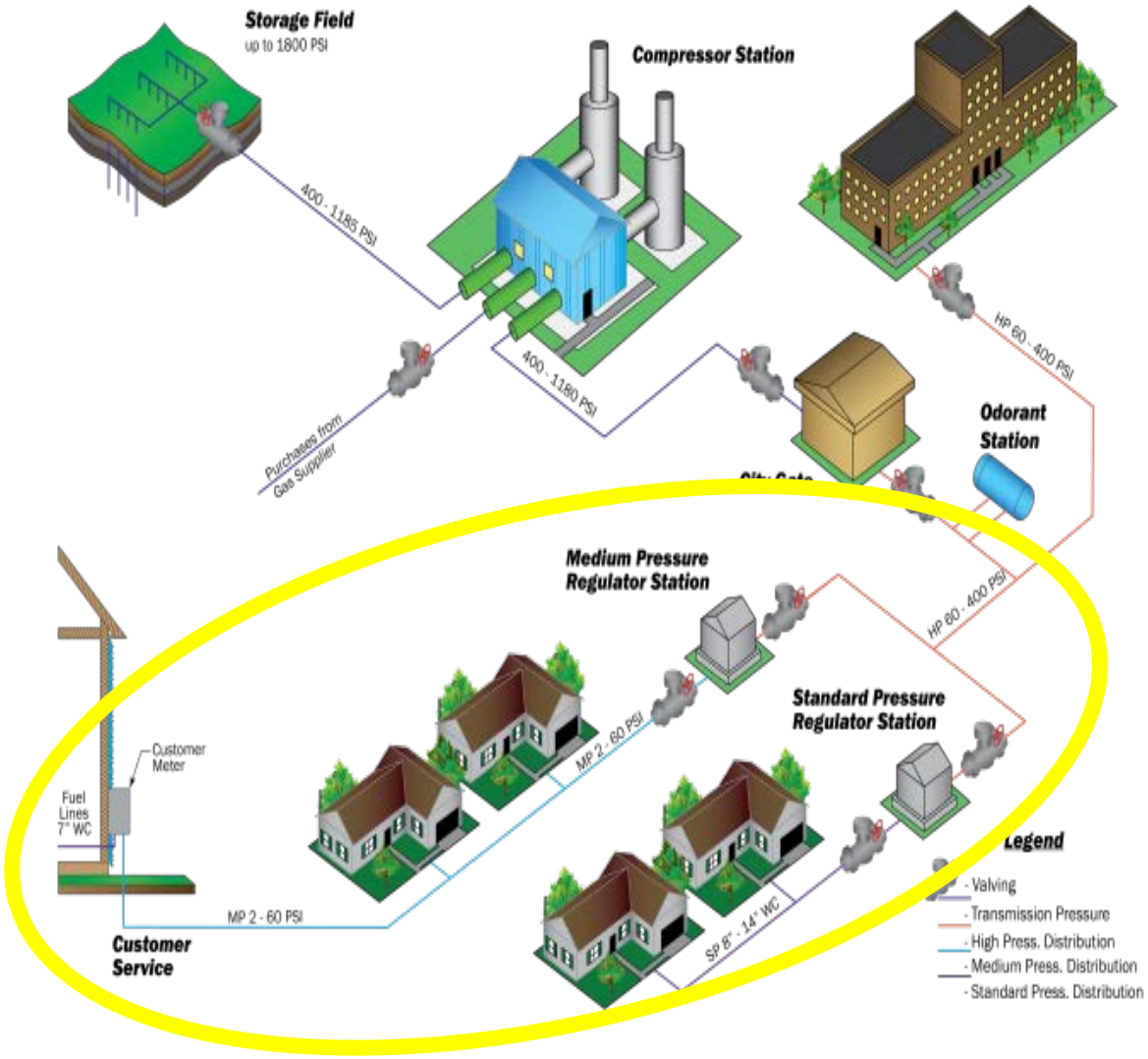
Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I testified in Case No. U-20322.

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 the Company's Gas Engineering and Financial Management 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 and financial management for this system as well as the engineering and financial management for the transmission system. These assets are the portion of the Company system that receives the gas at the outlet of the Company's city

gates and delivers the gas to customers. In the diagram below, these assets are inside the yellow highlighted section.



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 am not sponsoring capital expenditures for the Company's transmission system, these expenditures are being

sponsored by Company witnesses Chad L. Alley, Paul M. Wolven, and Craig C. Degenfelder.

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 Financial Management departments; and (ii) a description of the Company's Gas Distribution capital expenditures that I am sponsoring for 2018, 2019, the nine months ending September 30, 2020, and for the projected test year 12 months ending September 30, 2021.

Q. How does your direct testimony relate to the Natural Gas Delivery Plan ("NGDP") presented by Company witness Degenfelder?

A. Mr. Degenfelder'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 Financial Management staff represented in my direct testimony consists of the individuals and teams responsible for the engineering, design, project management, and construction support 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-111 (JRP-1)	Summary of Actual & Projected Gas Engineering and Financial Mgmt O&M Expenses For the Years 2018, 2019, 2020 and Test Year 12 Months Ending September 30, 2021;
Exhibit A-112 (JRP-2)	Summary of Actual & Projected Gas Engineering and Financial Mgmt

			O&M Expenses For the Years 2018, 2019, 2020, and Test Year 12 Months Ending September 30, 2021;
	Exhibit A-12 (JRP-3)	Schedule B-5.6	Projected Capital Expenditures, Distribution Plant, Summary of Actual & Projected Gas and Common Capital Expenditures;
	Exhibit A-113 (JRP-4)		Actual & Projected Gas Capital Expenditures - New Business Program;
	Exhibit A-114 (JRP-5)		Actual & Projected Gas Capital Expenditures - Asset Relocation Program;
	Exhibit A-115 (JRP-6)		Actual & Projected Gas Capital Expenditures - Regulatory Compliance Program;
	Exhibit A-116 (JRP-7)		Actual & Projected Gas Capital Expenditures - Material Condition Program;
	Exhibit A-117 (JRP-8)		Actual & Projected Gas Capital Expenditures – Capacity/ Deliverability Program;
	Exhibit A-118 (JRP-9)		Actual & Projected Gas & Common Capital Expenditures - Gas Operations Other Program; and
	Exhibit A-119 (JRP-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 Financial Management staff, which are described on Exhibit A-111 (JRP-1). The total O&M expenses for the years 2018, 2019, 2020, and the projected test year, the 12 months ending September 30, 2021, are $8,524,000; $8,764,000; $9,427,000; and $10,412,000; as set forth on this exhibit on line 3, column (c); line 3, column (d); and line 7, column (e), respectively. These expenses are shown in the table below.

Table 1: Gas Engineering and Financial Management O&M Expenses

	(a)	(b)	(c)	(d)	(e)
Line No.	Description	2018 Actual	2019 Projected	2020 Projected	12 Months Ending September 30, 2021 Projected
1	Gas Engineering and Regulatory Services	$ 7,890	$ 8,214	$ 8,957	$ 9,932
2	Gas Asset Strategy	$ 633	$ 549	$ 471	$ 480
3	**Total Expense**	**$ 8,524**	**$ 8,764**	**$ 9,427**	**$ 10,412**

My direct testimony also represents certain Gas Distribution capital investments through September 30, 2021, which are described on Exhibit A-12 (JRP-3), Schedule B-5.6. The total Gas Distribution capital expenditures represented by this direct testimony for the years 2018, 2019, the nine months ending September 30, 2020, and the projected test year ending September 30, 2021 are $258,877,000; $274,564,000; $220,320,000; and $270,067,000; 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 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 12/31/2018	12 Mos Ending 12/31/2019	9 Mos Ending 9/30/2020	21 Mos Ending 9/30/2020	12 mos. Ending 9/30/2021
1	New Business	76,609	82,574	61,276	143,850	60,164
2	Asset Relocation	77,352	90,892	66,705	157,597	81,223
3	Regulatory Compliance	29,925	39,000	33,230	72,230	37,784
4	Material Condition	50,873	49,877	48,223	98,100	76,624
5	Capacity/Deliverability	19,665	8,151	7,732	15,883	9,974
6	Gas Operations Other	4,453	4,070	3,154	7,224	4,297
7	**Total Capital**	258,877	274,564	220,320	494,884	270,067

Q. How has the Company projected its O&M expenses for 2019, 2020, and the test year 12 months ending September 30, 2021?

A. The Company has projected its O&M expenses for 2019, 2020, and the test year 12 months ending September 30, 2021, 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 Financial Management department, the timing of filling vacant positions, and a projection for added staff to support the new regulation and the NGDP. First, for the Gas Distribution O&M expenses representing the current Gas Engineering and Financial Management employee salaries and expenses, the Company projected the 2019 and first nine months of 2020 based on the May 2019 year-to-date salaries and expense levels. The test year salaries and expenses were projected to account for increasing staff levels to support new regulatory requirements and the NGDP investments.

Q. Please describe the methodology used to project the Company's Gas Distribution capital expenditures for the years 2019 through the 12 months ending September 30, 2021.

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 FINANCIAL MANAGEMENT DEPARTMENTS O&M EXPENSES

Q. Please explain the source of the 2018 actual O&M expenses for the Gas Engineering and Financial Management departments expenses shown on Exhibit A-111 (JRP-1), line 3.

A. The 2018 actual O&M expense amount of $8,524,000 for the Gas Engineering and Financial Management departments was taken from Consumers Energy's internal reporting records. This amount represents both labor and non-labor O&M expenses for these departments, and the splits between labor, material, contractor, non-labor overheads, and other non-labor expenses are detailed on Exhibit A-112 (JRP-2), pages 1 and 2. The 2018 level of expense allowed the Company to provide the engineering and support needed to serve 1.8 million natural gas customers and complete the 2018 investment strategy. The projected expenses for 2019 are $8,764,000 and for 2020 are $9,427,000, as shown on Exhibit A-112 (JRP-2), page 2, line 9, columns (c) and (d), 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 Financial Management departments O&M expenses for the test year as shown on Exhibit A-111 (JRP-1), line 3, column (e).

A. The expense levels for the Gas Engineering and Financial Management departments represented on Exhibit A-111 (JRP-1), line 3, were derived by starting with the May 2019 labor and expense costs for the engineering and technical support staff level at that time. From that point, the year-end 2019 labor costs were projected, including assuming that all positions that were vacant in May would be filled by January 1, 2020. As part of this projection, adjustments were made to account for the employees who support the increasing O&M workload in the Pipeline Integrity Program, as discussed in Company witness Wolven's direct testimony. There were no projected increases in expenses as part of the 2019 projection. For the first nine months of 2020, the labor costs were projected based on the year-end 2019 projection incorporating a 3.2% merit increase for the existing staff in May of 2020. Like 2019, there were no increases in expenses projected for the first nine months of 2019. The Company will need additional engineering and technical staff to support the NGDP as well as the new regulations in the natural gas industry. The calculation of the labor and expense costs for this additional staffing is further discussed below. The resulting projected costs for the 12 months ending September 30, 2021, are $10,412,000 and can be found on Exhibit A-112 (JRP-2), page 2, line 9, column (e). These expense levels for the Gas Engineering and Financial Management Departments Program 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 Financial Management staff to support the NGDP?

A. Yes. The Company's current staff is sized to support the Company's current level of investment. In order to increase that investment as outlined in the NGDP, the Company will need to hire and train more engineering staff to ensure that the Company has thoroughly reviewed, planned, and coordinated all considerations in engineering design so 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[1] titled "Skills and Experience Necessary for 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. By ensuring the right level of engineering staff, the Company will ensure that 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. Please describe how the cost projections for the additional Gas Engineering and Financial Management employees were derived.

A. The Company has projected expenses for additional engineering and support personnel to implement new federal rules regarding pipeline safety and the NGDP. The Pipeline and Hazardous Materials Safety Administration ("PHMSA") has recently published new rules regarding Pipeline Safety Management Systems and onshore transmission systems. These rules require additional oversight and enhancements to the Company's systems, inspection requirements and records. In order to support these additional programs, the Company is

planning to increase engineering and support personnel in the Regulatory Compliance and System Integrity departments.

Additionally, as Company witness Jared J. Martin outlines in his direct testimony, the NGDP includes increased investment in gas system replacement. According to the Company's Gas EIRP 2018 Performance Report, the Company installed 137 miles of distribution main (not including EIRP Transmission Operated by Distribution ("TOD") replacement mains), of which approximately 47 miles were part of the EIRP, and 90 miles were other replacement programs (New Business Program main excluded). Mr. Martin describes an installation of approximately 144 miles installed in 2021 in the EIRP alone, not including EIRP TOD replacement mains. The Company projects increased replacement in other programs as well, but even if it were to be assumed that all other programs remain constant, this increased EIRP mileage would result in a total installation, excluding new business, of nearly 235 miles, or approximately 71% more when comparing 2021 to 2018 actuals.

To support these planned increases in compliance requirements and construction, the Company is proposing an increase of 52 employees, (less than 10% increase) in engineering and support staff roles. Each affected department 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 is required beginning in the fourth quarter of 2020 and will be responsible for engineering planning, engineering design, permitting, and construction support for the gas system enhancements. To project the expenses for the additional employees required to support the NGDP, the Company used the average annual costs for its existing employees to calculate an average monthly rate, then multiplied that

cost by a weighted average of 2020 and 2021 months representative of the test year. The additional engineering staff will support the accelerated vintage material replacements, additions of remote closure valves, increased integrity inspections, and modernizing monitoring controls. These employees are necessary to enable the Company to complete the code compliance, risk evaluation, engineering, design, and construction support to enable the implementation of new federal requirements and the replacement strategies and construction efficiencies 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 Financial Management, as listed on Exhibit A-112 (JRP-2).

A. Gas Engineering and Financial Management is made up of five major departments:

- Gas Project Management;
- Gas Asset Management –which consists of the Gas Engineering, Distribution Engineering Planning, Compression Engineering, and System Integrity departments;
- Customer Energy Management;
- Gas Regulatory Services – consisting of Regulatory & Compliance – Gas, and Geospatial Management and Data Quality – Gas; and
- Gas Asset Strategy.

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 the project management methodology to achieve predictable results. The Gas Project Management team includes Company-employed and contract project managers that oversee large-scale gas projects and ensure that each project meets the intended scope, schedule, and budget. The Gas Project Management line item, as shown on Exhibit A-112 (JRP-2), page 2, line 1, consists of the salaries and expenses for project managers, and their Company-employed and contracted support staff(s). 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 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. 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 forecasted 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, etc.) and for large new industrial customers. Gas Compression Engineering is also a part of Gas Asset Management and is responsible for engineering of the Company's compressor station components. Gas Asset Management also includes Gas Storage Integrity, which has responsibilities for storage wells and the pipelines within the storage fields. The salaries and expenses of all the Gas Asset Management teams described above are represented on Exhibit A-112 (JRP-2), page 2, lines 2 through 4.

Q. The third department within the Gas Engineering and Financial Management group is Customer Energy Management. Please provide a brief summary of the activities in the Customer Energy Management department.

A. The Customer Energy Management team is focused on meeting customer needs by providing a single point of contact for customer-requested main, service, and meter installations and alterations. Customer Energy Management 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 2018, this department coordinated the work on over 45,000 customer requests. Within Customer Energy Management 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 is 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 will remain 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 Energy Delivery Support Team is 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 team are represented on Exhibit A-112 (JRP-2), page 2, line 5.

Q. Please describe the activities of the Gas Regulatory Services department.

A. Gas Regulatory Services interfaces with the MPSC Gas Safety Staff and the Federal Office of Pipeline Safety on regulatory compliance matters. Gas Regulatory Services maintains compliance-related program documents, such as Transmission Integrity Management, Distribution Integrity Management, Gas Operations Procedures, Public Awareness and Damage Prevention, and ensures periodic and incident reporting requirements are completed in accordance with both federal and state requirements. Gas Regulatory Services also includes the employees responsible for the Geospatial Information Systems and gas maps and records. The Gas Regulatory Services department is also managing the Company's implementation of the American Petroleum Institute Recommended Practice 1173 – Pipeline Safety Management Systems. The salaries and expenses for the employees within Gas Regulatory Services are described on Exhibit A-112 (JRP-2), page 2, lines 6 through 7.

Q. The last department listed within the Gas Engineering and Financial Management departments is Gas Asset Strategy, as set forth on Exhibit A-112 (JRP-2), page 2, line 8. Please describe the activities of the departments involved in Gas Asset Strategy.

A. Gas Asset Strategy provides asset strategy, business support, financial analysis, and business performance measurement for the gas transmission and distribution divisions. Gas Asset 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. This department also includes Gas Asset Strategy for compression, storage, transmission facilities, and distribution facilities and is responsible for the development, implementation, and support of the long-term plan for the natural gas systems and the development of the NGDP.

GAS DISTRIBUTION CAPITAL EXPENDITURES

Q. Please describe the Company's projections of capital expenditures for Gas Distribution.

A. As shown on Exhibit A-12 (JRP-3), Schedule B-5.6, the Gas Distribution capital expenditures I am sponsoring were $258,877,000 in 2018, and are projected to be $274,564,000 in 2019; $220,320,000 for the nine months ending September 30, 2020; and $270,067,000 for the 12 months ending September 30, 2021, 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. The Gas Distribution capital expenditures that I am sponsoring are also summarized in the table above.

Q. Please list the major programs within the Gas Distribution capital expenditures.

A. The major programs, as shown on Exhibit A-12 (JRP-3), Schedule B-5.6, are:

- New Business;
- Asset Relocation;
- Regulatory Compliance;
- Material Condition;
- Capacity/Deliverability; and
- Other Support/Technology.

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 except as noted below. The direct testimony of Company witnesses Alley, Wolven, and Timothy K. Joyce represent additional components of the gas transmission system as well as distribution regulating stations, compression, and storage systems. Additionally, the EIRP and VSR programs that are contained within the Material Condition Program are represented by Company witness Martin.

Q. Have you included contingency costs in the capital expenditures you are sponsoring?

A. Yes, the Lansing Board of Water and Light large new business project contains contingency costs. However, the Lansing Board of Water and Light is funding the entire project, including the contingency, through its customer contribution for the project. This contribution is being collected from the customer in installments and the entire project cost will be paid by the customer prior to the completion of construction. Once construction is complete and all costs have been accounted for, the Lansing Board of Water and Light will either be refunded the remaining contingency amount or issued an invoice for the project costs beyond the contingency. Once the actual project costs have been reconciled with the customer, the expenditures for this project will be only the actual construction costs,

therefore there will no longer be any contingency on the project and only actual costs will be submitted for rate recovery.

1. New Business

Q. Please describe the capital expenditures related to the New Business Program as shown on Exhibit A-12 (JRP-3), Schedule B-5.6, 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 meters 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 2018 were $76,609,000 and the Company's projections for the years 2019, the nine months ending September 30, 2020, and the 12 month test year ending September 30, 2021, are $82,574,000; $61,276,000; and $60,164,000, 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 the table below.

Table 3: New Business Capital Expenditures

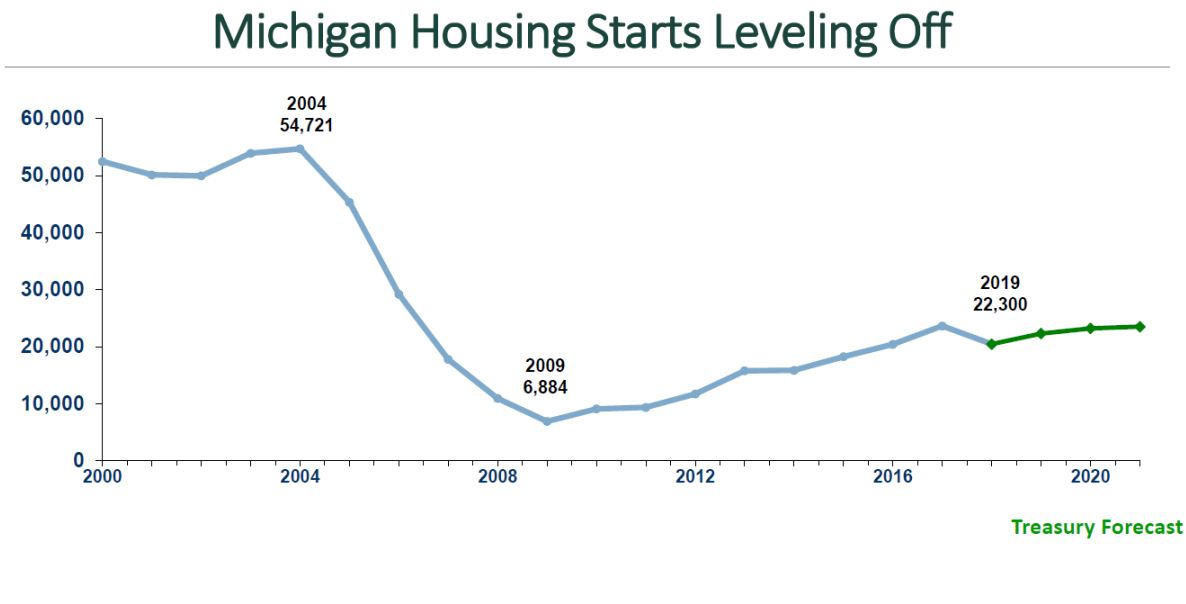
($000)	(a)	(b)	(c)	(d)	(e)	(f)
		New Business Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line No.	Program Description	12 Mos Ended 12/31/2018	12 Mos Ending 12/31/2019	9 Mos Ending 9/30/2020	21 Mos Ending 9/30/2021	12 mos. Ending 9/30/2021
1	Mains Services & Meter Stands - Dist	45,955	47,003	30,386	77,389	49,510
2	Large New Business Projects - Dist	452	22,017	30,092	52,109	9,679
3	Customer Attachment Program - Dist	30,202	13,554	798	14,352	975
4	**Total New Business Capital**	76,609	82,574	61,276	143,850	60,164

Exhibit A-113 (JRP-4) provides further details of the expenditures included in this program.

Q. Please explain the Company's gas new business connections forecast.

A. The Company uses forecasting data from multiple sources to forecast and plan for new business growth. Recent data presented to the Michigan Home Builders Association by Eric Bussis, Chief Economist and Director, Office of Revenue and Tax Analysis, Michigan Department of Treasury, suggests that housing starts (new house build projects) will have moderate growth in 2020. 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 forecasted a conservative growth forecast of 3% in both 2020 and 2021. The continued demand for new subdivision developments in 2019 will result in houses built, and services connected, over the upcoming years.

Figure 1: Michigan Housing Starts Projections



Key Source: Bussis, Eric. "Mid-Year Economic Forecast and State of the Industry Breakfast." June 13, 2019, PowerPoint file.

Q. How many new business connections are you projecting in this filing?

A. The New Business Program plans include 9,165 new attachments in 2019, 9,074 in 2020, and 9,247 for the full year 2021. There were 9,544 connections in 2018. This includes connections under the CAP Program, which are expected to decline in 2020 and 2021, in addition to the new connections that come on the gas system outside of customers converting to natural gas as described above. 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. New Business Program connections generally fall in to three categories:

i. There is an existing gas main at the customer's site and capacity is adequate to serve customer's load. In this case, the Company will install just a new service and meter to meet the customer's capacity needs;

ii. There is no main at the customer's site. In this case, the Company will need to extend gas main from the existing end point of the main to the customer's site. The primary components of the main extension analysis are the distance to the customer's site and the load required on the main. The distance to the site is a well-defined parameter based on the route required to get from the existing gas distribution mains network to the customer's site. The Company's minimum main size installed is 2" and therefore, the baseline for any main extension to a new customer is a 2" medium pressure main. However, the customer's load, or the projection of additional future loads in the area, may result in the Company selecting a different main size to install adequate capacity on the main once it is extended to the customer. In this way, when the Company needs to extend gas main to a customer's service location, the customer's expected maximum demand guides the Company's decision on the diameter of main to install. The length of new main installed is determined based on the distance of the customer from existing gas main, regardless of the diameter of the new main. The size of a customer's demand does not affect how many feet of new main are required to attach them to the system; and

iii. There is main at the customer's site, but it does not have adequate capacity to serve the customer's load. In this case, the Company will perform a load study analysis to determine what system replacement or improvements are required in order to provide the load needed by the customer. This may involve replacing upstream regulation facilities or main facilities or making additional new connections in the system to flow additional gas to the customer's site. This work will be required in addition to the service installation for the 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 will complete the last CAP main installation. The program will continue 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-113 (JRP-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 described above, 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 timeframes represented by this direct testimony, there are multiple projects included in this program. The projects in this program are specific in their requirements for each individual customer, and therefore it is difficult to compare

costs in the program year by year. In 2018, the Company connected a new agri-business customer in the Lansing area, which the Company worked closely with the MEDC to bring to the region. The project to connect this customer included gas main and service extensions in 2018, as well as a gas regulating station constructed in 2019. Also, in 2019, the Company will construct facilities to serve six additional customers. The largest of these is the Lansing Board of Water and Light Erickson Plant project, at an estimated total project construction cost of $52,000,000. Construction began in 2019 and will continue throughout 2020 to complete the gas system updates necessary to serve the new plant. Additionally, the Company connected two large agri-business customers in Saint Johns by constructing new mains, services and meter stands on the east side of the city. Construction of this project will also carry over in to the first half of 2020. The Company also connected new agri-business customers in the Pinconning, Reese, and Marshall areas under the Large New Business Program. None of these three customers were included in the Company's projections for Case No. U-20322, as these customers requested service after the previous filing. A northern Michigan agri-business customer, that the Company included in its 2019 projections in Case No. U-20322, decided to delay their upgrades so the Company is now projecting the expenses to serve that customer in 2020 instead of 2019. This customer is expanding their business, requiring the Company to rebuild a distribution regulation station and install new gas main and service facilities to their site, at an estimated project construction cost of $750,000. The Company will not be pursuing a contract with this customer due to the smaller investment amount and past knowledge of this customer's operations.

Additionally, the Company has partnered with the MEDC to help secure the expansion of a business in southwest Michigan, which will require approximately 4000' of high-pressure gas main, a new service and a new meter to enable this customer's growth. The Company is currently negotiating a contract for these facilities but does not expect it to be completed until the first quarter of 2020. The Company is still seeking recovery of this investment in this case, even though no contract has been executed yet, because the Company will commence with construction in 2020 and since the assets will be installed and operating during the test year, recovery of this investment is reasonable. In total, the 2020 large new business program is expected to consist 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 northern Michigan, and the industrial expansion in southwest Michigan. The Company does not know of any other large new business projects as of the time of this filing but does expect additional customers to emerge in this category, similar to what happened with the Pinconning, Reese, and Marshall customers that were added in 2019.

Q. Why is the Company not pursuing a contract with the northern Michigan agri-business customer described above?

A. The purpose of the Company pursuing contracts with large new business customers is to ensure recovery of the Company's investment when that investment is more than $150,000 and/or the customer's gas is unpredictable given the information known at the time of the customer's request. In the case of this northern Michigan agri-business, the customer is converting a boiler to natural gas fuel, meaning that the Company can project the gas usage based on historical use of the alternative fuel that the boiler currently uses. This makes the

revenue projection more certain than if it were a new process or new equipment being added. The Company's C8 tariff requires the Company bill the requesting customer for any revenue deficiency incurred; however, given that the projection is based on a known piece of equipment with known usage history, the Company is confident the customer's revenue will not be deficient.

Q. Please further explain the cost projections associated with service to the new Lansing Board of Water and Light power plant.

A. The Lansing Board of Water and Light project consists of a new city gate, with associated transmission line taps to feed that city gate, approximately 7 miles of new 12" high-pressure gas distribution main, a new 12" high-pressure service, and a turbo meter stand. The total estimated construction cost for the project is $52,000,000. The customer's projected annual usage at this new location will be 6 billion cubic feet annually, which results in a revenue credit to the customer of $35,007,728 when applying tariff Rule C8 from the Consumers Energy gas rate book. The contract executed with the Lansing Board of Water and Light specifies that the customer will contribute the full $52,000,000 to the project in four installments as project milestones are achieved. The customer has made the two installment payments required thus far. Once the customer starts using gas in 2021, they will receive an annual refund for each of the first five years of gas usage, which will total the tariff Rule C8-calculated amount of $35,007,728 if they achieve the usage target for all five years. This methodology is consistent with the way all large customer load additions are handled. Since the contract with the Lansing Board of Water and Light is potentially fully refundable if the customer generates sufficient amounts of revenue for the Company, the project costs will not be recovered through rates until the contract with the

customer concludes and the Company is certain the Lansing Board of Water and Light's revenue is as expected. Please see the testimony of Company witness Jason R. Coker for a discussion on how this project is treated in the rate case.

Q. Please explain the nature of the New Business Program expenditures.

A. As stated above, the New Business Program expenditures are driven by external demand from customers seeking new gas service to their home or business, requiring installation of new Company facilities. Each year, the Company projects these expenditures based upon historical spend levels and project details, while factoring in any current economic or industry trends that the Company believes will impact the New Business Program, as demonstrated in the housing starts chart above. The Company then monitors those requests throughout the year and compares the actual expenditures to the projection on a monthly basis. Since this program is driven by external demand, that demand may or may not materialize throughout the year. Additionally, each project is unique and may require more or less work than the average historical projects used for the original projection. While the Company attempts to project this work to a high level of accuracy, the largest factors influencing the expenditures in this program are externally driven, which impacts the accuracy with which the Company can forecast this work. For these reasons, the Company requests that it be allowed to defer the revenue requirement of any capital spending for new business above what is included in rates should the Commission not approve the full requested capital spending for new business in this case. See the testimony of Company witness Coker for a description of the deferral and the testimony of Company witness Karen M. Gaston for the necessary accounting approvals.

2. Asset Relocation

Q. Please describe the capital expenditures related to the Asset Relocation Program as shown on Exhibit A-12 (JRP-3), Schedule B-5.6, line 2.

A. The Asset Relocation Program includes gas distribution infrastructure replacement projects which 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 Civic. The expenditures for each of these programs are shown in the table below and Exhibit A-114 (JRP-5) provides further details of these expenditures.

Table 4: 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 December 2018	12 Mos Ending 12/31/2019	9 Mos Ending 9/30/2020	21 Mos Ending 9/30/2020	12 mos. Ending 9/30/2021
1	Asset Relocation - Civic Improvement	68,417	80,047	59,818	139,864	71,194
2	Asset Relocation - Reimbursable	8,935	10,845	6,888	17,733	10,029
3	**Total Asset Relocation Capital**	77,352	90,892	66,705	157,597	81,223

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 in accordance with the law.

Asset Relocation – Reimbursable Civic 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 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, and funding for these projects continues to increase as the Michigan economy remains strong. In their 2018 report card, 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 $2.3 billion in 2017.[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

[1] https://www.infrastructurereportcard.org/asce-gives-michigan-infrastructure-a-d/

[2] http://www.mcgi.state.mi.us/mitrp/tamcDashboards/reports/finance/finance?year=2017&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

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 1375' 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, which is more costly than plastic pipe installation. This trend has continued in 2019, with significant relocation of high-pressure facilities to accommodate work on Cork Street in Kalamazoo, and multiple smaller projects to relocate for bridge and/or drain crossings in the Jackson, Flint, Bad Axe, Hastings, and Livonia headquarters. Additional high-pressure work will be required for facilities in the I-75 corridor in the Company's Royal Oak headquarters in 2020. 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 5: Asset Relocation – Civic Improvement Project Details

	2017	2018	2019 (projected)
Projects completed	189	186	214
Asset Relocation Feet of Distribution Main Installed	244,718	301,215	294,086
Asset Relocation Services Replaced	3,230	2,423	3,057

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-114 (JRP-5), line 1, the capital expenditures for this program were $68,417,000 in 2018 and are projected to be $80,047,000; $59,818,000; and $71,194,000 for the years 2019; the nine months ending September 30, 2020; and the test year ending September 30, 2021, 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.

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 to some extent. In support of the Company's continual effort to promote coordination and efficient civic improvement projects, I have been involved in the Michigan Infrastructure Council meetings throughout 2019. Despite not being a council member, I have been asked by the Council to serve on two of the subcommittees to continue to advance project coordination statewide.

The Company's Gas Distribution Engineering 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. For example, the City of Lansing has a large, multi-year program to replace the sewer system, requiring major road construction and deep sewer installation. On many of these streets, the Company has cast iron gas main facilities and the construction activity is likely to cause these facilities to leak. In this case, the Company will coordinate on timing with the City of Lansing, but will not negotiate to save these facilities. 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.

As a counter-example, 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 in order to protect the Company's gas facilities and prevent relocation. The Distribution Engineering 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 an increasing trend in the number of main and service replacements required in this program, as demonstrated in Table 5 above.

Q. Please further describe the expenditures associated with the Asset Relocation – Reimbursable Civic Program.

A. The Asset Relocation – Reimbursable Civic 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.

In 2019, there was one large project in the Asset Relocation – Reimbursement Civic Program. This project consisted of approximately 1 mile of high-pressure gas main installation and a rebuild of the customer's meter stand. This project accounted for the significant increase in projected spend in Asset Relocating – Reimbursable Civic in the 2019 projection. The costs and projections for this program are reflected on Exhibit A-114 (JRP-5), line 2, and demonstrated in Table 4 above. The capital expenditures for this program were $8,935,000 in 2018 and are projected to be $10,845,000; $6,888,000; and $10,029,000 for the years 2019; the nine months ending September 30, 2020; and the test year ending September 30, 2021, 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.

Q. Please explain the nature of the Asset Relocation Program expenditures.

A. The Asset Relocation Program expenditures are driven by external demand from road right-of-way owner agencies like the Michigan Department of Transportation, municipalities, and counties, as well as by customers requesting alteration of the Company's facilities. The Company primarily locates gas distribution mains in the road right-of-way, meaning they are allowed there by permit from the right-of-way owner (city, county, etc.). When the right-of-way owner has a project, they can require the Company to relocate those facilities, essentially revoking the permit for the existing location. Each year, the Company projects these expenditures based upon historical spend levels and project details, while factoring in any current economic or industry trends that the Company believes will impact the Asset Relocation Program. The Company then monitors those requests throughout the year and compares the actual expenditures to the projection on a monthly basis. Since these programs are driven by external demand, that demand may or may not materialize throughout the year. Additionally, each project is unique and may require more or less work than the average historical projects used for the original projection. While the Company attempts to project this work to a high level of accuracy, the largest factors influencing the expenditure in this program are externally driven. In recent years, the demand has exceeded the Company's projections. For these reasons, the Company requests that it be allowed to defer the revenue requirement of any capital spending for asset relocation above what is included in rates should the Commission not approve the full requested capital spending for asset relocation in this case. See the testimony of Company witness Coker for a description of the deferral and the testimony of Company witness Gaston for the necessary accounting approvals.

3. Regulatory Compliance

Q. Please describe the capital expenditures relating to the Regulatory Compliance Program shown on Exhibit A-12 (JRP-3), Schedule B-5.6, 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, the only two components of this program currently are the Regulatory Base Distribution projects and the Meters Program. The capital expenditures for this program were $29,925,000 in 2018 (line 3, column (b)) and are projected to be $39,000,000 for the year 2019 (line 3, column (c)); $33,230,000 for the nine months ending September 30, 2020 (line 3, column (d)); and $37,784,000 for the test year ending September 30, 2021 (line 3, column (f)). The Regulatory Compliance expenditures are shown in the table below.

Table 6: 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 12/31/2018	12 Mos Ending 12/31/2019	9 Mos Ending 9/30/2020	21 Mos Ending 9/30/2020	12 mos. Ending 9/30/2021
1	Regulatory Base Distribution	5,524	8,963	5,751	14,714	6,774
2	Meters	24,402	30,037	27,479	57,516	31,010
3	**Total Regulatory Compliance Capital**	29,925	39,000	33,230	72,230	37,784

A further breakdown of the Regulatory Compliance Program expenditures is shown on Exhibit A-115 (JRP-6).

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 St. 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 St. in Owosso, was added due to observed station pressures, bringing the total back to 17 projects in the program. The Chipman St. 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 the table below:

Table 7: 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	2019 – Under Construction
11690	Flint	West Flint SP	2019 – Complete
11689	Flint	East Flint SP	2019 – Complete
14024	Jackson	Foote	2019 – Under Construction
11807	Jackson	Morrell	2019 – Under Construction
14016	Jackson	First St SP	2019 – Cancelled
11719	Bay City	Bay City West SP Walnut Street	2020 – Ready for Construction
12057	Bay City	Bay City East SP, Water Street	2020 – In Design
11720	Bay City	Bay City West SP Vermont Street	2020 – In Design
11717	Saginaw	Saginaw East SP	2021
16132	Owosso	Ada St	2021
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 here 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.

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 to be used in serving new business connections, for the Routine Meter Exchange Program, and for normal replacement of obsolete or broken meters. The Routine Meter Exchange Program involves replacing the customer's existing meter with a new 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 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-115 (JRP-6), line 2, also include gas meter communication modules, gas corrector units, and testing equipment.

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 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 (damage,

leak, obsolescence, etc.), project work such as EIRP and CAP, 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 actual inventories are observed. Historically, the Company allocated these planned meter purchases between the New Business and Regulatory Compliance Programs based on historical usage percentages. To eliminate the waste of reallocating the meters to two different programs, they have now been combined into this one program going forward. The actual and projected total number of meters purchased for the Meters Program for each period in this filing are shown in the table below:

Table 8: Actual and Projected Meters Program Purchases by Year

	2018 Actual	2019	2020	2021
Meter Units	65,471	61,055	62,425	63,574
Unit Cost	355	461	474	466
Total Meter Cost	23,227,560	28,151,460	29,601,311	29,650,914
Correctors	1,070	1,135	1,075	1,097
Unit Cost	1,048	1,311	1,220	1,220
Total Corrector Cost	1,121,307	1,488,539	1,311,855	1,338,088
Comm Modules	838	3762	200	200
Unit Cost	63	105	147	148
Total Comm Module Cost	52,648	396,887	29,324	29,588
Total Cost	**24,401,515**	**30,036,886**	**30,942,490**	**31,018,589**

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 which have affected the unit cost for the meters purchased. First, the Company is seeing an increase in larger meters required for customer demand. Smaller meters that have historically been used on individual homes are being replaced with larger meters to accommodate more gas-fired equipment such as pool heaters and generators, which results in larger, more expensive meters being needed. In fact, since 2015, the Company has experienced an increase of 112% in the number of meters set for the size most commonly used for whole house generators, from an average of 2,500 per year to an average of 5,300 per year.

Second, with the conclusion of the Advanced Metering Infrastructure ("AMI") and Automatic Meter Reading ("AMR") programs in 2018, the meters purchased now require a communication module to be included. While the AMI and AMR programs were being rolled out, these programs paid for the cost of these modules. With those programs now being complete, the cost of the modules will be a part of the costs in the Meters Program. Historically, each meter needed a module added to it, but now that the AMI and AMR programs are complete, meters being brought back from the field to the Metering Technology Center have a module that can be taken off the old meter and refurbished for use on a replacement meter. This lessens the number of modules required for purchase in future years, reducing costs for that portion of this program.

Third, the cost of meters purchased is reflecting a change in the type of meter the Company is buying. The current Metris meter with a regulator built in is only available from one supplier, therefore when this vendor has supply problems, the Company experiences shortages in meters. In January and February of 2019, the Company did not receive the expected meter deliveries. At that time of year, the Company was able to sustain the missed deliveries with minimal impact but were this to happen during the busier construction season it could delay new customer connections being put in to service. The Company is switching to a non-regulated meter which is more widely available and is used by most other utilities. There is an increased cost for these meters of approximately $35 per 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 is planning

to replace two pieces of equipment used to test meters for leaks and six meter-accuracy test stations. Each of these eight units is estimated to cost approximately $62,000 once completely installed.

4. Material Condition

Q. Please describe the capital expenditures relating to the Material Condition Program set forth on Exhibit A-12 (JRP-3), Schedule B-5.6, line 4.

A. Material Condition Program expenditures are used to improve the natural gas distribution system integrity, reduce service interruptions and impact to 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. In this rate case, these EIRP and VSR expenditures are being represented by Company witness Martin. The expenditures in this program also include capital replacements due to leaks and system damages, represented by the Material Condition Renewals Program, as well as emergent gas service and main replacement projects driven by conditions observed in the field, represented by the Material Condition Non-Modeled Program, and commercial and industrial meter replacement projects, represented by the Material Condition Commercial/Industrial Meters Program. The projects and expenditures for these three programs are described in more detail below. As shown on Exhibit A-12 (JRP-3), Schedule B-5.6, line 4, the capital expenditures for these three programs were $50,873,000 in 2018, and are projected to be $49,877,000; $48,223,000; and $76,624,000 for the years 2019; the nine months ending September 30,

2020; and the test year 12 months ending September 30, 2021, 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 the table below and further detailed on Exhibit A-116 (JRP-7).

Table 9: Material Condition Capital Expenditures

	(a)	(b)	(c)	(d)	(e)	(f)
($000)		Material Condition Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line No.	Program Description	12 Mos Ended 12/31/2018	12 Mos Ending 12/31/2019	9 Mos Ending 9/30/2020	21 Mos Ending 9/30/2020	12 mos. Ending 9/30/2021
1	Material Condition Non Modeled	38,650	26,270	20,196	46,466	45,816
2	Material Condition Renewals	12,223	23,607	27,050	50,657	29,651
3	Commercial/Industrial Meter Stands	-	-	978	978	1,157
4	**Total Material Condition Capital**	**50,873**	**49,877**	**48,223**	**98,100**	**76,624**

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/or

(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 costs for the Material Condition Non-Modeled Program are set forth on Exhibit A-116 (JRP-7), line 1, 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 move the Company toward finalizing 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 currently working 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 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. 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 2020, 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 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 at the Company's Macomb headquarters. 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, all located within the City of Mount Clemens. 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 last 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 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 St. - 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 21 miles are cast iron. The Company is planning to replace the first phase of this system in 2021, which consists of approximately 3 miles of cast iron main replacement and a total of 6 miles of the standard pressure system eliminated. 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 200 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 throughout 2019. The customers will benefit from a higher level of reliability with no water infiltration, and improved safety due to elimination of these vintage, more leak-prone facilities.

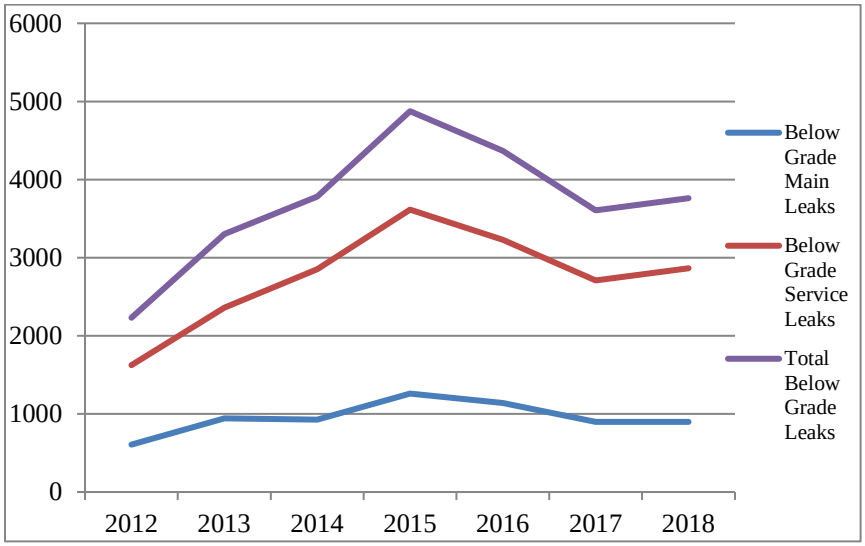
Q. Can you explain the purpose of the Material Condition Renewals Program?

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.

Q. Can you please explain the expenditures in the Material Condition Renewals Program?

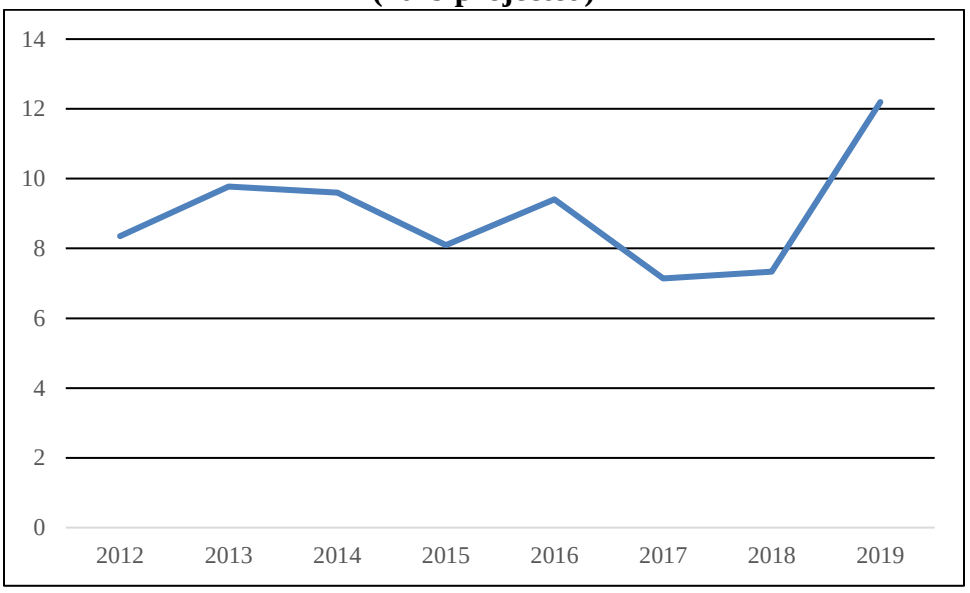
A. The Company has focused on many initiatives to reduce actionable leaks over the past few years. The graph below shows the below-grade leaks found from 2012 - 2018, as represented in Case No. U-20322. While the Company did experience a slight uptick in leaks in 2018, overall, the chart seemed to demonstrate a general downward trend for below-grade corrosion leaks from the peak year in 2015.

Figure 2: Below Grade Leaks Found 2012 - 2018



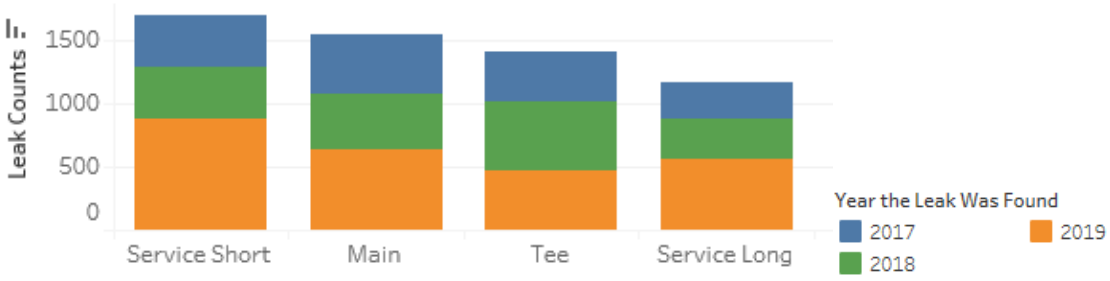
Previously, the Company noted a decreasing trend in leaks with cautious optimism, hopeful that the replacement rate for vintage facilities had overcome the deterioration rate of those facilities – but at the same time noted that it was only a short-term decreasing trend. The increase in leaks in 2018 is now being observed again in 2019, as the chart below showing corrosion leaks on gas mains indicates.

Figure 3: Gas Main Corrosion Leaks Repaired / 1000 System Miles 2012 – 2019 (2019 projected)



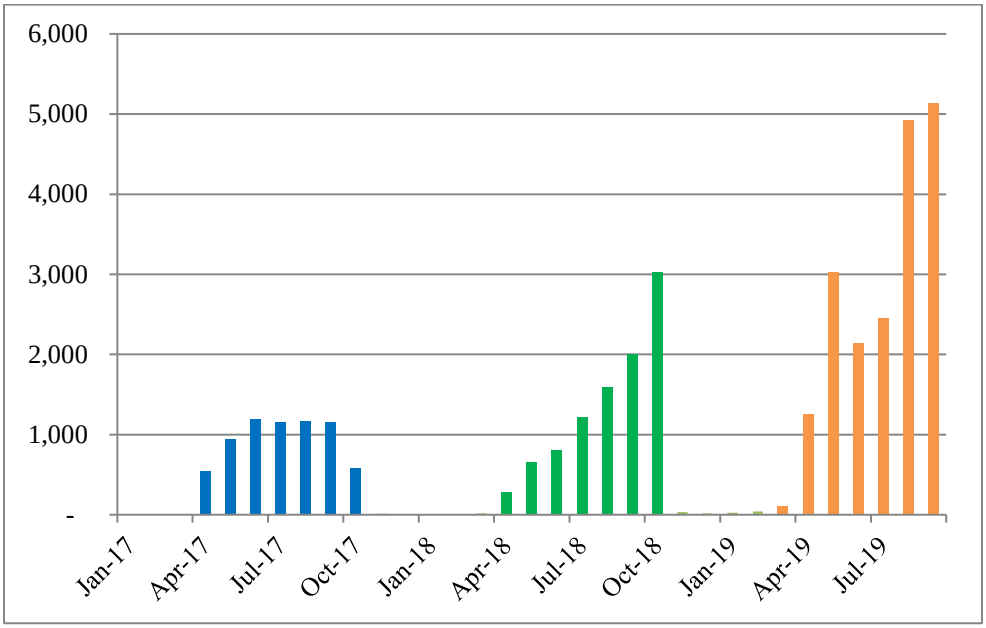
The majority of the leaks represented above for 2019 were found on leak survey. Figure 4 below shows the breakdown of below grade leaks found on survey by location. As demonstrated above, gas main leaks found in 2019 (628 found) have increased by 38% over the 2-year average of 2017 and 2018. Similarly, total (Service Long + Service Short) gas service leaks have increased by nearly 100% in 2019 (1435 found) over the average of what was found on survey in 2017 and 2018 (average of 715 found). 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 Gas Leaks Found by Survey
(As of October 2019)



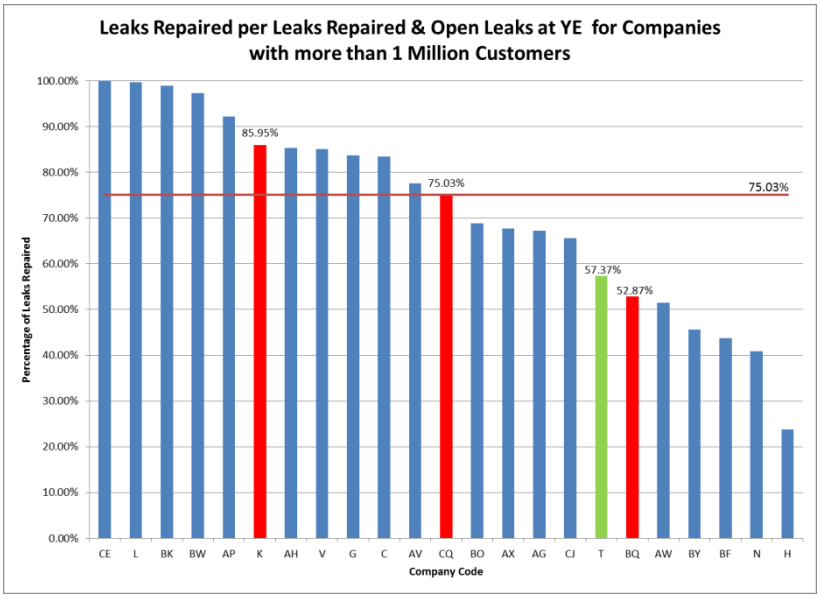
This demonstrates there is more work to be done on vintage facility replacement before a long-term, sustainable reduction in leaks is observed. The current trend for corrosion main leak information from January through July 2019 shows a linear correlation, so the year-end 2019 leak number in the chart above is a projection using that linear formula. 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 11,954 through August of 2019. The increase of leaks found drives increased required main and service replacements.

Figure 5: Total Number of Leaks Found During Leak Survey



Additionally, the graph 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



The Company is depicted in green with a ratio of 57.37%. 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 rather than repair them, which avoids the potential for future leaks on that same service. 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 that has already leaked (at least) once in the past. The historical and projected expenditures are detailed on Exhibit A-116 (JRP-7), line 2.

The additional leak replacements planned for 2020 and 2021 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. The charts below demonstrate the historical and proposed unit counts for gas main, service and meter stand replacements under the Material Condition Renewals Program.

Figure 7: Gas Main Renewal Projects

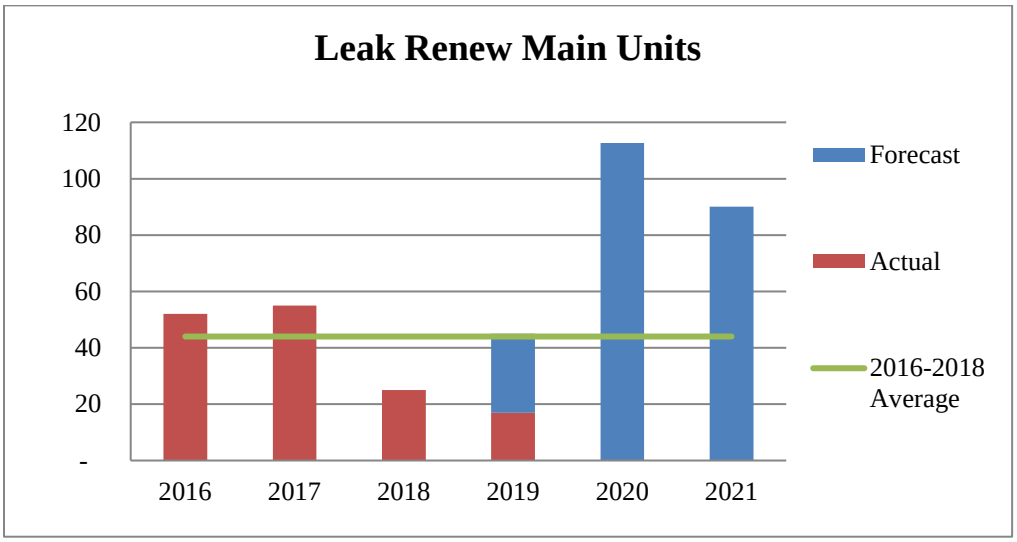


Figure 8: Gas Service Renewal Projects

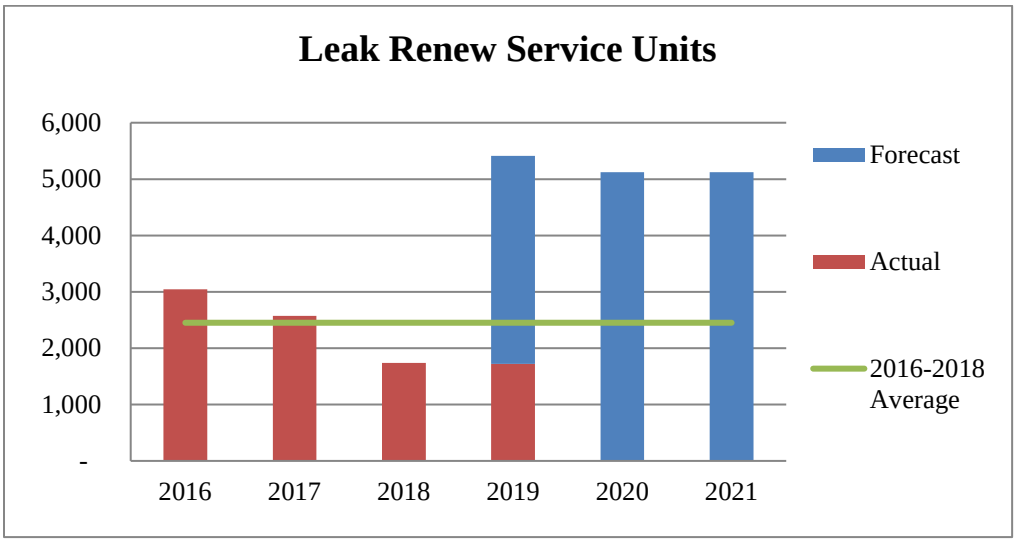
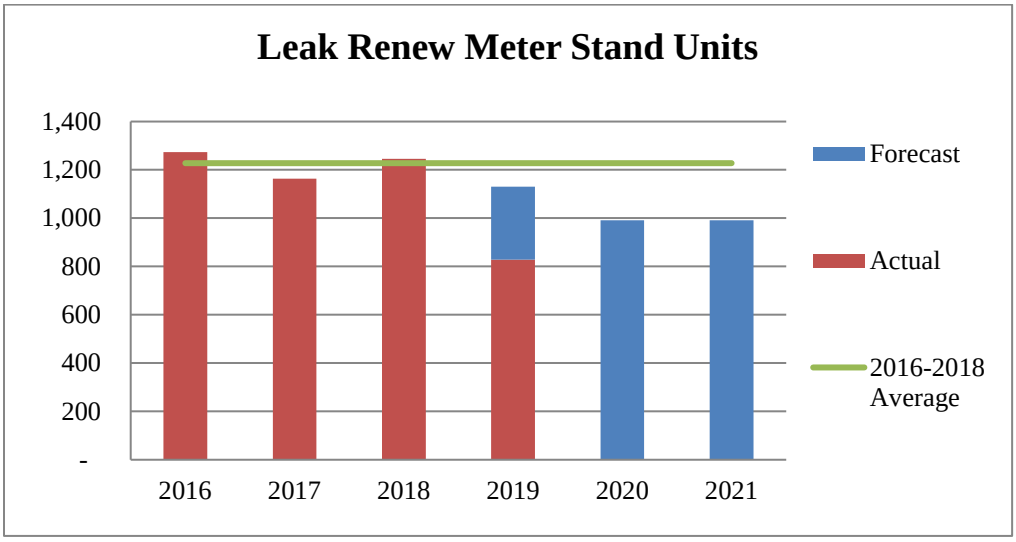


Figure 9: Gas Meter Stand Renewal Projects



Q. What is the impact of the NGDP 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 on them 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" described in Company witness Martin's testimony. 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 expenditures within the Material Condition Commercial/Industrial Meters Program.

A. In previous years, the Material Condition Non-Modeled Program has funded the replacement of several commercial and industrial meter stands due to corrosion of the stand, obsolete regulation equipment or excessive maintenance requirements. Beginning in 2020, this work type will be split out from the Material Condition Non-Modeled Program and tracked under the Material Condition Commercial / Industrial Meters Program. This new program was developed to separate the Material Condition Non-Modeled work, which is based primarily on main and service replacement work, from this work, which is driven by the condition of large customer meter stands. 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 2018, the Company completed 10 of these replacements, at a total cost of $3.437,049. There are 10 such replacements in 2019, with two of them having been completed as of October 1. The Company intends to replace eight stands in 2020 and eight additional in 2021. The planned expenditures for this program are further detailed on Exhibit A-116 (JRP-7), line 3.

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. Since joining this voluntary program in 2016, the Company has accomplished this goal by achieving a 6.2% reduction in 2017 and a 4.3% reduction in 2018. In addition to a safer, more reliable gas distribution system, these programs also contribute to a cleaner, more sustainable planet.

5. <u>Capacity/Deliverability</u>

Q. Please describe the capital expenditures relating to the Distribution Capacity and Deliverability Program as shown on Exhibit A-12 (JRP-3), Schedule B-5.6, line 5.

A. As shown on Exhibit A-12 (JRP-3), Schedule B-5.6, the capital expenditures the Company experienced in 2018, and is projecting for the years 2019, the nine months ending September 30, 2020, and the test year ending September 30, 2021, are $19,665,000; $8,151,000; $7,732,000; and $9,974,000; 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 the table below:

Table 10: Capacity/Deliverability Capital Expenditures

	(a)	(b)	(c)	(d)	(e)	(f)
($000)		Capacity/Deliverability Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line No.	Program Description	12 Mos Ended 12/31/2018	12 Mos Ending 12/31/2019	9 Mos Ending 9/30/2020	21 Mos Ending 9/30/2020	12 mos. Ending 9/30/2021
1	Augment	19,665	8,151	7,732	15,883	9,974
2	**Total Capacity/Deliverability Capital**	**19,665**	**8,151**	**7,732**	**15,883**	**9,974**

Exhibit A-117 (JRP-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 Grand Rapids, which the Company addressed by the Caledonia-Lowell augment supply project in 2017 and 2018. Capacity requirements can also 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. These substantial load requests, shifts in population and usage, and general system growth cause new low points 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 component of the actual costs from 2018 was the second phase of the Caledonia-Lowell augment. Phases I and II were completed in 2017 at a combined cost of $25,104,000. Phase III was completed in 2018 at a total cost of $17,673,786, compared to a total program spend of $19,665,000. The difference between the $17,673,786 for Phase III and the total capital expenditure of $19,665,000 is the sum of eight smaller augment supply projects to support the CAP Program and general customer growth. There are no large projects in the 2019 plan, but there has been some expenditure to complete hard and soft surface restoration from Caledonia-Lowell Phase III that was not completed in 2018 due to finishing the pipe installation late in the season. In 2019, the majority of the expenditures will be incurred for eight different smaller augment supply projects.

Like previous years, 2020 and 2021 will have a number of smaller system augmentation projects related to system growth. 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. Aside from the restoration carrying over, there are currently no major Augment Supply projects planned for 2020 or 2021. The Company will continue to review system models and pressures to ensure reliability.

6. Gas Operations Other

Q. Please describe the capital expenditures relating to the Gas Operations Other Program as shown on Exhibit A-12 (JRP-3), Schedule B-5.6, line 6.

A. The Gas Operations Other Program includes computer and related equipment, software, and tools. 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. Capital expenditures in the Gas Operations Other Program that the Company experienced in 2018; and is projecting for the year 2019; the nine months ending September 30, 2020; and the test year ending September 30, 2021, are $4,453,000; $4,070,000; $3,154,000; and $4,297,000 as set forth on Exhibit A-12 (JRP-3), Schedule B-5.6 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 the table below.

Table 11: 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 No.	Program Description	12 Mos Ended 12/31/2018	12 Mos Ending 12/31/2019	9 Mos Ending 9/30/2020	21 Mos Ending 9/30/2020	12 mos. Ending 9/30/2021
1	Routine Computer & Equipment	41	99	75	174	100
2	Tools	4,411	3,970	3,079	7,049	4,197
3	**Total Gas Operations Other Capital**	4,453	4,070	3,154	7,224	4,297

Exhibit A-118 (JRP-9) provides further details of the expenditures included in this program.

Q. Please describe Exhibit A-119 (JRP-10).

A. Exhibit A-119 (JRP-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-20322.

Q. Can you explain why columns (d), (e), and (f) of Exhibit A-119 (JRP-10) do not contain any data?

A. Yes, the information for column (d), the "Actual Spending in the Test Year," cannot be completed as the test year in Case No. U-20322, which was the 12 months ending September 30, 2020, is a time period that has yet to transpire as of the filing of this case. Since there is no data to display in column (d), the information for columns (e) and (f), which seek information concerning the variances from columns (c) and (d), cannot be completed at this time.

IT PROJECTS

Q. Is the Company planning technology projects that support the engineering, asset planning, design, construction, and maintenance of a safe, reliable, and affordable distribution system for its customers?

A. Yes. Company witness Christopher J. Varvatos 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. Varvatos. The projects for the areas which I am sponsoring are described below:

i. The Gas Compliance Code Program ("GCCP") - Service Information Mapping System ("SIMS") project requires $334,828 in capital and $1,555,500 in O&M. The GCCP – SIMS project will convert and migrate the SIMS gas service asset data into the gas Distribution Geographic Information System ("GIS") and reconfigure application and technical integrations, creating a single system of record for both gas service and distribution asset records. The project will provide value to the Company by:

a. Enabling spatial placement of gas services over an ortho-photo grid, supporting Global Positioning System tracking of leak survey routes to facilities; and

b. Creating an enhanced connectivity model by establishing a single GIS repository that represents the gas distribution main and services from the customer's meter stand to the city gate.

The project scope includes development and implementation of:

a. Data architecture that aligns to Utility Pipeline Data Model ("UPDM") standard, supporting near-future GIS platform upgrades;

b. Gas service GIS editing tools for new gas service posting requirements;

c. A custom integration from GIS to the SIMS application to transfer and synchronize service data; and

d. Gas service images for other applications that access gas service data. Also included in the scope is the purchase and implementation of updated National Agriculture Imagery Program GIS imagery. Non-technical alternatives were not considered for this project since all gas service asset records are electronic.

The team considered four implementation timing alternatives for this project:

a. Delay the entire project until future GIS platform migration;

b. Complete the project over three years;

c. Complete the project over four years; or

d. Complete the project over five years.

The alternative to delay gas service conversion was rejected given the level of complexity for the GIS platform migration, and execution of the SIMS project now can be completed in such a way to reduce future complexity by converting data to the next generation data model. The option to complete the project over five years was chosen by executive sponsors since it levelizes O&M spend over a longer duration, which allows funding allocations for other critical technology work. In addition, it allows business teams to manage project execution within existing teams, rather than augmenting staff to support daily operations and project work;

ii. The Gas Leak Asset and Work Management project requires $934,875 in capital and $83,525 in O&M. The Gas Leak Asset and Work Management project will implement functionality to automate gas leak compliance tasks and track all gas leak activity in GIS, creating a single system of record for gas leak data, and providing a spatial display of leak data to improve leak management visibility. The project provides value to both the Company and its customers, including:

a. Improving productivity and leak location accuracy;

b. Enabling near-real time reporting and automated metric reporting on open leak backlog;

c. Creating one system of record for all leak assets in GIS;

d. Implementing quality improvements for scheduling and routing of leak crews;

e. Increasing accuracy of leak placement;

f. Mitigating risk of future audit findings or non-compliance;

g. Optimizing resource allocation for gas service posting team by eliminating manual posting of leak repairs in GIS;

h. Optimizing resource allocation for the gas compliance team by eliminating the posting of leak repairs in Inspection Manager; and

i. Eliminating some custom solutions through full utilization of the asset data records in GIS.

The scope of this project encompasses:

a. Design and implementation of an integration between the asset system and the work management system to create, update, and manage leak maintenance, repair, and emergent orders and inspection schedules through the Enterprise Service Bus or similar;

b. Configuration of new SAP and Service Suite work order completion forms required to support new work processes;

c. Updating the business intelligence data-set to support reporting; and

d. Re-configuring workflows in Inspection Manager to capture all leak data from GIS.

Five alternatives were considered for the project:

a. Implement a Quality Assurance/Quality Control ("QAQC") process to ensure data is consistent between both SAP and Inspection Manager. This alternative was not selected because it requires an increase in labor costs for manual reporting and data checks. In addition, as demonstrated by the audit, manual processes, even manual QAQC processes, are subject to human error, and each error creates safety and noncompliance risk;

b. Implement a Robotic Process Automation to sync data. This solution was explored but is not viable because the processes are too complex;

c. Implement a new GIS-based compliance solution that can be integrated with SAP. This alternative is too costly, given recent investment in the current Inspection Manager solution;

d. Defer project implementation. The alternative selected is to implement this project now, rather than later, as a result of recent gas leak red audit findings; and

e. Implement functionality to automate gas leak compliance tasks and track all gas leak activity in the GIS. This alternative was selected because it leverages existing solutions in a new way, optimizing resources and technology investment; and

iii. The GIS-Integrated Design Project requires $322,779 in capital and $188,634 in O&M. The GIS-Integrated Design project replaces the Computer Aided Design ("CAD") and Work Requirements and Design software with Bentley's Open Utilities Map ("BOUM") to leverage GIS asset data to generate engineering designs, implement workflows with SAP, and mitigate risk associated with the aging software application. The project provides value to the Company in three ways:

a. The BOUM software is compatible with GIS integration and may be further developed after the Company implements the UPDM as the basis of its GIS systems;

b. The project mitigates risk of manual asset record imports, asset record manipulation for design white space management, or manual asset record

recreation for base design files, by enabling technology that creates a new design over existing electronic asset records; and

c. It enables technology that is compatible with the asset system of record and the Project Wise engineering document management system.

The project scope includes:

a. Replacing CAD engineering design software (Bentley Microstation J/v7) with BOUM;

b. Leveraging GIS asset data for the purpose of generating engineering designs;

c. Integrating workflows with SAP through Bentley Workflow Manager software;

d. Implementing GIS replication databases to isolate data editing from data viewing;

e. Replacing the desktop View Graphics custom application with a web-based application for searching and viewing asset records; and

f. Implementing a Primary Distribution Map ("PDM") generation service to generate electric PDM files for printing during storm and other emergency events.

Two alternatives were considered for the GIS-Integrated design project:

a. Replace the application with an iTron design application. After further review and complications in implementing an iTron solution, this alternative was not selected; and

b. Remain on the aging application. This alternative is not viable given the lack of vendor support, technology obsolescence, inability to maintain critical operating system patching and upgrade compatibility without additional risk and increasing maintenance expenses.

After a competitive bid process the option to replace the application with BOUM was selected as the best solution to meet the Company's requirements.

Q. Please describe how each of these projects will improve gas safety, reliability and/or the customer experience.

A. Each of these projects will provide safety and reliability benefits in the following ways:

1. The GCCP-SIMS project will enable the Company's designers and field employees to view all main and service assets on a single map, enabling a clearer view of the total gas system and allowing for more efficient decision-making. Additionally, the project will correct the locations of the

existing service tap information, which will improve project scoping and gas load and pressure analysis. Finally, having the mains and services spatially correct on the same platform can enable the Company to improve distribution risk modeling algorithms and is a pre-requisite to moving toward more advanced leak survey capabilities;

2. The Gas Leak Asset and Work Management project will enable the Company to streamline the tracking, documentation, and record retention of gas leaks. These improvements will increase visibility as to status throughout the leak management process, resulting in improved processes related to this important safety component. Increasing leak location accuracy will improve risk modeling results by providing a more spatially accurate leak location for the model input; and

3. The GIS-Integrated Design project replaces software that is no longer supported by the vendor. Replacing this software eliminates risk for the Company and its customers should the existing software experience a failure or corruption. Moving the Company's distribution and customer design teams to a platform that is supported and has a closer tie to the GIS creates stability in the software and allows for future integrations and process efficiency gains.

Q. Please summarize your direct testimony.

A. My direct testimony describes the Gas Engineering and Financial Management staffing O&M expenditures 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	)	Case No. U-20650
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

HEATHER M. PRENTICE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

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, and U-20322.

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-120 (HMP-1)	Manufactured Gas Plant Sites Information; and
Exhibit A-121 (HMP-2)	MGP Environmental Response Cash Outflows - January to December 2019 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 $12.7 million. These costs are reasonable and prudent, as discussed later in my testimony.

SECTION I – Information on MGP Sites

Q. How many MGP sites has Consumers Energy identified where it has a present or former ownership interest?

A. Consumers Energy has identified 23 sites that formerly housed MGPs at which it has a present or former ownership interest. These sites are listed on Exhibit A-120 (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-120 (HMP-1).

A. Exhibit A-120 (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; and (x) the current property use.

Q. What was the role of MGPs?

A. MGPs were formerly an integral part of gas utility service. Prior to the availability of natural gas, gas was manufactured. By the end of the 19th century, manufactured gas was widely used for lighting, heating, and cooking. As natural gas became available, it replaced manufactured gas as a base fuel. Even after natural gas became available, maintaining the ability to manufacture gas on a stand-by basis was viewed as important. At most of Consumers Energy's sites, after natural gas replaced manufactured gas, the plants retained their ability to manufacture gas for use in the event of gas shortages. In addition, the MGP storage tanks, often referred to as holders, were used to store natural gas.

SECTION II – Need for Environmental Investigation and Remediation

Q. Why is Consumers Energy undertaking environmental investigation and remediation activities at former MGP sites?

A. The levels of environmental awareness have increased significantly since the time when MGPs were operated. During MGP operations, the manufacture of gas resulted in various by-products which are now recognized as being environmentally harmful. Consumers Energy has discovered soil and/or ground/surface water contamination at all 23 of the former MGP sites during remedial investigations. Under current environmental standards, Consumers Energy will incur cleanup costs at all of the sites.

The costs of environmental investigation and remediation with respect to former MGP sites are necessary and ongoing costs of doing business which were not, and could not have been, anticipated during the time MGPs were in operation. Awareness of the environmental risk associated with these by-products did not exist during the MGP era.

The costs of investigation and remediation are prudent expenditures that are based on public policy considerations of protecting the environment and natural resources of the State to help ensure the quality of life that 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 of the former MGP sites listed on Exhibit A-120 (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 8,542 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 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 former Ionia MGP site in 2013, the site proper at Grand Ledge MGP in 2016, and the former Marshall MGP in February 2019. An NFA was submitted for the Sault Saint Marie MGP site but ultimately withdrawn due to lack of property owner signature on the necessary restrictive covenant. The Company is still working with the property owner on this issue. 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.

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 through December 2019 totals approximately $12.7 million.

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-121 (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-121 (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. Were MGP environmental response activity costs incurred prior to January 2019?

A. Yes. Costs for environmental response activities for periods prior to January 2019 were reviewed and audited by Staff in Case No. U-20322 and earlier cases; therefore, these costs have not been included on Exhibit A-121 (HMP-2) in the current case.

Q. At how many of the sites will Consumers Energy incur costs during the period January through December 2019?

A. Costs will be incurred at all 23 sites.

Q. Please identify Exhibit A-121 (HMP-2).

A. Exhibit A-121 (HMP-2) shows the cash outflows for environmental investigation and remediation during the period January through December 2019 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-121 (HMP-2) includes projected costs. Costs for January through December 2019 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 MGP environmental response expenditures from January through December 2019.

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. 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. All large projects performed during the timeframe included in this rate case were competitively bid.

Q. Did the company participate in any cost-sharing activities with current property owners?

A. Yes. The Company coordinated with the developer of the St. Johns MGP site to build in efficiencies for the work that was needed to advance the development and our remediation efforts. This coordination included cost sharing on demolition and restoration activities. Participating in these activities with the developer saved the Company both time and money in a reduction of consultant and contractor efforts.

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-121 (HMP-2) are for remedial actions. Remedial action costs were incurred at 15 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.

SECTION IV – Response Actions

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. Site investigations, remedial investigations, and interim response activities were conducted at a majority of the sites, where required. Investigations, interim responses,

and feasibility studies have been largely completed. Execution of specific remedial action scenarios are underway at 15 sites. Some remedial activities will continue for many years. The NFAs for the Ionia MGP, site proper at the Grand Ledge MGP, and Marshal MGP were approved by EGLE in 2013, 2016, and 2019, respectively. In addition, several other MGP sites are being considered for NFA.

It should be noted that a site may be going through multiple phases of environmental response activities at a time, based on the nature of the response activity and the type of activity.

Q. What are some examples of environmental response activities that have either been completed during the January through December 2019 timeframe or are currently underway?

A. Examples of projects that have been completed or are underway include the following:

- Bay City – Completion of the in-situ soil stabilization project within 9th Street, southerly adjacent to the MGP site and associated restoration;
- Kalamazoo – Evaluation of groundwater surface water interface and vapor intrusion pathways with existing site owner;
- Manistee MGP site (ongoing) – The Manistee MGP site consists of two separate sites: Jones Street and Cross Street. On the Jones Street site, river bank solidification is currently on-going. This work is a continuation of the upland in-situ soil stabilization project from 2018. At the Cross Street site, an in-situ soil stabilization project was performed to address non-aqueous phase liquid impacts from underneath the former holder. An evaluation of the groundwater is ongoing to determine if the existing groundwater treatment system can be decommissioned or run for a short period of time to assist with remaining groundwater impacts following the stabilization project;
- Marshall MGP site – Decommissioning of the passive groundwater treatment system and abandonment of the groundwater monitoring wells following approval of the NFA;
- Mt. Clemens MGP site – Demolition of the on-site building and excavation of non-aqueous phase liquid impacted materials on the property has been

completed. Groundwater monitoring well installation has been completed following the excavation project; and

- St. Johns MGP site – Select building demolition and source removal excavation project has been completed.

Additionally, investigations, routine monitoring, reporting, and pre- and post-NFA activities were also conducted.

Q. Was soil reuse considered a viable option during remedial design at the Manistee MGP?

A. Yes, soil reuse was a viable option during the construction of the in-situ soil stabilization project.

Q. Please explain how soil reuse was implemented during construction and the potential cost savings?

A. The shallower soils located above the water table had minimal impacts based on the data associated with the site. Given the proximity of the Cross Street site and space available, it was determined that the soil could be staged on the Cross Street site and sampled in accordance EGLE protocols for reuse. Based on the sampling results, approximately 13,000 cubic yards of material was reused, which resulted in cost savings due to importing less backfill and no disposal fees for the removed material.

Q. Are these cost savings included in the dollars provided in your Exhibit A-121 (HMP-2)?

A. Yes, they are.

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 through August 18, 2019, Consumers Energy obtained formal written approvals from EGLE for the following sites:

- Flint East MGP site – Certificate of Completion on Sediment Response Activity was approved by EGLE on July 19, 2019;
- Marshall MGP site – NFA Status Report was approved by EGLE on February 8, 2019; and
- Plymouth MGP site – EGLE request and concurrence on April 15, 2019 for vapor intrusion assessment on neighboring residential property.

Q. What is the progress of pursuing NFA status for MGP sites?

A. As mentioned earlier, Consumers Energy received approval of NFAs for the former Ionia MGP site in 2013, site proper of the Grand Ledge MGP in 2016, and the Marshall MGP in 2019. An NFA was submitted for Sault Saint Marie MGP site but was ultimately withdrawn due to lack of property owner signature on the necessary restrictive covenant. The Hastings MGP NFA report is currently being reviewed by EGLE.

In addition, Consumers Energy has initiated NFA discussions with EGLE on several MGP projects. These include Alpena, Zilwaukee, Charlotte, Bay City, Owosso,

and Kalamazoo MGP sites. Draft NFA reports, along with land use and resource use restrictions for Alpena, Charlotte, Zilwaukee, Royal Oak, and Bay City, have been prepared and are being discussed with stakeholders (*e.g.*, EGLE, property owners, local units of government, easement holders, etc.).

It should be noted that the NFA process is time-consuming and complex.

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 Jones Street site remediation system at the Manistee MGP has also been removed due to the in-situ soil stabilization project. 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. What is the status of the passive remediation system at the Marshall MGP site.

A. Based on approval of the NFA for Marshall, the passive groundwater treatment system was decommissioned in April 2019.

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.

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-20650

DIRECT TESTIMONY

OF

LATINA D. SABA

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

Q. Please state your name and business address.

A. My name is LaTina D. Saba, 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 the Facilities Manager of Transformation, Engineering, and Operations Support.

Q. What are your responsibilities as the Facilities Manager of Transformation, Engineering, and Operations Support?

A. I am responsible for the strategic alliance among Facilities Design, Space Management, and Operations within the Facilities Department. My responsibilities also include oversight of Facilities Management and Projects, Real Estate, and Administrative Operations.

Q. What is your formal educational experience?

A. I completed three years of a Construction Management program concurrently at Eastern Michigan University and Oakland Community College. Currently, I am completing my Bachelor of Science degree in Applied Management with a graduation date of November 2019, at Grand Canyon University. I hold and/or have held certificates in the following: a certificate issued by the Occupational Safety and Health Administration ("OSHA") for Construction Safety and Health training, a certificate issued by OSHA for Asbestos Awareness training, a certificate issued in Ontario for Basic Fall Protection training, and a certificate issued by 84 Lumber Company for its Management Basic Home Building course.

Q. Would you please describe your previous work experience?

A. In 2007, I worked as Project Engineer for Clark Construction Company based out of Lansing, Michigan. My projects included Retail, Healthcare, and Education sector projects, with special emphasis on safety, environmental protection, and profitability.

From 2009 until 2011, I worked in Canada as a Construction Office Manager for P.G. Aluminum Home Improvement in Brampton, Ontario, which specializes in residential construction aluminum building products and installation. In 2011, I took a position as the Assistant Construction Project Manager and Litigation Support for LB325 Bay Street for the Trump International Hotel & Tower, the largest skyscraper in Canada. The role required me to assist the Lead Project Manager of the 5,000-person site with responsibility for distribution of documents and materials; and for reviewing project estimates, contracts, bid packages and schedules, labor and materials cost forecasts, and monthly cost reporting. I assisted the superintendents of the project with monthly cost reports; expedited, reviewed, and approved all shop drawings and submittals; documented as-built changes; and maintained records drawings, specifications, and distribution. I was also responsible for organizing and charting cost completion and man-hour forecasts, oversight of trade subcontractors, and recording and signing time and material sheets.

I returned to the United States in 2012 and began work as the Construction Area Manager for a non-profit organization where I assisted with the Playscape playground construction project in Wayne, Michigan. My responsibilities included grant writing, managing the construction budget, and the review, analysis, and decision-making surrounding issues of financial feasibility.

From 2012 until 2014, I was the Construction Project Manager for OSH, which is an international construction company where I restored the historic Pontchartrain Hotel. Under my management, the project was awarded the coveted title of "2013 Development of the Year" by the International Hotel Group ("IHG"). In this position, I also prepared and hosted events for the 2014 International North American Auto Show in Downtown Detroit. Due to unforeseen circumstances pending the 2014 International North American Auto Show, I was required to renovate three floors of ballroom spaces in two and a half days to accommodate the event. That project required me to assist the owner with feasibility studies, and provide field advice and product selections for architects, engineers, City of Detroit, IHG officials, and compliance officials. I was also responsible for negotiating, awarding, and overseeing contracts while hiring, training, and governing more than 60 employees and 35 different contractors. I further prepared schedules and cost impact analyses for possible delays.

In 2014, I was hired as the Construction Project Manager, on a contract basis, for Audu Engineering Consultants, which is a Michigan-based civil and structural engineering consultant company. I provided construction management services as an Owner's representative, which included contract administration, contract bidding, project scheduling monitoring, and cost control and analyses as a Quality Control/Quality Assurance Professional. The owner of the project was Consumers Energy. Consumers Energy subsequently hired me as an employee in 2015 as a Senior Business Support Consultant I in the Facilities Services Department, serving Distribution Operations and Engineering and Transmission, Generation Operation, and Shared Services.

I was promoted to Facilities Manager (Director of Facilities) in 2018, and I am responsible for the oversight of 63 facilities enterprise-wide. In my position, I am tasked every day with all necessary activities for the planning and implementation of safe, efficient, and competitive maintenance and operation of the Company's facilities. On a daily basis, I am actively engaged in a wide variety of business functions and processes throughout the Company. I routinely provide leadership and support for the planning, business analysis, general management, budget preparation and analysis, negotiations, transactions, customer services, and auditing of specific operating and support areas related to the Company's facilities. My duties fluctuate between projects, departments, and offices and I am directly involved in providing business analysis and support for plans, reports, impacts, contracts, schedules, estimates, data collection, observations, and field investigations related to those projects, departments, and offices within the Company.

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

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

Case No. U-20134	2018 Consumers Energy Electric Rate Case; and
Case No. U-20322	2018 Consumers Energy Gas Rate Case.

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

A. My direct testimony will support Gas Operations Support. 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 Operation and Maintenance ("O&M") expenses for Facilities, Real Estate, and Administrative Operations for the historical test year ended December 31, 2018, the bridge period beginning January 1, 2019, and ending September 30, 2020, and the projected test year ending September 30, 2021; and

- Support the reasonableness and prudence of the capital expenditures for Asset Preservation for the historical test year ended December 31, 2018, the bridge period beginning January 1, 2019, and ending September 30, 2020, and the projected test year ending September 30, 2021.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-12 (LDS-1)	Schedule B-5.8	Summary of Actual & Projected Gas and Common Capital Expenditures;
Exhibit A-122 (LDS-2)		Summary of Actual and Projected Operations Support O&M Expenses;
Exhibit A-123 (LDS-3)		Programs and Projects – Projected Gas and Common Capital Expenditures;
Exhibit A-124 (LDS-4)		Facility Assessment – Lansing Service Center
Exhibit A-125 (LDS-5)		Facility Assessment – Kalamazoo Service Center
Exhibit A-126 (LDS-6)		Facility Assessment – 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 (LDS-1), Schedule B-5.8, details the actual and projected capital expenditures related to Gas Operations Support. Exhibit A-122 (LDS-2) details the O&M costs related to Gas Operations Support. Exhibit A-123 (LDS-3) identifies Gas Operations Support projects and programs and the projected capital expenditures related

to those projects and programs. Exhibit A-124 (LDS-4) is the Facility Assessment of the Lansing Service Center utilized to evaluate the need for capital expenditures. Exhibit A-125 (LDS-5) is the Facility Assessment of the Kalamazoo Service Center utilized to evaluate the need for capital expenditures. Exhibit A-126 (LDS-6) is the Facility Assessment of the Hastings Service Center utilized to evaluate the need for capital expenditures.

Q. Please explain the Gas Operations Support function.

A. The 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 to serve our customers efficiently and effectively.

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

A. No. Fleet Services will be addressed in the testimony of Company witness Kyle P. Jones.

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 our co-workers to serve our customers across the state in the most 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 our 63 buildings, the majority were built or acquired during this period and remain in operation today; as a result, these building are now well over 50 years old.

Multiple major systems throughout these facilities, such as boilers, chillers, cranes, elevators, emergency generators, heating, ventilation, and air conditioning ("HVAC") systems, lighting, power distribution, paving, roofing, Uninterruptible Power Systems ("UPS"), and vehicle hoists are beyond their useful lives and building materials in the facilities contain hazards such as asbestos and lead paint. Repairs on such aging infrastructures are not cost effective and can lead to lengthy projects and significant renovation or replacement of the entire structure. It is increasingly difficult to identify adequate parts and obtain expertise to work on the aging equipment. Additionally, these aging structures no longer adequately accommodate the way work gets done to allow for collaboration and efficiency in the space. The needs of our workforce have changed significantly since the 1950s and 1960s (i.e. there is a greater need for open office environments, collaborative work group spaces, computers in the workplace, internet, and wireless communication networks, etc.). In addition, the population and infrastructure of the state of Michigan look much different than they did in the 1950s and 1960s. The location of some of our facilities no longer allow us to optimize our service to our customers. Longer response times and increased drive times makes service delivery standards difficult for our co-workers who are dedicated to providing the best service to our customers.

Q. What process does Consumers Energy utilize to evaluate whether or not 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 Facilities department has experts in HVAC, plumbing, electrical, etc., 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. 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 a 75-point maximum score). Categories that are evaluated include safety (asbestos or other hazardous materials, traffic flow, compatibility with surrounding areas, etc.), quality (workplace efficiency, employee comfort, employee attraction and retention, etc.), cost (facility operating costs, space optimization, energy efficiency, etc.), and delivery (response times, driving distance within service territory, sustainability of operations, etc.). The facility evaluated will fall within one of three quality designation categories depending on the score received. A score of above 60 is designated as "Good"; a score of 30 to 60 is designated as "Serviceable," meaning that investment is needed; and a score under 30 is designated as "Poor," meaning that there are multiple systems failing at the facility. 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, 60 out of 75 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 (60 to 75 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

Standish Service Center has approximately 1,360 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 projects are included in the projected capital expenditures for Facilities?

A. There are approximately 23 separate projects which contribute to the projected Facilities capital expenditures for the 21-month projected bridge period ending September 30, 2020 and 12-month projected test year ending September 30, 2021. These projects are identified on Exhibit A-123 (LDS-3).

Q. Please describe the capital expenditures set forth on Exhibit A-12 (LDS-1), Schedule B-5.8.

A. As demonstrated on Exhibit A-12 (LDS-1), Schedule B-5.8, capital spending is divided into two programs: Asset Preservation, and Computer and Other Equipment. Asset Preservation is then broken down into multiple cost categories including contractor, labor, materials, and contingency. The majority of capital spending, as reflected on Exhibit A-12 (LDS-1), Schedule B-5.8, 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, 2021.

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 in order 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 capital expenditures include capital expenditures such as those made to parking lots, roofs, and elevators at various building and plant sites. See Exhibit A-123 (LDS-3), lines 7 through 10.

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. The request for these capital expenditures represents only a portion of the funds required to fully upgrade and/or maintain the needs across the state.

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-123 (LDS-3)?

A. Yes. The proposed Asset Preservation projects are identified in Exhibit A-123 (LDS-3), lines 7 through 23.

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, and construction of a Gas Technical Training and Storage facility ("Gas City").

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 allow our 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 multi-year project, the Company is purchasing land in a new location and beginning constructing on 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 operation including a contact center.

Q. Why has the Company chosen to build a new Lansing Service Center?

A. As demonstrated on Exhibit A-124 (LDS-4), a Facilities assessment of the existing Lansing Service Center produced a score of 28. 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-124 (LDS-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. 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 that include 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 Part 201 of State of Michigan Act 451 of 1994. This site has historical

environmental contamination issues resulting from operation of the MGP, including significant underground impacted soil materials (coal tar residual, etc.). 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 I previously discussed, Company facilities are assessed and scored based on multiple criteria (safety, quality, cost, delivery, etc.) 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 will 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 provide both improved customer response times and employee efficiency.

Q. What benefits will this new Lansing Service Center offer?

A. The new Lansing Service Center will benefit customers by lowering operational costs, providing better response times to gas customers, 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 multi-year project, the Company is beginning construction on a new facility on the existing property. Upon completion of the new facility, the Company will retire, demolish, and remediate environmental concerns of 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-125 (LDS-5), a Facilities assessment of the existing Kalamazoo Service Center produced a score of 45. 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 our Gas Operations partners. As discussed above, because this score falls below a score of 60, 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 for a number of reasons relating 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 support the need for a newly constructed rather than renovated facility. Because the Kalamazoo Service Center is optimally located for responding timely to the Company's customers, however, the new Kalamazoo Service Center will be constructed on the existing site.

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 work space efficiencies are achieved.

Q. Please describe the Hastings Service Center project?

A. Like the Kalamazoo Service Center, in this project, the Company is beginning construction on a new facility on the existing property.

Q. Why has the Company chosen to construct a new Hastings Service Center facility?

A. As demonstrated on Exhibit A-126 (LDS-6), a Facilities assessment of the existing Hastings Service Center produced a score of 34. As discussed above, and like the Kalamazoo Service Center, because this score falls below a score of 60, 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. Can you quantify the expected reduction in annual O&M expense associated with the construction of the new service centers?

A. Yes. I would expect that annual operating expenses would be reduced by 5% once the new facilities are in operation, which will include energy consummation 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. Please describe the Gas City project.

A. This project involves the construction of a new training facility on our existing Flint campus which will allow our gas operations workforce to learn and reinforce on-the-job

skills as they respond to our gas customers throughout the state. This training site will minimize travel for our gas employees since the majority of gas classroom training is held in Flint. This close proximity to hands-on training following classroom training is an ideal learning environment. This training site will have multiple simulated buildings situated in a manner as to represent a gas neighborhood with a facility administration building to allow for simulated training exercises. This type of hands-on facility training center has become an industry standard. Consumers Energy is one of only a few remaining gas utilities that does not have such a training center for gas employees. As a new technical training center, there is no existing Facility assessment score for this building. Business case support and further information regarding Gas City is provided by Company witness Craig C. Degenfelder.

Q. What other projects are included in the projected bridge year ending September 30, 2020 and projected test year ending September 30, 2021?

A. As demonstrated on Exhibit A-123 (LDS-3), additional projects include projects such as the ongoing Parnall Road Complex renovation, statewide roofing, and Energy Resources Asset Preservation.

Q. What was the Company's capital expenditure amount in the historical test year ended December 31, 2018?

A. As depicted in Exhibit A-12 (LDS-1), Schedule B-5.8, line 9, capital expenditures for the historical test year ended December 31, 2018 totaled $14.249 million. This amount is for the projects completed in 2018 and include the new construction of the Overisel Office building at the Gas Compression site, renovation of Parnall 1-1, and the new addition of the Marion Crew room.

Q. Please describe the capital expenditures related to Computer and Other Equipment for Gas Operations Support as shown on Exhibit A-12 (LDS-1), Schedule B-5.8.

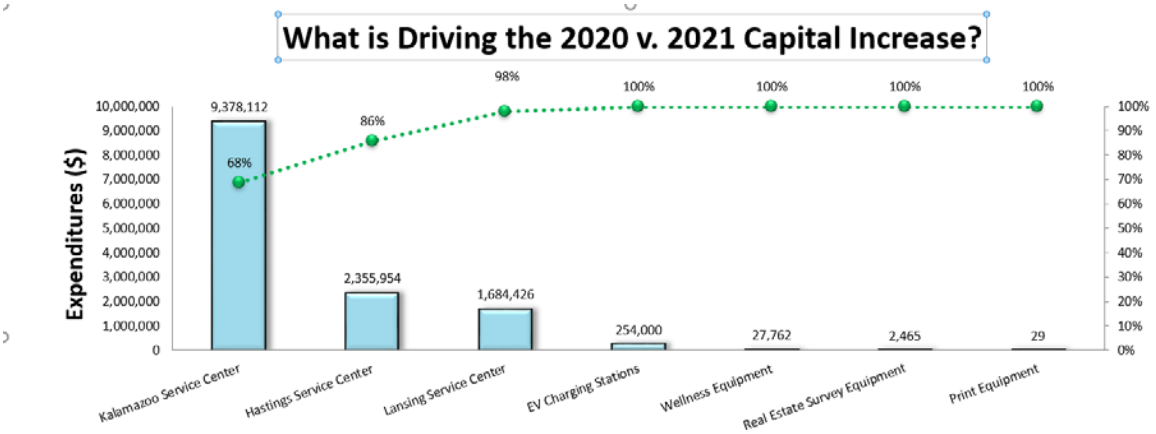
A. Computer and Other Equipment includes the purchase of miscellaneous printers, mechanical equipment, print equipment, and wellness equipment. These expenditures are itemized in Exhibit A-123 (LDS-3), lines 1 through 6.

Q. What is the Company projecting for project capital spending related to Gas Operations Support?

A. As depicted in Exhibit A-12 (LDS-1), Schedule B-5.8, line 18, capital expenditures are projected to be $16,815,000 for 12 months ending September 30, 2020, and $24,830,000 for 12 months ending September 30, 2021, for a two-year total of $41,645,000.

Q. What has been the primary contributor to the increase in capital spending from 2018 and 2019?

A. The new Kalamazoo Service Center project is the chief driver to the capital increase for the 2020 and 2021 calendar years. Please see below chart:



Q. Does Gas Operations Support also have projected O&M expenses?

A. Yes, As shown in Exhibit A-122 (LDS-2), Gas Operations Support operations include O&M for all Company gas-related facilities work, real estate services, and administrative operations.

Q. What O&M expenses are included in "facilities work"?

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 services"?

A. Real estate services includes a variety of real estate asset management functions to ensure system integrity and safeguard the public. This includes management of all land related uses of easements and rights of way, including encroachments, third-party requests for use of our 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 ("GIS") mapping system for property ownership and rights of way.

Q. What O&M expenses are included in "administrative operations"?

A. Administration Operations assists with administration support services for Consumers Energy's Security Command Center, Information Technology, 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. Please explain the calculated O&M expense for Gas Operations Support displayed on Exhibit A-122 (LDS-2), line 4.

A. The O&M expense reflected in the projected test year ending September 30, 2021, totals $11,900,000 and is shown on Exhibit A-122 (LDS-2), line 4, column (e). The projected test year O&M expense was derived by using three months of the 2020 outlook and nine months of the 2021 outlook from the Company's planning format based on historical cost data modified in effort to improve efficiencies and achieve continuous improvement in work processes.

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-20650

DIRECT TESTIMONY

OF

ERIC T. SALSBURY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

Q. Please state your name, employer, and business address.

A. My name is Eric T. Salsbury. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company"), and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. What is your position with Consumers Energy?

A. My position is Senior Business Support Consultant II.

Q. Would you briefly describe your background?

A. In 1995, I graduated from Michigan State University with a Bachelor of Arts degree with a major in Accounting. In 2010, I joined Consumers Energy as a Business Support Consultant II in FERC/NERC Regulatory. In 2013, I transferred to the Gas Supply Department as a Senior Business Support Consultant I. In 2016, I assumed the position of Senior Business Support Consultant II.

Q. What are your responsibilities as Senior Business Support Consultant II?

A. I am responsible for the nomination (scheduling) of all natural gas purchased for Gas Cost Recovery ("GCR") customers as well as the administration of GCR supplier payments, including review and confirmation of the transportation pipeline and natural gas supplier invoices. In addition I provide support for the purchase of reliable and reasonably priced GCR natural gas supplies and the release of our pipeline transportation capacity when needed, and assist in the preparation of various analyses related to GCR supply procurement.

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

A. No.

Q. What is the purpose of your direct testimony?

A. My direct testimony provides gas pricing information used to establish the 13-month average volume and cost of gas stored underground. I will provide an average cost of gas sold as well.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibit:

Exhibit A-127 (ETS-1) Storage Fields Month End Summary.

Q. Was this exhibit prepared by you or under your supervision?

A. Yes.

GAS STORED UNDERGROUND

Q. Please describe Exhibit A-127 (ETS-1).

A. Exhibit A-127 (ETS-1) is a listing of the Company's September 2018 through September 2021 underground gas storage volumes and dollars.

Q. Would you briefly explain the background for Exhibit A-127 (ETS-1)?

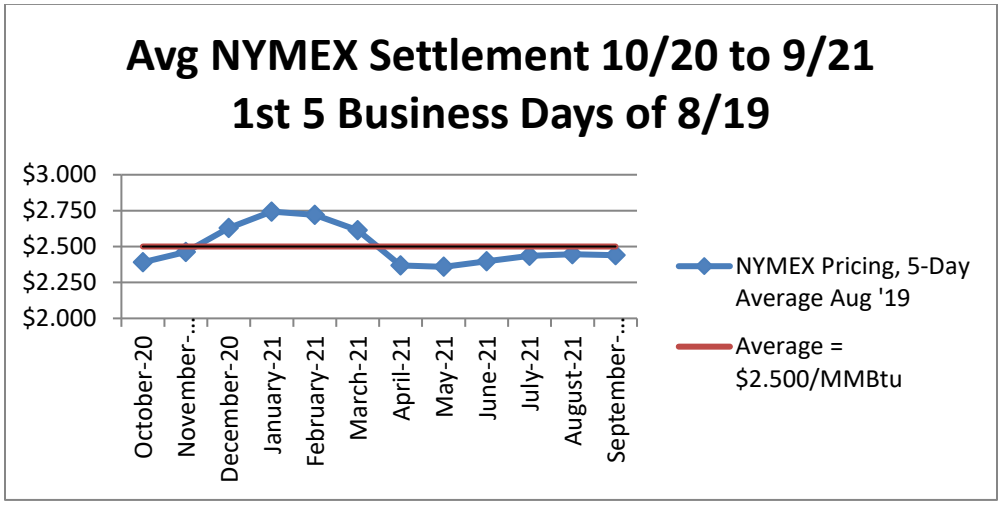
A. Yes. Exhibit A-127 (ETS-1) reflects the end of the month underground gas storage volumes and dollars that result from the Company's natural gas purchases for its GCR and Gas Customer Choice ("GCC") customers. The costs and volumes reflect the Company's existing supply and transportation contracts 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-127 (ETS-1)?

A. Through September 2021, the Company is projecting a 13-month average cost of gas in storage of $2.513/Mcf ($321,711,131/127,993,556 Mcf).

Q. What gas prices were assumed for October 2020 through September 2021 in developing your Exhibit A-127 (ETS-1)?

A. The average New York Mercantile Exchange ("NYMEX") settlement prices for October 2020 through September 2021, as of the first five business days of August 2019, were used. These NYMEX natural gas prices, as shown in the graph below, averaged $2.500/MMBtu for October 2020 through September 2021.



For the October 2020 through September 2021 GCR requirements (193,167,293 Mcf), 1% has been purchased at a fixed price, therefore 99% of the GCR requirements would be subject to the NYMEX average.

COST OF GAS SOLD

Q. What is the Company's projected average cost of gas sold for October 2020 through September 2021?

A. The Company is projecting an average cost of gas sold for October 2020 through September 2021 of $2.635/Mcf ($600,746,002/227,981,184 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 summarize your direct testimony.

A. My testimony supports the projected test year cost of gas stored underground and average cost of gas sold. Both costs 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 Jason R. Coker's Exhibit A-12 (JRC-45), Schedule B-4. The average cost of gas sold of $2.635/Mcf is used in the calculation of the Company's revenue requirement and also used to price out Company

Use and lost and unaccounted for gas volumes supported by Company witness Timothy K. Joyce in Exhibits A-71 (TKJ-2), A-72 (TKJ-3), and A-73 (TKJ-4).

Q. Does that 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-20650
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

R. MICHAEL STUART

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

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 of 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, and U-18332.

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. Yes. I am sponsoring:

Exhibit A-128 (RMS-1) EICP Performance Measures.

Q. Was this exhibit prepared by you or under your supervision?

A. Yes.

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-128 (RMS-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, and fulfill our 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 our 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 79% from 2006 through 2018. The resulting reduction in lost work days and medical expenses approximates $4.4 million of annual direct savings and $7.4 million of annual total savings that accrue to the benefit of the customer. The second metric that can be translated to cost avoidance for our customers is in the area of distribution reliability. Using cost per outage minute estimates from Berkeley Labs[1], the 5.7 minute annual average reduction in outage minutes from 2006 to 2018 results in annual economic benefits to our customers in excess of $17 million.

[1] https://www.osti.gov/servlets/purl/963320

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 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 Customer On-Time Delivery goals emphasize completing customer-requested work according to the customers' timeline (typically a shorter, quicker lead time) and within a narrower span of time. In order to deliver on those goals, first-time quality in customer interactions, design, scheduling, and field work is required, resulting in enhanced productivity and reduced costs. Additionally, meeting customer timeline commitments within a narrower, often shorter, window minimizes the impact on our customers' schedules, enhances economic development (which can lead to better customer rates by spreading fixed costs), and produces customer satisfaction and value. Third, the electric Generation Customer Value goal focuses on optimizing the use of the Company's electric generation fleet to maximize customer value.

Next are two goals that are generally associated with gas operations: (i) Eliminate Vintage Services; and (ii) Gas Flow Deliverability. Both deliver customer benefits by improving safety for combination (electric and gas) and gas only customers and reducing the Company risk profile, which yields more favorable Company credit ratings and financing terms (ultimately reducing customer rates). Last, but certainly not least, are the benefits resulting from our Company focus on our 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,[2] 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, and in 2017 many utilities, including Consumers Energy, were targeted by nation state attackers attempting to gain access to electric grid infrastructure. Additionally, potential costs for a cyber-attack against the Company are significant. According to the Lansing State Journal, the 2016 Lansing Board of Water and Light ransomware attack was initiated via a phishing email and cost them $2.4 million in operating costs.[3] The Company estimates through our enterprise risk mapping process that a sizeable data breach from phishing would likely result in costs in the range of $10 million after insurance coverage.

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 deliberate focus on productivity and customer value EICP metrics against the 2006 performance baseline, the Company's O&M costs have remained practically flat on average, 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 $242 million, which benefits customers.

[2] https://cofense.com/enterprise-phishing-susceptibility-report/
[3] https://www.lansingstatejournal.com/story/news/local/2016/11/25/bwl-prepared-ransomware-attack/94332454/

Q. Why have you included both electric and 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 gas operations. The quantified benefits 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 the 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 $85 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 particular 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 distribution of natural gas and for other relief.	)))))	Case No. U-20650

DIRECT TESTIMONY

OF

MICHAEL A. TORREY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

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; and
U-20322	Gas 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]

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

A. No, I am not.

[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. How is your direct testimony organized?

A. My direct testimony is organized as follows:

I. CUSTOMER VALUE

II. KEY DRIVERS

III. CUSTOMER IMPACTS

IV. ADJUSTMENT MECHANISMS AND ACCOUNTING REQUESTS

V. SUMMARY

I. CUSTOMER VALUE

Q. Why has the Company initiated this proceeding?

A. The Company has initiated this proceeding in order 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.

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 power businesses and warm homes. It also means acting as a solid 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 serve. 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 133 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 timely and efficiently. 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, 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 both the price they pay, and the service received when assessing value. The focus is to keep bills affordable, and 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 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, and other sources such as on-time delivery and call center metrics, to ensure the Company's proposals provide value for customers. This includes investments in technology, metering, customer service, reliability, safety, and communications; and

4. **Corporate Citizenship –** Customers expect the Company to do business in a socially responsible manner. This means taking actions to care 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 the Company, Michigan, and the world better than the Company found them. 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 loss 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 a number of methods for listening to customers. Informal methods include feedback from customer service representatives and business customer account managers who interact with customers on a daily basis. 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 Steven Q. McLean 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, Company witness McLean discusses the Company's investments that will help it better understand customers' needs, assess the impact of their behavior on their bills, and recommend personalized programs for better outcomes. 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. How does the Company measure customer satisfaction?

A. As described further in the testimony of Company witness McLean, Consumers Energy primarily relies on the CXi score developed by Forrester, in addition to J.D. Power evaluations and the Company's own internal customer satisfaction research. J.D Power analyzes the many aspects of customer experiences in a variety of industries to identify the multiple drivers of customer experience and to measure and understand the impact of these drivers. The CXi score is a widely-used customer experience survey framework that measures customer perception of an interaction. The framework consists of three questions: (i) How well did the Company meet your needs?; (ii) Was it easy?; and (iii) Was it enjoyable?. CXi data offers a more complete assessment of the quality of the Company's customer interactions than JD Power and is available in near real time, enabling a daily performance "pulse" and the quick identification and resolution of issues.

Q. How does the Company approach the analysis of all this data?

A. The Company uses J.D. Power customer feedback and CXi scores as guides for improvement, while also comparing Consumers Energy's performance to the three companies in the region who performed best on J.D. Power's overall customer satisfaction index. Using the CXi score, the Company can make near real-time improvements according to customers' feedback.

Q. After the Company has identified customer experience improvement opportunities, what does the Company do with this information?

A. Employee teams are charged with developing and implementing measures designed to improve performance and meet customer expectations. Such measures include: (i) implementing communication strategies; (ii) instituting policy changes; (iii) altering

processes to improve service; and (iv) enhancing technology to provide new programs and services.

Q. Has the Company been recognized for its approach to the customer experience?

A. Yes. The 2019 J.D. Power Gas Utility Residential Customer Satisfaction Study[2] ranked Consumers Energy the highest in customer satisfaction among large natural gas providers in the Midwest.[3] There are 17 utilities included in that category. This recognition validates the efforts the Company continually makes to improve its customers' experience, and shows how its commitment to maintaining a robust, talented workforce, offering innovative products and services and working proactively and effectively in the field has resulted in true value for customers. It indicates that Consumers Energy has accurately identified the aspects of natural gas service that its customers appreciate most and should inspire confidence in the Company's ability to continue delivering on its promise of hometown service and world-class performance.

II. KEY DRIVERS

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

A. The Company is requesting rate relief in the amount of $245 million which includes:

- Infrastructure Investment – $124 million
- Cost of Capital – $26 million
- Operating Expenses – $91 million
- Sales/Revenue – $2 million.
- Manufactured Gas Plant/Working Capital – $2 million

The $245 million in rate relief requested in this filing is driven by the need to serve Consumers Energy's customers and reflects the Company's continued investment in

[2] https://www.jdpower.com/business/press-releases/2019-gas-utility-residential-customer-satisfaction-study
[3] https://finance.yahoo.com/news/consumers-energy-ranks-1-customer-100000099.html

Michigan. Consumers Energy is committed to customer value and system safety and reliability. Through these commitments, the Company continues to make significant investments in the infrastructure necessary to mitigate the risks to our system by replacing damaged or aged infrastructure for improved safety and reliability. Furthermore, the Company's risk-based approach also allows for compliance with federal and state requirements. Over 50% of the requested rate relief is made up of investment-related costs. Fully funding the activities outlined in this request will enable Consumers Energy to execute the first year of this rolling ten-year Natural Gas Delivery Plan ("NGDP" or "Plan"), Exhibit A-36 (CCD-1), to deliver reasonable and prudent investments in support of safe, reliable, affordable, and clean service.

In order to provide an overview of the Company's long-term distribution and operation investment needs for the supply and delivery of natural gas, as discussed in Case No. U-20322, the Company is presenting its Plan. As discussed by Company witness Craig C. Degenfelder, the Plan calls for accelerating the replacement of high-risk pipeline, implementing better probabilistic risk management, optimizing the Company's system to improve compression reliability and to ensure a resilient supply of natural gas, promoting stable and predictable bill growth with demand response options, and reducing the Company's environmental impact.

Q. Have the Ray Natural Gas Compressor Station incident and Statewide Energy Assessment ("SEA") impacted this rate case?

A. Yes. The incident at the Company's Ray Natural Gas Compressor Station during extreme cold weather in January 2019 prompted Governor Gretchen Whitmer to direct the Commission to review the state's energy supply and preparedness for emergency

situations. The Commission issued its SEA on September 11, 2019 in Case No. U-20464. The SEA identified a variety of needs that the Plan will help address.

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 that serve its roughly 1.8 million natural gas customers. The Company operates 15 storage fields and seven 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. As discussed by Company witness Degenfelder, the gas industry continues to undergo more dynamic change, and it is prudent to develop a holistic long-term plan for its gas business. This will guide the Company through a decade of targeted, risk-based, and proactive investment in its natural gas assets, gas supply and demand planning, and pipeline safety activities. The Plan's formation has been guided by the Company's commitment to providing natural gas safely, reliably, affordably, and in as clean a manner as possible.

Q. In addition to the projects discussed above, what steps is Consumers Energy currently taking to prioritize natural gas delivery system safety?

A. The Company has an ongoing practice of reviewing its own internal procedures, standards, and systems, particularly considering significant gas industry safety events, including an over-pressurization incident that occurred in Massachusetts in 2018. Lessons learned from these types of incidents are used to identify previously-unknown threats and incorporate mitigation procedures into the Company's integrity management programs and decision-making. A cross-functional group of engineering, operations, and compliance

personnel routinely review industry reports, recommendations, and emerging best practices to help ensure continual improvement in the Company's ability to operate safely and reliably. Newly identified threats and mitigations are included into the Company's integrity management programs and lessons learned are incorporated into procedures, processes, and gas system enhancement decision-making.

In its September 26, 2019 Order in MPSC Case No. U-20322, the Commission stated that it expected Consumers Energy to develop and implement a Pipeline Safety Management System. Similarly, the National Transportation Safety Board and Pipeline and Hazardous Materials Safety Administration ("PHMSA") have encouraged natural gas operators to implement the American Petroleum Institutes' Recommended Practice 1173. Accordingly, as discussed by Company witness Degenfelder, Consumers Energy will implement a Pipeline Safety Management System to systematically manage pipeline safety, and continuously measure progress to improve overall pipeline safety performance and ensure public safety. The Company's Gas Safety Management System is expected to be fully implemented throughout the Company by 2022.

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

A. Consumers Energy has initiated this case in large part to secure spending approval for the first year in the Company's Plan. Significant natural gas investments included in this case are the Enhanced Infrastructure Replacement Program ("EIRP"), the Vintage Service Replacement ("VSR") Program, New Business Program, Compression and Transmission Replacement Programs, Pipeline Integrity Program, Asset Relocation Program, 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. The Company's investments are grouped into four main categories: (i) system reliability; (ii) compliance; (iii) demand management; and (iv) enhanced technology.

System Reliability

The ongoing EIRP Program 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 general public.

As of December 31, 2018, through the EIRP Program, over 401.8 miles of high-risk pipe has been replaced, including 157.3 miles of cast iron and over 45,793 services. As discussed by Company witness Jared J. Martin, through the well-planned, thoughtful execution of the EIRP Program, the Company can better manage high-risk distribution investments in a more cost-effective manner, as opposed to scenarios under emergent conditions. As discussed in its Plan, Consumers Energy is assessing the acceleration of this 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, and what resources and work management constraints will be required to make this possible.

Accelerated replacement is supported through both the EIRP Program and the VSR Program. Launched in 2017, the VSR Program works to replace outdated services materials not replaced under the EIRP Distribution, Material Condition Non-Modeled, and Asset 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, as well as service to a new Lansing Board of Water and Light natural gas power plant in the Lansing area. In total, the Company expects to install service to approximately 9,165 customers in 2019; 9,074 in 2020; and 9,247 for the full year 2021.

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 Degenfelder, Martin, Chad L. Alley, Jeffrey R. Parker, and Timothy K. Joyce.

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 PHMSA. 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. 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, update the risk ranking methodology to a probabilistic model, and increase the rate of remediation for Company assets. 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 have to 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 and Parker.

Demand Management

As discussed in the Plan, as part of its filing, the Company is proposing two gas demand response pilots – a residential pilot and a commercial and industrial pilot. The proposed gas demand response pilots will incentivize residential and commercial and industrial customers to reduce their gas consumption during times of peak system demand or abnormal system conditions. These pilots could add 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 resilience.

Additionally, the Company is proposing to update its gas curtailment tariffs. The Company utilized the curtailment tariff process for the first time during an emergency in January 2019. This emergency situation provided the Company with actual experience of, and unique perspectives in, implementing the tariff process for curtailment of gas service.

The details pertaining to these proposals are supported in the testimony of Company witnesses McLean and Karen J. Miles.

Enhanced Technology

Continually improving on customer service and internal operations will require significant Information Technology ("IT") upgrades as addressed in the testimony of Company witness Christopher J. Varvatos. The IT investments address projects that are specific to customer facing applications for an improved customer experience, support business operations, provide for physical and cyber security programs to further protect customer information and Company assets, and provide operational support for gas leak response and service design and installation. It is critically important that O&M funding

for existing IT infrastructure be aligned with the requirements of each IT project to ensure delivery of expected outcomes and avoid the unintended consequences that result from O&M shortfalls.

Additionally, the Company's ability to successfully deliver the outcomes envisioned in the Plan depends on several essential IT projects. Deploying the most effective risk-based approach to gas delivery relies on high-resolution system visibility that can only be achieved with better data gathering and analysis programs. Leveraging insights from these program upgrades will enable us to achieve the best possible pipeline integrity and predictive maintenance for compression assets. Related investments include replacing the Gas Supervisory Control and Data Acquisition Software, which reduces the risk of non-compliance by improving the ability to document and follow state and federal requirements and improving the Company's gas control management capabilities and migrating to a Standard Enterprise Gas Historian System that will create an accurate, easily-accessible data hub that can provide information real-time.

The Company has included additional information to justify these projects in the testimony of Company witnesses Degenfelder and Varvatos.

Q. What other key drivers make up the approximately $245 million in rate relief request?

A. The Company is requesting a return on equity of 10.5%. As Company witness Srikanth Maddipati explains in his direct testimony, this recommendation represents the middle of a reasonable 10-11% return on equity range, with the 52.5% equity ratio recommended by Company witness Marc R. Bleckman. These figures result from Consumers Energy's analysis of the economy and capital markets and the need 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.

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 2017 gas A&G costs, excluding pension and benefits, the sixth 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 optimize 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 reduce the total operational cost, as discussed by Company witness Varvatos.

Consumers Energy has also identified a "grid approach" method – explained in greater detail by Company witnesses Degenfelder and Martin – to vintage main pipe replacement that will offer many benefits to its cost per mile performance. Piloting this approach is expected to result in significantly larger project sizes, producing better economies of scale that will 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.

The Company also continues to undertake measures that reduce rework and process improvement initiates that improve efficiency across several operating areas. Consumers Energy has seen an average annual cost avoidance of more than $2 million since 2013, the first year that the Company measured first-time quality. As discussed by Company witness R. Michael Stuart, the Company's focus on employee safety has reduced incidents by 79% since 2006. The resulting reduction in lost work days and medical expenses is approximately $3.5 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. Further evidence of the Company's commitment to make the infrastructure investments necessary to improve service, results in the improvements in the customer service metrics noted throughout the testimony filed in this case.

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

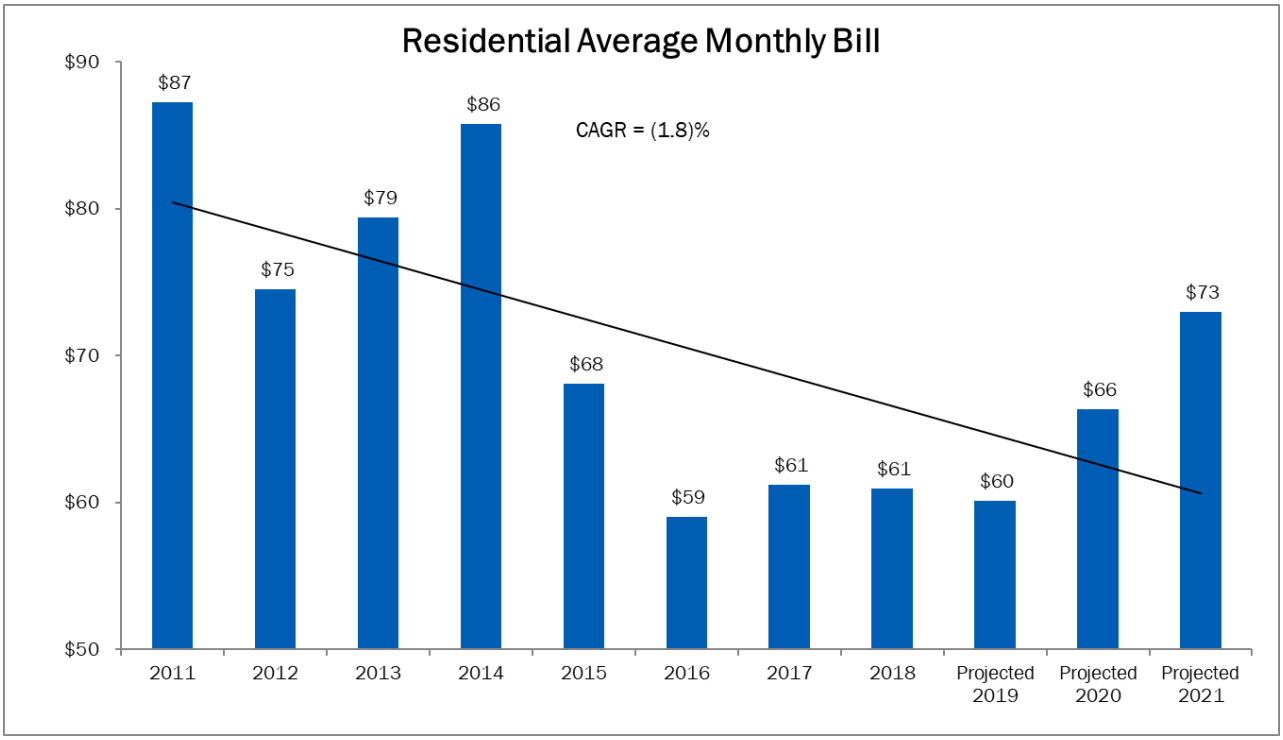
circumstance, the Company would need to compensate for this unforeseen spending by adjusting the amount it intended to spend on another program. It is not possible for Consumers Energy to anticipate every event or circumstance which may cause it to incur costs on behalf of its customers, so it is prudent 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 2021 will increase by 18.4% over current rate levels. Even with this increase, however, the compounded decrease of the monthly bill is expected to be about 1.8% compared to 2011. The ongoing downward trend in the monthly bill is shown in Figure 1 below, which illustrates the average weather-normalized bill from 2011 to 2018 and forecasts the periods 2019-2021. Consumers Energy expects that the average residential gas customer will pay approximately $2.40 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 to customers who may continue to be more impacted. Examples of this assistance include the Consumers Affordable Resource for Energy Program, the Residential Income Assistance Provision, and the Low-Income Assistance Credit. These programs are designed to assist customers with the management of their energy use and bills. In addition to these provisions and programs, the Company and its employees are generous contributors to community-based groups, including the United Way, the Salvation Army, the Heat and Warmth Fund, and many 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.

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, and which was approved, in Case No. U-20322. More details on this proposed mechanism are given by Company witness Alex M. Gast.

Q. Does the Company anticipate the need to defer the revenue requirement of any capital spending?

A. Yes, Consumers Energy is requesting approval to defer the revenue requirement of any capital spending for new business and asset relocation above what is included in rates should the Commission not approve the full amount of capital spending requested for new business and asset relocation. As described in the direct testimony of Company witness Parker, the demand for the Company's asset relocation services and new business connections has exceeded its projections in recent years. Because road right-of-way owners, such as municipalities and counties, can compel Consumers Energy to relocate gas facilities to accommodate the owner's projects, the associated Company expenditures vary from year to year based on external factors such as project size. Similarly, new business expenditures are driven by external demand from customers seeking new gas service to their home or business, requiring installation of new Company facilities. Each year, the Company attempts to anticipate these costs using historical data, but they are fundamentally unforeseeable. For this reason, the Company requests that the Commission

allow it to defer the accounting for this capital spending in the manner described by Company witnesses Gaston and Jason R. Coker.

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

A. Yes. Consumers Energy is proposing changes to its cost-of-service study ("COSS") methodologies. Company witness Emily A. Davis indicates that Consumers Energy is sponsoring two COSSs for this case: one using the methodology adopted by the Commission in the Company's last gas general rate case, Case No. U-20322, and a second that combines the information provided in the first study with the results of the Company's proposed minimum size study. A minimum size study separates distribution main costs into demand and customer components, comparing the cost to build a utility's distribution system using the smallest, most inexpensive pipe against the actual system configuration and cost. This information indicates proper cost allocation among customer classes. Considering the Commission's concerns in the Company's previous gas rate case, Consumers Energy is providing additional support and analysis as part of its proposal.

V. SUMMARY

Q. Please summarize your direct testimony in this case.

A. A key theme throughout this case is the Company's commitment to continual improvement. But this commitment contemplates more than finding better ways to execute the same projects and processes; rather, the approvals sought in this case reflect what has become a new standard for performance at Consumers Energy. The Company has broadened its focus from executing each next job with excellence, to examining the entire gas delivery space to see how a holistic view and a long-term comprehensive plan can

deliver more customer value and safety than ever before. This rate application is based on a Plan that provides the opportunity to achieve significantly enhanced performance across the business, driving the Company into a safer, more reliable and affordable, and cleaner future.

Q. Does this complete your direct testimony?

A. Yes.

Appendix 1: Company Witnesses and Testimony Topics

MICHAEL A. TORREY
DIRECT TESTIMONY

Alley, Chad – *Transmission* Projects

Bleckman, Marc – *Capital Structure and Debt Costs*

Christopher, Lora – Employee *Benefits*

Coker, Jason – *Revenue Requirement*

Conrad, Amy – *Incentive Compensation*

Davis, Emily – *Cost of Service*

Degenfelder, Craig – *Natural Gas Delivery Plan, Major Projects & Policy*

Delacy, Lisa – *Automated Meter Reading (Historic & Bridge)*

Gast, Alex – *Rate Design*

Gaston, Karen – *Corporate Departments*

Jones, Kyle – *Fleet*

Joyce, Timothy – *Compression & Storage Projects*

Keaton, Eric – *Sales Forecast*

Maddipati, Srikanth – *Return on Equity*

Martin, Jared – *Enhanced Infrastructure Replacement Program, Vintage Service Replacement and Gas O&M*

McLean, Steven – *Customer Experience & Demand Response*

Miles, Karen – *Tariffs*

Parker, Jeffrey – *Distribution Capital Projects*

Prentice, Heather – *Manufactured Gas Plant Remediation Program*

Saba, LaTina – *Facilities*

Salsbury, Eric – *Cost of Gas*

Stuart, R Michael – *Employee Incentive Compensation Program*

Torrey, Michael – Overall *Policy*

VanBlarcum, Brian – *Tax*

Varvatos, Christopher – *Information Technology*

Wolven, Paul – *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-20650
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

BRIAN J. VANBLARCUM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

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 Senior 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 Senior 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 Senior 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; and
- Gas Rate Case No. U-20322.

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, 2021) 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 ("TCJA") and the Commission's September 26, 2019 Order in the Company's Calculation C Case No. U-20309.

Q. Have you prepared any exhibits to accompany your direct testimony?

A. Yes. I am sponsoring:

Exhibit A-129 (BJV-1)	Development of the Property Tax Rate for the Test Year; and
Exhibit A-130 (BJV-2)	Amortization of Excess Deferred Federal Income Taxes for the Test Year.

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

A. Yes.

Development of the Property Tax Rate for the Test Year

Q. What is the Property Tax Rate for the test year?

A. As indicated on Exhibit A-129 (BJV-1), page 1, line 16, the Property Tax Rate for the test year is 0.013716306.

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-129 (BJV-1), page 1, line 10 divided by the total of the 2020 estimated year-end plant-in-service (Exhibit A-129 (BJV-1), page 1, line 11 plus one-half of the estimated 2020 Construction Work in Progress (Exhibit A-129 (BJV-1)), page 1, line 14.

Q. What is included in the Gas Property Taxes Paid – 2020 Estimate on Exhibit A-129 (BJV-1), page 1, line 1?

A. The Consumers Energy 2020 taxes paid of $130.9 million on behalf of the gas portion of the business represents estimated property taxes to be paid in 2020.

Q. What is included in the Gas Property Taxes on 2020 Plant Investment on Exhibit A-129 (BJV-1), page 1, line 2?

A. The $20.9 million increase is the estimated property taxes on the 2020 net additions that will be included in the 2021 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 49.1226 to obtain the estimated tax amount. This calculation is shown on Exhibit A-129 (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-129 (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 2021, our property tax model assumes a CPI rate of 2.2%. This calculation is shown on Exhibit A-129 (BJV-1), page 3.

Q. What is the result of including the Gas Property Taxes on 2020 Plant Investment and the Gas Property Taxes on Real Property Taxable Value Increase on the estimated 2021 property tax amount paid by the gas business?

A. The result of including these additional items is an estimated 2021 property tax amount to be paid for the gas business of $151.9 million as shown on Exhibit A-129 (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 2020 estimated gas property tax payments for Consumers Energy is added to the 2021 estimated gas payments since that amount will be expensed in 2021, while subtracting 49.7% of the 2021 estimated gas payments that will be expensed in 2022, arriving at a total 2021 property tax expense of $141.5 million as shown on Exhibit A-129 (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, 2020 through September 30, 2021 using a monthly budgeted sales percentage applied to the 2020 and 2021 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 $135.0 million. The Prorated Property Tax Expense for the test year is divided by the 2020 estimated year-end plant-in-service plus one-half of 2020 Estimated Construction Work in Progress to arrive at an average tax rate of 0.013716306.

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-130 (BJV-2), page 2, referenced as Exhibit A-6 in Case No. U-20309, provides the projected annual amortization of these balances based on the periods approved by the Commission.

Q. Based on the Commission's September 26, 2019 Order in Case No. U-20309, what amount of excess deferred federal income tax has the Company proposed to return to customers in this case?

A. Exhibit A-130 (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 $10.072 million to reflect the amortization periods discussed above. This amount is shown on Company witness Coker's Exhibit A-130, Schedule C-8, Lines 50 and 51 as 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. 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-20650

DIRECT TESTIMONY

OF

CHRISTOPHER J. VARVATOS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

Q. Please state your name and business address.

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

Q. How long have you worked in the Information Technology ("IT") field, both inside and outside of Consumers Energy ("Consumers Energy" or the "Company"), and what positions have you held?

A. I have worked in the IT field for over 34 years. Prior to joining Consumers Energy, I worked for Accenture (then Andersen Consulting), a leading business and technology consulting firm, for seven years as a staff consultant, senior consultant, and Manager, focused on large project delivery. I have been with Consumers Energy for over 27 years, having worked all of that time in the IT Department. Since joining Consumers Energy, I have held a number of increasingly responsible positions including team leader, large project manager, manager of application development, and director. I am currently the Executive Director of IT and Operational Technology ("OT") focused on technology supporting the Transformation, Engineering & Operations Support area of the Company. In this capacity, I have IT departmental responsibility for the delivery and operation of IT applications and OT for the Gas, Electric, and Generation Engineering; Enterprise Project Management & Environmental Services; and Operations Support departments covering Supply Chain, Fleet, Facilities, and Corporate Safety. As a member of the IT Leadership Team reporting to the Vice President of IT and Chief Digital Officer, I also have a shared role in leading the overall IT Department.

Q. Would you please state your educational background?

A. I earned a Bachelor of Science Degree in Industrial and Systems Engineering from the University of Michigan – Dearborn in May of 1985.

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

A. Yes, I filed rebuttal testimony in Case No. U-16855. I also testified in Case Nos. U-17087, U-17197, U-17643, U-17735, U-17882, U-17990, U-18124, U-18322, U-18424 and U-20322.

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

A. The purpose of my direct testimony is to identify and support the Company's IT and Security Capital and Operation and Maintenance ("O&M") expenditures required to provide excellent customer experiences and enable execution of the Company's Natural Gas Delivery Plan, filed by Company witness Craig C. Degenfelder. I will also demonstrate why final orders limiting the O&M allowed for IT expenditures for the Company's more recent rate case filings do not provide the Company sufficient O&M to adequately support its technology and security requirements.

The technology landscape at Consumers Energy has grown and changed significantly over the last five years and is changing faster with each new year. The pace of technology changes has increased, cyber security threats have intensified, and the Company's dependence on technology to operate a safe, reliable, affordable, and clean gas system with high levels of customer satisfaction has increased. The need for new digital capabilities to enable and make possible the Natural Gas Delivery Plan; things like updated Supervisory Control And Data Acquisition ("SCADA") and historian systems

that capture the real-time gas system data, probabilistic risk models, work management technology supporting all work groups, and gas demand response systems make the Company's technology investments prudent and in the best interests of its customers, who want safe, reliable, and affordable gas. All these drivers increase the operating expense needed to maintain and operate secure and reliable technology systems. This maintenance is so important that the Company has been spending more O&M dollars to operate its systems than the prior five-year average of operational O&M, but this is not sustainable.

In this case, the Company is asking for recovery of costs incurred to maintain safe, reliable technology assets, just like it maintains safe, reliable gas assets. The Company is also asking for financial support for the new technical capabilities needed to realize the ambitions of the Natural Gas Delivery Plan. Without these new digital capabilities, the Company will not be able to achieve the key strategic outcomes of the plan, which include optimizing the its Compression and Storage assets, modernizing the Distribution and Transmission system, incorporating predictive and condition-based maintenance, transforming work management, and ensuring physical and cyber security of the Company's assets.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

Exhibit A-131 (CJV-1)	Summary of Actual and Projected Information Technology Operations O&M Expense for the Year 2018, 2019, 2020 and Test Year 12 Months Ending September 30, 2021;

Exhibit A-132 (CJV-2)		Summary of Actual and Projected Information Technology Investments O&M Expense for the Year 2018, 2019, 2020 and Test Year 12 Months Ending September 30, 2021
Exhibit A-12 (CJV-3)	Schedule B-5.11	Summary of Actual and Projected Gas and Common Capital Expenditures; and
Exhibit A-133 (CJV-4)		Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures - For the years 2018, 2019, 2020 through 12 Months Ending September 30, 2021.

Q. Were these exhibits prepared by you or under your direction and 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 Natural Gas Delivery Plan. The Company has adopted a digital strategy to guide its approach for technology investments and operations. Digital is connecting people, "smart" things, and information (data) to create better products, services, and ways of working. The Company's evolving and pragmatic digital strategy will support the following:

- Faster and more adaptable delivery with new practices (e.g. adopting Agile frameworks);
- "Democratization" of digital skills and expectations;
- A move to cloud solutions where and when appropriate;

- Data as an asset & deployment of analytics on a larger scale;
- Deployment of a consistent Asset Management system/framework;
- Deployment of integrated control systems for system automation;
- Continuous operational improvements via automation; and
- A commitment to ensure digital investments do not introduce unnecessary risk and to protect sensitive data and critical infrastructure from cyber and physical threats.

Q. Please describe the functions that the IT and Security departments perform.

A. The IT Department provides secure digital solutions and services including the identification, delivery, operational support, and maintenance of both on-premise and cloud software solutions and computing and communications infrastructure. IT also provides the day-to-day operational support for each individual user of technology, whether that technology is a desktop, laptop, or mobile device, which includes ruggedized field devices, tablet computers, cell phones, smart phones, or other handheld devices.

The Security Department ("Security"), which is included in IT testimony and exhibits, ensures that Company systems, data, employees, and customers are protected from various cyber and physical threats facing the Company. Security also ensures regulatory compliance with a multitude of state and federal regulations, and manages security risk, awareness, and data privacy. There are strong interdependencies between the functions performed by the IT and Security teams. IT is responsible in many cases for implementing security best practices deemed necessary by Security.

Q. Please describe the Company's computing infrastructure.

A. Consumers Energy's computing infrastructure consists of hardware and communications networks which are utilized by virtually all aspects of the Company's operations. Hardware includes servers and data storage devices, workstations, printers, collaboration technologies, and mobile devices. Communications networks for telephone and radio systems enable voice, data, and wireless communications across the Company. The Company also employs a private cloud to automate the deployment of virtualized computing infrastructure on top of the previously mentioned hardware and networks, increasing the speed and quality of infrastructure deployment.

Q. How do the Company's customers benefit from the technology and services provided by the IT Department?

A. The Company's customers benefit from the technology provided by IT both directly and indirectly, as highlighted by a few scenarios that take place in the normal course of a day. To illustrate, a customer of the Company receives a text notification of her new bill, generated by SAP and supporting systems using meter reads collected through Automated Meter Reading technology. She accesses the Company's website to view her historical usage, checks out the Company's energy efficiency programs and enrolls in the automatic bill payment plan. The same customer is also benefitting from work performed by a Gas engineer, who is analyzing online risk and system planning models and reviewing asset records in the Company's Geographic Information System ("GIS") to develop system enhancements projects that will improve the safety and reliability of the gas system. Additionally, gas engineers are utilizing the technology tools in our pipeline integrity programs to analyze, schedule, and comply with the regulations. The engineer

creates electronically designed projects to maintain a safe, affordable, reliable, and clean gas system for the customer.

A different customer has a need for some gas service work in his home. He calls and navigates the Interactive Voice Response system through voice commands to confirm his payment information before talking to a contact center representative. The representative uses SAP to enter the customer's request. Schedulers and dispatchers use SAP and ServiceSuite to schedule the customer's appointment and dispatch a crew to complete the work. The field crew, who is verified by automated operator qualification checks, receives the work order on their field devices, checks out the electronic maps, directions and other instructions and updates the work order in real time. The crew leader identifies some additional work to be performed on site and enters the order in her device for later scheduling. Her dispatcher voices some safety updates to the crew leader over the 800 MHz radio system. In the future, the dispatcher will use the advanced fleet telematics application for visibility of crew and work locations, to further optimize crew and work dispatching.

As the customers continue their daily activities, gas controllers continually monitor the gas system using SCADA. They keep their skills current by using the Gas Transmission Simulator to train in various control and monitoring scenarios. In the future, the controllers will take advantage of Natural Gas Delivery Plan digital investments, including an updated Gas SCADA system integrated with GIS for gas system visibility and transparency, and deployment of Remote Control Valves integrated with SCADA to eventually have the ability to control and perform remote shut-off to preserve safety and reliability of the gas system.

Gas engineers will utilize advanced analytics investments, including data collection, standardization, and analytical model frameworks to implement probabilistic risk models for transmission and distribution. The engineers will apply advanced statistical and predictive modeling tools and techniques for deriving insights from gas system data. Such projects will enable customer level load profiling, and predictive models with propensity ranking for future gas demand response programs.

Also during this normal day, gas is procured and controlled, customers are billed; payments are processed; materials are procured and warehoused; vendors are paid; employees are onboarded, paid and trained; financial plans are managed; financial statements are generated; plants, facilities and fleet vehicles are managed; and data is analyzed, all using technology orchestrated, maintained and secured by the Company's IT and Security teams.

On a 24x7 basis, the Information Security and IT teams keep the Company's gas and electric systems safe, protecting customer and employee data, detecting, and defending against cyber-attacks, and ensuring hardware and software solutions are kept current so they can be secured against modern, consistently evolving, and more advanced cyber threats.

IT continuously monitors system processing and health around the clock using automated tools that learn the behavior of the systems and detect and correct anomalies before customers and employees are impacted. IT teams use cloud-based service management and project management systems to manage the work they perform to complete system upgrades, replace aging technology assets, maintain access to cloud/Internet providers, address service requests from technology users across the

Company, fix technical problems and keep the growing base of technology assets upon which the Company and its customers are dependent high-performing and available when needed.

OPERATIONS O&M EXPENSES – MAINTAIN AND OPERATE EXISTING ASSETS

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

A. Operations O&M expense is used by the Company to provide the required level of operational support, reliability and security for technology investments deemed prudent in prior and current rate cases. Operations activities include system monitoring, break/fix activity, maintenance activity, hardware and software vendor support and services, cloud subscriptions/contracts, technology and application upgrades, security improvements and other activities required to keep the Company's digital and information assets protected and performing at optimal levels to obtain the committed value for the Company and its customers. The Company's customers have benefitted from the system stability and reliability that have resulted from the activities supported by IT Operations O&M expense. If the Company does not have sufficient funding to adequately support, maintain and secure its existing technology assets, its customers and employees will experience interruptions in systems they rely on to contact and transact with the Company, view account information, receive gas services, maintain and operate the gas system, and make investments in the gas system that ensure safety and reliability.

Nearly half of the Company's IT and Security operations costs are committed in contracts with vendors who provide software and hardware support and maintenance services so that our systems remain safe from cyber intrusions, mechanical failures, and

software failures. Lapses in support coverage caused by financial constraints expose the Company to unfavorable security and operational risks and issues.

Q. Please describe Exhibit A-131 (CJV-1).

A. Exhibit A-131 (CJV-1) is a Summary of Actual and Projected IT Operations O&M Expenses for the Years 2018, 2019, 2020, 12 months ending September 30, 2021, and the Year 2021. It provides a summary of the gas allocation of actual and projected IT Department operational expenditures. Specifically:

- Column (a) provides the operations O&M expense category;
- Column (b) identifies the 2018 historical operations O&M expense as $28,044,000;
- Column (c) identifies the 2019 projected operations O&M expense as $31,024,000;
- Column (d) identifies the 2020 projected operations O&M expense as $32,971,000;
- Column (g) identifies the 12 months ending September 30, 2021 projected operations O&M expense as $33,374,000; and
- "Labor" line items include employee labor. "Contracts" line items include hardware and software licenses/maintenance, staff augmentation, the Company's Managed Services contract, and other contracted services.

Q. Please describe the projected operations O&M expense for the IT Department in 2019.

A. The projected operations O&M expense in 2019 of $31,024,000 is 10.6% higher than the 2018 actual operations O&M expense. As I will explain in more detail in this testimony, this is due mainly to the expenses needed in Operations to operate, maintain, and keep secure the capital investments made in 2018. Year-to-date, through September, the IT Department has incurred over 75% of the 2019 projected O&M expenses, which is in line

with meeting IT's spend targets at year end. Each new technology investment comes with the need for on-going support and maintenance, to ensure the new systems are supported, reliable, and protected from cyber intrusions. As the Company has invested in new technologies, the associated support cost has been added to IT's on-going cost model.

Q. Please explain some of the key drivers for the projected increase in Operations expense for 2019.

A. The increase in IT Operations O&M expense from 2018 to 2019 is, in part, a result of the continued investments in programs that both sustain and improve the experience customers have in interacting with the Company, and maintain, improve, and secure critical enterprise systems to protect customer and employee data and prevent obsolescence and risk to business operations. Key drivers for the increase include: (i) cyber-attack prevention and application security services ($570,000); (ii) collaboration tools ($400,000); (iii) customer interaction tools ($335,000); and (iv) data center operations tools ($500,000).

Q. Please describe the projected IT Department Operations O&M expense for 2020.

A. The operations O&M expense in 2020 of $32,971,000 is projected to be 6.3% higher than 2019. The reason for the increase in 2020 operations O&M is the result of the continued investments in programs that both sustain and improve the experience customers have in interacting with the Company, and maintain, improve, and secure critical enterprise systems that support operating the Company's natural gas system, to prevent obsolescence and risk to business operations. Key drivers for the increase include: (i) cloud solutions for IT service management, customer analytics, disaster recovery

("DR") and business continuity ($1,440,000); (ii) project management, desktop automation, collaboration tools and application development tools and runtimes ($740,000); and (iii) security application support ($177,000).

Q. 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. This includes software to collect logs, look for vulnerabilities, detect intrusions, and provide antivirus and encryption services. Second, systems must be patched on a regular basis, typically monthly. Vendors regularly release security updates, which must be tested and deployed to technology assets. Third, as security best practices change, IT teams must make changes to existing systems to meet new requirements. This could include changing the way an application is setup and/or the process of managing security.

Q. How has the work required to meet cyber security requirements increased in the last five years?

A. The threat landscape, and therefore cyber security requirements, have changed significantly over the past five years. Examples include ransomware and grid attacks. Five years ago, ransomware was a little known attack, typically impacting individuals only. Today it is of the greatest risks an organization faces with real examples impacting Michigan. Similarly, concern over attacks to utility infrastructure has become top of mind across the utility industry. Security best practices have had to evolve, and this has

put pressure on the IT organization to keep pace with the time and expense of retrofitting existing infrastructure and applications.

In 2019, the Company increased its cyber security focus and resources in protecting assets at key gas locations. The five areas of cyber security in particular include: (1) secure network connectivity to the Industrial Control Systems enterprise network; (2) security visibility through log collection, antivirus and endpoint monitoring tools; (3) cyber maintenance including patching, inventory and change management, (4) Identity and Access Management including account and password management; and (5) infrastructure administration such as hardware, operating system and network support.

Q. Do cyber security requirements increase the frequency for keeping IT assets current?

A. Yes. Security patching has become a key control for any security program. Patches are released by vendors regularly. Most organizations patch at least monthly. In 2018, Consumers Energy had two instances of highly critical patches in which we instituted the Company's Incident Command Structure ("ICS") in order to patch within ten days. In 2019, the Company has already had four such ICS events on a growing asset base. The need for security patches also increases the need to keep applications current. Vendors establish an end-of-life process for applications 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. For OT hardware, the number of devices requiring patching has increased by nearly ten times between 2014 and 2019.

The Company has tracked closely its performance in applying security patches and invested heavily in improving its protection of its IT assets. From January 2017 to September 2019, the Company reduced its average number of missing patches per workstation by 87%. From January 2016 to September 2019, the Company reduced its number of missing patches per server by 90%. This demonstrates the Company's increased focus and time spent on maintaining the currency and security of its technology and data.

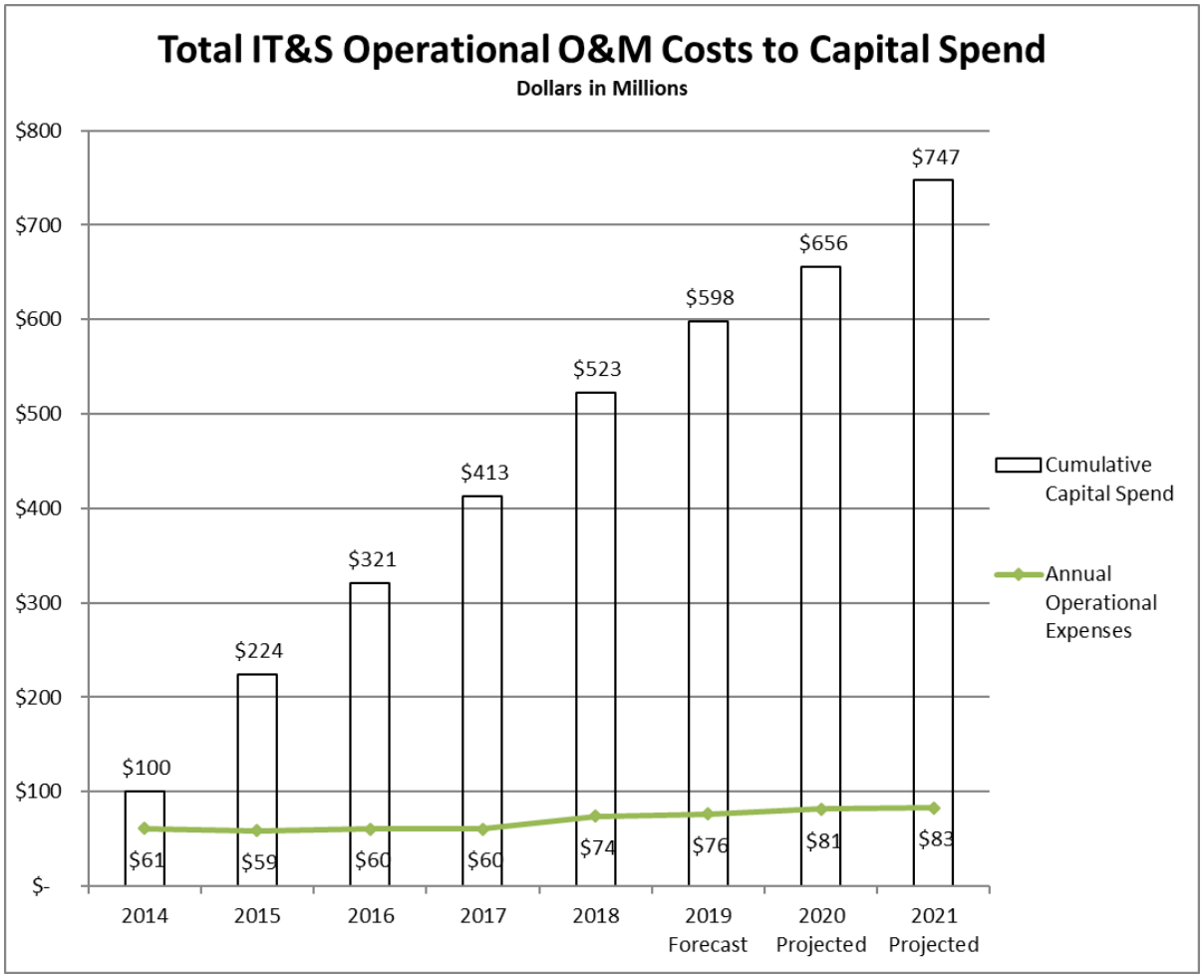
Q. What is another example of operational work for cyber security beyond patching?

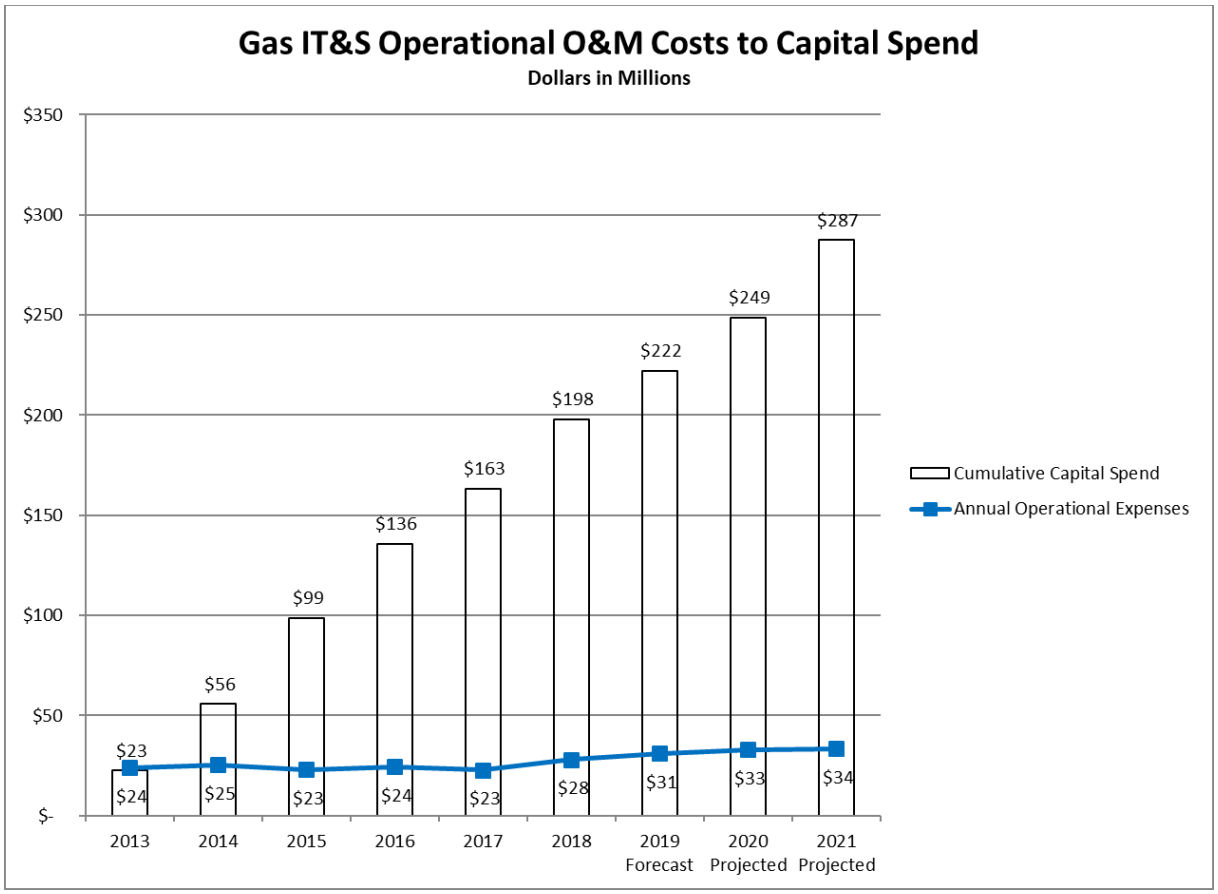
A. As security best practices or regulatory requirements shift, legacy applications and/or their underlying infrastructure often need to be changed in order to meet new standards. For instance, in response to ongoing ransomware attacks across all industries, the Company has been properly securing all operating system and application accounts with elevated privileges. The account management practices for these accounts were perfectly acceptable at deployment, but changing requirements dictate the need for updated practices.

Q. What is the trend for the Company's IT operational O&M expenses?

A. Both the growing work requirements for cyber security described above and the growing base of IT assets in the Company have been contributing to higher operational O&M expense and a sustained upward trend. The graphs below show the IT and Security Operational O&M Costs relative to the cumulative capital spend on IT assets (Total Company and Gas). The graphs demonstrate the upward trend in the operational O&M required to keep new and existing capital investments secure and reliable, and maintain

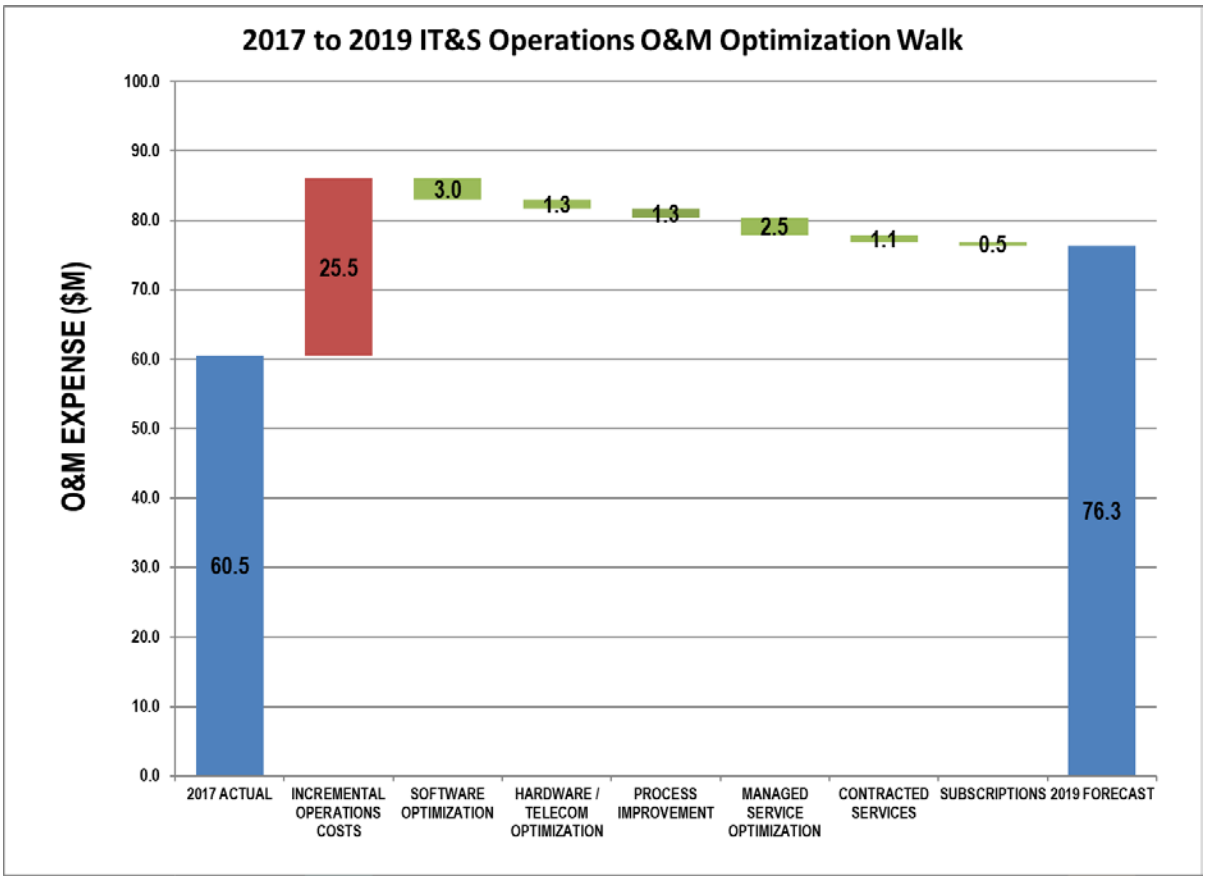
an increasing number of cloud-based solutions. The trend would have been higher without cost reduction efforts undertaken by the Company, described below.





Q. How has the IT Department controlled the rate of increase in operational O&M expenses?

A. The IT Department has undertaken a continued focused effort to optimize total operations O&M expense required to maintain the Company's technology assets. As demonstrated in the graph below, investments in technology would have increased the total operational costs by $25.5 million from 2017 to 2019. Through efforts to reduce software and hardware maintenance agreements, improve processes for labor efficiency, and reduce managed services contract costs, IT was able to offset O&M increases with a sustained $9.7 million reduction, limiting the increase to $15.8 million over that period.

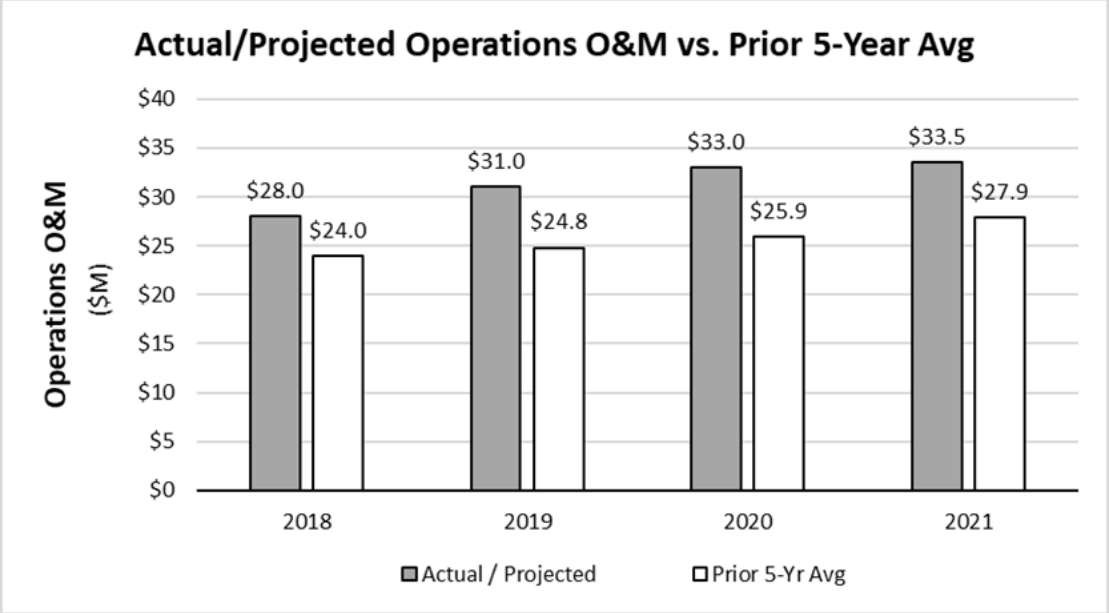


Q. Does the use of a five-year average to project the Company's IT operations O&M expenses put the Company and service to its customers at a higher risk?

A. Yes, significantly. The level of IT Operations O&M expense is closely linked to increasing security requirements, a growing technology asset base through prior capital investments, and increasing use of cloud solutions. Collectively, these are not adequately supported using a five-year average. Typically, the Company has received final rulings in favor of all or a majority of the IT capital expenditures requested in previous rate cases. To fully and appropriately support the assets created by those capital investments that have been deemed prudent, and keep them secure, the Company needs to be approved to spend the specific IT Operations O&M expense requested. IT assets have increased every year for the past five years. That growth curve, and the cumulative asset

base, does not support an historic five-year average method of estimating operations levels. Additionally, the Company projects an increase in cloud solutions, which have a higher level of O&M spend not found in the historic five-year period. While the Company is working hard to contain the growth in technology support costs as demonstrated in the above graphs, the five-year average method never catches up to the actual need, and substantially understates the O&M needed to support the current and projected asset base. Approval based on a five-year average, which would be lower than the requested amount, would limit the Company's ability to adequately support and maintain the capital expenditures made previously on behalf of its customers.

If the Company is not able to operate, support, secure and maintain the technology systems it already has due to lack of operating expense, it expects to experience reliability and cyber issues. If maintenance fees are not paid to software vendors, for example, vendors no longer provide security patches, expert troubleshooting advice, or upgrades that make it possible to run on newer operating systems and databases. Keeping the Company's systems secure and reliable is so important that the Company spent $4 million more than the prior five-year average for gas IT Operations O&M in 2018. The Company forecasts spending $6.2 million more than the five-year average in 2019, and the trend continues in 2020 and 2021. This is shown in the chart below. If approval is received based on a five-year average, this model is not sustainable.



INVESTMENTS O&M EXPENSES - MAINTAIN ADEQUATE SYSTEM CURRENCY AND NEW CAPABILITIES

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

A. Investment 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, including those that support the Natural Gas Delivery Plan. Investment O&M funds project activities that must be expensed according to the Federal Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 350-40 guideline for Internal Use Software. These are activities performed during the Preliminary Project Stage and specific activities performed during the Development Stage of a project. In addition, all activities for software projects that do not provide any new functionality, such as technology upgrades to keep IT assets secure and operational, must be expensed to O&M.

Q. Describe the importance of upgrading IT systems for cyber security requirements and operational stability?

A. Upgrading applications, operating systems and data base management systems is essential to delivering safe, reliable, and affordable service to the Company's customers. New versions of technology enable the Company to maintain vendor support, remediate vendor security vulnerabilities, address vendor defects that impair stability and functionality, and address version interdependencies and compatibility between systems.

Q. What would happen if the Company does not keep its systems upgraded?

A. Technologies that are not upgraded are often no longer supported by vendors, increasing security risk as security patches are regularly released based on known vulnerabilities. By not keeping its systems upgraded, the Company would increase the risk of a significant cyber event impacting Company operations and service to its customers.

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

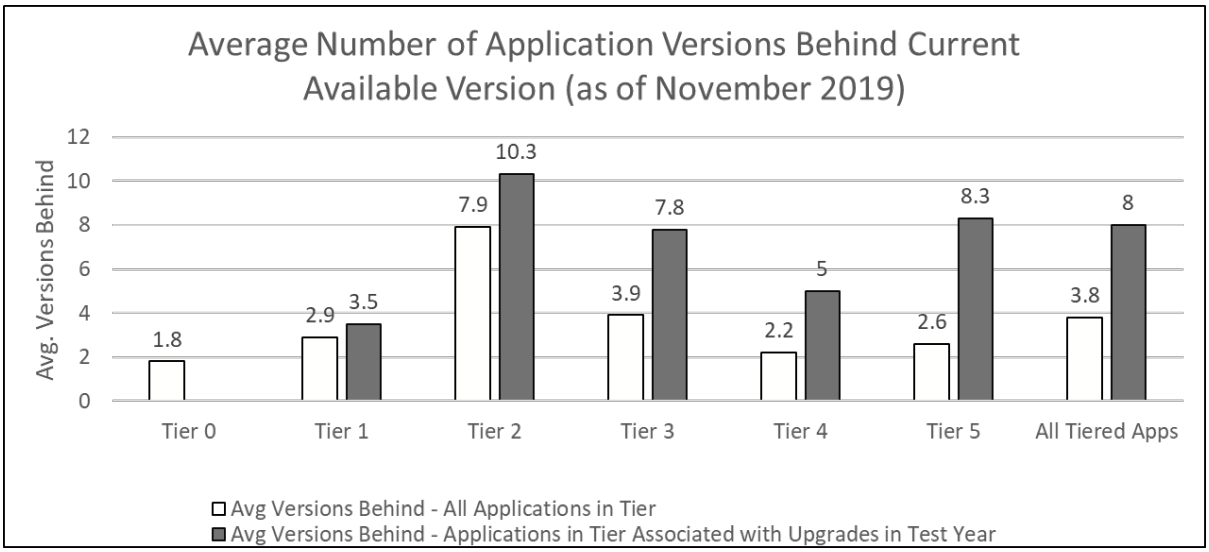
A. While the Company would prefer to maintain an upgrade strategy of staying at most one version behind the vendor's currently available version, the Company applies multiple considerations to determine when upgrades are needed. These include application criticality, security and operational risk, operational impacts of performing the upgrade, ability to defer, 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 the project.

Historically and currently, the Company has not been authorized the O&M needed in rates to maintain and keep systems current. Therefore, obsolescence has increased, and the Company is in a position of catch-up, reaction, and higher risk that a

significant cyber security or technical issue could not be remediated or mitigated, causing direct impact to Company operations and/or its customers. The Company has had to prioritize the most important technology, and is now to the point where even some of the most important technology cannot be kept current and is at risk. The Company is also prioritizing operational support over new investments when resources are scarce, thus putting the Natural Gas Delivery Plan at risk.

Q. Please describe the risk level of the Company's IT systems based on software versions.

A. The Company has six tiers (designated "0" through "5") for its most important applications. 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 these application tiers, 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 7.9 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 10.3 versions behind the vendors' current version.



Generally, applications that are farther behind the vendor's current available version are at higher risk of not having vendor support, which includes the ability to obtain and apply security patches for the applications. The graph demonstrates the Company's focus on those applications at greatest risk. 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 or desktop operating systems and databases.

Q. Please describe Exhibit A-132 (CJV-2).

A. Exhibit A-132 (CJV-2) is a Summary of Actual and Projected IT Investment O&M Expenses for the Years 2018, 2019, 2020, 12 months ending September 30, 2021, and the Year 2021. It provides a summary of the Gas allocation of actual and projected IT Department investment O&M expenditures. Specifically:

- Column (a) provides the investment O&M expense category;

- Column (b) identifies the 2018 historical investment O&M expense as $8,876,000;
- Column (c) identifies the 2019 projected investment O&M expense as $8,614,000;
- Column (d) identifies the 2020 projected investment O&M expense as $10,328,000;
- Column (g) identifies the 12 months ending September 30, 2021 projected investment O&M expense as $13,752,000; and
- "Labor" line items include employee labor. "Contracts" line items include hardware and software licenses/maintenance, staff augmentation, and other contracted services.

Q. Are the Preliminary Project Stage activities that must be part of Investment O&M expense per 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. The activities cover much of the work included in the Company's investment planning for IT projects. This includes identifying high-level business requirements, determining whether the technology needed already exists, exploring alternatives, identifying performance requirements, identifying 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.

Q. Is the investment planning activity speculative?

A. No, it is not speculative. In fact, the outcome of this investment planning process is the very information ordered by the MPSC in Case No. U-18238 as part of the rate case filing requirements for IT and OT. The required information includes a project description and functionality of the system; project timelines and spending plans; project

benefits; project timeline including expected implementation date; a description of alternatives considered and rationale behind decision; cost benefit ratio; and project business case.

During this phase, the Company spends the necessary time on up-front planning and due diligence for the technology investment, as is done with any other class of assets in the Company. As an example, execution of the Company's Natural Gas Delivery Plan will require investment in a new Gas SCADA system. The Company has already spent time on up-front planning to confirm the high-level scope and needs, and assess alternatives. More time must be spent to evaluate vendor solutions and organize the project, which is necessary and not 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 both necessary work to meet the rate case filing requirements, and it is part of the normal and expected work done on the front end of IT projects, regardless of company or industry. It is in the best interest of the Company's customers that the Company perform these investment planning activities versus launching a project effort for every good idea that gets identified without clear knowledge of the expected value, or any semblance of a plan. The work is required by the MPSC for technology investments, is prudent, and is not free. The Company should receive recovery for this required expense.

Q. Would it be more accurate to use a five-year average to project the Company's IT Investment O&M expenses?

A. No. The level of IT Investment 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 in favor of all or a majority 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 should be approved to spend the specific and forward-looking IT Investment O&M requested for the test year period, versus a backward-looking average. Approval based on a five-year 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 Natural Gas Delivery Plan, improve customer service and keep its systems upgraded for security and reliability. Additionally, the Company projects an increase in cloud solutions, which often have a higher level of O&M Investment spend not found in the historic five-year period.

INVESTMENTS - CAPITAL EXPENDITURES

Q. Please describe the capital expenditures shown on Exhibit A-12 (CJV-3), Schedule B-5.11.

A. Exhibit A-12 (CJV-3), Schedule B-5.11 identifies the gas allocation of projected capital expenditures to procure, install, and implement the software and infrastructure requested in this testimony to meet business requirements. Specifically, on page 1 of the exhibit:

- Column (a) provides the program designation for the capital expenditures, using programs that have been used historically to categorize IT projects:
  - (i) Upgrades and Replacements (Enterprise);
  - (ii) Upgrades and Replacements (Business Partner);
  - (iii) Security;
  - (iv) IT Service Delivery;
  - (v) Enhancements;
  - (vi) Business Partner (BP) Functionality; and
  - (vii) Architecture.
- Column (b) identifies the 2018 historical capital expenditures as $34,621,000;
- Column (c) identifies the 2019 projected bridge year capital expenditures as $24,241,000;
- Column (d) identifies the 9 months ending September 30, 2020 projected bridge year capital expenditures as $19,768,000;
- Column (e) identifies the 21 months ending September 30, 2020 projected bridge year capital expenditures as $44,009,000; and
- Column (f) identifies the 12 months ending September 30, 2021 projected test year capital expenditures of $35,731,000.

Q. Please explain Exhibit A-133 (CJV-4).

A. Exhibit A-133 (CJV-4) identifies the gas allocation of projected capital and O&M expenditures to procure, install, and implement the software and infrastructure requested in this testimony to meet business requirements. As explained above, 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 Project's assigned UNITE Category;
- Column (f) provides a synopsis of the project, which includes 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. These categories are:
  - (j) Software Costs;
  - (k) Material Costs;
  - (l) Labor Costs;
  - (m) Contractor Costs;
  - (n) Overhead and Other Costs; and
- Column (o) provides the Project's gas portion total O&M spend for the applicable year.
- 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. Categorical spend is not available for projects before 2019. These categories are:
  - (p) Software Costs;
  - (q) Material Costs;
  - (r) Labor Costs;
  - (s) Contractor Costs; and

- (t) Overhead and Other Costs.

INVESTMENT IDENTIFICATION, APPROVAL AND DELIVERY

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 witness Degenfelder and representatives from gas departments to identify technology projects and foundational digital investments to enable the Natural Gas Delivery Plan. The joint teams prepared business cases for the projects utilizing standard format and content.

IT project approvals follow the corporate planning processes for inclusion in the Company's business plan. 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. Because of the rapid pace of technology change and because of quickly changing business conditions, it is difficult to predict with 100% accuracy the exact projects that will be completed through the course of the year. Emergent projects are identified and vetted through IT and the affected internal business areas throughout the year as business objectives, Company goals, and customer needs and expectations evolve.

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

A. IT investment forecasts begin with a Rough Order of Magnitude ("ROM") estimate. The Company follows a ROM estimating process similar to that outlined by the Project Management Institute ("PMI") in its Project Management Body of Knowledge ("PMBOK"), where the actual project costs may be in the range of -25% to +75% of the ROM estimate. ROM estimates are typically determined by technology and subject matter experts inside and outside the Company in comparison to similar projects; but with high level estimates that should be directionally accurate.

From that point, investment forecasting depends on the method used to deliver the intended solution. In the case of Agile delivery (see below), which makes up over 40% of releases delivered by IT, the project team targets the delivery of the highest 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. Ideally, the definitive estimate would be close to the ROM estimate developed much earlier for project prioritization and budgeting decisions. However, based on the additional information gathered during the planning and design phases, the definitive estimate is likely to be different. The PMBOK provides guidance that a project's actual costs may be in the range of -5% to +10% of the definitive estimate. Factors that arise during the project lifecycle, such as the need for more or less resources to complete a project, changes in project schedule that shift spending between years, and changes in project scope or complexity that may result in funding needs being lower or higher than initially estimated.

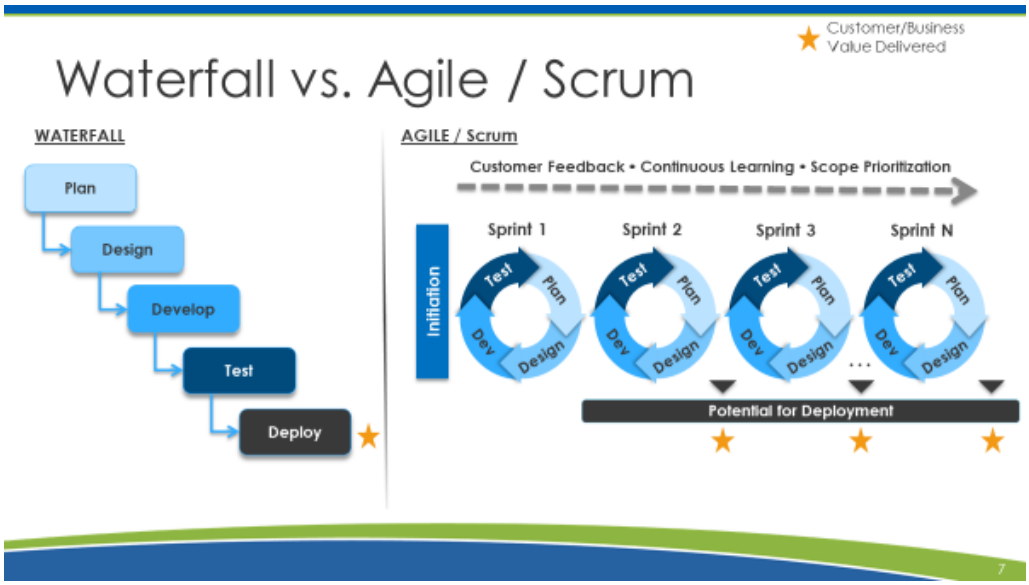
Q. Do the projects included in the test year have detailed project plans and schedules?

A. 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 in which 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 (described below), 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.

Q. How is the Company increasing the speed and frequency at which value from digital investments is delivered to customers, while also controlling cost?

A. The IT department has been expanding the adoption of Agile for delivering technology solutions due to the numerous benefits it provides. Agile's focus on iterative planning and development, and incremental delivery, has enabled teams to deliver customer value earlier and more frequently in contrast to a traditional Waterfall approach. This is illustrated in the diagram below. A key component is the continual refinement and prioritization of scope based on the value it provides. By iteratively planning and developing small blocks of the prioritized scope, the Company can ensure teams are continually delivering the highest value items first, while reducing or avoiding investment on the low value or "nice-to-have" scope. Each iteration provides the

opportunity to respond to changes or unknowns, reducing the risk and potential for impactful, costly changes that are more likely exposed late in the build or testing phases of a traditional Waterfall project.



INVESTMENT PROJECTS

Q. Please provide a breakdown and 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-133 (CJV-4). The IT investment projects are grouped into the following areas for explanation in testimony:

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

- **Customer Experience and Operations** ("CE&O") projects that enable the Company to comply with regulatory billing changes, improve billing functionality, improve customer satisfaction, and 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; HR; 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 Applications 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;

- **Digital Foundations and Capabilities** projects to create the technology platforms, tools, processes, and frameworks that enable Natural Gas Delivery Plan and customer service outcomes; and

- **Security** projects that enable physical and cyber security for the Company's customer information, employees, IT applications and infrastructure, and Company facilities and assets.

Q. Please explain the projects enabling the Natural Gas Delivery Plan.

A. Below are the projects enabling the Natural Gas Delivery Plan. A full synopsis of each project with its value is included in the testimony of Company witnesses Jared J. Martin, Jeffrey R. Parker, Chad L. Alley, Craig C, Degenfelder, and Paul M. Wolven as indicated below.

Project	Capital	O&M	Witness
Enhanced Infrastructure Replacement Program Technology Enablement	$1,159,499	$345,628	Martin
Field Contractor Work Management Technology Enablement	$644,413	$66,331	Martin
Field Mapping and Graphics	$475,140	$9,216	Martin
Gas Leak Asset and Work Management	$934,875	$83,525	Parker

Gas Measurement Application Server	$6,375	$20,875	Alley
Gas Measurement, Regulation, Pipeline, and Storage Field Work Management Enablement	$1,057,879	$22,976	Martin
Gas SCADA System	$0	$795,000	Degenfelder
Gas T&D Historian	$978,750	$169,500	Degenfelder
Gas Transmission Probabilistic Risk Model	$0	$49,275	Wolven
GCCP - SIMS	$334,828	$1,555,500	Parker
GIS-Integrated Design Project	$322,779	$188,634	Parker
One Call Ticket Risk Analysis Model for Damage Prevention	$192,960	$48,374	Martin
Work Management Scheduling Analytics and Reporting	$321,372	$57,636	Martin

Q. Please explain the projects included in the CE&O area.

A. Below are the projects included within the CE&O area. A full synopsis of each project with its value is included in the testimony of Company witness Steve Q. McLean.

Project	Capital	O&M
Customer Operations Commercial Theft	$103,707	$50,917
Large Customer Rate Tool	$68,194	$49,311
On-Bill Financing	$444,474	$53,423
Voxai Survey Tool	$55,296	$3,060
Dashboard Redesign	$840,730	$63,623
Cross-Channel Analytics	$0	$40,800
Data Lake Entry	$133,661	$13,961
Website Redesign	$1,058,992	$167,854

Landlord Small Business Portal	$696,603	$57,611
Business Customer Interval Web Portal	$209,201	$105,266
Move In/Move Out Digital Redesign	$367,753	$17,856
Bill Design and Delivery Transformation	$1,732,507	$358,148
Move In Move Out Version 3.0	$486,483	$67,989

Q. Please explain the projects included in the Corporate Services and Enterprise area.

A. Below are short descriptions for the projects included within the Corporate area. A full synopsis of each project is included in the direct testimony of Company witness Karen M. Gaston.

Project	Capital	O&M
Accounts Payable Automation	$60,672	$54,443
EHS Compliance	$86,016	$39,819
Enterprise Content Management - Managing Business Records	$117,362	$254,852
Financial Planning Transformation - Intake and Monthly Plan Management	$1,133,107	$124,780
HR - 2020 Union Changes	$0	$118,414
Rates Case Implementation	$0	$88,676
Workforce Connect –Talent Enablement	$109,728	$552,196

Q. Please explain projects included in the Operations Support area.

A. Below are explanations of projects included within the Operations Support Area:

- Th**e ServiceNow Customer Service Management ("CSM")** project requires $21,965 in capital and $35,639 in O&M. This project will implement the CSM module of ServiceNow to enable the recently defined Supply Chain ("SC") service delivery model to support SC Optimization. This project will provide value to the Company and its customers through: (1) waste

elimination; (2) cost savings; (3) maturing processes; and (4) movement to a sustainable service delivery model to continually improve the customer experience. This project specifically will enable the newly designed processes and service delivery model as it will: (1) enhance the delivery of SC services to both internal customers and suppliers; (2) include an integrated knowledge base and case management system, improving the customer experience by having one place to go for information and help; and (3) provide standard workflow and funnel the previously disparate intake channels for SC support into one solution. This technology solution is the backbone of a SC Support Center and will enable: (1) better management of work; (2) more efficient and accurate response to questions; and (3) improved satisfaction of internal customers and external suppliers. The scope of the project includes: (1) configuring and implementing the CSM ServiceNow module for Supply Chain processes; (2) implementing self-service, including a virtual chat agent; (3) configuration and implementation of workflow for case resolution; (4) implementation of management dashboards and reporting; and (5) development and implementation of simple integrations to and from SAP. Alternatives considered include: (1) continue to use manual processes to manage the SC service delivery model; (2) consider alternate service delivery providers; (3) develop a home-grown application to provide the same functionality; and (4) extend the company's ServiceNow implementation with the CSM module. With the first alternative, many of the benefits captured in the overall SC Optimization business case conducted last year would not be sustainable if the SC service delivery model was not improved. Additionally, success requires building and gaining trust from business partners to shift work to the strategic procurement efforts with the most opportunity for savings. The second alternative was ruled out because the Company already has a ServiceNow instance in IT and it would be very costly to find a different but redundant customer service application. The third option was dismissed as it would not only be expensive due to the complexity inherent in this option, but it would significantly delay the timeline without increasing benefits. Selecting the fourth option enables the Company to save the costs inherent to creating a new relationship with a vendor, and address the gaps identified in the current SC service delivery process.

- The **Contract Life Cycle Management** project requires $10,138 in capital and $30,983 in O&M. The Contract Life Cycle Management project will implement new contract management solution to manage the life cycle of contracts. This project will provide value to the Company and its customers through: (1) an improved user experience; (2) standardization of the supply chain platform for sourcing and contracts; (3) reduction of manual steps to select approvers; (4) integration with SAP; and (5) reduced annual subscription fee for the solution. The scope of this project includes: (1) implementation new contract life cycle management solution; (2) integration of this solution with SAP supply chain; (3) transition of active contract information from current solution; (4) discontinuing use of current

solution for contract management. As part of the review process, alternatives considered included: (1) delay implementation of a new solution; or (2) remain on the current platform. The alternative to defer implementation was not selected because it defers a significant reduction in support costs and opportunities to reduce manual efforts. The alternative to remain on the current platform was not considered due to the intensive manual effort to route physical documents for approvals, inability to streamline source-to-pay workflows, and costly support model. The option to implement new contract management life cycle management cloud-based solution was chosen after evaluation of leading vendor software applications for Source-to-Pay (S2P) solutions through a Request for Information and vendor demonstration process.

- The **Corporate Capital** line item is requesting $230,000, and is a standard year-over-year request for onboarding, moving, and equipping expenditures for senior officers, corporate officers, and corporate departments. The alternative of failing to fund this initiative can lead to a higher failure rate of faulty or obsolete equipment, restricting effective communications within the various corporate organizations. The facility moves and equipping of officers and directors are critical to effective communication and collaboration between cross-functional organizations. This request is expected to provide continuous improvements in communication methods and a speed of transactions between top level organization leaders.

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 lifecycle expectations for the specific assets in each type of program. Assets that are replaced 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. Refreshing hardware at the recommended refresh cycle allows the Company to:

- Reduce security risks and helps to ensure devices are updated and patched to avoid vulnerabilities;
- Avoid costs due to increasing hardware failures;
- Avoid frustration for its customers and lost productivity for its employees due to downtime;

- Refresh equipment for continued operating system support as older versions are retired by the manufacturer; and

- Refresh equipment ensuring employees have the required software to support their work.

Below are links to some industry standards the Company has researched to determine its hardware refresh time periods:

Link - Michigan.gov, Information Technology Equipment Life Cycle: https://www.michigan.gov/documents/dtmb/Sec._829_IT_Lifecycle_Report_2018_619021_7.pdf

Link - 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 explain ARP and infrastructure projects.

A. These are the ARP and infrastructure projects:

- The **ARP — Infoblox Refresh** project requires $73,014 in capital and $3,853 in O&M. The ARP — Infoblox project will replace the Company's Infoblox system. The value of this program includes: (1) enabling the Company to efficiently manage and control their networks; and (2) providing Domain Name System, Dynamic Host Configuration Protocol, and Internet Protocol address management. The scope of this project includes the annual replacement of network assets under this program. The alternative considered was to continue operating on existing Infoblox equipment past the vendor's end-of-support date in February of 2021, and extended support is not an option. This alternative was not selected because it carries risks with not having vendor support, software bug fixes, security updates, and other software fixes. The alternative to replace the existing Infoblox equipment with the latest hardware and software provided by the vendor was selected to avoid these risks and continue a regular refresh cycle.

  Following are the projected capital costs for ARP – Infoblox Refresh project attributable to the gas business for 2020, 2021 and the test year in the table below.

Units	Avg. Unit Cost	Total 2020 Units	Total 2021 Units	Total 2020 Dollars	Total 2021 Dollars	Total Test Year Dollars	Gas Allocation Dollars
Trinzic 1425 Software Bundle, DDI and Grid	$24,586.70	4	0	$98,346.80	$0.00	$24,586.70	$10,562.45
Trinzic 1405	$3,651.70	4	0	$14,606.80	$0.00	$3,651.70	$1,568.77
FRU, Trinzic 1405 & 2205 Series AC Power Supply Unit, 600W	$1,923.90	4	0	$7,695.60	$0.00	$1,923.90	$826.51
Trinzic 1415 Software Bundle, DDI and Grid	$17,113.70	11	0	$188,250.70	$0.00	$47,062.68	$20,218.13
Trinzic 1405	$3,651.70	11	0	$40,168.70	$0.00	$10,042.18	$4,314.12
FRU, Trinzic 1405 & 2205 Series AC Power Supply Unit, 600W	$1,923.90	11	0	$21,162.90	$0.00	$5,290.73	$2,272.90
Trinzic 825 Software Bundle, DDI and Grid	$7,944.70	5	0	$39,723.50	$0.00	$9,930.88	$4,266.30
Trinzic 805	$1,902.70	5	0	$9,513.50	$0.00	$2,378.38	$1,021.75
Reporting & Analytics Software Bundle 1405	$31,794.70	1	0	$31,794.70	$0.00	$7,948.68	$3,414.75
Reporting and Analytics 1405	$5,771.70	1	0	$5,771.70	$0.00	$1,442.93	$619.88
Software, labor, contractor and overhead and other costs				$222,800.00	$0.00	$55,700.00	$23,928.72
Total Gas Allocation				$679,834.90	$0.00	**$169,958.73**	**$73,014.27**

- The **ARP — OT Support** project requires $351,227 in capital and $17,808 in O&M. The ARP — OT Support project will replace dated and obsolete servers and workstations. This project creates value by maintaining the currency of the Company's IT infrastructure and core enterprise software that are utilized to support and enhance customer interactions, as well as ensure the stability of technology for business operations that are in service of the Company's customers. 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. The alternative considered was extending maintenance. This solution was not selected because systems would become unavailable to the end user as normal growth will exceed the computer resources currently available.

Following are the projected capital costs for ARP – OT Support project attributable to the gas business for 2020, 2021 and the test year in the table below.

Units	Avg. Unit Cost	Total 2020 Units	Total 2021 Units	Total 2020 Dollars	Total 2021 Dollars	Total Test Year Dollars	Gas Allocation Dollars
Servers	$15,000.00	10	30	$150,000.00	$450,000.00	$375,000.00	$161,100.00
Tape Libraries	$25,000.00	2	0	$50,000.00	$0.00	$12,500.00	$5,370.00
Hyper-Convered Solution	$100,000.00	2	0	$200,000.00	$0.00	$50,000.00	$21,480.00
Switch	$15,000.00	4	5	$60,000.00	$75,000.00	$71,250.00	$30,609.00
Firewall	$30,000.00	0	4	$0.00	$120,000.00	$90,000.00	$38,664.00
Software, labor, contractor and overhead and other costs				$167,900.00	$235,791.00	$218,818.25	$94,004.32
Total Materials Gas Allocation				$627,900.00	$880,791.00	$817,568.25	**$351,227.32**

Following are the actual and projected capital costs for ARP – OT Support project attributable to the gas business for 2018 and 2019 in the table below.

Units	Avg. Unit Cost	Total 2018 Units	Total 2019 Units	Total 2018 Dollars	Total 2019 Dollars	2018 Gas Allocation Dollars	2019 Gas Allocation Dollars
698-2700 MHZ 8-10 DB LOG	$101.28	20	0	$2,025.52	$0.00	$846.67	$0.00
698-896/1700-2700 MHZ	$78.78	10	0	$787.81	$0.00	$329.30	$0.00
Antenna	$136.45	60	0	$8,187.18	$0.00	$3,422.24	$0.00
Antennas - GAS SCADA	$96.87	0	110	$0.00	$10,655.29	$0.00	$4,577.51
Cisco 5508 Firewalls-Hydro Site	$1,548.32	0	12	$0.00	$18,579.87	$0.00	$7,981.91
Cisco 5508 Firewalls-Hydro Site	$885.01	0	8	$0.00	$7,080.09	$0.00	$3,041.61
Cisco Connected Grid 2G/3G/4G LTE GRWIC	$1,070.00	0	4	$0.00	$4,279.98	$0.00	$1,838.68
Cisco Firepwr Mgmt Ctr 2500C Appliances	$17,870.38	4	0	$71,481.50	$0.00	$29,879.27	$0.00
CISCO Modems -IST 4451 SEC BUNDLE	$12,320.49	3	0	$36,961.48	$0.00	$15,449.90	$0.00
CISCO NETWORK EQUIPMENT	$4,667.71	0	2	$0.00	$9,335.42	$0.00	$4,010.50
CISCO PWR SPPLY - NTWK EQUIP PERIPHERALS	$169.32	0	4	$0.00	$677.29	$0.00	$290.96
CONNECT 4G X BOOSTER KIT	$884.93	1	0	$884.93	$0.00	$369.90	$0.00

DC/DC POWER SUPPLY 6V	$35.17	1	0	$35.17	$0.00	$14.70	$0.00
Dell UltraSharp 49 Curved Monitor – U4919DW	$1,166.00	8	0	$9,328.00	$0.00	$3,899.10	$0.00
GAS SCADA - RED LION	$1,131.98	20	0	$22,639.62	$0.00	$9,463.36	$0.00
HARDWARE - SN6000 ROUTERS ATT/VZ	$652.88	20	307	$13,057.53	$200,433.09	$5,458.05	$86,106.05
HIPswitch 400e appliance	$8,051.51	1	0	$8,051.51	$0.00	$3,365.53	$0.00
HP LTO 6 Ultrium WORM Tap Cartridge	$36.26	150	0	$5,439.64	$0.00	$2,273.77	$0.00
Hypervisors	$24,419.22	6	0	$146,515.33	$0.00	$61,243.41	$0.00
KVM Switch (32 port)	$4,390.40	7	0	$30,732.79	$0.00	$12,846.31	$0.00
Laptop	$2,551.13	7	0	$17,857.93	$0.00	$7,464.61	$0.00
Laptop	$1,965.24	0	1	$0.00	$1,965.24	$0.00	$844.27
Server	$4,250.00	0	1	$0.00	$4,250.00	$0.00	$1,825.80
Omni & Yagi Antennas	$85.99	60	0	$5,159.40	$0.00	$2,156.63	$0.00
Power Edge R740 Servers	$49,449.92	4	0	$197,799.69	$0.00	$82,680.27	$0.00
PowerEdge R740 Servers	$9,507.96	0	7	$0.00	$66,555.71	$0.00	$28,592.33
Red Lion - Industrial RTU 2M NVRAM 64M D	$1,883.00	24	0	$45,191.88	$0.00	$18,890.21	$0.00
SANs (2x 20TB)	$57,963.14	0	2	$0.00	$115,926.27	$0.00	$49,801.93
Sentinal Monitoring Appliance	$22,525.00	0	1	$0.00	$22,525.00	$0.00	$9,676.74
Severs/SAN's	$57,754.65	6	0	$346,527.90	$0.00	$144,848.66	$0.00
SFP	$53.27	80	0	$4,261.20	$0.00	$1,781.18	$0.00
SHREDDER/DEGAUSER HARDWARE	$27,701.76	1	0	$27,701.76	$0.00	$11,579.34	$0.00
SMARTNET NETWORK EQUIP MAINTENANCE (SFP)	$197.46	0	2	$0.00	$394.92	$0.00	$169.66
Switch	$10,018.05	0	2	$0.00	$20,036.09	$0.00	$8,607.50
Switches	$7,353.61	12	0	$88,243.26	$0.00	$36,885.68	$0.00
Thin Client	$975.77	0	3	$0.00	$2,927.31	$0.00	$1,257.57
Tier 5 (2,501 - 5,000) HIP Switch 250gd a	$4,243.59	2	0	$8,487.17	$0.00	$3,547.64	$0.00
Tier 5 Hipswitch VZN/ATT Modem	$1,397.32	100	0	$139,732.40	$0.00	$58,408.14	$0.00
VERIZON SN6000 ROUTER AND SET UP	$427.18	0	4	$0.00	$1,708.72	$0.00	$734.07
VZ and ATT 4G LTE Modems for Gas SCADA	$1,088.97	12	0	$13,067.68	$0.00	$5,462.29	$0.00
Workstation	$3,571.59	5	0	$17,857.93	$0.00	$7,464.61	$0.00
Software, labor, contractor and overhead and other costs				$459,727.19	$193,249.63	$192,165.97	$83,020.04
Total Gas Allocation				$1,727,743.40	$680,579.92	**$722,196.74**	**$292,377.13**

- The **ARP — OT Storage Area Network ("SAN")** project requires $100,634 in capital and $16,571 in O&M. The ARP — OT SAN Program will refresh aging SAN with Unity SANS. This project creates value by maintaining the currency of the Company's IT infrastructure and core enterprise software that are utilized to support and enhance customer interactions, as well as ensure the stability of technology for business operations that are in service of the Company's customers. The program scope consists of (1) annually replacing SAN hardware under the program; and (2) installing additional new compute capacity to account for organic growth requirements. The alternative considered was to purchase extended maintenance. This alternative was not chosen due to the risk of increased downtime of critical infrastructure and maintenance costs. The cost of bringing personnel on site to make system corrections in the event of a serious interruption is higher than the cost of buying new.

  Following are the projected capital costs for ARP – OT SAN project attributable to the gas business for 2020, 2021 and the test year in the table below.

Units	Avg. Unit Cost	Total 2020 Units	Total 2021 Units	Total 2020 Dollars	Total 2021 Dollars	Total Test Year Dollars	Gas Allocation Dollars
Unity Storage - 20TB	$65,000.00	3	0	$195,000.00	$0.00	$48,750.00	$20,943.00
Unity Storage - 50TB	$125,000.00	2	0	$250,000.00	$0.00	$62,500.00	$26,850.00
Data Domain	$83,000.00	0	0	$0.00	$0.00	$0.00	$0.00
Software, labor, contractor and overhead and other costs				$273,000.00	$73,000.00	$123,000.00	$52,840.80
Total Gas Allocation				$718,000.00	$73,000.00	$234,250.00	**$100,633.80**

- The **ARP — Printer Asset Management ("PAM")** project requires $281,899 in capital and $5,501 in O&M. The ARP — PAM project will replace printers, plotters, and multi-function printing devices. 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 program scope consists of the annual replacement of printer assets under this program. The alternatives considered for the project included looking at refresh cycles from three to seven years and running the assets to failure. The selection of a five year cycle was deemed to be the best solution in that 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 in maintenance of the equipment and downtime negatively impacting employee productivity.

Following are the projected capital costs for ARP – PAM project attributable to the gas business for 2020, 2021 and the test year in the table below.

Units	Avg. Unit Cost	Total 2020 Units	Total 2021 Units	Total 2020 Dollars	Total 2021 Dollars	Total Test Year Dollars	Gas Allocation Dollars
SP 6430	$1,181.90	1	0	$1,181.90	$0.00	$295.48	$90.77
MPC 307	$1,664.20	23	19	$38,276.60	$31,619.80	$33,284.00	$10,224.84
MPC W2201	$8,204.40	4	15	$32,817.60	$123,066.00	$100,503.90	$30,874.80
SPC 8200	$2,757.06	0	1	$0.00	$2,757.06	$2,067.80	$635.23
IM C8000	$15,537.48	0	2	$0.00	$31,074.96	$23,306.22	$7,159.67
MPC 2004	$3,021.00	5	26	$15,105.00	$78,546.00	$62,685.75	$19,257.06
MPC 3004	$5,596.80	18	36	$100,742.40	$201,484.80	$176,299.20	$54,159.11
MPC 3504	$6,191.46	27	30	$167,169.42	$185,743.80	$181,100.21	$55,633.98
MPC 6004	$7,303.40	15	37	$109,551.00	$270,225.80	$230,057.10	$70,673.54
Software, labor, contractor and overhead and other costs				$108,040.08	$108,039.78	$108,039.86	$33,189.84
Total Gas Allocation				$572,884.00	$1,032,558.00	$917,639.50	**$281,898.85**

Following are the actual and projected capital costs for ARP – PAM project attributable to the gas business for 2018 and 2019 in the table below.

Units	Avg. Unit Cost	Total 2018 Units	Total 2019 Units	Total 2018 Dollars	Total 2019 Dollars	2018 Gas Allocation Dollars	2019 Gas Allocation Dollars
SP 6430	$1,181.90	0	4	$0.00	$4,727.60	$0.00	$1,452.32
MPC 307	$1,664.20	36	61	$59,911.20	$101,516.20	$18,129.13	$31,185.78
MPC W2201	$8,204.40	5	5	$41,022.00	$41,022.00	$12,413.26	$12,601.96
MPC 2004	$3,021.00	12	13	$36,252.00	$39,273.00	$10,969.86	$12,064.67
MPC 3004	$5,844.84	4	42	$23,379.36	$245,483.28	$7,074.59	$75,412.46
MPC 3504	$6,257.60	15	53	$93,864.06	$331,653.01	$28,403.26	$101,883.81
MPC 6004	$7,158.25	68	18	$486,761.19	$128,848.55	$147,293.94	$39,582.27
MPC 8003	$15,669.98	4	0	$62,679.92	$0.00	$18,966.94	$0.00
Software, labor, contractor and overhead and other costs				$123,357.03	$32,165.79	$37,327.84	$9,881.33
Total Gas Allocation				$927,226.76	$924,689.43	**$280,578.82**	**$284,064.59**

- The **ARP — Collaboration** project requires $235,119 in capital and $159,753 in O&M. The ARP — Collaboration Program will replace the Company's collaborative tools and equipment. This project creates value by ensuring that the Company's audio, visual, telephony, and other communications systems are stable and reliable. The program scope consists of: (1) annually replacing collaboration assets; and (2) installing new collaboration assets to account for organic growth requirements. The alternatives considered were to: (1) refresh all audio and visual assets identified in the plan; (2) refresh visual assets and a portion of the audio assets; (3) refresh a portion of the audio assets only; and (4) refresh visual assets only. Option 1 was chosen based on the continued refresh cycle for visual asset replacement and the start of an audio replacement program to begin the foundational retirement of the legacy Avaya PBX systems that have reached end of mainstream manufacturer support. Options 2-4 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 discounted systems in favor of education on the newest available technology.

Following are the projected capital costs for ARP – Collaboration project attributable to the gas business for 2020, 2021 and the test year in the table below.

Units	Avg. Unit Cost	Total 2020 Units	Total 2021 Units	Total 2020 Dollars	Total 2021 Dollars	Total Test Year Dollars	Gas Allocation Dollars
LED HDTV	$1,715.00	8	8	$13,720.00	$13,720.00	$13,720.00	$4,214.78
Wireless Presentation System	$1,675.00	6	6	$10,050.00	$10,050.00	$10,050.00	$3,087.36
Camera	$3,645.00	6	6	$21,870.00	$21,870.00	$21,870.00	$6,718.46
Tabletop Conference System Video Package	$2,120.00	8	8	$16,960.00	$16,960.00	$16,960.00	$5,210.11
Group Video Conferencing	$14,415.00	3	3	$43,245.00	$43,245.00	$43,245.00	$13,284.86
Projection Screen	$1,458.15	8	8	$11,665.20	$11,665.20	$11,665.20	$3,583.55
Professional Laser Projector	$6,475.00	8	8	$51,800.00	$51,800.00	$51,800.00	$15,912.96
ACM Package Server	$100,000.00	1	0	$100,000.00	$0.00	$25,000.00	$7,680.00

Software, labor, contractor and overhead and other costs				$571,051.80	$571,051.80	$571,051.80	$175,427.11
Total Gas Allocation				$840,362.00	$740,362.00	$765,362.00	**$235,119.21**

Following are the actual and projected capital costs for ARP – Collaboration project attributable to the gas business for 2018 and 2019 in the table below.

Units	Avg. Unit Cost	Total 2018 Units	Total 2019 Units	Total 2018 Dollars	Total 2019 Dollars	2018 Gas Allocation Dollars	2019 Gas Allocation Dollars
84" Microsoft Surface Hub	$24,292.99	10	0	$242,929.90	$0.00	$101,544.70	$0.00
Evoko Lisko Room Manager	$1,269.67	10	0	$12,696.70	$0.00	$5,307.22	$0.00
RealPresence Group 700-720p HD Codec Video Conferencing	$11,659.58	8	0	$93,276.65	$0.00	$38,989.64	$0.00
LUNA HSM System	$354,754.39	1	0	$354,754.39	$0.00	$148,287.34	$0.00
Auditorium Systems	$124,065.33	2	0	$248,130.66	$0.00	$103,718.62	$0.00
IP Based Call Recording System	$156,015.81	1	0	$156,015.81	$0.00	$65,214.61	$0.00
Conference Room Projector Only System	$4,241.76	22	0	$93,318.72	$0.00	$39,007.22	$0.00
BIAMP Tesira Forte Audio System Server	$7,188.16	0	1	$0.00	$7,188.16	$0.00	$2,208.20
New Generation Surface Hubs	$14,625.00	0	4	$0.00	$58,500.00	$0.00	$17,971.20
EP2-135 Audio System	$62,573.39	0	1	$0.00	$62,573.39	$0.00	$19,222.55
Flint Audio	$9,400.00	0	1	$0.00	$9,400.00	$0.00	$2,887.68
UPS	$87,000.00	0	1	$0.00	$87,000.00	$0.00	$26,726.40
Flint HVAC	$43,000.00	0	1	$0.00	$43,000.00	$0.00	$13,209.60
Avaya R8.1 SYS/SES Manager system	$60,000.00	0	1	$0.00	$60,000.00	$0.00	$18,432.00
Inno Center Hub stands	$736.52	0	8	$0.00	$5,892.16	$0.00	$1,810.07
Software, labor, contractor and overhead and other costs				$875,487.74	$230,726.51	$365,953.88	$70,879.18
Total Gas Allocation				$2,076,610.57	$564,280.22	**$868,023.22**	**$173,346.88**

- The **ARP — Wireless Network** project requires $1,534,719 in capital and $122,957 in O&M. The ARP — Wireless Network project will replace portions of the Company's aging wireless systems. This project creates value for the Company by: (1) ensuring real-time communications between Company crews and dispatch locations; (2) ensuring efficient gas leak and electric outage response times for customers; and (3) maintaining critical infrastructure and regulatory compliance. The program scope consists of: (1) replacing wireless assets annually; and (2) installing additional new wireless assets to account for organic growth requirements. The alternatives considered for system replacement were: (1) running parallel systems while the new system is deployed, and the old system is dismantled; (2) leasing a system from a vendor; and (3) replace existing assets based on its refresh cycle. Alternatives 1 and 2 were not chosen because: Alternative 1 would be highly disruptive due to systems having to run independent of one another as well as high cost of acquiring additional radio frequency spectrum; and Alternative 2, the Company would be dependent on the response times offered by a shared vendor system that offers lower system reliability. The Company chose Alternative 3 to avoid extended support cost, provides a seamless transition that allows both the old and new systems to interact with little to no disruption to the end user.

Following are the projected capital costs for ARP – Wireless Network project attributable to the gas business for 2020, 2021 and the test year in the table below.

Units	Avg. Unit Cost	Total 2020 Units	Total 2021 Units	Total 2020 Dollars	Total 2021 Dollars	Total Test Year Dollars	Gas Allocation Dollars
Havis Boxes	$2,120.00	227	227	$481,240.00	$481,240.00	$481,240.00	$206,740.70
Modem (MP70)	$1,060.00	367	367	$389,020.00	$389,020.00	$389,020.00	$167,122.99
800Mhz Mobile front mount	$3,174.00	300	300	$952,200.00	$952,200.00	$952,200.00	$409,065.12
800Mhz Mobile remote mount	$3,174.00	58	58	$184,092.00	$184,092.00	$184,092.00	$79,085.92
Conventional Radio (fixed site)	$8,191.00	11	11	$90,101.00	$90,101.00	$90,101.00	$38,707.39
Conventional (low end subscriber)	$265.00	272	272	$72,080.00	$72,080.00	$72,080.00	$30,965.57
Conventional (high end subscriber	$1,060.00	240	240	$254,400.00	$254,400.00	$254,400.00	$109,290.24
Dispatch Consoles	$30,917.00	12	12	$371,004.00	$371,004.00	$371,004.00	$159,383.32

Vida Cores (Central Electronics	$636,000.00	1	1	$636,000.00	$636,000.00	$636,000.00	$273,225.60
Site UPS Batteries	$1,060.00	11	11	$11,660.00	$11,660.00	$11,660.00	$5,009.14
Software, labor, contractor and overhead and other costs				$130,353.00	$130,735.00	$130,639.50	$56,122.73
Total Gas Allocation				$3,572,150.00	$3,572,532.00	$3,572,436.50	**$1,534,718.72**

Following are the actual and projected capital costs for ARP – Wireless Network project attributable to the gas business for 2018 and 2019 in the table below.

Units	Avg. Unit Cost	Total 2018 Units	Total 2019 Units	Total 2018 Dollars	Total 2019 Dollars	2018 Gas Allocation Dollars	2019 Gas Allocation Dollars
Havis Boxes	$1,626.95	150	200	$244,042.50	$325,390.00	$102,009.77	$139,787.54
Modem (MP70)	$1,150.26	0	411	$0.00	$472,756.86	$0.00	$203,096.35
Modem (GX450)	$636.69	125	0	$79,586.25	$0.00	$33,267.05	$0.00
Generator (Tawas)	$22,415.00	0	1	$0.00	$22,415.00	$0.00	$9,629.48
LED Flash Lighting system	$9,710.00	4	4	$38,840.00	$38,840.00	$16,235.12	$16,685.66
800Mhz Mobile front mount	$2,575.80	50	0	$128,790.00	$0.00	$53,834.22	$0.00
800Mhz Mobile front mount	$2,411.65	250	200	$602,912.50	$482,330.00	$252,017.43	$207,208.97
800Mhz Mobile remote mount	$2,486.77	200	200	$497,354.00	$497,354.00	$207,893.97	$213,663.28
800Mhz Portable Radios	$2,976.48	0	100	$0.00	$297,648.00	$0.00	$127,869.58
800Mhz Portable Radios	$2,410.12	0	75	$0.00	$180,759.00	$0.00	$77,654.07
Desktop microphones	$155.76	70	0	$10,903.20	$0.00	$4,557.54	$0.00
Radio keys	$111.68	107	40	$11,949.76	$4,467.20	$4,995.00	$1,919.11
VHF Antenna system	$5,887.64	0	1	$0.00	$5,887.64	$0.00	$2,529.33
JRL Trunked radio equip	$15,884.74	0	1	$0.00	$15,884.74	$0.00	$6,824.08
Conventional Radio Repeaters	$5,880.03	0	3	$0.00	$17,640.09	$0.00	$7,578.18

JGS/GRY conventional systems	$9,862.77	0	2	$0.00	$19,725.54	$0.00	$8,474.09
800MHz Tower Ant	$12,562.74	1	0	$12,562.74	$0.00	$5,251.23	$0.00
Software, labor, contractor and overhead and other costs				$311,952.02	150,179.40	$130,395.94	$64,517.07
Total Gas Allocation				$1,938,892.97	$2,531,277.47	**$810,457.26**	**$1,087,436.80**

- The **ARP — Field Device Asset Management ("FDAM")** project requires $666,516 in capital and $4,064 in O&M. The ARP — FDAM project will replace field devices. This value of this project is: (1) to mitigate potential costs for hardware repairs; and (2) allow field workers to complete their job tasks. The program scope consists of replacing field device assets. The alternatives the Company reviewed for the FDAM project included: (1) extending refresh cycles from four to five years; and (2) running the assets to failure. The selection of a four year cycle was deemed to be the best solution because replacement in less than four years would result in additional unnecessary expense for replacement of assets that are still in peak operating condition and replacement cycles that exceed four years, including running the asset to failure, would result in additional expenses in maintenance of the equipment and downtime, which negatively impact employee productivity.

  Following are the projected capital costs for ARP – FDAM project attributable to the gas business for 2020, 2021 and the test year in the table below.

Units	Avg. Unit Cost	Total 2020 Units	Total 2021 Units	Total 2020 Dollars	Total 2021 Dollars	Total Test Year Dollars	Test Year Gas Allocation Dollars
Field Devices	$3,969.70	454	459	$1,802,243.80	$1,822,092.30	$1,817,130.18	$558,222.39
LeakCon Devices	$3,969.70	0	100	$0.00	$396,970.00	$297,727.50	$91,461.89
Software, labor, contractor and overhead and other costs				$54,126.20	$55,013.70	$54,791.83	$16,832.05
Total Gas Allocation				$1,856,370.00	$2,274,076.00	$2,169,649.50	**$666,516.33**

Following are the actual and projected capital costs for ARP – FDAM project attributable to the gas business for 2018 and 2019 in the table below.

Units	Avg. Unit Cost	Total 2018 Units	Total 2019 Units	Total Actual 2018 Dollars	Total Projected 2019 Dollars	2018 Gas Allocation Dollars	2019 Gas Allocation Dollars
Field Devices G1's & Accessories	$3,969.70	406	436	$1,611,698.20	$1,730,789.20	$487,699.88	$531,698.44
Meter Reading	$4,452.00	35	52	$155,820.00	$231,504.00	$47,151.13	$71,118.03
Software, labor, contractor and overhead and other costs				$10,147.26	$250.98	$3,070.56	$77.10
Total Gas Allocation				$1,777,665.46	$1,962,544.18	**$537,921.57**	**$602,893.57**

- The **ARP — Workstation Asset Management ("WAM")** project requires $2,442,591 in capital and $44,676 in O&M. The ARP — WAM project will replace and install new desktops, laptops, and tablets. This value of this project is: (1) improved stability and availability of business critical applications by proactively replacing workstations prior to the chance of hardware failures increasing; and (2) allows business partners to complete their job tasks. The program scope consists of: (1) replacing workstation assets; and (2) installing new units for new resources. The alternatives considered were: (1) extending the replacement cycle from four years to five years for all desktops and laptops; (2) extending the replacement cycle only on desktops from four years to five years; and (3) using 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 by $4 million in future years; (4) technology obsolescence; and (5) an inability to apply security patches. The Company selected the refresh to alleviate these concerns.

Following are the projected capital costs for ARP – WAM project attributable to the gas business for 2020, 2021 and the test year in the table below.

Units	Avg. Unit Cost	Total 2020 Units	Total 2021 Units	Total 2020 Dollars	Total 2021 Dollars	Total Test Year Dollars	Gas Allocation Dollars
Replacements							
Desktops	$922.20	984	563	$907,444.80	$519,198.60	$616,260.15	$189,315.12
Laptop	$2,144.38	2,200	1,400	$4,717,636.00	$3,002,132.00	$3,431,008.00	$1,054,005.66
Rugged Devices	$3,914.58	8	4	$31,316.64	$15,658.32	$19,572.90	$6,012.79
Monitors	$265.00	4,109	3,925	$1,088,885.00	$1,040,125.00	$1,052,315.00	$323,271.17
New Purchases							
Laptops	$2,144.38	520	520	$1,115,077.60	$1,115,077.60	$1,115,077.60	$342,551.84
Rugged Devices (Semi Rugged devices)	$3,657.35	201	201	$735,127.49	$735,127.49	$735,127.49	$225,831.16
Desktop 5060MT Bundled	$922.20	20	20	$18,444.00	$18,444.00	$18,444.00	$5,666.00
Desktop 5820 Bundled	$2,544.00	10	10	$25,440.00	$25,440.00	$25,440.00	$7,815.17
SFF Desktop	$752.60	20	20	$15,052.00	$15,052.00	$15,052.00	$4,623.97
Tablets	$1,500.28	18	18	$27,005.07	$27,005.07	$27,005.07	$8,295.96
Monitors	$265.00	1,578	1,578	$418,170.00	$418,170.00	$418,170.00	$128,461.82
Accessories				$145,683.00	$145,683.00	$145,683.00	$44,753.82
Software, labor, contractor and overhead and other costs				$441,200.40	$295,582.92	$331,987.29	$101,986.50
Total Gas Allocation				$9,686,482.00	$7,372,696.00	$7,951,142.50	**$2,442,590.98**

Following are the actual and projected capital costs for ARP – WAM project attributable to the gas business for 2018 and 2019 in the table below.

Units	Avg. Unit Cost	Total 2018 Units	Total 2019 Units	Total 2018 Dollars	Total 2019 Dollars	2018 Gas Allocation Dollars	2019 Gas Allocation Dollars
Replacements							
Desktops	$795.00	713	700	$566,835.00	$556,500.00	$171,524.27	$170,956.80
Desktop 5820 Bundled	$2,696.64	36	0	$97,079.04	$0.00	$29,376.12	$0.00
Laptop	$1,800.94	1,744	850	$3,140,839.36	$1,530,799.00	$950,417.99	$470,261.45
HP 7730 bundled	$4,282.40	96	0	$411,110.40	$0.00	$124,402.01	$0.00
Rugged Devices	$3,914.58	13	15	$50,889.54	$58,718.70	$15,399.17	$18,038.38
Monitors	$265.00	3,598	2,300	$953,470.00	$609,500.00	$288,520.02	$187,238.40
New Purchases							
Laptops	$1,800.94	536	359	$965,303.84	$646,537.46	$292,100.94	$198,616.31
HP 7730 bundled	$4,282.40	81	0	$346,874.40	$0.00	$104,964.19	$0.00
Rugged Devices (Semi Rugged devices)	$3,096.26	40	25	$123,850.40	$77,406.50	$37,477.13	$23,779.28
Desktop 5060MT Bundled	$795.00	56	30	$44,520.00	$23,850.00	$13,471.75	$7,326.72
Desktop 5820 Bundled	$2,544.00	1	4	$2,544.00	$10,176.00	$769.81	$3,126.07
SFF Desktop	$0.00	0	0	$0.00	$0.00	$0.00	$0.00
Tablets	$1,418.99	9	25	$12,770.88	$35,474.67	$3,864.47	$10,897.82
Monitors	$265.00	332	400	$87,980.00	$106,000.00	$26,622.75	$32,563.20
Curved Monitors	$1,007.00	365	0	$367,555.00	$0.00	$111,222.14	$0.00
Accessories	$0.00	0	0	$151,653.77	$145,000.00	$45,890.43	$44,544.00
Software, labor, contractor and overhead and other costs				$249,467.21	$115,237.67	$75,488.78	$35,401.01
Total Gas Allocation				$7,572,742.84	$3,915,200.00	**$2,291,511.98**	**$1,202,749.44**

The **ARP — Server and Storage** project requires $3,555,510 in capital and $211,818 in O&M. The ARP — Server and Storage will replace or augment server and storage infrastructure for the Company. 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 chance of hardware failures increasing; 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 technologies based on its refresh cycle. The organization refreshes these critical technologies to mitigate the risk of failure.

Following are the projected capital costs for ARP – Server and Storage project attributable to the gas business for 2020, 2021 and the test year in the table below.

Units*	Avg. Unit Cost	Total 2020 Units	Total 2021 Units	Total 2020 Dollars	Total 2021 Dollars	Total Test Year Dollars	Gas Allocation Dollars
Nutanix xc640-10 Nodes	$127,200.00	25	25	$3,180,000.00	$3,180,000.00	$3,180,000.00	$976,896.00
Nutanix xc740xd-24 Nodes	$169,600.00	25	25	$4,240,000.00	$4,240,000.00	$4,240,000.00	$1,302,528.00
vBlock Blades (Full)	$87,375.00	8	0	$699,000.00	$0.00	$174,750.00	$53,683.20
Avamar	$185,500.00	0	1	$0.00	$185,500.00	$139,125.00	$42,739.20
Data Domain	$1,590,000.00	0	2	$0.00	$3,180,000.00	$2,385,000.00	$732,672.00
Llabor, contractor and overhead and other costs				$1,151,999.00	$1,556,068.00	$1,455,050.75	$446,991.59
Total Gas Allocation				$9,270,999.00	$12,341,568.00	$11,573,925.75	**$3,555,509.99**

*Units includes hardware and software costs.

Following are the actual and projected capital costs for ARP – Server and Storage project attributable to the gas business for 2018 and 2019 in the table below.

Units*	Avg. Unit Cost	Total 2018 Units	Total 2019 Units	Total 2018 Dollars	Total 2019 Dollars	2018 Gas Allocation Dollars	2019 Gas Allocation Dollars
vBlock Blades (Half)	$43,562.82	0	5	$0.00	$217,814.10	$0.00	$66,912.49
Nutanix xc640-10 Nodes	$102,854.71	0	9	$0.00	$925,692.38	$0.00	$284,372.70
Vblock Rack	$11,968.00	2	0	$23,936.00	$0.00	$7,243.03	$0.00
Avamar 2400	$146,327.34	1	0	$146,327.34	$0.00	$44,278.65	$0.00
Data Domain 9800	$927,233.44	2	0	$1,854,466.87	$0.00	$561,161.67	$0.00
Server Blade (B200 M4/m5)	$54,151.68	28	16	$1,516,247.07	$866,426.90	$458,816.36	$266,166.34
Stand Alone Site Server	$6,591.26	12	7	$79,095.12	$46,138.82	$23,934.18	$14,173.85
Isilon	$357,690.48	2	0	$715,380.95	$0.00	$216,474.28	$0.00
Data Domain Shelf	$254,539.63	0	3	$0.00	$763,618.88	$0.00	$234,583.72
Vmax Shelf	$349,673.02	3	0	$1,049,019.05	$0.00	$317,433.16	$0.00
VMAX Network Card	$8,256.43	1	0	$8,256.43	$0.00	$2,498.40	$0.00
Commvault License 1TB	$3,252.52	16	0	$52,040.32	$0.00	$15,747.40	$0.00
Llabor, contractor and overhead and other costs				$437,532.45	$529,118.20	$132,397.32	$162,545.11
Total Gas Allocation				$5,882,301.60	$3,348,809.27	**$1,779,984.46**	**$1,028,754.21**

*Units includes hardware and software costs.

- The **Data Center 2.0** project requires $39,552 in capital and $161,798 in O&M. The Data Center 2.0 project enhances the Company's DR capabilities by co-locating to an enhanced Backup Recovery Center ("BRC") at a vendor facility. This project creates value for the Company by significantly strengthening DR capabilities through: (1) mitigating physical and location risks at the current BRC site; (2) creating computing environments with sufficient capacity to recover and indefinitely operate 100% of all the production systems in Tiers 0-5, should a disaster be declared; (3) minimizing negative impact to non-productions systems during DR activity; (4) addressing DR program and backup process audit findings; and (5) operationalizing (people, process, technology) the new and enhanced capabilities. Additionally, the project will enhance DR testing capabilities for

applications in Tiers 0-5 in the DR application tiering list as well as provide scalability. These improvements reduce risk for the current antiquated location by creating 100% DR capacity for production systems per the risk tolerance in business impact assessment. The scope of the project includes: (1) migration of the BRC to a co-located vendor data center; (2) expanding DR system capacity and capabilities; and (3) enabling migration of non-production workloads to the Cloud. This adds 100% of Tier 0-5 capacity should a disaster be declared. The Company performed an analysis of two alternatives to expand DR capabilities as well as address constraints and risks: (1) Remain at the current BRC; and (2) locate to a third-party co-location facility. The estimate for the BRC data center build out was $3.3 million with ongoing capital replacements of $1.7 million over 15 years. The co-location vendor provides the building, cooling, power, and physical security the Company lacks for its servers, storage, and other computing and networking equipment at the current BRC. Based on the analysis, the Company decided to implement the second alternative.

Q. Please explain Upgrades and Application Currency projects.

A. These are the Upgrades and Application Currency projects:

- The **Genesys Upgrade** project requires $8,294 in capital and $2,077 in O&M. The Genesys Upgrade project will upgrade and enhance Genesys Software features and functionality with improved call routing, reporting, and recording contacts. The project adds the following value: (1) Improved functionality which offers convenience to customers by letting them schedule interactions and callbacks with customer service over any channel or device; (2) Support for transfer, supervise, and conference co-browse and chat sessions; and (3) Enhanced social media and text functionality for customers. The scope will include all Genesys applications: Work Force Management, Speechminer recording application, interactive insights reporting, and Pulse contact monitoring. The upgrade ensures that the Company is on a version supported by the vendor and upgrade provides improved functionality across all applications. Alternatives considered include: (1) delay the upgrade and risk experiencing system performance issues and support problems; (2) continue with the current process which does not offer a callback or interactive option; (3) move to a new IVR platform which would cost the company millions of dollars; and (4) upgrade and enhance Genesys Software. Options 1, 2, and 3 are not feasible solutions due to increased risk of working on old versions of applications with no support, or increased cost. Option 4 was chosen because it is the most cost-effective option, upgrades existing application and improves system performance and customer satisfaction.

- The **Gas GIS Platform Upgrade** project requires $1,034,750 in capital and $455,875 in O&M. The Gas GIS Platform Upgrade project will upgrade the GIS platform applications, servers, application hosting servers, and databases

to the next major versions to remediate the outdated platform technology. The project adds value by: (1) remediating GIS, Windows, and Citrix technology obsolescence, creating a stable and sustainable foundation platform for critical business functions; (2) improving platform resilience by remediating current single-point-of-failure areas; (3) sharing technology resources (servers, databases, etc.) across gas and electric platforms to optimize them, yet still ensuring the ability to meet diverse business area functional needs; and (4) adding new capabilities for spatial analytics, real-time visualization of data, three-dimensional infrastructure network trace ability, which, if implemented, create additional business value. In addition, the GIS platform remediation enables the next iteration of the GIS platform migration to the Utility Network. Project scope includes: (1) building GIS platform servers, software, and data; (2) expanding the GIS platform capabilities; (3) re-architecting current single-point-of-failure areas; (4) designing and developing new architecture; (5) upgrading database technology; (6) re-platforming application hosting platform (Citrix); and (7) upgrading and reconfiguring applications that utilize the GIS platform. Three alternatives were considered for the GIS Platform Upgrade: (1) Delay implementation and pay a premium for extended Windows support and incur cyber security risk for the application hosting platform and the GIS platform. The first alternative was not selected because of the security of business continuity risk; further project delays prolong the risk impact and increases the probability because of the level of effort required to complete the project. (2) Upgrade platform to the Utility Network as a "big bang" approach without the incremental GIS version upgrade. The second alternative was not selected because the Utility Network upgrade effort is a transformational technology project, requiring extensive data migration in addition to the scope outlined with this project. Furthermore, the second alternative will also incur the security and business continuity risk given the complexity of a prolonged planning and design effort. (3) Perform an iterative platform upgrade to the next GIS version with application platform hosting upgrade, server replacements, and database upgrade and shift the Utility Network upgrade to a future year. The selected alternative to implement this project as an iterative upgrade approach decreases the overall project complexity while mitigating aging technology platforms, which enables the future upgrade to the Utility Network in addition to addressing overall platform stability and sustainability in a timelier manner.

- The **Enterprise Service Bus ("ESB") Application Upgrade** project requires $165,544 in capital and $376,954 in O&M. The ESB Application Upgrade project will upgrade and migrate the Business Works developer application to the next version. This value this project provides the Company includes: (1) accelerated productivity; (2) continuous delivery and integration; (3) an open ecosystem for improved operational visibility; (4) integration with web, mobile apps, and application programming interfaces in real-time; and (5) improved administrative and operational efficiencies. The upgrade will also provide for easy integration with other coud-based solutions such as Amazon Web Services and provides for easy migration to cloud-based

containers in the future. The project scope includes: (1) implementing new versions of all applications that are part of the ESB in two security zones; and (2) a server refresh. The new products will be implemented on the latest version of the Suse Enterprise Edition operating system. The alternative considered was to incur additional 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 product deficiency would impact many areas of the company such as billing, revenue collection, and remote meters. This alternative was not chosen due to these reasons, and the additional expense.

- The **Windows 10 Upgrade** project requires $29,923 in O&M. The Windows 10 Upgrade project will upgrade the Company's computing devices from Windows 7 to Windows 10. The project will add value by: (1) allowing the Company to leverage Microsoft support without additional cost; (2) ensuring application compatibility with the latest Microsoft Operating System; (3) increasing computer and application performance; (4) adding new security features; and (5) ensuring security compliance. The project scope includes: (1) converting Windows 7 computing devices to Windows 10; (2) an assessment of the tools and image process to ensure industry standards are being applied; (3) communications with employees on project expectations; (4) completion of device operating system upgrades; and (5) providing on-site post support at company locations. The alternative considered was to pay additional support fees for Microsoft to continue supporting Windows 7 for up to four years beginning in 2020. Work station assets are currently replaced on a four-year cycle. This alternative was not selected due to the high cost of additional support fees, the risk to business processes, and security concerns.

- The **Human Resources ("HR") Support Pack and Business Software Inc. BSI Upgrade** project requires $350,788 in O&M. The HR Support Pack and BSI upgrade will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes. This project creates value for the Company by ensuring that it is in compliance with new financial rules and regulations and 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 regulation.

- The **Electronic Shift Operations Management System ("eSOMS") Upgrade** project requires $11,520 in capital and $82,942 in O&M. The eSOMS project will perform a major upgrade of the eSOMS application, including servers. This project will completely rewrite the clearance and narrative logs, and the safety critical emailer functionality to enable compatibility with the new version. The project will add value by:

(1) reducing the human struggle with manual workarounds and old applications; (2) empowering employees with proper electronic tools to meet Customer expectations; (3) enabling process improvements to deliver outages more effectively; (4) reducing plant downtime; and (5) increasing reliability. The scope of this project includes: (1) assessing any new functionality for value to the Company; (2) replacing the servers and upgrading the application software; (3) making necessary configuration changes; (4) testing any integrations to or from the application; (5) testing the upgrade; and (6) updating documentation related to the integration changes. Alternatives considered include: (1) continue to use the application without vendor support at the risk of a critical application issue that results in an employee safety incident, extended plant production outage, prolonged plant reliability issue, or regulatory or compliance violation; (2) instituting the manual business continuity process until the application upgrade is possible which would increase the previously mentioned business risks; or (3) revisit the decision to utilize eSOMS and replace the application with customizing SAP. Upgrading the existing eSOMS application is the best alternative to minimize cost and risk to the company and employees.

- The **Consumers Affordable Resource for Energy ("CARE") Annual Updates** project requires $105,764 in O&M. The CARE Annual Updates project will implement software changes to improve the process for offering energy assistance to low income customers and streamline the process for the assistance agencies who utilize the application though improved user interface 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. The project will provide the following value: (1) complete modifications to internal SAP application and Agency Portal to receive annual Low Income Home Energy Assistance Program ("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 Michigan Agency for Energy. Alternatives considered were to: (1) continue with current process which would lead to loss of grant funding, thus decreasing or eliminating energy assistance dollars for customers; and (2) 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 2 was selected since it provides long-term proactive energy assistance to customers and prevents loss of grant funds. All the changes are internal SAP and Agency Portal related, therefore a cloud alternative is not viable.

- The **800 MHZ Modernization Project** requires $3,662,984 in capital and $9,308 in O&M. The 800MHZ Modernization Project will replace antiquated head-end (the main audio routing switch for tower sites and dispatch consoles), tower site, dispatch, and radio infrastructure as well as user subscriber equipment with infrastructure that meets current Project 25 ("P25") standards. P25 standards for digital mobile radio communications that are used by North American public saety and dispatch organizations. The current equipment is no longer manufactured or sold, so the Company is not able to find replacement parts. This project creates value for the Company by: (1) moving the Company to current production equipment that can be replaced and is more stable; (2) enabling the organization to migrate from an unsupported to a supported platform; and (3) allowing for quicker response to electric outages, and increasing customer and employee safety. The scope of the project includes: (1) the design; (2) configuration; and (3) implementation of P25 systems for head ends, tower sites, dispatch consoles, and subscriber equipment. The alternatives considered were to: (1) remain with the current system; and (2) forklift the migration to other manufacturers and architecture. Option 1 was not selected because the equipment is not supported, and the organization is not able to find replacement parts. Option 2 was not chosen because there would be a larger learning curve, it would be more disruptive to business, and it would require a complete replacement of the existing system. The Company chose to go with the upgrade because it has been incrementally adopting the P25 standard through the wireless ARP, and this prudently utilizes current and ongoing investments. The upgrade is the easiest and least disruptive path to migrate to the P25 standard.

- The **4G SAP Implementation** project requires $83,076 in capital and $44,810 in O&M. The 4G SAP Implementation project will create the technology that enables ITRON to upgrade smart meter communication modules from 3G to 4G technology. This project will add value by continuing the ability to: (1) communicate with the smart meters; (2) provide accurate and timely bills to customers; (3) execute remote turn-ons/turn-offs; (4) receive outage information; and (5) administer demand response events. The project scope includes: (1) building technology interfaces to Meter Installation Vendor technology which include an interface to extract list of 3G meter information, an interface for posting work order completion data in SAP, and an interface for tracking exceptions and errors; and (2) end to end testing of the interfaces and back-end technology (meter-to-cash processes). The alternatives considered were: (1) migrate to a new meter platform; and (2) do not implement 4G technology in 3G meters. The first option would require a substantially larger modification to all supporting systems and infrastructure and the second option is not feasible with the Company's infrastructure. The option of implementing 4G technology was chosen so the Company can continue to reap the benefits of the smart meter technology previously implemented. These benefits include improved timeliness and accuracy of

billing, retain remote disconnect/reconnect of services, administer demand response programs, and enable automated meter reads, outage reporting, and faster restoration.

- The **SAP Data Encryption** project requires $84,857 in capital and $470,379 in O&M. The SAP Data Encryption project will implement Information Security standards for encryption of Personal Identifying Information ("PII"). These standards include SAP data in various states: at rest, in use, and in transit. This project creates value for the Company and its customers by: (1) reducing the risk of a compromise of customers' personal information and the resulting impact to the Company's reputation; (2) ensuring compliance with Information Security standards for encryption for SAP data at rest and in transit; (3) reducing the Company's liability due to personal data breaches; and (4) ensuring compliance with future federal legislation that may make this mandatory. The scope of this project includes data encryption for data at rest, in use, and in transit; and applies to all SAP PII collected, used, retained, disclosed, and disposed of by the Company is in the standards. Such information includes the PII of customers, employees, contractors, directors, and shareholders. As part of the review process the alternative considered was to accept all risks as outlined above and not implement the data encryption standards. However, this was not considered a viable activity since accepting the risk could compromise customers' personal information and does not align with current internal cyber security standards. Additionally, there is pending federal legislation that may mandate this work.

- The **Structured Query Language ("SQL") Server Database Upgrade** project requires $175,553 in capital and $421,553 in O&M. The SQL Server Database Upgrade project will upgrade all SQL Server 2000-2014 instances to the latest version. 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. 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 extended support would not be provided 2012 and 2014 versions and the organization would not reap the benefits of new features offered through the upgrade. The Company decided in favor of the upgrade to avoid these issues and ensure system stability.

- The **Software Platform Refresh** project requires $232,539 in O&M. The Software Platform Refresh project will upgrade server operating systems, hypervisors (virtual machine monitors), and databases to retain low-cost, unlimited vendor support. 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. 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. A funding options matrix was completed to review the alternatives. The options were: (1) fund the full project for $1 million and pay no support liability in 2020; (2) fund $750,000 of the project and pay $1.6 million in support liability in 2020; (3) fund $500,000 of the project and pay $2.4 million in support liability in 2020; and (4) not funding the project and pay $3.3 million for support liability in 2020. Alternatives 2-4 were not selected due to the high cost of support liability. Option 1 was chosen to avert these costs and to ensure system stability.

- The **Role Based Access Control** project requires $77,279 in O&M. The Role Based Access Control project will develop business roles based on job functions for the SAP environment. Business roles are a collection of SAP access rights based on bottom up usage data and top down job function definition. The value of completing the project is: (1) more efficient access control policy maintenance and certification; (2) more efficient provisioning by network and systems administrators; (3) reduced new employee downtime from more efficient provisioning; (4) enhanced organizational productivity; and (5) enhanced system security and integrity. The scope of this project includes the following systems: (1) SAP ERP Central Component; (2) Customer Relationship Management; (3) Business Warehouse, (4) Governance Risk and Compliance; (5) Solution Manager; (6) Process Orchestration; and (7) NetWeaver Development Infrastructure. As part of the review process the alternative considered was to continue with access provisioning based on selection of specific functions and processing multiple approvals. However, this alternative was not selected because it does not eliminate waste in the form of human struggle, rework, and extra processing. The alternative to implement role-based access control was selected because the financial savings and process improvements.

- The **Redwood Cronacle Upgrade** project requires $90,305 in capital and $16,586 in O&M. The Redwood Cronacle Upgrade project will upgrade the Redwood Cronacle batch job scheduling software. This project will create value for the Company and its customers by providing a supported platform for billing, payment, payroll, and financial processing. The scope of this

project includes: (1) upgrading Redwood Cronacle and the associated database to the latest release of the software; and (2) upgrading the operating system. The alternative considered was to not upgrade and agree to the vendor's terms. This alternative was not selected because those terms specify that the system would be unsupported. The Company selected the upgrade to resolve production issues that require vendor assistance.

- The **OSIsoft PI Historian Upgrade** project requires $275,521 in capital and $16,940 in O&M. The OSIsoft PI Historian Upgrade project will maintain application and hardware platform currency for the OSIsoft PI system. The project will create value for the Company and its customers by: (1) reducing security vulnerabilitie; (2) improving efficiencies 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 implementation of: (1) OSIsoft Meter Operational Data Management; (2) OSIsoft Electric Distribution Historian; (3) OSIsoft Generation; (4) OSIsoft Low Voltage Distribution/High Voltage Distribution; (5) OSIsoft Gas Automated Meter Read; and (6) data archiving for analytics purposes. The alternative considered was to delay the upgrade until a future year. The hardware has not been refreshed since 2014. Continuing to delay the upgrade could lead to the inability to apply security and system patch sets. A timely upgrade will allow the Company to sustain system performance and supportability. Other vendors were not considered due to a longstanding Enterprise Agreement with OSIsoft, Inc.

- The **Oracle Server Database Upgrade** project requires $49,259 in capital and $309,754 in O&M. The Oracle Server Database Upgrade project will upgrade Oracle server databases to the next version and supportability across business portfolios. 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 business systems. As this is an upgrade of an existing system the alternative considered was to delay the upgrade. This alternative upgrade was not chosen due to the risk to the stability and supportability of the system.

- The **Itron Field Collection Systems ("FCS") Upgrade** project requires $528,844 in O&M. The Itron FCS Upgrade project will upgrade the Itron FCS and Meter Collection System ("MCS") software to the latest version available while ensuring the underlying hardware is supported, or include a platform refresh as required for maintaining supportability. The value of completing the project is ensuring all features and functionality required by the business partners and IT portfolios are available to enable this billing process to be accurate, stable, and timely. Included in the implementation is upgrading the Itron FCS and MCS applications to the latest versions. This

includes database migration to the latest version supported by the application and a hardware refresh to maintain operating system currency as supported by the application. As part of the review process the alternative considered was to accept all risks as outlined above and not perform the upgrade. However, this was not considered a viable activity since accepting the risk could negatively impact critical gas billing processes.

- The **Itron Enterprise Edition ("IEE") Upgrade** project requires $126,720 in capital and $213,053 in O&M. The IEE Upgrade project will upgrade IEE, the primary control software for bulk interrogation requests from Advanced Metering Infrastructure smart meters and bulk fulfillment of daily billing requests. This project creates value for the Company by: (1) ensuring the new features and functionality added to meet business requirements are available to business partners and IT; (2) meeting Information Security's requirement to keep applications patched to control cyber debt; and (3) allowing for validation, estimation, and editing functions for all data collected. The scope of this project includes: (1) an operating system refresh; (2) migrating from Windows 2012 to the next Windows version; and (3) migrating the database from SQL Server version 2012 to the next SQL Server version. As this is an upgrade of an existing system the alternative considered was to delay the upgrade. This alternative upgrade was not chosen due to the risk to the stability and cyber security of the system.

- The **Service Suite Upgrade** project requires $480,909 in capital and $480,531 in O&M. The Service Suite Upgrade project will implement new Service Suite Work Management that allows for easier distribution to the field and maintains a current version on a vendor supported platform for this mission critical enterprise application used across Operations and Engineering. The product enhancements in Service Suite and TC Technology Mobile Information Management System ("MIMS") will be implemented to provide additional business value and benefits. The project will add value by: (1) implementing a new version that provides the highest level of vendor support for this 24x7 mission critical system that serves over 100,000 work orders weekly; (2) implementing Service Suite Fieldworker Mobile for a touch based interface and migration to cloud based configurations; (3) providing live traffic display on Dispatch Application; and (4) improving readability and usability of Dispatch Application schedule view. The scope of the project includes implementing the new version of Service Suite Work Management including other field supported technology: MIMS Mobile solution for mobile mapping on the field device to improve safety, response, usability and supportability of the mission critical application. The alternatives considered included: (1) remain on the current Service Suite version; or (2) create a custom-developed department solution. These alternatives were not considered because: (1) the alternative to remain on the same version would cause continuation of additional manual steps in the emergency response and work assignment; and (2) the alternative to create a

custom solution would increase waste and inefficiency without the same level of Service Suite integration. Upgrading Service Suite was chosen because it allows the Company to stay on the current and supported version of the application already being used and also adds functionality that will provide additional business value and benefits.

- The **Enhancements - Cloud Automation** project requires $240,674 in capital and $60,696 in O&M. 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 value of this enhancement project is 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. 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 to provide funding for 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 **Time Entry and Expense Reports - Flash Remediation** project requires $33,745 in O&M. The Time Entry and Expense Reports project will replace Adobe Flash with HTML 5 technology. Time entry and approvals and expense report approvals leverage Adobe Flash technology. By the end of 2020, Microsoft will remove the ability to run Adobe Flash in Microsoft Internet Explorer. The value of the project includes: (1) reducing security vulnerabilities that exist in Flash; (2) ensuring employees and managers can enter and approve time so employees are paid on-time; and (3) ensuring managers can approve expense requests for reimbursement. The scope of the project includes: (1) replacing Adobe Flash technology with HTML 5; and (2) eliminating security risks associated with Adobe Flash. Alternatives considered for this project include: (1) Replace the current Adobe Flash solution to HTML 5. This option does not require retraining for 8,000 employees or the development of new custom time entry rules or enhancements. (2) Use Fiori technology that provides mobile capabilities and reduces license and support costs with the external vendor. This would reduce functionality and impose a major training impact on 8,000+ employees. (3) Implement other software applications such as Concur. This alternetive requires integration with SAP, retraining of all employees, additional licensing and support costs, and custom development of rules and redevelopment of enhancements. Alternative (1) was selected because it is the least costly alternative with little to no impact to 8,000 employees.

- The **ISIS Papyrus Upgrade** project requires $55,724 in O&M. The ISIS Papyrus Upgrade project will upgrade the Papyrus Objects suite of applications to the most recent version available per vendor recommendation. The value of this project includes: (1) providing a more stable operational model by upgrading to the most recent version available; and (2) resolving tuning and stability issues with the vendor. The scope of the project is to upgrade the various licensed products that comprise the Papyrus Objects suite of applications. As this is an upgrade of an existing system the alternative considered was to delay the upgrade and continue operating with the current version. This alternative was not chosen due to the risk of application stability and the inability to maintain cyber security patching.

- The **SharePoint Upgrade Project** requires $145,920 in capital and $23,269 in O&M. The SharePoint Upgrade project will implement Microsoft 365 Cloud-based hosting, which extends and enhances the existing SharePoint 2010 platform by providing additional functionalities and an enhanced user experience. This project will create value for the Company and its customers by: (1) maintaining system currency and security; (2) supporting mobile device browsing; (3) maintaining a vendor-supported platform; and (4) increasing audit capabilities. Current vendor support ends in October of 2020. The project scope includes: (1) creating a new SharePoint environment in the next current version; and (2) migrating all applications and data in the existing SharePoint 2010 environment to the new one. Alternatives considered include: (1) fund the full project, which would upgrade all 2010 SharePoint sites; (2) fund 50% of the project, which only would include business-critical SharePoint sites and non-complex user sites; and (3) fund 25% of the project, which only would include non-complex user sites. Alternatives 2 and 3 were not selected because of the increased cost to maintain two SharePoint environments, and the risk of cyber security, stability, and performance of the unsupported version. The selected alternative is to fund the full project to mitigate these risks and minimize application support costs.

- The **SAP Optimization and Tuning** project requires $89,605 in O&M. The SAP Optimization and Tuning project will maintain and improve the operation of the SAP system by addressing data issues within the system, optimizing database structures, and fixing sub-optimal code. The project creates value by improving the performance of the SAP system, which improves the customer's self-service experience and allows employees serving the customer to complete timely transactions. The project scope includes: (1) normalizing multiple account assigned to a single business partner; (2) purging duplicate or unnecessary records; (3) purging unneeded technical data; (4) reviewing and optimizing custom code; and (5) implementing minor service pack updates provided by the vendor. Alternatives considered include: (1) Breaking the scope into individual work efforts to be individually completed. This alternative was not selected

because the efforts are interrelated and completing them separately could lead to duplication of work effort. (2) Balancing the project scope. The scope that is the selected alternative was determined to be the best balance of maintaining the overall SAP performance and optimizing cost.

- The **SiteCore Upgrade** project requires $275,774 in O&M. 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 manager for consumersenergy.com website. 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 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 include: (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 it is not a viable solution at this time; and (3) Annually upgrade the existing Sitecore platform. This alternative was chosen as it provides the functionality and stability needed while meeting financial requirements and mitigating cyber security risks.

- The **SAP Data Archiving** project requires $126,374 in capital and $66,173 in O&M. The SAP Data Archiving project will move outdated data from an online database to offline storage. This project will create value for the Company by increasing system stability by reducing data growth, and maintaining maintenance cost associated with data storage. The project scope includes: (1) archiving data based on the fastest growing and largest objects in SAP; (2) building and archiving solutions that allow the business to retrieve archived data in the required form; and (3) setting up the solution so that the business areas meet compliance standards. Three alternatives were explored and determined non-viable for the project: (1) Allow the database to grow in size. This option was not selected because it would put system performance at risk and result in prohibitive storage costs; (2) Decrease the overall scope and archive less projects. This option was not selected due to minimal positive impact to system growth and significant storage-related costs; and (3) Increase the scope and archive more objects in a shorter timeframe. After considering each of these options, it was determined that the current scope of the project

was the best strategy to achieve the best balance of addressing the problem and balancing annual spending.

- The **SAP Access Controls** project requires $36,518 in capital and $96,900 in O&M. The SAP Access Controls project replaces the current software tool that manages and monitors Sarbanes-Oxley Act ("SOX") compliance for SAP transactions. The project will add value through: (1) reducing risk and eliminating waste through new tools that provide higher levels of automation and process optimization; (2) decreasing maintenance and upgrade costs by implementing the out-of-the-box solution without customization; (3) increasing the ability to meet requirement changes from auditors and the Public Company Accounting Oversight Board; and (4) creating complete and accurate report capabilities. The project scope includes: (1) automating the SAP periodic user access review; (2) automating the emergency access management process; (3) displaying areas of risk and identifying how to mediate that risk; (4) tracking mitigations; and (5) converting the current rule set into the new tool. Alternatives considered include: (1) continue using the current application as-is, accepting the audit risks stemming from the known issues, and continue following current error-prone manual processes. This option was not selected because of the known risk as well as the end of standard SAP support on December 31, 2020. (2) Use Robotic Process Automation in a limited scope to automate some manual tasks and reduce errors. This alternative was not selected because the functionality is too limited to mitigage risks and gaps in the current tool. (3) Develop a custom solution to perform some of the work. This alternative was not selected because it is expected to be more costly and include higher maintenance and support costs. (4) Continue to apply program patches and fixes from SAP to the current tool. This alternative was not selected because it may not address or fulfill all requirements and requires support from an external vendor which increases supposrt costs. (5) Replace the existing tool with a new solution. Alternative 5 was selected because it meets Company requirements, avoids hiring two additional resources, is more cost effective in the long term, adds more process automation, and increases SOX compliance.

- The **S4 HANA Platform Assessment** project requires $45,900 in O&M. The S/4HANA Platform Assessment project will review options for moving to the new platform before the current SAP Platform is no longer supported, currently projected to occur in 2024. 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 2024 end of SAP Support, and ensure that all alternatives have been explored so that 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 utilize in place of S4/HANA; (3) reviewing support options for the existing SAP Platform past

2024; 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 until a later date. This option was not considered since it would not give the Company enough time to prepare for the implementation. (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. The option selected gave the Company the best opportunity to look at all viable options and to have enough lead time for a some transition to the new database.

- The **Application Currency and Enhancements – Corporate Services - Capital** project requires $265,958 in capital and $42,106 in O&M. The Application Currency and Enhancements Corporate Services initiative will utilize both Capital and O&M funding to keep applications current for security and reliability, and make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete the preliminary planning phase for Capital enhancements and upgrades. The project will also upgrade applications that support Corporate Services. The value of regular upgrades to applications in the Corporate Services Portfolio lies in: (1) enhancing security protections; (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 new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services. 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; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Finance; HR; Learning & Development; Legal; Governmental, Regulatory and Public Affairs; Corporate Security; Strategy and IT Governance. Prior to implementing the listed applications, a review was completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements were considered. This project makes ongoing upgrades and support for the listed applications possible and fortifies the Company’s ability to make software

changes as part of process improvements and regulatory changes, and to meet legally required system changes. Timing for an application upgrade is 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.

- The **Application Currency and Enhancements - Analytics, Cloud, DevOps, and Architecture ("ACDA") - Capital** project requires $43,333 in capital and $15,849 in O&M. The Application Currency, and Enhancements ACDA initiative will utilize both Capital and O&M funding to keep applications current for security and reliability, and make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete the preliminary planning phase for Capital enhancements and upgrades. The project will also upgrade applications that support the ACDA Portfolio. The value of regular upgrades to applications in the ACDA Portfolio lies in: (1) enhancing security protections; (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 new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for the ACDA Portfolio. 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; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for areas supported by the ACDA Portfolio. Prior to implementing the listed applications, a review was completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements were considered. This project makes ongoing upgrades and support for the listed applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Timing for an application upgrade is 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.

- The **Application Currency and Enhancements - ACDA - O&M** project requires $56,779 in O&M. The Application Currency and Enhancements ACDA initiative will apply O&M funding to keep applications current for security and reliability, and make enhancements to existing software and to address requests generated by changing business requirements. The project will also upgrade the applications that support the ACDA Portfolio. The value of regular upgrades to applications in the ACDA Portfolio lies in: (1) enhancing security protections; (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 new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for ACDA Portfolio. 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; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for the ACDA Portfolio. Prior to implementing the listed applications, a review was completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements were considered. This project makes ongoing upgrades and support for the listed applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Timing for an application upgrade is 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.

- The **Application Currency and Enhancements – CE&O - Capital** project requires $235,008 in capital and $74,460 in O&M. The Application Currency and Enhancements CE&O initiative will utilize both Capital and O&M funding to keep applications current for security and reliability, and make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete the preliminary planning phase for Capital enhancements and upgrades. The project will also upgrade the applications that support the CE&O portfolio. The value of regular upgrades to applications in the CE&O Portfolio lies in: (1) enhancing security protections; (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 new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for CE&O. 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; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for the CE&O Portfolio. Prior to implementing the listed applications, a review was completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements were considered. This project makes ongoing upgrades and support for the listed applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Timing for an application upgrade is 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.

- The **Application Currency and Enhancements – Corporate Services - O&M** project requires $126,888 in O&M. The Application Currency and Enhancements initiative will apply O&M funding to keep applications current for security and reliability, and make enhancements to existing software and to address requests generated by changing business requirements. The project will also upgrade applications that support the Corporate Services Portfolio. The value of regular upgrades to applications in the Corporate Services Portfolio lies in: (1) enhancing security protections; (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 new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services. 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; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to

provide functionality for areas such as Finance; HR; Learning & Development; Legal; Governmental, Regulatory and Public Affairs; Corporate Security; Strategy and IT Governance. Prior to implementing the listed applications, a review was completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements were considered. This project makes ongoing upgrades and support for the listed applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Timing for an application upgrade is 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.

- The **Application Currency and Enhancements - Infrastructure Applications and Operations ("IAO") - O&M** project requires $125,259 in O&M. The Application Currency and Enhancements - IAO initiative will apply O&M funding to keep applications current for security and reliability, and make enhancements to existing software and to address requests generated by changing business requirements. The project will also upgrade applications that support the IAO Portfolio. The value of regular upgrades to applications in the IAO Portfolio lies in: (1) enhancing security protections; (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 new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for the IAO Portfolio. 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; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for the IAO Portfolio. Prior to implementing the listed applications, a review was completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements were considered. This project makes ongoing upgrades and support for the listed applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Timing for an application upgrade is 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.

- The **Application Currency and Enhancements - OT - Capital** project requires $13,440 in capital and $12,494 in O&M. The Application Currency and Enhancements - OT initiative will utilize both Capital and O&M funding to keep applications current for security and reliability, and make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete the preliminary planning phase for Capital enhancements and upgrades. The project will also upgrade the following applications that support the OT Portfolio. The value of regular upgrades to applications in the OT Portfolio lies in: (1) enhancing security protections; (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 new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for OT, 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; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for OT. Prior to implementing the listed applications, a review was completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements were considered. This project makes ongoing upgrades and support for the listed applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Timing for an application upgrade is 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.

- The **Application Currency and Enhancements - Operations - Capital** project requires $253,532 in capital and $22,338 in O&M. The Application Currency and Enhancements Operations initiative will utilize both Capital and O&M funding to keep applications current for security and reliability, and make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete the preliminary planning phase for Capital enhancements and upgrades. The

project will also upgrade applications that support the Operations Portfolio. The value of regular upgrades to applications in the Operations Portfolio lies in: (1) enhancing security protections; (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 new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Operations. 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; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for the Operations area. Prior to implementing the listed applications, a review was completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements were considered. This project makes ongoing upgrades and support for the listed applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Timing for an application upgrade is 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.

- The **Application Currency and Enhancements - Operations - O&M** project requires $89,708 in O&M. The Application Currency and Enhancements - Operations O&M initiative will apply O&M funding to keep applications current for security and reliability, and make enhancements to existing software and to address requests generated by changing business requirements. The project will also upgrade applications that support the Operations Portfolio. The value of regular upgrades to applications in the Operations Portfolio lies in: (1) enhancing security protections; (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 new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application

investments for Operations. 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; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for the Operations Portfolio. Prior to implementing the listed applications, a review was completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements were considered. This project makes ongoing upgrades and support for the listed applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Timing for an application upgrade is 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.

- The **Application Currency and Enhancements - Transmission, Engineering and Operations Support ("TEOS") - Capital** project requires $135,168 in capital and $2,275 in O&M. The Application Currency and Enhancements TEOS Support initiative will utilize both Capital and O&M funding to keep applications current for security and reliability, and make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete the preliminary planning phase for Capital enhancements and upgrades. The project will also upgrade applications that support the TEOS Portfolio. The value of regular upgrades to applications in the TEOS Portfolio lies in: (1) enhancing security protections; (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 new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for the TEOS Portfolio. 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; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for the TEOS portfolio areas. Prior to implementing the listed applications, a review was completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements were considered. This project makes ongoing upgrades and

support for the listed applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Timing for an application upgrade is 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.

- The **Application Currency and Enhancements - CE&O - O&M** project requires $23,868 in O&M. The Application Currency and Enhancements CE&O initiative will apply O&M funding to keep applications current for security and reliability, and make enhancements to existing software and to address requests generated by changing business requirements. The project will also upgrade applications that support the CE&O Portfolio. The value of regular upgrades to applications in the CE&O lies in: (1) enhancing security protections; (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 new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for the CE&O Portfolio. 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; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for areas supported by the CE&O Portfolio. Prior to implementing the listed applications, a review was completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements were considered. This project makes ongoing upgrades and support for the listed applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Timing for an application upgrade is 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.

- The **Application Currency and Enhancements - TEOS -O&M** project requires $92,792 in O&M. The Application Currency and Enhancements for TEOS initiative will apply O&M funding to keep applications current for security and reliability, and make enhancements to existing software and to

address requests generated by changing business requirements. The project will also upgrade applications that support the TEOS Portfolio. The value of regular upgrades to applications in the TEOS Portfolio lies in: (1) enhancing security protections; (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 new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for the TEOS Portfolio. 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; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for areas supported by the TEOS Portfolio. Prior to implementing the listed applications, a review was completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements were considered. This project makes ongoing upgrades and support for the listed applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Timing for an application upgrade is 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.

Q. Please explain the Digital Foundations and Capabilities projects.

A. These are the Digital Foundations and Capabilities projects:

- The **Digital - Data and Analytics in the Cloud** project requires $348,660 in capital and $51,098 in O&M. The Data and Analytics project will extend the current company's data and analytics environment into a cloud environment which will enable data and analytics at-scale and enable the delivery of outcomes for the Natural Gas Delivery Plan, customer programs other business needs. The project will add value by: (1) providing the ability to perform data analytics at-scale; (2) allowing the ability to leverage the leading Machine Learning ("ML") and Artificial Intelligence ("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 solution; (6) reducing Total Cost Ownership (TCO); and (7) providing

operational tools for monitoring, incident management and resolution. The project scope includes: (1) the execution of data analytics at-scale 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 continue to expand the on-premise infrastructure and purchase multiple tools to solve individual capability gaps. The Company did not chose this alternative because it is a more costly option as the infrastructure itself is more expensive. Also, the man power required to implement is much greater than cloud.

- The **Digital - Work Automation** project requires $50,458 in capital and $125,035 in O&M. The Digital - Work Automation Project will implement and enhance Robotic Process Automation, ML, and AI tools. The Digital - Work Automation project will provide the foundation that will allow business areas to automate key processes based on individual uses case to meet gas, electric and customer plans. Each use case will deliver benefits, reduce errors, and improve overall productivity to support customer and employees of the Company. The scope of the project will be to leverage the existing platforms to provide the foundation of Robotics Process Automation, ML, and AI to support uses cases across all business units. Two alternatives were considered in developing the work automation foundation. The first alternative considered was to continue with existing manual processes. It was determine that moving forward to provide a foundation would benefit the company through benefits of reduce errors and increased productivity. The next alternative considered was to move forward to provide a foundational automation platform. This alternative was selected to allow each business use case to stand on its own for the benefits would allow for the company to maximize use of the tool to maximize benefits.

- The **Digital - Data Governance** project requires $253,078 in capital and $92,884 in O&M. The Digital - Data Governance project will be used to establish data governance roles and responsibilities, processes, and the purchase of a tool to support best practices across gas, electric and customer plans. The project will add value by: (1) increasing productivity of data analysts across the Company from less 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, and establishing processes and cadence for introducing new data elements into their domain; (2) enabling people to become functional and technical data stewards through education; and (3) implementing technology by selecting and implementing a data cleansing, data quality, data extract, and transformation tool, including enterprise-wide

semantic definition. Alternatives considered include: (1) Not implementing a data governance solution; (2) develop an internal tool(s) to help manage the Company's data footprint; or (3) purchase a third party solution. The alternative of purchasing a third party solution was selected because the internal skill sets 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 - Application Programming Interface ("API") Fabric** project requires $332,083 in capital and $92,329 in O&M. The Digital API project will replace the current API Exchange Gateway environment to make use of the API Management Tool which will enable API management and cloud integrations at-scale and enable the delivery of integration needs for the electric, gas, and customer plans. The project will add value by: (1) implementing functionality to perform API services at-scale; (2) allowing partner management; (3) providing the ability to reuse microservices; (4) enabling monitoring of API traffic; (5) implementing functionality to perform API throttling (traffic management); (6) visualizing API traffic and analytics through Key Performance Indicators ("KPI"); (7) providing tools to manage the Software License Agreement ("SLA") for API services; (8) implementing functionality to make use of continuous integration/continuous deployment pipelines for configure and deploy; (9) providing the ability to leverage ML and predictive analytics of API on SLAs, KPIs and Volumetrics; (10) providing tools to provision infrastructure at-scale rapidly; (11) enabling pay-for-use; (12) enabling faster prototyping/testing and deployment of integrations; (13) reducing Total Cost Ownership; and (14) providing operational tools for monitoring, incident management, and resolution. The project scope includes: (1) evaluating multiple API management tool vendors; (2) executing API on-boarding and partner on-boarding at-scale without scalability constraints; (3) configuring and deploying API services with out of the box CI/CD to achieve faster speed to market; (4) phasing out flexible transitioning with technology platforms as they evolve; (5) implementing new services and innovations on the Cloud Software-As-A-Service ("SAAS") Integrations; (6) increasing capacity pay-per-use; and (7) laying the foundation for future digital transformation, cloud integration, and maintenance. Two alternatives were explored and determined non-viable for the Digital Application Programming Interface Fabric: (1) Remain on the TIBCO platform. This option was not selected because it does not support the future needs of the Company including efforts to modernize the grid. (2) Scale back on the implementation of the API fabric over a longer period. This alternative was not selected because API is foundational to other technology efforts and needs to be complete to support other projects. The current scope and direction was the best fit to support current Company initiatives.

- The **Digital - Foundation Enhancements** project requires $90,317 in capital and $81,345 in O&M. The Digital Foundation Enhancements initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements to support gas, electric and customer plans. 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 scope of the enhancement includes requests that will be fulfilled to provide functionality to support the digital foundation, including: (1) advanced analytics; (2) electronic content management; and (3) agile and DevOps, among others. Timing for an application upgrade is 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. 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 to 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 **Cloud Automation Phase 6** project requires $75,500 in capital and $15,432 in O&M. The Cloud Automation Phase 6 project will add additional features and enhancements to the Company's cloud automation platform. 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 deployment in the hybrid cloud; (3) data lake cloud storage automation; (4) automation of ML and AI services; (5) additional lifecycle and governance tooling; and (6) 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 manually at scale is not practical, and severely limits the Company's ability to innovate through 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 **Business Process Performance Monitoring — AppDynamics** project requires $52,469 in capital and $29,326 in O&M. The Business Process Performance Monitoring project will deploy the AppDynamics tool across enterprise applications like SAP, the Outage Management System ("OMS"), and other business critical systems. This project will create value for the Company by providing for visibility into business process performance, AI, and automation, leading to better system troubleshooting, root cause determination and a reduction in mean time to resolution. The project scope includes: (1) SAP; (2) OMS; (3) Advanced Device Metering System; and (4) other enterprise applications. The Company evaluated multiple products for this project and AppDynamics fit the cost and functionality expectations. The others were cost prohibitive and lacked the functionality of the product selected.

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

A. These are the projects included within the Security area:

- The **AccessNOW** project requires $84,480 in capital and $21,367 in O&M. The AccessNow project will implement configurable identity, Access Management functionality and best practices, and will enforce compliance. This project will add value by: (1) reducing waste and failure points through automation; (2) improving and standardizing the business partner experience; (3) centralizing access management; (4) ensuring regulatory compliance; and (5) ensuring system stability and continuous improvement. The project scope includes implementing additional integrations to Active Directory domains that are not currently connected to the AccessNOW application (arreCorp.com, DMZ.cms, ems.com, rtqa.cmsenergy.com, ciphqa.cmsenergy.com) and integration to the Company's SAP system(s) to allow for automation of SAP role access provisioning. In addition, the project scope includes: (1) design, configuration and testing of technical connections; (2) completion of application support pack upgrades to the next version(s) to maintain system stability and to stay current with vendor releases; and (3) review and implement enhancements to improve and standardize the

business partner experience. As part of the review process the alternative considered was using manual processes. This option was not chosen because it was deemed too costly and inefficient.

- The **ARP - Cyber Security** project requires $193,320 in capital. The ARP will replace cyber security infrastructure to support increasing user demands and applications, and to prevent system failures and service interruptions. This program includes projects that bring value to the Company by maintaining the currency of the security infrastructure and core enterprise software. These are used to support and enhance customer interactions as well as ensure the stability of technology for business operations. This project will support continued systems stability. The scope encompasses: (1) evaluation, validation, and replacement of cyber security firewalls and servers; and (2) asset and application upgrades. As part of the review process the alternative considered was to not upgrade or replace assets as required. This approach is likely to introduce security risks, system vulnerabilities, and out-of-warranty repair costs.

Following are the projected capital costs for ARP – Cyber Security project attributable to the gas business for 2020, 2021 and the test year in the table below.

Units	Avg. Unit Cost	Total 2020 Units	Total 2021 Units	Total 2020 Dollars	Total 2021 Dollars	Total Test Year Dollars	Gas Allocation Dollars
CyberArk Appliances	$20,000.00	5	0	$100,000.00	$0.00	$25,000.00	$10,740.00
OT High End PC/Server	$25,000.00	0	2	$0.00	$50,000.00	$37,500.00	$16,110.00
Qradar Server Replacements	$25,000.00	8	10	$200,000.00	$250,000.00	$237,500.00	$102,030.00
Software, labor, contractor and overhead and other costs				$150,000.00	$150,000.00	$150,000.00	$64,440.00
Total Gas Allocation				$450,000.00	$450,000.00	$450,000.00	**$193,320.00**

Following are the actual and projected capital costs for ARP – Cyber Security project attributable to the gas business for 2018 and 2019 in the table below.

Units	Avg. Unit Cost	Total 2018 Units	Total 2019 Units	Total 2018 Dollars	Total 2019 Dollars	2018 Gas Allocation Dollars	2019 Gas Allocation Dollars
Ahead Server Replacement	$119,562.67	1	0	$119,562.67	$0.00	$49,977.20	$0.00

Qradar Servers	$16,950.00	1	0	$16,950.00	$0.00	$7,085.10	$0.00
PA-3020 Refresh	$2,156.00	1	0	$2,156.00	$0.00	$901.21	$0.00
PA-5060's Refresh	$14,014.00	2	0	$28,028.00	$0.00	$11,715.70	$0.00
Symtanec BlueCoat Reporter Refresh	$81,340.30	1	0	$81,340.30	$0.00	$34,000.25	$0.00
Rach Mount Trays for PA-220's	$173.99	44	0	$7,655.56	$0.00	$3,200.02	$0.00
Qradar IBM Refresh	$51,409.00	0	4	$0.00	$205,636.00	$0.00	$63,171.38
Qradar Net New Hardware	$20,700.00	0	4	$0.00	$82,800.00	$0.00	$25,436.16
Qradar High Availability Appliance	$3,921.97	0	2	$0.00	$7,843.94	$0.00	$2,409.66
PA5020's Firewall Replacement	$38,500.00	0	4	$0.00	$154,000.00	$0.00	$47,308.80
Software, labor, contractor and overhead and other costs				$106,460.57	$162,887.57	$44,500.52	$50,039.06
Total Gas Allocation				$362,153.10	$613,167.51	**$151,380.00**	**$188,365.06**

- The **Cloud Access Security Broker ("CASB") Expansion** project requires $9,216 in capital and $510 in O&M. The CASB Expansion project will integrate a security access solution to additional SAAS applications that the Company is using, which help address cloud service risks, enforce security policies, and assist in compliance to regulations. Completion of this project will provide value to the Company through: (1) increasing its security posture for cloud applications by mitigating cloud service risks; (2) enforcing security policies; and (3) assisting in compliance to regulations. The project will plan to move the top five high-risk applications to the CASB solution. The scope of this project encompasses continued integration of the CASB solution into the Company's technical network. The project will aim to integrate CASB with five additional high risk applications. Alternatives considered include: (1) remain at the current state and not continue to integrate the CASB solution into the company's could environments; or (2) continue with additional integrations with CASB solution the Company has invested in. The preferred option is to continue integrations to increase the Company's security posture.

- The **Continuous Readiness in Information Security Program ("CRISP")** project requires $12,902 in capital and $59,500 in O&M. The CRISP project will implement a CRISP, which is a cyber security program coordinated by the Department of Homeland Security ("DHS"). The primary focus of the project is to install a network sensor on the Company's networks to grant

DHS monitoring capabilities for intrusion attempts by nation-state level actors who have intent to impact critical infrastructure. Much of the data used in CRISP is classified, which is why the government will be managing the program and notifying the Company in the event of malicious activity to mitigate cyber security risk. Completion of this project will provide value to the Company through: (1) ensuring that the trust relationship with employees is kept intact; (2) promoting key security habits in all employees; and (3) optimizing the Company's current technologies. The scope of this project encompasses: (1) forming an agreement with the DHS; (2) procuring a network sensor; and (3) working through architecture designs, deployment, and testing of the network sensor. As part of the review process the alternative considered was to not to implement the CRISP, which limits the Company's ability to respond to future advanced threats and vulnerabilities.

- The **Cyber Security Enhancements** project $61,200 in O&M. The Cyber Security Enhancements project will fund emerging or unplanned cyber security activities resulting from audits, incidents, or a changing threat landscape, and support initiatives that may not meet the criteria for a formal project. Requests for this funding are governed by project management and the security governance board, which is comprised of representatives from each area of security and meets monthly to evaluate and prioritize the work. The board assesses requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing software application investments for Security. The enhancement requests are fulfilled to provide functionality for areas such as Security program management, Cyber Security incident response, corporate physical security, compliance, privacy and risk management, and cyber security engineering and standards. As part of the review process the alternative considered was to not upgrade or enhance software or hardware, which could reduce the Company’s ability to respond to future threats and vulnerabilities.

- The **Data Governance** project requires $368,640 in capital and $12,750 in O&M. The Data Governance project will develop an enterprise-wide data governance solution as an aspect of an enterprise data pivacy and management strategy. Completion of this project will provide value to the Company through programmatic data governance resulting in increased data quality which will: (1) increase customer satisfaction; (2) decrease operational cost; (3) increase employee satisfaction and productivity; (4) enhance system performance efficiencies; and (5) support better informed decision making. The scope of this project encompasses: (1) achieving consistency in collecting and reporting data across various organizational users and source systems; (2) achieving high quality in the collection, maintenance, analysis, and reporting of data; (3) responding to data issues; (4) promoting and ensuring consistent enterprise-wide data definitions, increasing controls regarding data

creation, modification, and access; (5) proposing and implementing system controls for maintaining data quality (field level validation, reporting, batch job cleansing, etc.); (6) facilitating the development of a data quality assurance process, including policy, process, and system (including system access) reviews against data; and (7) creating a process to include holistic review of data management methodology for the effective collection, management, and access to for data quality control. Alternatives considered include: (1) remain at the current state and not implement a data governance solution; (2) evaluate, select, and implement a technology solution to fulfill the Company's data governance needs; or (3) determine if any existing solutions the Company has built or purchased can meet the needs. A final decision will be made after requirements and use cases have been reviewed in the planning phase of the project.

- The **Email Protection** project requires $52,224 in O&M. The Email Protection project will implement a company-wide email filtering toolset to ensure protection against current cyber security risks, including malware and non-malware threats, email fraud and ransomware. Completion of this project will provide value to the Company by: (1) evaluating and procuring a leading email filtering toolset; (2) configuring the toolset to help eliminate human error; and (3) implement the toolset enterprise-wide for company email. The scope of this project encompasses protection for both incoming and outbound emails. The project team will need to define and configure system level agreements (SLAs) for "filter" criteria and test to ensure these SLAs are being managed between the solution. The solution is thought to be a cloud service. Alternatives considered were to: (1) implement a technology solution to give more advanced protection against phishing; (2) continue with focused Cyber Security and phishing training programs for employees. Security awareness training has reached peak effectiveness, and a technical solution is needed to further mitigate the risk of human error. A final decision on what solution is implemented will be made during the planning phase of the project.

- The **Enterprise Incident Response Toolset** project requires $15,360 in capital and $850 in O&M. The Enterprise Incident Response Toolset project will implement an incident management platform that enables the Cyber Security Incident Response Team ("CSIRT") to automate alert triage, currently a manual process through technical playbooks, providing greater capability to track and manage incidents, and integrating threat intelligence with security orchestration. The Company will gain value from the completion of this project through improved response time to events, limiting the risk to the Company from a cyber-security incident. The scope of this project encompasses: (1) implementing and incident response tool set which allows for building and automating incident response playbooks; (2) providing basic training to the CSIRT team; and (3) establishing security information and event management access. As part of the review process other automation tool were vetted via on-site demonstrations or webinars. These

tools were not chosen because the selected tool has lower development costs due to integration ability, simplified repairs and supportability, allows for complete control to write integrations, and has resource management features other tool set do not.

- The **Fusion Center** project requires $295,358 in capital and $42,867 in O&M. The Fusion Center Project will procure a location to combine the (physical) Security Command Center and the CSIRT. This project will focus on constructing a physical office space to facilitate these two teams working in a collaborative fashion. This project will add value by: (1) physically co-locating the physical and cyber security command centers; (2) creating an emergency operations area to be used by leadership during major events; (3) evaluating and potentially implementing a shared intelligence capability across both areas; and (4) further integrating existing processes and workflows. The project scope encompasses building an integrated security command center across physical and cyber security domains that takes into consideration physical space, technology, process integration, analytics and intelligence capabilities without changing existing organizational structures. As part of the review process the alternative considered was to continue to run a separate Security Command Center for physical security incident response and a separate Cyber Security Incident Response Center. The two centers would continue to run separate, non-integrated systems and tools. This option was not chosen due to the potential to miss key security vulnerabilities and risks.

- The **Fusion Center Technologies** project requires $345,600 in capital and $34,850 in O&M. The Fusion Center Technologies project will move the Physical and Cyber Security units into a shared work space, with the vision to grow and further integrate these two teams through implementation of new technologies. This project will evaluate, replace, and implement new capabilities for monitoring physical sites and technology assets, significantly improving the Company's quality and timeliness of detection and response to both physical and cyber Security incidents. Completion of this project will provide value to the Company through: (1) implementing a new toolset to move MITRE ATT&CK coverage from 30% to 80% (MITRE ATT&CK Framework is an industry leading framework to detect malicious activity); (2) replacing the vulnerability management platform, Qualys, which has several capability gaps at a significant cost; and (3) evaluating and implementing a bio-metric tool set, such as facial recognition, to eliminate piggybacking issues and to proactively alert to unwanted or unknown personnel at Company facilities. The scope of this project encompasses: (1) all end points and servers and all facilities that house employees; (2) defining system scalability requirements; (3) designing new platform architecture; and (4) purchasing and implementing hardware and software once alternatives are reviewed. Alternatives considered include: (1) remain on current tool sets and not implement additional physical security

countermeasures; or (2) evaluate, replace, and implement new capabilities for monitoring physical sites and technology assets. The preferred option is replace and implement new capabilities because the company has outgrown common tools. A final decision will be made after requirements and use cases have been reviewed in in the project planning phase.

- The **Lock and Key Management System** project requires $230,400 in capital and $12,750 in O&M. The Lock and Key Management System project will identify and implement a physical smart-lock and key management system throughout the Company's service territories. Current estimates show there are approximately 10,000-14,000 locks throughout the state and the Company has no management system to properly manage ownership of specific physical keys and control who uses them to access sites throughout the state. Completion of this project will provide value to the Company by: (1) assessing and taking inventory of current locks and key that are used throughout the state; (2) determining core functionalities needed to ensure proper lock and key management state wide; and (3) reviewing and implementing a solution to give the physical security team a lock and key management capability. The scope of this project includes: (1) an assessment of the type of locks and keys used and at what sites they will be needed to properly plan this project; (2) a determination of the different levels and functions of different smart lock systems available; and (3) purchase and implementation of a lock and key management system based on findings of the assessment. Alternatives considered include: (1) remain at the current state and forfeit implementing new lock and key management capabilities; or (2) evaluate, select and implement a smart lock and key solution. The preferred option is to mitigate known and observed risks with the lack of lock and key management capabilities. A final decision will be made after requirements and use cases have been reviewed in the project planning phase.

- The **Passive Vulnerability Assessment** project requires $11,520 in capital and $850 in O&M. The Passive Vulnerability Assessment project will evaluate, procure, and deploy a tool to passively provide vulnerability assessment services to OT Control Networks. The project creates value for the Company by: (1) obtaining a more accurate and timely lists of assets; (2) improving the ability to make data-driven operational and security decisions; (3) completing an assessment of existing vulnerabilities in the environment without the risk of negatively impacting the reliability of the Company's electric generation and energy delivery systems; and (4) increasing incident response capability, speed, and effectiveness. The scope of this project encompasses evaluating a zero-cost proof-of-concept to determine capabilities and drive the decision to implement an on-site or off-site deployment strategy. As part of the review process the alternative considered was to implement a traditional vulnerability scanner to interrogate all systems on the network. However, this was determined not to be the best solution to fit the Company's requirements.

- The **Physical Security Asset Refresh** project requires $902,160 in capital. The Physical Security Asset Refresh project ensures continued efforts to enhance or replace physical security assets as part of the lifecycle replacement program. The Company has several thousand physical security asset devices currently in use, including security cameras, motion detectors, intrusion detection systems and card access systems. The value provided by completing the project is to maintain compliance, reduce redundancies and gaps in functionality, and optimize overall performance. An integrated solution is efficient and allows for centralized management, situational awareness, real-time monitoring, compliance with regulations and guidelines, and faster, more effective/consistent response to emergencies and incidents. Included in the project is enhancement or replacement of assets including: (1) advanced door systems at Company buildings; (2) security cameras for monitoring capabilities; and (3) gate and lock systems, which includes security cameras, motion detectors, intrusion detection systems, and card access systems. As part of the review process the alternative considered was not to do this work, but this would assume the risk that the Company will not meet FERC requirements.

  Following are the projected capital costs for Physical Security Asset Refresh project attributable to the gas business for 2020, 2021 and the test year in the table below.

Site	Equipment	Total 2020 Units	Total 2021 Units	Total 2020 Dollars	Total 2021 Dollars	Total Test Year Dollars	Gas Allocation Dollars
Adrian	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$3,750.00	$1,611.00
Backup SCC	Install/Replace Assets & Furniture	1	0	$120,000.00	$0.00	$30,000.00	$12,888.00
Bad Axe	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$3,750.00	$1,611.00
Badge Printers	Install/Replace Badge Printers	6	0	$75,000.00	$0.00	$18,750.00	$8,055.00
Battle Creek	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$3,750.00	$1,611.00
Bay City SC	Install/Replace Cameras & Card Readers	4	0	$75,000.00	$0.00	$18,750.00	$8,055.00
Bellevue	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$3,750.00	$1,611.00
Campbell Plant	Install/Replace Cameras	20	0	$150,000.00	$0.00	$37,500.00	$16,110.00

Clare	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$3,750.00	$1,611.00
Cross Winds Energy Park	Install/Replace Network Video Recorder	1	0	$40,000.00	$0.00	$10,000.00	$4,296.00
Flint	Install/Replace Cameras & Network Video Recorder	6	0	$75,000.00	$0.00	$18,750.00	$8,055.00
Fremont SC	Install/Replace Cameras & Network Video Recorder	4	0	$30,000.00	$0.00	$7,500.00	$3,222.00
Grand Rapids SC	Install/Replace Cameras & Network Video Recorder	4	0	$65,000.00	$0.00	$16,250.00	$6,981.00
Groveland	Install/Replace Cameras & Card Readers	2	0	$15,000.00	$0.00	$3,750.00	$1,611.00
Hamilton	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$3,750.00	$1,611.00
Jackson CEIC	Install/Replace Cameras	4	0	$20,000.00	$0.00	$5,000.00	$2,148.00
Kalamazoo SC	Install/Replace Cameras & Network Video Recorder	12	0	$75,000.00	$0.00	$18,750.00	$8,055.00
Laingsburg	Install/Replace Cameras	4	0	$30,000.00	$0.00	$7,500.00	$3,222.00
Lake Winds	Install/Replace Network Video Recorder	1	0	$30,000.00	$0.00	$7,500.00	$3,222.00
Lansing	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$3,750.00	$1,611.00
Livonia	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$3,750.00	$1,611.00
LPS	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$3,750.00	$1,611.00
Ludington SC	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$3,750.00	$1,611.00
Macomb	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$3,750.00	$1,611.00
Muskegon DPO	Install/Replace Cameras	8	0	$36,000.00	$0.00	$9,000.00	$3,866.40

OEP Parking - Gate Arms	Install/Replace Cameras, Card Readers and Gate Arm	16	0	$45,000.00	$0.00	$11,250.00	$4,833.00
Owosso	Install/Replace Cameras	4	0	$35,000.00	$0.00	$8,750.00	$3,759.00
Page Ave Sub	Thermal Radar Test	2	0	$85,000.00	$0.00	$21,250.00	$9,129.00
Parnall NVR 1	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$3,750.00	$1,611.00
Ray Compressor	Install/Replace Cameras & Network Video Recorder	6	0	$75,000.00	$0.00	$18,750.00	$8,055.00
Refresh Security Trailer 1	Install/Replace Cameras	4	0	$20,000.00	$0.00	$5,000.00	$2,148.00
Refresh Security Trailer 2	Install/Replace Cameras	4	0	$20,000.00	$0.00	$5,000.00	$2,148.00
Royal Oak	Install/Replace Cameras & Network Video Recorder	6	0	$75,000.00	$0.00	$18,750.00	$8,055.00
Saginaw SC	Install/Replace Cameras & Network Video Recorder	6	0	$60,000.00	$0.00	$15,000.00	$6,444.00
St. Clair	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$3,750.00	$1,611.00
White Pigeon	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$3,750.00	$1,611.00
White Pigeon - Valve site	Install/Replace Cameras & Intrusion Detection System	4	0	$350,000.00	$0.00	$87,500.00	$37,590.00
Battle Creek	Install/Replace Cameras		15	$0.00	$100,000.00	$75,000.00	$32,220.00
Freedom Compressor	Install/Replace Cameras		6	$0.00	$200,000.00	$150,000.00	$64,440.00
Groveland	Install/Replace Cameras		6	$0.00	$30,000.00	$22,500.00	$9,666.00
Jackson Meter Tech	Install/Replace Cameras		12	$0.00	$85,000.00	$63,750.00	$27,387.00
Jackson Service Center	Install/Replace Cameras		30	$0.00	$135,000.00	$101,250.00	$43,497.00
Lansing	Install/Replace Cameras		15	$0.00	$100,000.00	$75,000.00	$32,220.00
Macomb	Install/Replace Cameras		10	$0.00	$45,000.00	$33,750.00	$14,499.00
Northville Compressor	Install/Replace Cameras		6	$0.00	$200,000.00	$150,000.00	$64,440.00

One Energy Plaza	Install/Replace Cameras		25	$0.00	$175,000.00	$131,250.00	$56,385.00
Overisel Compressor	Install/Replace Cameras		6	$0.00	$200,000.00	$150,000.00	$64,440.00
Parnall	Install/Replace Cameras		25	$0.00	$175,000.00	$131,250.00	$56,385.00
Parnall East	Install/Replace Cameras		12	$0.00	$85,000.00	$63,750.00	$27,387.00
Pontiac Direct Payment Office	Install/Replace Cameras		8	$0.00	$75,000.00	$56,250.00	$24,165.00
Ray Compressor	Install/Replace Cameras		15	$0.00	$100,000.00	$75,000.00	$32,220.00
South Monroe	Install/Replace Cameras		8	$0.00	$75,000.00	$56,250.00	$24,165.00
White Pigeon Compressor	Install/Replace Cameras		15	$0.00	$100,000.00	$75,000.00	$32,220.00
Software, labor, contractor and overhead and other costs				$289,000.00	$220,000.00	$237,250.00	$101,922.60
Total Gas Allocation				$2,100,000.00	$2,100,000.00	$2,100,000.00	**$902,160.00**

Following are the actual and projected capital costs for Physical Security Asset Refresh project attributable to the gas business for 2018 and 2019 in the table below.

Site	Equipment	Total 2018 Units*	Total 2019 Units	Total 2018 Dollars	Total 2019 Dollars	2018 Gas Allocation Dollars	2019 Gas Allocation Dollars
Alma	Install/Replace Cameras		0	$45,165.00	$0.00	$18,878.97	$0.00
Battle Creek	Install/Replace Cameras		0	$62,521.70	$0.00	$26,134.07	$0.00
Benzonia	Install/Replace Cameras		0	$31,313.00	$0.00	$13,088.83	$0.00
Birch Run	Install/Replace Cameras		0	$36,521.00	$0.00	$15,265.78	$0.00
Boyne City	Install/Replace Cameras		0	$31,452.00	$0.00	$13,146.94	$0.00
Cadillac	Install/Replace Cameras		0	$39,030.00	$0.00	$16,314.54	$0.00
Corporate Garage	Install/Replace Cameras		0	$15,749.00	$0.00	$6,583.08	$0.00
East Kent	Install/Replace Cameras		0	$36,689.00	$0.00	$15,336.00	$0.00
Gaylord	Install/Replace Cameras		0	$60,821.32	$0.00	$25,423.31	$0.00
Grand Rapids	Install/Replace Cameras		0	$63,538.00	$0.00	$26,558.88	$0.00
Greenville	Install/Replace		0	$48,245.00	$0.00	$20,166.41	$0.00

	Cameras						
Hastings	Install/Replace Cameras		0	$26,711.00	$0.00	$11,165.20	$0.00
Howell	Install/Replace Cameras		0	$114,187.00	$0.00	$47,730.17	$0.00
Huron Compressor	Install/Replace Cameras		0	$74,502.54	$0.00	$31,142.06	$0.00
IRC	Install/Replace Cameras		0	$44,700.00	$0.00	$18,684.60	$0.00
Midland	Install/Replace Cameras		0	$32,590.00	$0.00	$13,622.62	$0.00
Lansing SC	Install/Replace Cameras		0	$80,496.00	$0.00	$33,647.33	$0.00
Lansing State Building	Install/Replace Cameras		0	$7,979.00	$0.00	$3,335.22	$0.00
Lansing	Install/Replace Cameras		0	$38,638.00	$0.00	$16,150.68	$0.00
Ludington	Install/Replace Cameras		0	$117,659.07	$0.00	$49,181.49	$0.00
Marshall	Install/Replace Cameras		0	$49,826.00	$0.00	$20,827.27	$0.00
Marion Gas Storage	Install/Replace Cameras		0	$25,579.00	$0.00	$10,692.02	$0.00
Mio Dam	Install/Replace Cameras		0	$36,013.04	$0.00	$15,053.45	$0.00
Norton Shores	Install/Replace Cameras		0	$65,563.00	$0.00	$27,405.33	$0.00
OEP	ASM300 Software		0	$32,256.00	$0.00	$13,483.01	$0.00
OEP	Install/Replace Cameras		0	$56,197.81	$0.00	$23,490.68	$0.00
Overisel	Install/Replace Cameras & Network Video Recorder		0	$78,448.77	$0.00	$32,791.59	$0.00
Owosso	Install/Replace Cameras		0	$51,391.00	$0.00	$21,481.44	$0.00
Parnall	IT Card Reader/Camera		0	$34,680.00	$0.00	$14,496.24	$0.00
Royal Oak	Install/Replace Cameras		0	$17,855.00	$0.00	$7,463.39	$0.00
Saginaw T&S	Install/Replace Cameras		0	$29,553.00	$0.00	$12,353.15	$0.00
South Haven	Install/Replace Cameras		0	$104,054.00	$0.00	$43,494.57	$0.00
St. Clair	Install/Replace Cameras		0	$238,761.00	$0.00	$99,802.10	$0.00
Thetford Generation	Install/Replace Cameras		0	$59,379.00	$0.00	$24,820.42	$0.00
Trail Street	Install/Replace Cameras		0	$66,812.00	$0.00	$27,927.42	$0.00
Traverse City	Install/Replace Cameras		0	$17,866.00	$0.00	$7,467.99	$0.00
Adrian	Install/Replace Cameras	0	6	$0.00	$17,655.00	$0.00	$7,584.59

Alcona	Install/Replace Cameras & Network Video Recorder	0	8	$0.00	$29,949.00	$0.00	$12,866.09
Allegan	Install/Replace Cameras & Network Video Recorder	0	6	$0.00	$19,885.00	$0.00	$8,542.60
Alma	Install/Replace Cameras & Network Video Recorder	0	9	$0.00	$43,244.00	$0.00	$18,577.62
Bad Axe	Install/Replace Cameras	0	5	$0.00	$17,592.00	$0.00	$7,557.52
Battle Creek	Install/Replace Cameras & Card Readers	0	3	$0.00	$30,038.00	$0.00	$12,904.32
Bay City	Install/Replace Cameras	0	3	$0.00	$13,541.00	$0.00	$5,817.21
Cadillac	Install/Replace Cameras	0	4	$0.00	$19,990.00	$0.00	$8,587.70
Caro	Install/Replace Cameras & Network Video Recorder	0	4	$0.00	$21,974.00	$0.00	$9,440.03
Clare	Install/Replace Cameras	0	5	$0.00	$15,482.00	$0.00	$6,651.07
Commonwealth	Install/Replace Cameras	0	6	$0.00	$15,020.00	$0.00	$6,452.59
Cooke Dam	Install/Replace Cameras & Network Video Recorder	0	6	$0.00	$26,493.00	$0.00	$11,381.39
Cross Winds	Install/Replace Cameras	0	4	$0.00	$10,349.00	$0.00	$4,445.93
Croton Dam	Install/Replace Cameras & Network Video Recorder	0	8	$0.00	$52,044.00	$0.00	$22,358.10
Five Channels	Install/Replace Cameras & Network Video Recorder	0	16	$0.00	$64,075.00	$0.00	$27,526.62
Foote Dam	Install/Replace Cameras & Network Video Recorder	0	6	$0.00	$24,941.00	$0.00	$10,714.65
Groveland	Install/Replace Cameras & Network Video Recorder	0	9	$0.00	$24,423.00	$0.00	$10,492.12
Hamilton	Install/Replace Cameras & Network Video Recorder	0	6	$0.00	$18,722.00	$0.00	$8,042.97

Hardy	Install/Replace Cameras & Network Video Recorder	0	11	$0.00	$46,989.00	$0.00	$20,186.47
Hodenpyle	Install/Replace Cameras, Network Video Recorder & Intercom	0	10	$0.00	$52,483.00	$0.00	$22,546.70
Jackson Service Center	Install/Replace Cameras	0	9	$0.00	$36,144.00	$0.00	$15,527.46
Karn	Install/Replace Cameras & Network Video Recorder	0	14	$0.00	$106,390.00	$0.00	$45,705.14
Lake Winds	Install/Replace Cameras	0	83	$0.00	$117,942.00	$0.00	$50,667.88
Livonia	Install/Replace Cameras	0	11	$0.00	$25,297.00	$0.00	$10,867.59
Loud	Install/Replace Cameras & Network Video Recorder	0	9	$0.00	$31,916.00	$0.00	$13,711.11
Ludington Pump Storage	Install/Replace Cameras	0	10	$0.00	$26,960.00	$0.00	$11,582.02
Macomb	Install/Replace Cameras	0	8	$0.00	$30,759.00	$0.00	$13,214.07
Midland	Install/Replace Cameras & Card Readers	0	9	$0.00	$49,802.00	$0.00	$21,394.94
Mio	Install/Replace Cameras	0	7	$0.00	$25,127.00	$0.00	$10,794.56
Northville	Install/Replace Cameras, Network Video Recorder & Card Readers	0	20	$0.00	$142,295.00	$0.00	$61,129.93
OEP	Install/Replace Cameras & Network Video Recorder	0	91	$0.00	$369,884.00	$0.00	$158,902.17
Overisel	Install/Replace Cameras	0	3	$0.00	$12,960.00	$0.00	$5,567.62
Overisel Compressor	Gate Camera Monitors Cabling	0	1	$0.00	$6,900.00	$0.00	$2,964.24
Parnall	Install/Replace Cameras & Network Video Recorder	0	36	$0.00	$178,909.00	$0.00	$76,859.31
Pontiac	Install/Replace Cameras	0	4	$0.00	$7,460.00	$0.00	$3,204.82
Roger Dam	Install/Replace Cameras & Network Video Recorder	0	7	$0.00	$30,788.00	$0.00	$13,226.52
Saginaw	Install/Replace Cameras	0	7	$0.00	$32,635.00	$0.00	$14,020.00

South Haven	Install/Replace Cameras, Network Video Recorder & Card Readers	0	39	$0.00	$75,709.00	$0.00	$32,524.59
Traverse City	Install/Replace Cameras & Card Readers	0	10	$0.00	$59,980.00	$0.00	$25,767.41
Webber	Install/Replace Cameras & Network Video Recorder	0	14	$0.00	$56,243.00	$0.00	$24,161.99
West Branch	Install/Replace Cameras & Network Video Recorder	0	12	$0.00	$34,614.00	$0.00	$14,870.17
Zeeland	Install/Replace Cameras	0	21	$0.00	$70,616.00	$0.00	$30,336.63
Software, labor, contractor and overhead and other costs				$34,257.89	$246,949.13	$14,319.80	$106,089.35
Total Gas Allocation				$2,007,000.14	$2,341,168.13	**$838,926.06**	**$1,005,765.83**

*Unit data not available in 2018 for this program; line items include software, labor and, contractor costs

- The **PII Data Discovery Tool** project requires $23,040 in capital and $2,125 in O&M. The PII Data Discovery Tool project will implement software that enables data management decisions for unstructured data, reducing security risk and lowering costs associated with data. The file analysis software scans, maps, and manages unstructured data stores. The Company will gain value from this project through: (1) the added ability to monitor unstructured data for PII/privacy-related data; (2) closing the gap in security visibility; and (3) maturation of the Privacy Program. Additionally, the Company will benefit though discovery of the scope, risk, and opportunities associated with the ever-growing volume of unstructured data. The scope of this project encompasses evaluation, procurement and implementation of a software solution to analyze, index, search, track, and report on file metadata and content. The unstructured data types included in the project scope and analysis consist of: (1) file shares; (2) email databases; (3) content collaboration platforms; (4) records management and Enterprise Content Management ("ECM") systems; (5) Microsoft SharePoint; (6) Log files; (7) Internet of Things (IoT)-generated objects; and (8) data archives. No alternatives were considered beyond the data discovery tool due to the large amount of data that needs to be monitored. Manual or native monitoring techniques are not possible for effective real-time results. By not having a solution in place, the Company will not have visibility into PII data in unstructured data sources.

- The **Radar Intrusion Detection** project requires $422,400 in capital and $17,000 in O&M. The Radar Intrusion Detection project will integrate and deploy new radar detection technology to enable the detection and tracking of individuals at Company sites. The radar would alert in real time and allow for the dispatch of security or law enforcement to investigate. 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 the team is currently experiencing. The scope of this project encompasses: (1) assessing radar intrusion detection solutions to obtain a solution that fits the needs of the Company; (2) establishing a priority list of sites where the solution will be rolled out; and (3) installing updated radar intrusion at physical sites in the Company's service territory with a focus on critical infrastructure sites, including but not limited to gas compressor stations, electric substations, and hydro-electric sites. Alternatives considered include: (1) keeping the current fence intrusion detection solution; or (2) evaluating, selecting, and implementing a new intrusion detection solution. The preferred option is to implement a new solution, given limitations with the current solution that result in multiple false alarms that must be investigated. A final decision will be made after requirements and use cases have been reviewed in the project planning phase.

- The **Replace and Re-badge** project requires $153,678 in capital and $21,250 in O&M. The Replace and Re-badge project will replace and re-badge existing card readers with Human Interface Device Multiclass readers and re-badge employees and contractors with more secure badges, mitigating security vulnerabilities seen with the current legacy technology being used. The value of completing the project is avoidance of the security risk for one of the Company's key security controls. The scope of the implementation includes: (1) replacing existing card readers; (2) re-badging to I-class badges, and (3) encrypting the new badges. As part of the review process the alternative considered was to continue with current, sub-optimal badge readers. This option was not chosen due to the potential to miss key security vulnerabilities and risks.

- The **Security Analytics** project requires $38,998 in capital and $7,926 in O&M. The Security Analytics project will implement the use of data collection, aggregation, and analysis tools for security monitoring and threat detection. These tools can can incorporate large and diverse data sets into detection algorithms, which will assit in data analysis of security incidents, protection from unauthorized users, unintentional modification and compliance shortcomings. Completing the project will provide the value of proactive security incident detection and response, regulatory compliance, and improved cyber forensics capabilities. The project scope includes identifying and implementing a security analytics tool set that collects data from network traffic, endpoint and user behavior, cloud resources, business applications, non-IT contextual data, identity and access management, and external threat intelligence sources. As part of the review process the alternative considered

was to not invest in a new tool. This choice was not selected as it would forfeit a proactive approach and enhanced capabilities for addressing potential cyber incidents. A final decision on tooling will be made after top solutions in this space are compared and vetted internally.

Q. Are the expenditures identified here reasonable and prudent?

A. Yes. The capital and O&M expenditures requested in this case will enable the Company to achieve the outcomes of the Natural Gas Delivery Plan, continually improve the experience of its customers in interacting with the Company, and maintain a reliable, secure, and growing technology base that is exposed to ever-increasing and more serious cyber threats over time. The Company has demonstrated the prudency of project expenditures, support for its operational O&M requirements, and the inability to sustain O&M funding based on a five-year average.

The Company has described how digital investments will enable the Natural Gas Delivery Plan through increased visibility, monitoring and control of the gas system; improved asset and work management capabilities; and advanced analytics and enhanced risk modeling. The Company has thoroughly explained how O&M funding based on a five-year average requires it to prioritize dollars on operating, maintaining and securing existing technology, and does not enable it to make those important gas digital investments. The Company has explained how technology versions have fallen behind reasonable levels, and how funding based on a five-year average does not enable it to patch and upgrade its systems to reasonable levels of version currency. This puts the Company's systems at risk of not being secure to growing cyber threats, available and performing well when customers are both expecting it and depending on it.

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-20650

DIRECT TESTIMONY

OF

PAUL M. WOLVEN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2019

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 had 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 17 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 gas rate case, MPSC Case No. U-20322. I have also testified in two recent Act 9 proceedings: MPSC Case No. U-20618, which requests Commission approval regarding the Company's Mid-Michigan Pipeline, and MPSC 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 expenses associated with supporting Information Technology ("IT") projects, 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-134 (PMW-1)		Summary of Actual & Projected Pipeline Integrity, Corrosion Control, and Cathodic Protection O&M Expense For the Years 2018, 2019, 2020, and Test Year 12 Months Ending September 30, 2021;
Exhibit A-12 (PMW-2)	Schedule B-5.7	Summary of Actual & Projected Gas Capital Expenditures, Regulatory Compliance Program;
Exhibit A-135 (PMW-3)		Actual & Projected Gas Capital Expenditures, Regulatory Compliance Program; and
Exhibit A-136 (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"). 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. 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. 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 that the reliability of the Company's transmission system remains intact by taking measures to prevent an unexpected failure on the system.

Q. What kind of safety and reliability incidents can be prevented through a robust Integrity Management Program?

A. A robust Integrity Management Program is designed to prevent safety related incidents from occurring. One example of this type of safety incident is a pipeline rupture that occurred in Sissonville, West Virginia in 2012.[1] Based on information readily available to the industry, a 20-inch pipeline in Sissonville, West Virginia ruptured due to significant external corrosion on the pipeline. This pipeline was not designated as being located in HCA and therefore was not part of the operators Integrity Management Program. The operator had not performed an ILI of the pipeline and the corrosion control system was not adequate. This incident highlights the threat of external corrosion and the need to assess pipelines outside of HCA. Similar threats can be found in non-HCA as demonstrated by the Sissonville incident. Consumers Energy's transmission system is susceptible to external corrosion, and the Company is taking appropriate actions in assessing and remediating pipelines that may experience this threat within and outside of an HCA.

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

[1] https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1401.pdf

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:

- Identifies HCA and threats to covered pipeline segments;
- 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, and Company-driven changes.

Q. Is the TIMP Manual provided to the MPSC Staff ("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, Exhibit A-36 (CCD-1), discuss Consumers Energy's 10-year plan related to the Pipeline Integrity Program?

A. Yes. Over the ten-year period of the Natural Gas Delivery Plan, 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 will also update its risk ranking methodology and will transition its current relative risk model into a probabilistic risk model over time to ensure investments are concentrated on the right assets. Under the Natural Gas Delivery Plan, the Company will undertake the following:

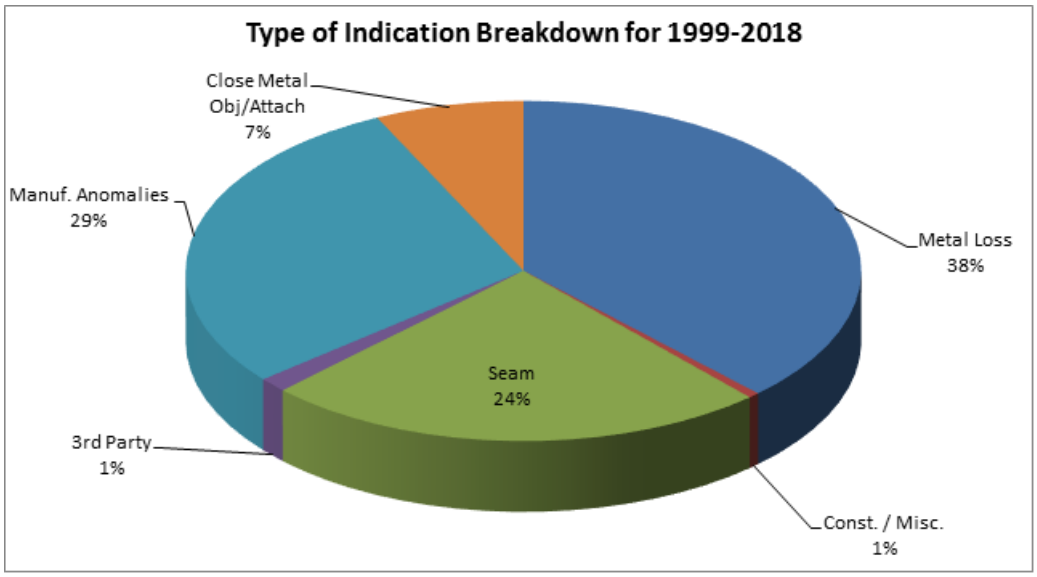
- Create a plan to complete baseline inspections for approximately 90 miles of the Company's transmission system pipeline over the next 5-10 years, and maintain that plan based on a reassessment plan.
- Assess and remediate an estimated 200-300 miles of high-risk pipelines that are prone to Stress Corrosion Cracking ("SCC"), specifically on lines 100A, 100B, 100C, 400, 600, 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.
- 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-36 (CCD-1), Section VII, 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 a number of 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 2018 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; and

6. Third Party Damage includes any dents, deformations, and gouges on the pipelines.

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 transmission integrity management program, and a robust corrosion control process that reduces the corrosion rate on pipelines.

Q. Are there additional threats on the Company's transmission system?

A. Yes. An additional threat on the Consumers Energy transmission system is SCC. SCC is 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 (2016-2019)			
2016	2017	2018	2019 (Through September 30)
3	1	0	19

Q. Has the Company recently identified any new threats to its gas transmission system?

A. Yes. The Company has identified bending strain and/or potential pipe movement on a pipeline due to compressible soils. In November 2017, Consumers Energy experienced a pipeline rupture, the cause of which was due to overburden of the pipeline within compressible soils. The overburden placed enough stress on the pipe to cause the material to fail. To address a bending strain or pipe movement, an operator may need to remove the strain on the pipe via soil removal/replacement or relocate/replace the pipeline so that it is no longer within a compressible soil.

Q. How is the Company addressing this new threat to its gas transmission system?

A. To address this new threat, the Company has begun conducting 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. In support of continuous improvement efforts as part of the Company's TIMP, the Company is taking actions to identify and mitigate the threat of pipe movement on its transmission system. To perform accurate pipe movement studies, a comparison of ILI runs is required where the Inertial Measurement Units ("IMU") tool has also been run on both runs that are being compared. 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, the Company has performed nine bending strain analyses and seven pipe movement studies. The tables below summarize the results of these studies.

Bending Strain

Year	Line #	# of Locations Reported (0.125% +)	Max Strain (%)	# of Locations Reported (0.4% +)
2016/2017	100C Airport to Herrick	3	0.21	0
2017	600-Clarkston to Sq	4	0.43	1*
2018	600-Dixie to Sq	4	0.27	0
2018	1200A-V to Ch	18	0.25	0
2018	1500 – St C to Ro	10	0.26	0
2018	2010 – Sq to Ad	3	0.43	1
2019	1200A-ChtoNo	15	0.24	0
2019	100A- Fr to Dan	6	0.22	0
2019	300 – CB to MRCS	27	0.29	0
2019	1400 – Cl to No	Not Reported Yet	Not Reported Yet	Not Reported Yet

**Note - The reported max strain location coincided with a rupture that occurred in November 2017. This reporting was requested/developed post-rupture. This section of piping was replaced.*

Pipeline Movement

Year	Line #	IMU runs (years)	# of Pipeline Movement Areas[1]	Max Strain associated with movement (%)
2018	600-Clarkston to Sq	2015/2018	0	NR
2018	600-Dixie to Sq	2015/2018	0	NR
2018	1200A-V to Ch	2012/2018	3	0.15
2018	1500 – St C to Ro	2011/2018	3	0.24
2019	1200A-Ch to No	2013/2019	0	NR
2019	100A- Fr to Dan	2013/2019	0	NR
2019	300 – CB to MRCS	2013/2019	0	NR
2019	1400 – Cl to No	Not Reported Yet		

Note 1: Reporting threshold includes 3 factors: (1) max calculated movement greater than or equal to 0.2 m, (2) bending strain pattern has Characteristic Pipeline Movement Pattern, (3) pipeline movement area is longer than 1 pipe spool.
NR – None Reported

Q. Briefly describe the results of the bending strain analyses and pipe movement studies.

A. The bending strain analyses examine the amount of deformation of the pipeline material. Permanent deformation of pipelines or high strain can cause potential leaks, ruptures, cracking, etc. This deformation or high strain can occur due to several factors, including pipeline construction activities, soil subsidence, excessive overburden, grading activities, flooding, etc. Pipeline strain can be identified as vertical, horizontal, or a combination of both. There are two regions of strain: elastic strain and plastic strain. Elastic strain is strain that can be eliminated by removing whatever is causing the strain on the pipeline. Plastic strain is strain that is beyond elastic strain and results in permanent deformation of the pipeline. Pipe movement, in addition to bending strain, can show indications that permanent deformation has occurred on a pipe depending on the significance of the movement and strain. Like pipeline strain, this movement can be horizontal, vertical, or a combination of both. The Company is working with an engineering consultant on

managing this integrity threat and to develop a program to systematically address locations across the transmission system that have strain or a combination of movement and strain that require additional review.

There is no single limit for pipeline movement which is accepted throughout the industry that can be used to determine the significance of the reported pipeline movement areas. When performing bending strain analyses, the output consists of a value of the percentage of strain detected on the pipeline. Locations with a percentage of strain greater than 0.125% are reported. This is the reporting threshold and is not necessarily an indication of a significant level of strain, as this is a value within the elastic region for pipe steels where the material will not permanently deform. At 0.2% strain, the pipe material transitions to a plastic region where permanent deformation can begin to occur. In 2018, there were 35 locations with strain values greater than 0.125% and so far in 2019, there have been 48 locations identified with values greater than 0.125%. The Company will continue to monitor each of these reported locations during the next ILI to see if there is any increase detected in the percentage of strain.

The pipeline strain studies to date have identified two locations with strains above 0.3%, both at 0.43%. One location was the site of a 2017 rupture on Line 600, in which the strain assessment was conducted post-rupture. The ruptured pipe section and surrounding piping has been replaced. The other location above 0.3%, on a different pipeline system, Line 2010, remains in the system at this time. The level of movement, or deflection, for this remaining location is not known, due to the lack of consecutive ILI runs that include the IMU tool. The Company is actively developing a course of action

for this location, which may include a geotechnical assessment and pursuing additional actions to mitigate the strain levels.

The Pipeline Movement studies, which require two ILI runs with the IMU tool, identify areas that not only have measurable deflection, but a strain component as well. The pipeline movement studies conducted to date have identified six locations with combined movement and strain. Three locations were identified on each of two separate lines (Line 1200A and Line 1500). Five of the six locations have a strain level below 0.2%. One location has a strain of 0.24% (Line 1500).

Each of the seven locations outlined above (one strain-only and six movement + strain) are in the process of being reviewed and managed by the Company. The remaining strain-only locations will continue to be monitored as additional ILI runs take place.

Q. Will this data be utilized 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 Christopher J. Varvatos 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 Varvatos. The Gas Transmission Probabilistic Risk Model project and the benefits of the project are described below.

- The **Gas Transmission Probabilistic Risk Model** project requires $49,275 in O&M. The Gas Transmission Probabilistic Risk Model project will implement a risk analysis model for comprehensive predictive risk analysis and modeling on gas transmission pipeline assets. 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. 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 decisions based on improved quality inputs in a measurable model. 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) continuing the use of the relative risk model, but investing in substantial effort to build customization to bring the model into compliance; (2) implementing a custom, Excel-based probabilistic risk model through a consulting effort; and (3) implementing an on-premise probabilistic risk model. The first 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. 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. 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 technology, and an ongoing vendor support and upgrade model.

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. 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 modelling 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 utilize 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 utilized 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 would 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.

Q. Through the MPSC Case No. U-20322 proceedings, the Company indicated that it was going to perform a study of the pre-1970's Electric Resistance Weld ("ERW") seamed pipe. Please provide an update on that study.

A. The Company is planning on performing the study of pre-1970's ERW seam pipe on its transmission system over the next year. The Company plans to engage a third-party integrity engineering firm in early 2020 to assist with performing this study. As discussed in MPSC Case No. U-20322, the study will include the review of the manufacturer and vintage of transmission pipelines containing a Low Frequency-ERW or other susceptible seams. Also, the Company will review the material testing and proof testing it has performed on these pipelines and may apply the results of this testing to analogous pipelines (for example, those with the same material properties and manufacturer). The study will consider whether or not the pipelines have a valid Subpart J pressure test.

Q. Is the Company complying with the MPSC Case No. U-18424 requirements for Pipeline Integrity?

A. Yes, the Company continues to comply with the requirement agreed to as part of MPSC Case No. U-18424. The required documentation was submitted to Staff on March 15, 2019, as set forth in the requirements. Additionally, as part of the order in MPSC Case No. U-20322, the Commission approved an agreement between Staff and the Company that, in the event of an anomaly, Consumers Energy should not replace more than 1.5 times the diameter of the pipeline of additional pipe on each side of the extent of a target anomaly for pipeline replacement, or eight feet, whichever is more.

Q. Under PHMSA's regulations, is the execution of pipeline integrity remediation required to be conducted in a specific manner?

A. No. Pipeline Integrity requires professional judgement, subject matter expertise, and knowledge of the specific pipeline situation being addressed. Pipeline Integrity remediation can be done a variety of different ways. PHMSA requires that an operator remediate various anomalies on a pipeline within certain timeframes based on the severity and type of anomaly. Some examples of remediation are the grinding out of certain defects, the application of composite sleeves, and pipe replacement. It is up to the Company to determine which method should be utilized and how much pipe should be replaced if that option is chosen. The Company must make this determination to increase the safety of the pipeline being remediated. Therefore, these decisions are not dictated by PHMSA within the Pipeline Integrity regulations.

Q. Are the O&M and Capital spending amounts for the Company's Pipeline Integrity Program similar to the amounts projected in MPSC Case No. U-20322?

A. No, they are not. The total amount for the programs is approximately the same. However, based on additional data gathered from 2018 and 2019 remediation, the Company has modified the percentage of remediation digs that it would expect to be capital and O&M. 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 is different than the 30% Capital and 70% O&M outlined in MPSC Case No. U-20322. This percentage was developed based on the Company's experience during 2018 and the first half of 2019, which is shown in the table below.

Based on this new estimated percentage, the projected O&M expenses have increased in the test year versus the historical years.

Total O&M Remediation Digs (January 2018 -June 2019)	Total Capital Remediation Digs (January 2018 – June 2019)	Total Remediation Digs (January 2018 – June 2019)	Percentage of Digs O&M
233	48	281	83%

Q. Are there other repair methods available for remediation digs other than pipe replacement?

A. Yes, there are other repair methods available. Two of the common repair methods are composite reinforcement sleeves and steel compression sleeves. The Company continues to review remediation digs for the potential use of these sleeves. Steel compression sleeves have been used on various seam defects, and composite sleeves have been used on third-party damages (dents and gouges). An example of when the Company has used these sleeves is where an immediate response condition was found, and the Company could not take the line out of service to make the repair. Additionally, in 2018, the Company used repair sleeves on Line 3100 because there are plans to retire the section of Line 3100 in 2021 as part of the South Oakland Macomb Network projects. However, there are some limitations with the use of repair sleeves. For instance, if an anomaly is extensive in length and requires more than one repair sleeve, it may be more economical to replace a section of pipe. The Company's experience with repair sleeves and pipe replacement is they are comparable in cost when comparing digs with similar site conditions. That being said, the Company continues to explore the increased use of repair sleeves as a remediation method when it is in the best interest of its customers.

In 2019, the Company targeted sleeve installation on Line 100A between Freedom Compressor Station and Dansville Valve Site due to the planned retirement and installation of the Mid-Michigan Pipeline. During the remediation, eight sleeves were installed at seven dig locations. The same is planned for next year (2020) on the Line 100A between Dansville Valve Site and Ovid Valve Site for same reasoning. The Company found on this particular pipeline that installing sleeves at all dig locations was not feasible due to interacting anomalies that extended wider than a 3 foot sleeve or the decision was made to cut out anomalies so that more destructive testing (Proof Hydro-testing and Lab Testing) could be performed to increase our knowledge of anomalies discovered.

Q. Please explain the development of the Pipeline Integrity O&M expenses.

A. As shown on Exhibit A-134 (PMW-1), the projected Pipeline Integrity O&M expense for the test year ending September 30, 2021 is $44,044,000. The Company intends to inspect 199 miles of pipe in 2019, 164 miles in 2020, and 357 miles in 2021. Additionally, there are certain baseline assessments on longer pipeline segments that will lead to additional digs. These 26 inspections are for scheduled reassessments, newly identified HCA segments, 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, as demonstrated by the Sissonville incident discussed earlier, and therefore is prudently inspecting and remediating those segments, which are also included in the expenses in this program. Through previous inspections the Company has performed on non-HCA segments of pipeline, it 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.

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 it 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 our 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 and 2019, the Company has completed EMAT tool runs on four pipelines and one pipeline, respectively. By including expenses for the use of EMAT tools and the subsequent remediation in the Pipeline Integrity – Transmission Program in 2018 and 2019, 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 19 locations, which has increased safety, reliability, and resiliency of the pipelines.

Q. Is it reasonable for the Company to utilize the EMAT tool?

A. Yes. The Enbridge oil pipeline (Line 6B) rupture in Marshall, Michigan in 2010 was determined to be caused by corrosion fatigue and near neutral pH SCC.[2] It is prudent for the Company to utilize EMAT tools to identify cracking and SCC in order to minimize the potential for pipeline failures and increase the safety of its Michigan gas transmission system.

Q. What additional benefits to customers does the utilization 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 utilize 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

[2]See https://www.gpo.gov/fdsys/pkg/FR-2014-05-06/pdf/2014-10248.pdf See also https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1201.pdf

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. Utilizing the above grade surveys with prior ILI information can provide indications of possible disbonded coating. SCC Direct Assessment ("SCCDA") (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.

Additionally, the results from the EMAT inspections have allowed the Company to better define soils where SCC may be found. This has improved the SCCDA Program as the soils data is an important part in the SCCDA process. Along the same lines, the EMAT tool is looking for cracking regardless of soil type or other external data. As such, the data is not swayed by prior history or bias based on where SCC has been found on other pipelines. Cracking detected by EMAT in a soil that has not shown prior historical likelihood would still be excavated. In a typical SCCDA methodology, the accuracy of selecting digs that are likely to find SCC is heavily dependent on the statistical relevance of the model. In order to gain confidence in the model, a significant number of excavations must be performed. This is difficult to obtain early on in a program without utilizing a tool similar to EMAT which provides actual pipe wall measurements designed to identify cracking.

Another advantage of the EMAT technology is that it allows for inspection of the entire line from launcher to receiver. SCCDA, without utilizing the EMAT tool, could be

performed only at HCA, or only at locations/soils most likely to have SCC. This would greatly reduce the amount of pipeline that is assessed and would not provide as high a level of safety. Additionally, this would greatly reduce the size of the data set available to identify where SCC is most likely to be found in the future.

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-134 (PMW-1), line 3, for the projected test year, the Company projects O&M expenses in the amount of $1,154,000. The Company will assess 193 miles of pipe in 2019, 272 miles in 2020, and 100 miles in 2021. 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. As shown in Exhibit A-36 (CCD-1), Section VII, the Company is increasing its assessment of TOD pipe as part of the Natural Gas Delivery Plan to increase the safety of its natural gas system, so the projections for the current test year include indirect survey work for the planned increase in TOD Direct Assessment work.

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. A portion of the pipeline cleaning falls into the test year projection for this case. 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. Approximately three miles of pipeline will be cleaned. After the pipeline is cleaned, an ILI using a traditional free-floating pig will be performed on the same segment of pipe to complete inspection of the pipeline.

Q. Please explain the development of the Pipeline Integrity -Transmission capital expenditures.

A. As shown on Exhibit A-12 (PMW-2), Schedule B-5.7, line 1, the capital expenditures for this program were $23,754,000 in 2018 and are projected to be $10,855,000 in 2019; $16,508,000 for the nine months ending September 30, 2020; and $22,533,000 for the 12 months ending September 30, 2021, 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 1

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
($000)		Historical	Projected Bridge Year			Projected Test Year
Line No.	Program Description	12 Mos Ended 12/31/2018	12 Mos Ending 12/31/2019	9 Mos Ending 9/30/2020	21 Mos Ending 9/30/2020	12 mos. Ending 9/30/2021
1	Pipeline Integrity - (Transmission)	23,754	10,855	16,508	27,363	22,533

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 in order 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 our cathodic protection to help ensure system integrity. As discussed previously, the Company anticipates 20% of the remediation digs will be capital. Exhibit A-135 (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-5.7, line 2, the capital expenditures for this program were $7,384,000 in 2018 and are projected to be $6,356,000 in 2019; $5,835,000 for the nine months ending September 30, 2020; and $13,949,000 for the 12 months ending September 30, 2021, 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 2

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
($000)		Historical	Projected Bridge Year			Projected Test Year
Line No.	Program Description	12 Mos Ended 12/31/2018	12 Mos Ending 12/31/2019	9 Mos Ending 9/30/2020	21 Mos Ending 9/30/2020	12 mos. Ending 9/30/2021
2	Pipeline Integrity- Transmission Operated by Distribution (TOD)	7,384	6,356	5,835	12,191	13,949

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 749 UT sensors and 338 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 suspect. 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-135 (PMW-3) provides further details of the expenditures included in this program.

Q. Are there any additional details you would like to provide regarding the projected capital expenditures for the Pipeline Integrity – TOD Program?

A. Yes. In regard to Line 1002 f and g in Macomb County, the pipe along 14 Mile Road between the 14 mile and Schoenherr regulation station and the ITC corridor, has various locations with sediment build-up. Due to the configuration of the pipeline, using a cleaning pig is not an option. Therefore, pipeline replacement will reconfigure the outlet of Red Run City Gate east to the regulation station at 14 Mile and Schoenherr. Pipe will also be replaced along 14 Mile Road at Red Run Street, and at the ITC corridor to allow

the city gate to continue to feed the pipe to the south along the ITC corridor. A portion of the pipe replacement project is included in the Company's capital projections in the Pipeline Integrity – TOD Program.

CATHODIC PROTECTION PROGRAM

Q. Please describe the Cathodic Distribution Program and its O&M expenses.

A. As shown on Exhibit A-134 (PMW-1), line 1, the projected O&M expense for the test year ending September 30, 2021 is $3,608,000 for the Cathodic Distribution 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 54,149 test points that it reads annually, and 1,002 that are read on a bi-monthly schedule. It is projected that 2,694 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 699 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 projected O&M expense for the test year ending September 30, 2021 is $775,000 for the Corrosion Control – Transmission Program, as shown on Exhibit A-134 (PMW-1),

line 2, column (b). O&M expenses for the transmission system include special projects like large atmospheric painting 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) and projected to include additional close interval survey and internal corrosion monitoring.

Q. Please describe the Cathodic Distribution Program capital expenditures.

A. As shown on Exhibit A-12 (PMW-2), Schedule B-5.7, line 3, the capital expenditures for this program were $5,962,000 in 2018, and are projected to be $5,775,000 in 2019, $4,307,000 for the nine months ending September 30, 2020, and $6,131,000 for the 12 months ending September 30, 2021, 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 3

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
($000)		Historical	Projected Bridge Year			Projected Test Year
Line No.	Program Description	12 Mos Ended 12/31/2018	12 Mos Ending 12/31/2019	9 Mos Ending 9/30/2020	21 Mos Ending 9/30/2020	12 mos. Ending 9/30/2021
3	Cathodic Distribution	5,962	5,775	4,307	10,082	6,131

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 906 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-135 (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 Programs allow the Company to maintain compliance with federal regulations for cathodic protection of facilities. As shown on Exhibit A-12 (PMW-2), Schedule B-5.7, line 4, the capital expenditures for the Cathodic Compression, Storage, and Pipeline Program were $387,000 in 2018 and are projected to be $1,043,000 in 2019, $1,641,000 for the nine months ending September 30, 2020, and $1,822,000 for the 12 months ending September 30, 2021, 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 4

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
($000)		Historical	Projected Bridge Year			Projected Test Year
Line No.	Program Description	12 Mos Ended 12/31/2018	12 Mos Ending 12/31/2019	9 Mos Ending 9/30/2020	21 Mos Ending 9/30/2020	12 mos. Ending 9/30/2021
4	Cathodic Compression, Storage & Pipeline	387	1,043	1,641	2,683	1,822

The capital activities included in this program are the installation of new or replacement rectifiers and anode beds, the installation of remote monitoring units, 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 have to occur within one year of identification. As such, the dollar amounts identified for these programs are based on historical averages. Exhibit A-135 (PMW-3) provides further details of the expenditures included in this program.

Q. Please describe Exhibit A-136 (PMW-4).

A. Exhibit A-136 (PMW-4), in accordance with Attachment 11 to the filing requirements prescribed in MPSC 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, MPSC Case No. U-20322.

Q. Can you explain why columns (d), (e), and (f) of Exhibit A-136 (PMW-4), do not contain any data?

A. Yes, the information for column (d), the "Actual Spending in the Test Year," cannot be completed as the test year in MPSC Case No. U-20322, which was the 12 months ending September 30, 2020, is a time period that has yet to transpire as of the filing of this case. Since there is no data to display in columns (d), the information for columns (e) and (f), which seek information concerning the variances from (c) and (d), cannot be completed at this time.

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 technology (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.