BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

RE: IN THE MATTER OF ADVICE LETTER NO. 912-GAS FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 6-GAS TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE ON 30-DAYS NOTICE.	**)** **)** **)** **)** **)** **)** **)** **)**	**PROCEEDING NO. 17AL-____G**

DIRECT TESTIMONY AND ATTACHMENTS OF CHERYL F. CAMPBELL

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

June 2, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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SUMMARY OF DIRECT TESTIMONY OF CHERYL F. CAMPBELL

Ms. Cheryl F. Campbell is the Senior Vice-President, Gas at Xcel Energy Inc. (“XES”). Ms. Campbell is responsible for the oversight of the overall gas business, including strategic planning and public and employee safety in each state in which Xcel Energy operates a gas system[1]. Ms. Campbell’s duties and responsibilities include, among other things, the design, operation, and maintenance of Public Service Company of Colorado’s (“Public Service” or “Company”) natural gas pipeline system.

In her Direct Testimony, after introducing the Company’s other witnesses who are filing Direct Testimony and Attachments in support of the Company’s requested rate increase, Ms. Campbell first describes the Company’s journey to operating in a proactive and predictive manner and the overall vision for the Company’s gas system. She explains the progress the Company has made in incorporating the key principles of

[1] The states include Colorado, Michigan, Minnesota, North Dakota, South Dakota, Texas, and Wisconsin. Xcel Energy does not operate a gas system in New Mexico.

integrity management - know your assets understand the risks and threats to those assets and be proactive in addressing the risks and threats – into our overall management processes. For example, Public Service has been able to reduce the leaks found on its system from the 2015 Phase I by 20 percent. Further since 2012, the beginning of the pipeline renewal programs, all known cast iron pipe, 43 miles of bare steel pipe and 75 miles of polyvinyl chloride ("PVC") pipe have been removed from our gas system.

Ms. Campbell then explains the key risks to Public Service's transmission and distribution systems. In light of these risks, she describes the Company's focus in maintaining both the transmission and distribution systems. Further, Ms. Campbell addresses the various proposed and final rules issued by the Pipeline and Hazardous Materials Safety Administration. Of particular significance in terms of work and cost, is the rule proposed in 81 Federal Register 20722 ("Transmission Rule"), which would impose additional record keeping requirements.

Second, Ms. Campbell testifies regarding the an infrastructure cost recovery mechanism, the Pipeline System Integrity Adjustment ("PSIA"), through which Public Service is permitted to recover the revenue requirements associated with its pipeline integrity management programs, which is due to end on December 31, 2018. If the Company's proposed Multi Year Plan ("MYP") that is comprised of forward calendar years of 2018, 2019 and 2020, is approved, Ms. Campbell explains Public Service's request to roll-in the PSIA into rate base when it ends on December 31, 2018. If however a historical test year ("HTY") for the calendar year ending December 31, 2016 is approved, Ms. Campbell testifies that Public Service will request and extension of the PSIA until December 31, 2020.

Finally, Ms. Campbell discusses the major drivers affecting the gas distribution and transmission costs reflected in the HTY and MYP base rate revenue requirements in this rate case, including, particularly, changes in operations and maintenance ("O&M") expenses and additions to plant in-service. Ms. Campbell also supports (1) key known and measurable adjustments to the 2016 HTY O&M expenses that form the basis for the MYP period and (2) the major gas plant additions to be placed into service during the MYP period.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF COLORADO

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DIRECT TESTIMONY AND ATTACHMENTS OF CHERYL F. CAMPBELL

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LIST OF ATTACHMENTS

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
2010 Phase I	Proceeding No. 10AL-963G
2011 Pipeline Safety Act or 2011 Act	Job Creation Act of 2011
2012 Phase I	Proceeding No. 12AL-1268G
2014 TY	The 12 months ending December 31,2014
2015 Phase I	Proceeding No. 15AL-0135G
2016 HTY	The 12 months ending December 31, 2016
2018 Forward Test Year	The 12 months ending December 31, 2018
2019 Forward Test Year	The 12 months ending December 31, 2019
2020 Forward Test Year	The 12 months ending December 31, 2020
AFUDC	Allowance for Funds Used During Construction
AGA	American Gas Association
AMRP	Accelerated Main Replacement Program
API	American Petroleum Institute
CIS	Close Interval Survey
CAB	Cellulose Acetate Butyrate
CIG	Colorado Interstate Gas
Commission	Colorado Public Utilities Commission

Acronym/Defined Term	**Meaning**
CWIP	Construction Work in Progress
DCVG	Direct Current Voltage Gradient
DIMP	Distribution Integrity Management Program
DOT	United States Department of Transportation
ECDA	External Corrosion Direct Assessment
FERC	Federal Energy Regulatory Commission
Gas Utility	Public Service's natural gas operations
GIS	Geospatial Information System
GOTS	Gas Operations Technical Specialists
HCAs	High consequence areas
HP	High Pressure
Historical Test Year or HTY	Historical Test Year - 12 months ending December 31, 2016
ILI	In-Line Inspection
IP	Intermediate Pressure
IP Line	Intermediate Pressure Distribution Line
MAOP	Maximum Allowable Operating Pressure
MEA	Midwest Energy Association

Acronym/Defined Term	Meaning
MYP	Multi-Year Plan period of January 1, 2018 through December 31, 2020, which includes the 2018, 2019, and 2020 Test Years.
NPRM	Notice of Proposed Rule Making
OCC	Office of Consumer Counsel
PIPES Act of 2016	Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016
PHMSA	Pipeline Hazardous Materials and Safety Administration
PPRP	Programmatic Risk-Based Pipe Replacement Program
PVC	Polyvinyl chloride
PSIA	Pipeline System Integrity Adjustment
PSMS	Pipeline Safety Management System
Public Service, or the Company	Public Service Company of Colorado
ROE	Return on Equity
RSVs	Remote Shut Off Valves
SCADA	Supervisory Control and Data Acquisition
SGA	Southern Gas Association
TIMP	Transmission Integrity Management Program
Transmission Rule	Safety of Gas Transmission and Gathering Lines
Xcel Energy	Xcel Energy Inc.

Acronym/Defined Term	**Meaning**
XES	Xcel Energy Services Inc.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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DIRECT TESTIMONY AND ATTACHMENTS OF CHERYL F. CAMPBELL

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, RECOMMENDATIONS AND COMPANY WITNESS PRESENTATION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Cheryl F. Campbell. My business address is 1800 Larimer Street, Suite 1400, Denver, Colorado 80202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Xcel Energy Services Inc. ("XES"), as Senior Vice-President, Gas. XES is a wholly-owned subsidiary of Xcel Energy Inc. ("Xcel Energy"), and provides an array of support services to Public Service Company of Colorado ("Public Service" or the "Company") and the other operating subsidiaries of Xcel Energy on a coordinated basis. My responsibilities include oversight of the overall gas business, including strategic planning, and public and employee safety in each state in which Xcel Energy operates a gas system[2]. In this position, I am responsible for, among other things, the design, operation, and maintenance of Public Service's Colorado natural gas pipeline system.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Public Service.

Q. PLEASE BRIEFLY OUTLINE YOUR RESPONSIBILITIES FOR PUBLIC SERVICE.

A. I oversee the design, operation, and maintenance of Public Service's gas transmission and distribution pipelines and underground storage facilities. I also direct gas control, gas emergency response and repairs, and gas distribution and gas transmission engineering activities in Colorado, as well as in the other states in which Xcel Energy provides regulated natural gas service. I am also responsible for gas compliance, gas standards, and integrity management programs across Xcel Energy's operating areas and for the gas transportation business on the Public Service gas system. A statement of my education and relevant experience is provided at the end of my Direct Testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony, in brief, is to provide witness introductions, present an overview of Public Service's natural gas business, describe developments, and detail the major contributors to changes in the Company's costs since our

[2] The states include Colorado, Michigan, Minnesota, North Dakota, South Dakota, Texas, and Wisconsin. Xcel Energy does not operate a gas system in New Mexico.

last gas rate case in Proceeding No. 15AL-0135G (“2015 Phase I”).

With respect to Public Service’s gas operations, in Section II of my testimony, I describe the Company’s journey to operating in a proactive and predictive manner and the overall vision for the Company’s gas system. I describe the progress the Company has made in incorporating the key principles of integrity management - know your assets understand the risks and threats to those assets and be proactive in addressing the risks and threats – into our overall management processes. For example, Public Service has been able to reduce the leaks found on its system from the 2015 Phase I by 20 percent. Further since 2012, the beginning of the pipeline renewal programs, all known cast iron pipe, 43 miles of bare steel pipe and 75 miles of PVC pipe have been removed from our gas system.

I then explain the key risks to our transmission and distribution systems. In light of these risks, I describe the Company’s focus in maintaining both the transmission and distribution systems. Further, I address the various proposed and final rules issued by the Pipeline and Hazardous Materials Safety Administration (“PHMSA”). Of particular significance in terms of work and cost, is the rule proposed in 81 Federal Register (“FR”) 20722 (“Transmission Rule”), which would impose additional record keeping requirements.

In Section III of my testimony, I testify to the an infrastructure cost recovery mechanism, the Pipeline System Integrity Adjustment (“PSIA”), through which Public Service is permitted to recover the revenue requirements associated with its pipeline integrity management programs, which is due to end on December 31, 2018. If the Company's proposed Multi Year Plan ("MYP") that is comprised of forward calendar years of 2018, 2019 and 2020, is approved, I explain Public Service's request to roll-in the PSIA into rate base when it ends on December 31, 2018. If however a historical test year ("HTY") for the calendar year ending December 31, 2016 is approved, I explain that Public Service will request and extension of the PSIA until December 31, 2020.

Finally, I discuss the major drivers affecting the gas distribution and transmission costs reflected in the HTY and MYP base rate revenue requirements in this rate case, including, particularly, changes in operations and maintenance ("O&M") expenses and additions to plant in-service. Ms. Campbell also supports (1) key known and measurable adjustments to the 2016 HTY O&M expenses that form the basis for the MYP period and (2) the major gas plant additions to be placed into service during the MYP period.

Q. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR DIRECT TESTIMONY?

A. Yes, I am sponsoring the following attachments:

- Attachment CFC-1: A map of our gas system service territory;
- Attachment CFC-2: Public Service Gas Utility's OSHA Recordable Injury Count;
- Attachment CFC-3: Public Service Gas Utility's Leak Ratio for Distribution Mains;
- Attachment CFC-4: Public Service Gas Utility's TIMP Health Assessment Progress;

- Attachment CFC-5: Public Service Gas Utility's Historical Accelerated Main Replacement Program ("AMRP") Results;
- Attachment CFC-6: PHMSA's Advisory Bulletins'
- Attachment CFC-7: PHMSA Pipeline Rules and Status;
- Attachment CFC-8: PHMSA Presentation on Pipeline Integrity Management;
- Attachment CFC-9: The American Gas Association's ("AGA") Commitment to Enhancing Safety (Revised February 2016);
- Attachment CFC-10: Federal Energy Regulatory Commission ("FERC") Account Details
- Attachment CFC-11: O&M by Cost Element
- Attachment CFC-12: O&M by FERC
- Attachment CFC-13: Public Service Gas Utility's Denver/Metro Peak Hour Firm Requirements;
- Attachment CFC-14: Public Service Gas Utility's Planned Capital Additions for the MYP period of 2018-2020.

Q. WHAT RECOMMENDATIONS ARE YOU MAKING IN YOUR DIRECT TESTIMONY?

A. In brief, I recommend that the Colorado Public Utilities Commission ("Commission") approve:

- if an MYP is approved, the roll-in of the recovery of the costs of PSIA projects into base rates beginning on January 1, 2019, once the recovery of such costs ends under the PSIA on December 31, 2018;
- the Company's request to defer Operations and Maintenance expenses related to the proposed Transmission Rule that will likely become final during 2018 and establish a regulatory asset; and
- the Gas Utility's distribution and transmission business areas' capital

additions for the MYP Test Years as the related costs will be prudently incurred and reasonable and used an useful in providing customer service

Q. PLEASE INTRODUCE THE OTHER PUBLIC SERVICE WITNESSES AND DESCRIBE THEIR AREAS OF TESTIMONY.

A. In addition to my testimony, Public Service is presenting the testimony of the following sixteen witnesses in its direct case:

Table CFC-D-1

Witness	Area of Testimony
Luke A. Litteken	• Presents the Company's Enhanced Emergency Response Program and the related deferral mechanism and a proposal to implement the second phase of this program. • Discusses the Damage Prevention Program and the related deferral mechanism. • Supports for the Supervisory Control and Data Acquisition ("SCADA")/Gas Control Monitoring Improvement Program.
Steven P. Berman	• Presents the Company's revenue requirement and sponsors various schedules that support those revenue requirements. • Discusses the various components of the cost of service and the adjustments made to those components, including rate base, operating revenues, O&M expense, administrative and general expense, taxes other than income taxes, income tax expense, and capital structure. • Supports the jurisdictional and functional allocation used in this proceeding.
Scott B. Brockett	• Supports tariff and the customer impacts of the changes in base rates • Presents the Company's requests in this proceeding and provide much of the policy justification for our positons in this proceeding.

Mary P. Schell	• Discusses the Company's current financial integrity. • Supports the capital structure and cost of capital included in this filing.
John J. Reed	• Provides a recommendation and support for the Company's Return on Equity ("ROE"). • Provides an assessment of the Company's capital structure to be used for ratemaking purposes.
Jannell E. Marks	• Provides historical information regarding customer counts and related sales trends. • Presents and supports the retail gas forecast for the MYP and its methodology. • Discusses and supports the Company's methodology regarding how historical weather normalization is performed.
Paul A. Simon	• Supports the property tax expenses expected to be incurred during the MYP. • Details how property taxes are assessed on the Company.
Melissa L. Ostrom	• Sponsors the plant in-service and other plant-related balances used in the MYP and the HTY. • Supports the MYP depreciation and amortization expenses calculated pursuant to depreciation and amortization rates currently in effect.
Adam R. Dietenberger	• Provides a description of the Xcel Energy organization and how costs flow from Xcel Energy to the Company. • Presents XES and the cost allocation and assignment manual for allocating XES costs to the Company. • Supports the fully distributed cost study detailing the costs that have been assigned and allocated to Public Service's non-regulated activities.

Gregory J. Robinson	• Provides background information regarding Xcel Energy's capital budget development and management processes to support the MYP rate base. • Supports the capital additions related to the GL and WAM Replacement Project. • Presents the responsibilities of the Shared Corporate Business Areas. • Supports the Shared Corporate Business Areas capital additions and O&M expenses included in the MYP, other than the GL and WAM Replacement Project.
Timothy R. Brossart	• Presents the Company's assessment of its existing systems, its decision-making process with respect to the new SAP platform, and its implementation of the GL and WAM systems. • Supports the capital additions related to the GL and WAM Replacement Project.
Richard R. Schrubbe	• Supports the pension and benefits expenses for the Company. • Provides details regarding the actuarial studies provided regarding pension and benefits. • Recommends inclusion of the legacy prepaid pension asset in rate base at the Weighted Average Cost of Capital ("WACC").
Sharon L. Koenig	• Addresses the reasonableness of compensation and benefits (Total Rewards Programs) Xcel Energy provides to its employees; and • Supports the costs included in the January 1, 2016 – December 31, 2016 Historical Test Year ("Historical Test Year" or "HTY") for compensation and benefits are just and reasonable
David C. Harkness	• Supports the O&M and Capital expenditures for Business Systems
Gene H. Wickes	• Supports the Company's requests to include a prepaid pension asset and a prepaid retiree medical asset in rate base; and (2) to earn a return on those assets at the Company's weighted average cost of capital ("WACC").

Mark N. Lowry	• Appraise the plan that Public Service is proposing for its gas services. • Benchmark the Company's proposed revenue requirements in the three MYP years. • Develop an index -based escalator for O&M revenue that includes a productivity adjustment • Use statistical methods to consider whether HTYs improve utility cost performance.

Q. HOW IS YOUR DIRECT TESTIMONY ORGANIZED?

A. My Direct Testimony is separated into two parts. In the first part of my testimony, I will:

- Provide a general description of Public Service's natural gas business;
- Describe Public Service's journey to operating in a proactive and predictive manner and the overall vision for the Company's gas system, including the challenges the Company faces and the plan to address those challenges;
- Explain the various proposed and final rules issued by PHMSA, including the proposed Transmission Rule, which would impose additional record keeping requirements; and
- Provide an update of the Company's Integrity Management Programs, the projects that the Company receives cost recovery under the PSIA and describe the proposals regarding the PSIA and the Transmission Rule.

In the second part of my testimony, I will:

- Provide support for the major cost drivers of the increase requested in this gas rate case related to Public Service's natural gas operations (the "Gas Utility"), including a description of the increases in O&M expenses for the Gas Utility's distribution and transmission business areas between the 2015 Phase I and the 2016 HTY;
- Discuss the key known and measurable adjustments to the 2016 HTY

O&M expenses that form the basis for the MYP period;

- Provide support for the major gas plant additions to be placed into service during the MYP period;
- Sponsor and explain the development of the Gas Utility's distribution and transmission business areas capital budgets for the MYP period;
- Detail how Public Service controls its O&M and capital costs; and
- Detail how Public Service continually monitors the status of its distribution and transmission projects.

II. PUBLIC SERVICE'S GAS BUSINESS

A. Overview of Public Service's Gas Business

Q. PLEASE PROVIDE AN OVERVIEW OF PUBLIC SERVICE'S NATURAL GAS BUSINESS.

A. As a regulated natural gas public utility, Public Service is in the business of purchasing, transporting, distributing, and reselling natural gas to customers in Colorado. Except for a small segment of our gas transportation business, our rates and services are regulated exclusively by this Commission. Public Service's natural gas operations are a large and important part of the overall gas, electric, and steam utility services that the Company provides to Colorado customers.

As depicted in the map in Attachment CFC-1, the Company's natural gas pipeline network extends north from the San Juan Basin in southern Colorado through the San Luis Valley over Rollins Pass to the Front Range, and then terminates near the Wyoming border. The Front Range System extends south from near the Wyoming state line through the Denver metropolitan area. The system extends just across the Douglas County line, through and including Highlands Ranch, and also includes the City of Pueblo and its environs. The system also extends from Grand Junction to Steamboat Springs on the Western Slope.

Public Service's natural gas system is comprised of over 2,100 miles of transmission pipelines, over 21,000 miles of distribution pipelines, and approximately 1.2 million individual service lines. It also includes about 37,000 horsepower of compression located at 17 distinct sites around the state, two natural gas storage fields, and two gas processing plants. It is a diverse system, spanning rural, suburban, and urban environments. Public Service employs approximately 800 employees to operate and manage the system of which about 60 percent are bargaining employees.

Public Service provides gas sales and transportation service to many Front Range communities (*e.g.*, the greater Denver metro area, Fort Collins, and Pueblo), the Western Slope (*e.g.*, Grand Junction, Rifle, Meeker, etc.), and mountain resort communities (*e.g.*, Alamosa, Steamboat Springs, Copper Mountain, Vail, Durango, Pagosa Springs, Crested Butte, and Leadville). We operate facilities in 30 of the 64 counties within the state.

Public Service's system has direct access to major gas supply areas in Colorado, including residue plants in the Denver-Julesburg Basin, the San Juan Basin, and certain production fields on the Western Slope. Through gas transportation capacity held on upstream interstate pipelines, Public Service also is able to access major gas supply areas in Wyoming, Colorado, Utah, Texas, Kansas, and Oklahoma.

The Company provides natural gas service to residential, commercial, and industrial customers, as well as to gas-fired electric generation facilities. Public Service is the upstream gas transportation service provider for several local gas distribution systems owned and operated by Atmos Energy Corporation, the Town of Center, Colorado Natural Gas, Inc., and Black Hills Corporation. The

Company also transports gas in interstate commerce by delivering gas supplies to interconnected pipeline systems that subsequently transport the gas to out-of-state markets. This interstate service is regulated by the FERC and is provided pursuant to a limited-jurisdiction certificate of public convenience and necessity issued by the FERC in 1992. *See Public Service Co. of Colorado*, 61 FERC ¶ 62,012 (1992).

Q. PLEASE PROVIDE A BREAKDOWN OF THE NUMBER OF GAS CUSTOMERS SERVED BY PUBLIC SERVICE AND THEIR ANNUAL USAGE.

A. At the end of 2016, the Company had approximately 1.4 million natural gas sales customers, residential and commercial, and over 7,000 transportation customers. The number of customers and their usage by class and type of service are explained in Table CFC-D-2 below:

Table CFC-D-2

2016 Customer Profile		
	Number of Customers	Volumes (Dekatherms)
Residential Sales	1,265,001	90,842,431
Commercial Sales	100,954	37,093,559
Interruptible Sales	12	467,472
Transportation	7,480	114,251,037

B. Moving Public Service's Gas System into the Future

Q. WHAT IS THE BASIC MISSION OF PUBLIC SERVICE'S GAS BUSINESS?

A. Our mission is to provide safe and reliable service to our Colorado customers. This goal is paramount. We understand that natural gas service is absolutely critical to the State of Colorado and its citizens. When customers need natural gas for heating or any other end use, we must be ready to provide that service on demand. Moreover, we must design and operate our system to ensure the safety of our customers, our employees and contractors, and the public.

Q. DOES PUBLIC SERVICE PROVIDE SAFE AND RELIABLE SERVICE TO ITS CUSTOMERS?

A. Yes. However, we cannot be complacent. In fact, like the rest of the gas industry in the United States, Public Service is focused on operating in a proactive and predictive manner.

Q. IN THE 2015 PHASE I, YOU DESCRIBED PUBLIC SERVICE'S TRANSFORMATION FROM A GAS UTILITY THAT OPERATES IN A REACTIVE MANNER TO A GAS UTILITY THAT OPERATES IN A PROACTIVE AND PREDICTIVE MANNER. IS THAT TRANSFORMATION COMPLETE?

A. Public Service has made great strides on its transformation to a gas utility that operates in a proactive and predictive manner since the 2015 Phase I. However, our transformation into a gas utility that totally operates in a proactive and predictive manner is not complete. As with most transformation efforts, this is a journey in which Public Service is actively engaged.

Q. IN ITS JOURNEY TOWARDS OPERATING IN A PROACTIVE AND PREDICTIVE MANNER, WHAT IS PUBLIC SERVICE'S OVERALL VISION FOR THE DESIGN AND OPERATION OF ITS GAS SYSTEM?

A. The overall vision for the Company's gas system is to ensure that the natural gas (a combustible substance) that we deliver to customers remains in our transmission and distribution pipelines until the point of use. While the overall vision may seem simple, it becomes complicated as we work to incorporate the key principles of integrity management into our overall management processes. These key principles can be summarized as know your assets, understand the risks and threats to those assets and be proactive in addressing the risks and threats. We must also balance this work with the needs of our customers and communities.

For instance, a key distribution risk is leaks from vintage, leak prone materials such as cast iron, bare steel, vintage steel and early polymers. These materials have significantly higher leak ratios than modern plastics and steel, creating a public safety hazard. Our programs are designed to systematically renew these materials over time. At the same time, we are monitoring that risk by performing an accelerated leak survey on these materials so we can continue to update health and condition information, improve our selection of the next renewal project and protect the public around the gas system. Since 2008, with the creation of the AMRP and then through the PSIA, Public Service has been working to replace these problematic pipe materials and, in fact, has replaced all known cast iron pipe on its gas system and much of the bare steel. Up until recently, our leak ratio has been climbing, suggesting that we had not yet been proactively replacing these outdated materials. Recent data suggests that the leak ratio is stabilizing and looks to be starting to decline – an indication that we are moving more into a proactive mode on managing leaks on the system. I discuss the accomplishments of our integrity programs as well as top risks and threats later in my Direct Testimony.

Public Service is also working to improve its overall asset knowledge, systematically working through key legacy data gaps. Federal rules make it clear that each individual pipeline operator is responsible for identifying and evaluating the risks on its system and for addressing those risks in a proactive manner. This ability begins with understanding the assets and threats, which begins with records and information about those assets. Programs, such as In Line Inspection ("ILI") Assessments (transmission), Pipeline Data Project - Distribution, Intermediate Pressure Distribution Line ("IP Line") assessments, Accelerated Leak Survey (distribution), have provided valuable information to improve safety and business decisions. However, the work is ongoing and the PHMSA continues to add to record keeping requirements.

Finally, when an event does occur on its gas system, Public Service's response should be quick to render the event site safe. The Company has made great strides regarding emergency response times but there continues to be room for improvement as discussed by Company witness Mr. Luke A. Litteken in his Direct Testimony. If an event requires a shutdown in order to effectuate repairs, then Public Service should minimize the impact to a manageable number of customers to re-light timely while maintaining public and system safety. Furthermore, Public Service should be able prevent certain outages through (1) improved monitoring, which allows the Company better visibility of the gas system and directs employees to a site before an event occurs; and (2) redundancy of key assets and points, which reduces outages and improves public and employee safety.

1. Progress Made to Date

Q. WITH RESPECT TO THE THREE KEY ITEMS OF INTEGRITY MANAGEMENT – KNOW YOUR ASSETS, IDENTIFY RISKS AND THREATS TO ASSETS, AND PROACTIVELY MITIGATE THOSE RISKS/THREATS, HAS PUBLIC SERVICE MADE PROGRESS TOWARDS THE OVERALL VISION DESCRIBED ABOVE?

A. Absolutely. With Distribution Integrity Management Program ("DIMP"), Transmission Integrity Management Program ("TIMP"), and the recovery allowed through the PSIA, the Company has made great progress enhancing the safety and reliability of its gas system. Progress has been made with respect to a number of key indicators, including leak ratios, renewal, asset health, and records improvement.

Q. WHAT PROGRESS HAS PUBLIC SERVICE MADE ON LEAK RATIOS?

A. Attachment CFC-3 provides historical leak information for pipeline mains. In 2014, the test year for the 2015 Phase I, the Company recorded 813 leaks on underground mains or 0.037 leaks per mile of main. In 2016, that has been reduced to 655 leaks or 0.030 leaks per mile of main. This represents approximately a 20 percent reduction in leaks found on gas mains which suggests that Public Service has identified and properly prioritized the correct mains to renew through our pipe replacement programs.

Q. WHAT PROGRESS HAS BEEN MADE ON THE PIPELINE RENEWALS?

A. The Company has made great progress with pipeline renewals. All known cast iron has been removed from our system. Also, 43 miles of bare steel and 75 miles of PVC have been removed since the beginning of the Company's systematic pipe renewal programs which began in 2012. Our ability to plan ahead of time, minimizing customer inconvenience and maximizing impact to public safety has been a great benefit of the PSIA program.

Q. WHAT PROGRESS HAS BEEN MADE ON ASSET HEALTH ASSESSMENTS?

A. 'Know your assets' is a main point in the Company's integrity management program, and health assessments are a pivotal aspect of accomplishing that goal. The Company has made significant progress with health assessments going from 34 percent of transmission pipeline mileage assessed in 2011 up to 66 percent in 2016. On our distribution system, since 2013, 144 miles of IP lines have had health assessments. Attachment CFC-4 provides an overview depicting both historical and forecasted health assessments performed by year.

Q. WHAT PROGRESS HAS BEEN MADE RELATED TO RECORDS IMPROVEMENT?

A. Regarding records improvement, since end of 2014 the Company has reduced the miles of main in our Geospatial Information System ("GIS") with unknown vintage by 43 percent while increasing the total mileage by 1.4 percent. . Additionally, with the Maximum Allowable Operating Pressure ("MAOP") verification research, 100 percent of pressure test records for transmission lines have been evaluated for traceability, verifiability, and completeness which has helped the Company establish the basis for remediation projects in anticipation of the PHMSA's Notice of Proposed Rulemaking titled "Safety of Gas Transmission and Gathering Pipelines" which proposes to amend 49 CFR 191 and 49 CFR 192. For the purposes of my testimony I will refer to this notice of proposed rulemaking as the "Transmission Rule.[3,4]" Research has now started on material records which will form the basis for material verification in accordance with proposed section 49 CFR 192.607. Public Service Company also will work on the valves, regulators and other appurtenances for these pipelines – as they must also meet the proposed rules for MAOP and material verification.

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[3] PHMSA published 81 FR 20722 to the Federal Register as a Notice of Proposed Rulemaking to amend 49 CFR191 and 49 CFR 192, Docket No. PHMSA-2011-0023

[4] https://federalregister.gov/a/2016-11240

Q. IS PHMSA CONTINUING TO FOCUS ON RECORDS?

A. Yes. This continued focus by PHMSA on records improvement is demonstrated by the pending “Transmission Rule”, which proposes expanding TIMP records requirements not only for MAOP verification, but for investigations, tests, analysis, assessments, repairs, replacements, alternations and other actions. The focus of this new rule is to have asset records which are traceable, verifiable, and complete, or taking action when they are not.

Q. HOW HAS PUBLIC SERVICE’S PROGRESS IN THESE KEY INDICATORS HELPED IT TO UNDERSTAND THE THREATS TO ITS GAS SYSTEM?

A. For the distribution system, the top three threats to distribution mains are pipe - weld or joint failure, excavation damage, and corrosion. Pipe weld or joint failure, and excavation damage have tended to be the top two, occasionally exchanging places as the top threat. For distribution services, the top threats are equipment failure, pipe - weld or joint failure, and excavation damage. Equipment failure for distribution services has consistently been the top threat. Progress made in monitoring leak ratios for specific pipe types and vintages has helped us identify and prioritize renewal of higher risk assets. For example, evaluating distribution leak trends for coated steel by installation year resulted in identifying the 1950-1955 vintage coated steel cohort as having the highest leak rates. Many of our DIMP renewal projects are focused on this cohort of vintage coated steel. Health assessments as well as improved leak tracking on IP lines have identified mechanical coupling failure, corrosion and third party damage risks on our IP system. The health assessments have also provided information on corrosion prevention and the condition of the coating on these lines leading to renewals of approximately ten miles of vintage IP lines, a number of coating repairs and changes to our corrosion prevention program.

Our assessment program for transmission assets has identified the top three threats as external corrosion, construction, and third party damage. Based on what we've learned, we have made changes to our corrosion prevention program, particularly around electric transmission lines, improving corrosion prevention for these assets. MAOP records research has helped us prioritize assets for remediation, including pressure testing or renewal. We also now have enough data to see trends with specific cohorts, areas or vintages, leading to improved identification of potential anomalies. In short, we can track how anomalies are changing over time and better determine when and how to repair or replace an asset.

Q. BASED ON THE KNOWLEDGE GAINED, WHAT PROACTIVE ACTIONS HAS PUBLIC SERVICE TAKEN TO MITIGATE RISKS TO ITS GAS SYSTEM?

A. As the Company has made progress with records improvement, the information has greatly informed our risk ranking and prioritization of integrity work, allowing us to appropriately focus our efforts on mitigating the greater risks on our system. For example, as mentioned earlier, segregating vintage steel by cohort led to higher leak ratios for the 1950-1955 cohort for those assets, which led to the discovery of problematic mechanical couplings and screw fittings installed during that period. The Company then gave a higher prioritization to renewal for those assets which will have a larger impact to reduce operating risk on the system. Additionally, the Company accelerated the inspection of the 8” North San Luis Valley pipeline due to findings on similar vintage lines in similar terrain. This line was made ready for ILI tools in 2016 and is currently scheduled for a full health assessment in August 2017. ILI health assessments have led to repairs of anomalies identified on transmission pipelines, some of them serious. An example is a 2013 assessment which identified over 80 anomalies on the Fraser to Frisco pipeline, all of which have been mitigated. In addition, part of this line was relocated away from residential homes and out of a water table, helping maintain the health of the line going forward. This pipeline experienced a failure in a remote area in November of 2012 that could have negatively impacted almost 30,000 customers. Another example is MAOP research, which determined that the 1954 vintage Wellington lateral had insufficient records to support the necessary MAOP to maintain service to customers. This pipeline was replaced in 2016 with modern steel and construction methods ensuring safe, reliable service into the future.

Q. GIVEN THE O&M AND CAPITAL COSTS EXPENDED TO MAKE THE NECESSARY INVESTMENTS IN ITS GAS SYSTEMS, HOW DOES PUBLIC SERVICE COMPARE TO ITS PEERS WITH RESPECT TO O&M EXPENSE PER CUSTOMER OR COST PER DECATHERM ("Dth") BASIS?

A. According to an AGA benchmarking study utilizing 2015 data, Public Service O&M expense ratio of $59 per customer ranks in the lowest quartile compared to peer gas utilities meaning Public Service's O&M costs per customer are lower than the majority of its peers. In addition, Public Service's total cost to customer continues to be lower than the majority of its peers, showing that we've made tremendous progress on our integrity programs, while staying competitively priced.

Q. DOES XCEL ENERGY PARTICIPATE IN THE DISCUSSION OF PIPELINE SAFETY AT THE NATIONAL LEVEL?

A. Yes. The Company remains extremely active with regulating authorities and other pipeline operators through industry trade associations (including AGA, Midwest Energy Association ("MEA"), Southern Gas Association ("SGA")), the United States Department of Transportation ("DOT") Gas Pipeline Advisory Committee, industry benchmarking (including the AGA peer review) and industry conferences. In addition, the Company has adopted API RP1173[5] Pipeline Safety Management Systems, and is actively working to close identified gaps in

[5] Recommended practice released by the API establishing a PSMS framework for organization that operate hazardous liquids and gas pipelines jurisdictional to the US Department of Transportation

current processes. My leadership team participates at many levels in the above groups/discussions and we have been recognized for a number of best practices to improve public and system safety. A few examples include:

- Use of excavation simulator and development to a welding lab to improve employee training;
- Development of a Gas Boot Camp for employees in leadership positions with limited gas experience;
- Use of a standards committee with representation from field, office, technical and standards groups, driving engagement and standardized processes;
- 2017 AGA SAVE Award external video category for public safety;
- Process to prioritize pipeline renewal projects prioritizes risk over construction efficiencies;
- 90 percent of HCA's are piggable and company is driving use of ILI to gain superior knowledge of health and condition of transmission system ;
- Company is utilizing transmission assessment principles on critical distribution IP lines; and
- Company has a well-developed plan for the MAOP validation process.

2. <u>Paths Forward for the Transmission and Distribution Systems</u>

Q. WHAT ARE THE KEY RISKS ASSOCIATED WITH TRANSMISSION AND DISTRIBUTION SYSTEMS?

A. The key risks identified for transmission systems are defined in 49 CFR Part 192, Subpart O, Section 192.917. These risks include time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking; static or residual threats, such as fabrication or construction defects; time independent threats such as third party damage and outside force damage; and human error. The Company performs periodic inspections to monitor the condition of assets based on these threats. In 2016, Public Service inspected approximately 227 miles of transmission pipeline and identified 378 anomalies which required repairs. As previously stated, Public Service's top three threats to its transmission system are external corrosion, construction, and third party damage.

With respect to the distribution system, the key risks are defined in 49 CFR Part 192, Subpart P, Section 192.1007. These risks include corrosion, natural forces, excavation damage, other outside force damage, material, or welds, equipment failure, incorrect operations, and other concerns. In 2016, the Company eliminated/repaired over 1,000 leaks on mains caused by these threats. Pipe weld or joint failure was the leading cause of main leaks in 2016, representing 40 percent of all leaks repaired.

Below I will discuss the paths going forward for the transmission and distribution system.

a. The Transmission System

Q. GIVEN THE RISKS DESCRIBED ABOVE, WHAT IS PUBLIC SERVICE'S KEY FOCUS FOR THE TRANSMISSION SYSTEM MOVING FORWARD?

A. Public Service has a three prong approach to managing its transmission system: continued heath assessments, ongoing improved recordkeeping, and strategic investments.

Q. PLEASE EXPLAIN HOW CONTINUED HEATH ASSESSMENTS WILL HELP TO MANAGE THE RISKS ASSOCIATED WITH THE TRANSMISSION SYSTEM.

A. The Company's proactive approach to operating and maintaining its gas systems relies on risk assessments of potential threats to each gas transmission pipeline. Based on this evaluation, assessment method or methods are identified. Industry best practices, as well as the Company, have determined that ILI provides the most comprehensive profile of the integrity of a pipeline, including assessment for multiple threats. Other approved assessment methodologies (pressure testing or direct assessment) only assess for a single threat. Most pipelines have more than one threat, making ILI tools that address multiple threats a good choice. Furthermore, ILI tools are improving significantly every year, allowing us to see more potential anomalies on pipelines before they become risks to reliability or safety.

Each defect or anomalous condition found is tracked, and a timeline developed that provides an approximation to when it might compromise the integrity of the pipeline. The Company can then address the condition before it reaches an unsafe level. This method allows us to compare the changes in anomalies since the last time a health assessment was performed, consider interaction of multiple threats and determine a course of action. In many cases, the action is monitor through ongoing health assessments at regular intervals.

Since program inception, over 60 percent of the gas transmission system has been inspected using ILI tools. These assessments have identified approximately 3,800 anomalies that have been repaired and/or eliminated, significantly increasing the safety and reliability of the system. Other anomalies continue to be monitored to ensure ongoing safe operation.

It is important to note that pipeline operators are expected to understand threats to the entire system, to apply the knowledge gained across all pipelines in the system, and to implement preventative measures to mitigate risks on all assets in the system.

As new information becomes available, or threats to the system emerge or change, the Company evaluates and incorporates this knowledge into its program. This entails determining the extent of the risk and developing new or modifying existing measures to mitigate the risk. In some cases, the health and condition of some pipelines have been determined to be better than anticipated, which allows us to direct our resources on assets that have a higher level of risk.

Q. PLEASE EXPLAIN HOW RECORDKEEPING WILL HELP TO MANAGE THE RISKS ASSOCIATED WITH THE TRANSMISSION SYSTEM.

A. A key building block in managing pipeline system risk is asset knowledge, or know your assets. This information allows us to monitor how health is changing over time and how threats might be interacting with each other. For instance, corrosion near a dent can create a more current threat than corrosion alone or a dent alone. In addition, crews knowing that three repairs over five years for the same issue at a particular regulator station might change our preventative maintenance on that regulator station or lead to a decision to replace the regulator station. In short, more asset knowledge and overall record keeping helps make more informed decisions around repair versus replace as well as when to perform preventative maintenance on an anomaly. Overall, this will improve safety and improve efficiencies over time as we can perform the work when other activities are occurring in that area.

Q. WHAT STRATEGIC INVESTMENTS WILL HELP TO MANAGE THE RISKS ASSOCIATED WITH THE TRANSMISSION SYSTEM?

A. Public Service continues to perform health assessments and make repairs per the prescriptive requirements of the federal code. In addition, the Company is installing remote shut off valves ("RSVs") as well as additional Supervisory Control and Data Acquisition ("SCADA") points to monitor the transmission system. RSVs allow an operator to shut down a segment of pipeline from Gas Control, which helps minimize the impact of an unplanned gas release. While the final PHMSA rules on placement of this equipment remains a work in process, Public Service has completed approximately 25 percent of the risk-based identified sites through 2016. In addition, Public Service has begun to install additional SCADA sites to more effectively and completely monitor its gas transmission system which should be completed in 2019. This allows Gas Control to more quickly identify potential problems and dispatch an operator to correct an operational issue before it becomes a more involved event. Please see Mr. Litteken's Direct Testimony for a discussion of additional SCADA sites and the benefit to our customers. These types of strategic investments improve public safety as well as our ability to respond, lowering overall call outs, outages and costs over time.

b. The Distribution System

Q. GIVEN THE RISKS DESCRIBED ABOVE, WHAT IS PUBLIC SERVICE'S KEY FOCUS FOR THE DISTRIBUTION SYSTEM MOVING FORWARD?

A. As previously discussed, leaks on vintage, leak prone materials is currently the first or second threat to the Company's distribution system. The Company will continue to systematically renew known problematic pipe types as well as perform accelerated leak survey to monitor these material types and ensure the safety of the public. In addition, the Company will continue to conduct heath assessments on IP pipelines to monitor health and identify other threats for these assets. Any newly identified threats will be evaluated against our current risk model and prioritized appropriately. Additionally, some of the aforementioned SCADA points are located on the distribution system, allowing Public Service to more quickly see and respond to change operating conditions.

Q. PLEASE DISCUSS THE KNOWN PROBLEMATIC PIPE TYPES THAT PUBLIC SERVICE WILL RENEW IN ORDER TO MITIGATE RISKS.

A. Public Service is actively pursuing renewal of several different problematic pipe types including vintage steel, Aldyl-A, coupled IP mains, bare steel and PVC. These programs focus on replacing the poorest performing pipe types, most of which are 40 plus years old, with modern plastics and steel. These programs are currently managed through the Programmatic Risk-Based Pipe Replacement Program ("PPRP") and AMRP programs within the PSIA. In 2017, through the PPRP, Public Service plans to replace over 30 miles of main, over 3,500 services and test or move over 1,000 meters. Additionally, through the AMRP in 2017, the Company estimates replacing approximately 36 miles of PVC main, four miles of bare steel, almost 2,000 distribution services, and performing air-tests and tie overs for 650 services. These estimates are based on historical trends, and actual results will depend on the final field conditions encountered. Attachment CFC-5 provides a summary of historical AMRP results.

The risks that these pipe types pose are supported through several PHMSA advisory bulletins[6] which discuss in detail the known issues with the aforementioned pipe types and provide remediation recommendations. The relevant PHMSA advisory bulletins can be found in Attachment CFC-6. The Company's experience with these pipe types matches industry experience. The Company has made significant progress in eliminating these threats and intends to maintain focus on renewal until the threat is eliminated. Since the beginning of these programs, the Company has replaced approximately 230 miles of problematic pipe including removing all known cast iron. There remains approximately 640 miles of PVC, bare steel, Coupled IP, Aldyl-A and vintage steel in the system which the Company plans to replace by 2024. In the 2017

[6] https://phmsa.dot.gov/pipeline/regs/advisory-bulletin

PSIA Filing, a detailed Five Year Business Plan for the 2017-2021 period can be found in Exhibit 4 and a full listing of all planned projects can be found in Exhibit 11 filed on November 28, 2016 in Proceeding No. 16AL – 0883G.

Q. PLEASE DISCUSS HOW ASSESSMENTS OF IP LINES WILL HELP MITIGATE THESE RISKS.

A. Federal Pipeline Safety rules require that operators determine and implement measures to reduce the risks from failure of their gas distribution pipelines. The IP system is comprised of steel pipe susceptible to the threats of corrosion, manufacturing defects (material defects, long seam defects), construction methods (compression couplings and welds), and third party damage. The consequence associated with a failure of these pipelines is heightened due to the higher operating pressures and the location of many of these lines in heavily developed areas in the Denver metro area.

The Company is applying the knowledge gained from assessing transmission pipelines to assessments of IP distribution lines. Assessment methodologies include ILI and indirect surveys. As a result of the lower operating pressures of IP lines as compared to transmission pipelines, ILI can be difficult or impracticable. The number of current products on the market that perform ILI of distribution lines while a pipeline is in service is extremely limited, but under development. After piloting a robotic smart tool in 2012, the Company concluded the tool could provide significant information on the health and condition of select, critical IP pipelines. However, battery life limitations, which limit the range of the tools to distances much shorter than ILI tools used on TIMP Assessments, make robotic ILI tools economically infeasible for all but the most critical applications. Indirect surveys typically include Close-Interval Survey ("CIS") and Direct Current Voltage Gradient ("DCVG") surveys commonly utilized as part of External Corrosion Direct Assessment ("ECDA") on transmission pipelines. These surveys are used to assess for external corrosion and third party damage threats. The CIS technique provides information on the level of cathodic protection on coated steel pipelines. A complementary survey, DCVG, provides information on the condition of the coating on the pipeline. To date, the Company has conducted 144 miles of indirect surveys on IP distribution pipelines. These assessments have identified areas of inadequate corrosion protection and the Company has made repairs to the pipelines as well as the corrosion prevention systems.

3. Path Forward for Integrity Management

Q. YOU MENTIONED EARLIER IN YOUR DIRECT TESTIMONY THAT PUBLIC SERVICE NEEDS TO CONTINUE TO IMPROVE ITS OVERALL ASSET KNOWLEDGE. WHAT IS THE PATH FORWARD FOR INTEGRITY MANAGEMENT?

A. Under the Federal Rules, integrity management can be broken down into three parts: know your assets; identify the risks and threats to these assets; and be proactive in mitigating those risks and threats. The Company will continue to improve asset data over time, which allows more effective risk based decisions.

We have already seen instances where improved information has changed a decision about an asset. In addition, the Company will continue to stay engaged at the national level, benchmarking with peers as well as in the rule making process. We will also monitor key metrics to show changes to programs over time.

Q. CAN YOU DESCRIBE THE PROGRAMS CURRENTLY IN EXISTENCE TO RENEW OR MITIGATE AND HOW THOSE PROGRAMS WILL EVOLVE OVER TIME?

A. Current renewal programs include bare steel, early polymer plastics (primarily PVC and Aldyl-A), coupled IP, and vintage steel. Renewal for these known problematic pipe types will decrease and cease as the known inventory moves to zero (as it has with cast iron). Risk models will allow us to monitor other threats that might trend upward, and develop plans to mitigate and manage it before it becomes a larger program such as the vintage steel. For instance, I previously discussed our ability to isolate the 1950-1955 vintage steel cohort that is creating a lot of leaks on the system today. The couplings used during that time period, prevalent through about 1960, are failing. And while we are not currently focused on assets in the 1956-1960 timeframe, we are monitoring that cohort for increased failures.

4. <u>Customer Service</u>

Q. HOW WILL THE COMPANY'S OVERALL VISION OF ITS GAS SYSTEM IMPACT CUSTOMER SERVICE?

A. Ultimately the purpose of moving to a proactive and predictive manner of operating is to ensure we are providing safe and reliable service to our customers. Our customers expect this day in and day out. We currently have very few outages on the system and seek to maintain that trend. In addition, we'd like to improve the customer experience by improving our emergency response times – not having customers wait for long time periods for a responder to arrive and investigate an issue.

Q. HOW HAVE THE PROGRAMS AND PROJECTS THAT PUBLIC SERVICE HAS UNDERTAKEN ENHANCED CUSTOMER SERVICE?

A. The Enhanced Emergency Response Program that was approved in the 2015 Phase I has improved Public Service's response metric and the Company has made progress overall in responding to customer calls. As explained further by Mr. Litteken, as Public Service has continued to improved so has its peers, it is critical to continue to decrease the Company's response time to events because as I said earlier, the safest place for the gas that is delivered to our customers is in the Company's pipes. To the extent that an event occurs, Public Service needs to be on site quickly to mitigate the risk and maintain safety, avoiding injuries or property damage.

Furthermore, Public Service's damage prevention program has helped reduce the number of damages per 1,000 locate requests by approximately 27 percent since 2007. As described in detail in Mr. Litteken's Direct Testimony, maintaining a robust damage prevention program is extremely important to quickly and accurately respond to requests to locate our facilities and ensure that our facilities and assets are not damaged by a third party. It's also important to note that this program is required by statute, and is free to our customers when they call.

Q. PURSUANT TO THE OVERALL VISION YOU DESCRIBED ABOVE, WHAT ARE PUBLIC SERVICE'S PLANS TO CONTINUE TO ENHANCE SERVICE TO ITS CUSTOMERS?

A. As we continue to reduce leak ratios on the system, public safety improves. Other preventative maintenance programs also reduce costs over time – it is cheaper to operate a system with minimal after hour call outs than it is to repair it once there is an issue. The aforementioned SCADA systems will also improve visibility, improving public safety and reducing emergencies over time. Getting a knowledgeable responder on site prior to an event and potentially stopping the event from occurring is always better than managing an event – from a public safety, customer cost and service perspective.

Q. HOW HAVE THE PROGRAMS AND INVESTMENTS THAT THE COMPANY HAS ALREADY INSTITUTED AND PLANS TO INSTITUTE BENEFIT CUSTOMERS?

A. Public Service's system operating risk is less than it was in 2011 when the PSIA was initially approved. We can measure this by the stabilizing and declining leak ratios, the improvements in damages per 1,000 locates and the number of gas transmission repairs we have made. In addition, response times have decreased and methane emissions are down as leaks are repaired quicker and avoided. By many measures, the system is safer today than it was in 2011.

5. PHMSA Rules That Will Impact Gas Operations

Q. HAS PHMSA ISSUED OR FINALIZED RULES THAT WILL IMPACT PUBLIC SERVICE'S GAS OPERATIONS?

A. Attachment CFC-7 shows upcoming rules, rules in process and rules that have recently been published. Many of these are from National Safety Transportation Board ("NTSB") recommendations in the aftermath of San Bruno[7], the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Pipeline Safety Act" or "2011 Act"), or the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 ("PIPES Act of 2016"). I want to highlight a few of these to demonstrate what they entail and the impact they will have on Public Service Company's gas utility.

[77] "San Bruno" refers to the explosion of a 30" natural gas pipeline on September 9, 2010 in the residential neighborhood of San Bruno, California.

The excess flow valve rule was originally proposed in July 2015 with the final rule published October 2016 with an effective date of April 17, 2017. The rule requires operators to:

- expand installation of excess flow valves to multi-family homes, small commercial customers where loads do not exceed 1,000 standard cubic feet per hour CFH;
- notify eligible existing customers of their right to request installation of an excess flow valve on their service line; and
- install either manual shut off valves or excess flow valves ("EFVs") on new or replaced service lines with loads in excess of 1,000 SCFH. These valves must be installed in a way to be accessible in an emergency and are subject to regularly scheduled maintenance.

While this rule change may seem straight forward, it takes quite a bit of time and work to make the change. For instance, the following occurred: (1) Supply Chain needed to obtain the equipment for increased installation of EFVs; (2) crews had to be notified of the change and any necessary training updated; (3) Regulatory needed to determine who would pay for customer requested EFVs and discuss with Commission Staff; (4) Communications developed the notification information and updated the internet site; (5) Customer Care needed to understand the change and how to handle customer requests for EFVs; and (6) Engineering and Designers needed to understand the change, be trained if appropriate and incorporate the change into designs and maintenance plans developed for larger emergency valves and EFVs for larger service lines. As we install more EVF's, it will have an impact on our costs as this maintenance is all O&M.

Q. ARE THERE OTHER RULES YOU WOULD LIKE TO HIGHLIGHT?

A. Yes. The interim final rule for underground gas storage went into effect on January 18, 2017. This rule expands safety regulations into gas storage for the first time, and it requires development of training, integrity plans, emergency plans, periodic monitoring and more in accordance with API RP 1171. We've completed an initial gap analysis against API RP 1171 as well as the interim final rule incorporating changes in our plans. Public Service Company is also installing more wellhead safety valves to address this new rule.

One of the more significant rules in process is the Safety of Gas Transmission and Gathering Lines ("Transmission Rule"). This rule was originally proposed in August 2011, and a notice of proposed rulemaking was published in April 2016. Industry and other stakeholders are providing comments to PHMSA, and the next Pipeline Advisory Committee meeting on this rule is June 6 and 7, 2017. The rule is expansive and includes topics such as recordkeeping requirements (including requiring records are traceable, verifiable and complete), clarifying the definition of transmission versus distribution lines, strict requirements for MAOP verification and material verification, expanded corrosion control programs and expanding integrity assessments into "moderate consequence areas" or MCAs. As proposed, this rule would require operators to test or re-test pipelines in the absence of complete records. This is a rule we are carefully monitoring as it will have a significant impact on operators across the United States, including Public Service Company.

The Company will remain engaged as these rules work through the regulatory process. Once rules are final, the Company will develop plans to implement, utilizing existing technology and systems as much as possible.

Q. WHAT IS PSMS?

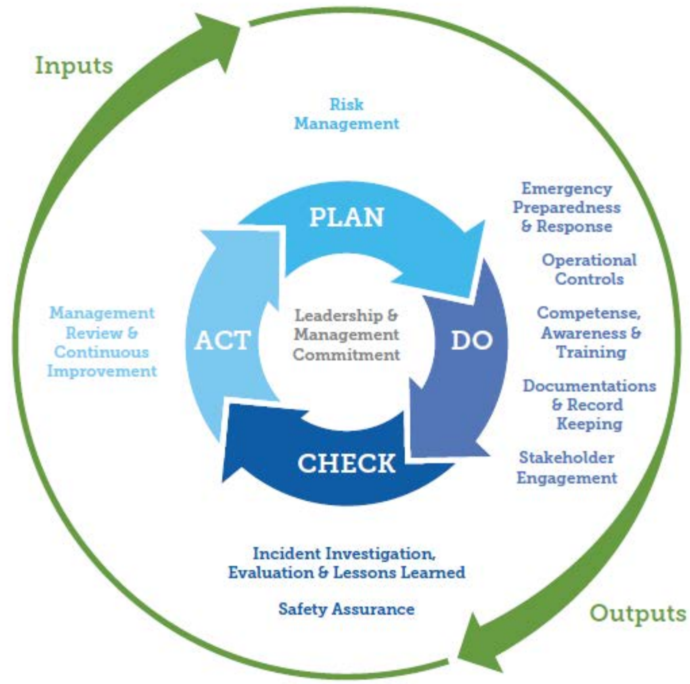
A. A group of industry experts, along with safety experts, developed the Pipeline Safety Management System ("PSMS"), released in 2015. The PSMS was released as API RP1173 and while it is not mandatory, PHMSA is monitoring adoption within the industry. Public Service adopted PSMS in late 2015 as the framework to help improve our overall operating management system and further improve public safety. The PSMS document is available from API on their website[8].

The Company completed a preliminary gap analysis shortly after adopting API RP1173. Based on that gap analysis, the Company decided to focus on incident investigation, management of change and Incident Command in 2016. In 2017, work will continue in all these areas. It is important to note that a safety management system is a journey, and the Company will continue to learn over time and make adjustments to its operating protocols and overall management system as it finds gaps.

[8] http://www.api.org/~/media/files/publications/whats%20new/1173_e1%20pa.pdf

PSMS focuses on continuous improvement and the plan, do, check, act cycle that so many of us are familiar with. Figure CFC-D-1 provides the framework highlighting this cycle.

Figure CFC-D-1



As shown in Figure CFC-D-1, many of the items the Company has been working on over the last five to six years are included (operational controls, emergency preparedness and response, documentation and record keeping, et cetera). The Company intends to continue to work on implementation of PSMS, improving operations and public safety over time.

Q. WHAT IS PUBLIC SERVICE COMPANY DOING ABOUT CYBER SECURITY FOR ITS GAS ASSETS?

A. Public Service works with the Transportation Security Administration ("TSA"), which is part of the Department of Homeland Security for both cyber and physical security for its gas assets. We were last reviewed by TSA in 2015, with the report date in December 2015. There were no recommendations or considerations and TSA identified eight industry best practices they were going to share with other companies. But we are not standing still. We recently reviewed our gas assets and control systems, identifying several other changes we can make to continue improving cyber security. I expect those changes to be made over the next few years as part of Xcel Energy strengthening its overall cyber security. In addition, our Chairman, President and CEO, Ben Fowke, sits on the National Infrastructure Advisory Council. We are actively engaged at the national level on cyber security and continue to look for cost effective measures to ensure the overall security of our assets and control systems.

III. THE COMPANY'S INTEGRITY MANAGEMENT PROGRAMS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I will discuss the Federal statute and rules that require the integrity management programs. I will also explain the progress made under these integrity management programs, including discussion on leak ratio performance, shifting system threats, asset health assessments and our path moving forward regarding our integrity management programs. Finally, I will discuss the Company's proposal regarding the PSIA and recovery of costs for certain proposed PHMSA rules.

A. Federal Statute and Rules Initiating the Integrity Management Programs

Q. ARE THE COMPANY'S INTEGRITY MANAGEMENT PROGRAMS REQUIRED BY STATUTE OR RULE?

A. TIMP[9] and DIMP[10] are federally-mandated programs. These rules provide clear guidance that each individual pipeline operator is responsible for identifying and evaluating the risks on their systems and addressing those risks in a proactive manner. While the requirements under DIMP are designed to allow operators some flexibility in dealing with the risks that are unique to their systems, there are prescriptive rules governing specific dates by which transmission pipelines must be assessed and anomalies remediated.

[9] 49 CFR Part 192, Subpart O Regulations; Gas Transmission Pipeline Integrity Management
[10] 49 CFR Part 192, Subpart P Regulations; Gas Distribution Pipeline Integrity Management

Q. WHO REGULATES THE SAFETY OF THE COMPANY'S NATURAL GAS PIPELINES?

A. While Congress delegates certain responsibility and funding to states, overall responsibility for pipeline safety rests primarily with PHMSA, which is the administrative arm of the DOT. The Commission conducts its pipeline safety program with regard to intrastate pipelines in Colorado in accordance with PHMSA's state pipeline safety certification regulations. PHMSA also oversees any supplemental state-specific safety requirements.

Q. DO PIPELINE SAFETY REGULATIONS SPECIFY THE FULL EXTENT OF ACTIONS A PRUDENT OPERATOR IS EXPECTED TO UTILIZE WHEN OPERATING THEIR SYSTEM?

A. No. Within the section defining the overall scope of the regulations within 49 Part 192.1 it states the following:

> *What is the scope of this part?*
>
> *(a) This part prescribes minimum safety requirements for pipeline facilities and the transportation of gas, including pipeline facilities and the transportation of gas within the limits of the outer continental shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).*

The pipeline safety regulations, or code (including the federal code and complementary codes adopted by the states), were never meant to be all-inclusive. In other words, the federal code prescribes the minimum that should be done to construct, operate, and maintain a natural gas system. Inherent in the code, and in the integrity rules, is the requirement that pipeline operators do what is reasonably necessary for the public good. PHMSA has stated publicly that operators are solely responsible for the safety of their gas systems and are expected to take action as necessary for the public good. Attachment CFC-8 is a presentation given by Alan Mayberry of PHMSA at an API pipeline conference in 2014. Mr. Mayberry was recently named the Associate Administrator for Pipeline Safety for PHMSA. Mr. Mayberry's message is operators need to move beyond basic compliance and build robust risk management systems with performance goals. He also stresses adopting and developing a pipeline safety management system as a framework for these risk management systems (see slides 5-10 in Attachment CFC-8). In short, PHMSA does not view the code as the only activities to keep pipelines safe, but that operators understand their assets, the threats against those assets and then proactively move to address issues. Basic compliance with prescriptive rules is not sufficient to continue to drive the incident rate down.

Q. HOW HAVE INDUSTRY GROUPS RESPONDED WITH RESPECT TO GAS OPERATORS GOING BEYOND MINIMUM CODE?

A. The AGA originally released its "Commitment to Enhancing Safety" in October 2011 with the most recent update published February 2016. AGA's "Commitment to Safety" describes how member companies are going beyond minimum compliance with current regulations to ensure the safety of the nation's 2.4 million miles of gas transmission and distribution pipelines. A copy of AGA's Commitment to Safety is contained in Attachment CFC-9. The report was prepared at request of federal and state officials having oversight of pipeline safety.

The Company is an active member of the AGA and fully supports the Commitment to Safety. The Company is implementing the actions that the report lays out as part of its ongoing mission to provide safe and reliable service to our Colorado customers.

Q. WHAT CHALLENGES DO YOU SEE AHEAD FOR THE INTEGRITY MANAGEMENT PROGRAMS?

A. There are a number of challenges facing the Company's integrity management programs. The first is that the DIMP and TIMP plans must reduce operating risk over time and ensure that all specific federal requirements are met. This regulatory landscape continues to evolve as demonstrated by the numerous advisory bulletins issued by PHMSA as well as the pending "Transmission Rule."

A second challenge is the timing and prioritization of resources. Resources must be allocated where they will provide the best value to customers in terms of safety and cost. This resource allocation requires considerable analysis and judgment. The result is some projects can be completed within a short period, but others must be completed over years as it is not cost-effective or practical to complete all projects in a short period. For these long-term projects, the Company develops schedules or milestones to ensure that the ultimate goal will be achieved. Furthermore, not all projects have a completion dates. TIMP pipeline assessments and mitigation of identified risks is an ongoing obligation.

Third, integrity management plans need to be flexible enough to account for uncertainties or new legislative and regulatory developments. The litmus test of an effective plan is not whether the planned activities were carried out exactly as forecasted, but whether the plans were based on the best information known at the time and were flexible enough to adapt to unforeseen changes. As new information becomes available (*i.e.* based on the "know your assets" criteria), the short-term and long-term plans should be modified to capture this knowledge.

For example, the Company works diligently to coordinate its assessments, repairs, and renewals with the communities in which the Company performs its work. This might include other planned utility work or street reconstruction or paving activities. This minimizes costs and inconvenience to our customers. When scheduling and executing projects in the field, the Company strives to minimize impacts on the affected communities; however, the requirements of local governmental bodies might change the scope, cost, and/or timing of various projects. We strive to accommodate changes within the construct of our overall risk management, but keep the safety of the public at the forefront of planning our work.

There are a variety of factors that impact resource needs in any given year. While the Company uses its experience to forecast potential repairs and replacements, the results of the assessments themselves drive the amount of repair and renewal work during the year. In addition, unforeseen weather and natural disasters, such as the 2013 floods or recent wildfires, also impact our ability to complete planned integrity management work.

Finally, another fundamental challenge is emerging and/or pending regulations. Such changes, particularly if they entail the completion of specific activities by certain dates, usually require the Company to modify its long-term plans to incorporate the new projects which result from new regulation. The Company regularly reviews communications received from PHMSA in the form of advisory bulletins published in the Federal Register and considers this information when stepping through the phases of "know your system, identify threats, and proactively mitigate risks."

The Company considers all of these challenges when developing its plans including relative risk assessments, known or anticipated regulations, resource availability, and the requirements or preferences of local communities. We make modifications to the plans during the year as these circumstances arise.

B. <u>Progress Under The Integrity Management Programs</u>

Q. PLEASE EXPLAIN HOW THE COMPANY'S INTEGRITY MANAGEMENT PROGRAMS AND THE VARIOUS INITATIVES THEREUNDER HAVE CHANGED SINCE THE 2015 PHASE I.

A. The Company has made good progress under TIMP and DIMP since the 2015 Phase I. The Company is making significant progress regarding asset knowledge and activities are ongoing to proactively identify risks and threats to our system. Assessments have been ongoing to identify anomalous conditions. I previously discussed the improvement in unknown vintage for our distribution assets as well as we now have 100 percent of MAOP records reviewed and characterized for our transmission assets. Over time, available assessment technology is continually evolving providing a more complete knowledge of assets health. The Company monitors this new technology and sometimes utilizes it when economic and feasible.

In addition to gaining asset knowledge, significant progress has also been made on other TIMP and DIMP programs since the 2015 Phase I, such as:

1) Completed major construction on the multi-year, West Main Transmission Line renewal project;
2) Completed renewal of all known Cellulose Acetate Butyrate ("CAB") services;
3) The TIMP Automatic Shut Off/Remote Controlled ("ASV/RCV") Valves project is nearly 25 percent complete; and
4) Completed over 102 miles of main renewals;
5) Our leak ratio is stabilizing and beginning to decline, an indication we are moving more into a proactive mode on managing leaks on the system;
6) Completed 227 miles of transmission pipeline assessments, increasing asset knowledge; and
7) Installed above ground facility protection at more than 3,000 locations, protecting them from vehicle and other damage.

The Company continues to file an annual work plan for major integrity management initiatives and subsequent year-end status updates under the currently-approved PSIA program. We also meet with the Commission's Staff and Office of Consumer Counsel ("OCC") regularly throughout the year providing updates on work against the plan as well as any expected changes

1. Distribution Integrity Management Plan (DIMP)

Q. WHAT IS DIMP?

A. The Company's DIMP activities are focused on improving asset knowledge (health and condition), which directly impacts our ability to drive a proactive risk model. In addition, the Company is focused on remediating known distribution risks, such as renewing early polymers and vintage steel pipelines. The federal DIMP rules were promulgated by PHMSA in 2009. The DIMP rules address how gas utilities identify, prioritize and evaluate risks, identify and implement measures to address risks, and validate the integrity of their gas distribution system. Under the federal rule, pipeline operators were required to develop their DIMP plans on or before August 2, 2011. The Company published its DIMP plan in August 2011 and submitted it to the Commission on September 28, 2011.

The basic elements of integrity management remain for DIMP - know your system (assets), identify the threats and risks to those assets, and proactively mitigate those threats. The exact requirements are less prescriptive than TIMP as PHMSA determined that more general requirements were needed for distribution systems given the diversity of those systems and the unique threats they may have.

Q. WHAT SPECIFIC DIMP PROGRAMS ARE CURRENTLY INCLUDED IN THE PSIA?

A. The following programs are part of the Company's capital DIMP program

Renewal Programs

1. AMRP, which systematically replaces outdated and poor performing pipe types (cast iron, bare or black steel, and PVC);

2. PPRP, which systematically replaces poor performing distribution mains and services not covered by AMRP or CAB programs;
3. Distribution Valve Replacements, which replaces existing distribution system isolation valves to improve isolation capabilities;
4. Bridge Crossings/Exposed Pipes, which programmatically renews poor performing pipelines installed on bridges or that are otherwise exposed to the elements, which can lead to atmospheric corrosion;

Public Safety Enhancement Programs

1. Shorted Casings, which mitigates corrosion risk on pipelines with casings;
2. Above Ground Facility Protection (also referred to as Meter Barricades), which installs protection to above ground facilities to protect from vehicle and other damage.

Q. HOW DOES THE COMPANY RECOVER THE COSTS ASSOCIATED WITH THE DIMP PROGRAM AND WHAT CHANGES IS THE COMPANY PROPOSING WITH REGARD TO RECOVERY OF DIMP-RELATED COSTS?

A. The Company plans to continue managing capital DIMP efforts through the PSIA, which expires on December 31, 2018. Following 2018, the Company proposes to recover DIMP costs through base rates if an MYP is approved. However, if an HTY plan is approved, the Company plans to request further extension of the PSIA beyond 2018. The ability to systematically perform renewal projects with certainty is of benefit to our customers and our communities and some level of certainty around the ongoing program facilitates that systematic renewal. Please refer to the direct testimony of Mr. Scott Brockett for additional discussion of the Company's proposal for DIMP related capital costs.

O&M program costs associated with DIMP were moved out of the PSIA and included in base rates as part of the 2015 Phase I. The Company plans to continue that work.

2. <u>Transmission Integrity Management Plan ("TIMP")</u>

Q. WHAT IS TIMP?

A. The Company's TIMP was developed pursuant to the Pipeline Safety Improvement Act of 2002, and the regulations promulgated thereunder by the DOT's Office of Pipeline Safety. Now administered by PHMSA, this federal law required transmission pipeline operators to initially assess pipelines that are in high consequence areas ("HCAs") by December 17, 2012, which the Company completed timely. TIMP is an ongoing program, and pipelines are required to be reassessed periodically based on risk, but not to exceed every seven years. It is important to note that pipeline operators are also expected to understand threats to the entire system, to apply the knowledge gained across all pipelines in the system, and to implement preventative measures to mitigate risks on all assets in the system. This program is prescriptive and extensive.

Q. WHAT SPECIFIC TIMP CAPITAL PROGRAMS ARE CURRENTLY INCLUDED IN THE PSIA?

A. The programs currently part of the Company's TIMP program are as follows:

<u>Renewal Programs</u>

1) West Main Transmission Line Replacement Project, replaced 74 miles of vintage transmission pipe, abandoned almost 25 miles of vintage

transmission pipe, and is largely complete with restoration work in process;

2) 8" Fraser to Frisco Pipeline Reroute Project, reroutes and replaces approximately two miles of pipeline in Frisco;

<u>Asset Knowledge Programs</u>

3) In Line Inspection ("ILI") Assessments, which prepares transmission pipelines for ILI tools and performs the initial ILI assessment;

<u>Pipeline Safety Enhancement Programs</u>

4) MAOP Validation Project, which ensures key operating criteria (specifically MAOPs) are supported by records that are traceable, verifiable, and complete;

5) ASV/RCV Valves, which installs mainline isolation valves or adds actuators to existing valves to quickly minimize the impact of unplanned gas release;

6) Above Ground Facility Protection, which installs protection to above ground facilities to protect from vehicle and other damage; and

7) Shorted Casings, which mitigates corrosion threats on pipelines with casings.

Q. HOW DOES THE COMPANY RECOVER THE COSTS ASSOCIATED WITH THE TIMP PROGRAM AND WHAT CHANGES IS THE COMPANY PROPOSING WITH REGARD TO RECOVERY OF TIMP-RELATED COSTS?

A. The Company plans to manage capital TIMP programs through the PSIA program, which expires on December 31, 2018. Following 2018, the Company proposes to recover capital TIMP costs through base rates if an MYP is approved. However if an HTY plan is approved, the Company plans to request further extension of the

PSIA beyond 2018. Please refer to the direct testimony of Mr. Scott Brockett for additional discussion of the Company's proposal for capital TIMP related costs.

O&M program costs associated with TIMP were moved out of the PSIA and included in base rates as part of the 2015 Phase I. The Company plans to continue that work.

3. The PSIA and Pending PHMSA Rules

Q. PLEASE PROVIDE A BRIEF HISTORY OF THE PSIA.

A. In the 2010 Phase I rate case, Proceeding No. 10AL-963G ("2010 Phase I"), the Company requested approval of the PSIA, allowing the Company to continue significant safety and reliability work of our gas pipeline system. By adopting the settlement agreement in that rate case, with slight modifications, the Commission approved the PSIA program with a term ending December 31, 2014. In the 2012 Phase I rate case, Proceeding No. 12AL-1268G ("2012 Phase I"), the Commission extended the PSIA's term until December 31, 2015. In the 2015 Phase I, the PSIA's term was extended until December 31, 2018; however, the Commission noted that if the Company requested any further extension, such extension request would need to include a plan stating how the PSIA will be terminated in the future[11].

[11] Specifically, the plan would need to include 1) a thorough analysis of all projects to be included in an ongoing PSIA; 2) the criteria used to determine whether future projects qualify for PSIA treatment; 3) a timeline for all PSIA projects to be completed (at a minimum the Company shall propose a quantitative risk assessment system that resolves its concerns about the lack of defined objective criteria in Staff's proposal); and, 4) a plan stating how remaining projects in the PSIA and other future pipeline replacements or significant safety expenditures will be addressed through the ordinary course of business when the PSIA is terminated. See 2015 Phase I, Decision No. R15-1204 at 31, ¶111; Decision No. C16-0123 at 29, Ordering ¶6.

With the approval of the PSIA program in the 2010 Rate Case, and subsequent extensions, the Company has made great strides in enhancing the safety and reliability of our gas system. I discuss major accomplishments of the program earlier in my testimony. In the end, the Company believes that the PSIA program has been a success and appreciates the support of the Commission as we've worked to incorporate the integrity rules into our overall management systems.

Q. WHAT IS THE COMPANY'S PROPOSAL REGARDING THE PSIA PROGRAM?

A. The Company is proposing to recover capital costs currently within the PSIA program through the PSIA rider through December 31, 2018 at which point recovery of these costs will move to base rates during the 2019 and 2020 FTYs for the MYP. Alternatively, if an HTY plan is approved, the Company will be requesting an extension of the PSIA through a separate filing. Please refer to witness Scott Brockett for more information about extending the PSIA in the event an HTY is approved in this rate proceeding. Additional detail regarding expenditure levels for PSIA work during the MYP can be found in the Capital Costs subcategory of Section IV of my Direct Testimony.

As previously described in this section of my testimony, the work performed under the Company's integrity programs is vital to maintaining a safe and reliable gas system that is in compliance with federal requirements. Although the PSIA program has proven to be successful in helping the Company make significant progress in mitigating the highest risks to its gas systems, continued investment is needed to manage on-going and emerging integrity risks. As described in detail in the 5-year plan included in Exhibit 4 of the 2017 PSIA filing, Proceeding No. 16AL – 0883G, there are a mixture of programs with varying time horizons and priorities. As the system continues to age at varying rates, new integrity work will emerge and it is necessary to remain vigilant in identifying and mitigating emerging system integrity risks as they are discovered in working through the integrity management programs. Overall, long-term continued investment in the system is necessary to maintain a safe and reliable gas system.

Q. WHAT IS THE COMPANY'S PROPOSAL REGARDING THE O&M EXPENSES AND CAPITAL COSTS ASSOCIATED WITH THE PENDING "TRANSMISSION RULE"?

A. As I discussed earlier in my testimony, the pending "Transmission Rule", filed as 81 FR 20722 in the federal register, is an extensive and comprehensive rule which will more than likely result in increased compliance requirements for TIMP/DIMP compliance activities, additional pipeline surveys, and material verification requirements. The pending "Transmission Rule" represents the most significant increase in gas pipeline management rules since 1970. However, the specificity and extent to which the pending rule will impact the Company's gas system is yet to be determined. PHMSA issued a Notice of Proposed Rule Making ("NPRM") in April of 2016 and published to the federal register in April of 2016, but the final rule has not been issued at this time. While there is uncertainty as to timing of the final rule, there is a high likelihood that the rule will be finalized during the MYP period.

As the rule is not yet finalized, the Company proposes to manage incremental capital costs related to the new “Transmission Rule” via the PSIA through December 31, 2018. The Company proposes to incorporate expenditures for 2019 and 2020 through base rates and has included them herein. The Company currently recovers O&M costs related to integrity management through base rates. The Company believes most incremental costs from the proposed rule will likely be O&M and cannot predict with any accuracy what the impact might be at this time. For instance, as written, the Company’s best estimate of O&M impact in year one is over $20 million, the majority of which is around material verification and pressure testing. Therefore, the Company is requesting a deferred accounting mechanism for all O&M costs which would result from finalization of this rule. The Company commits to keeping the Commission and interested stakeholders appraised of the new requirements and impact on overall programs. As it has demonstrated to date, the Company will provide transparent information to ensure that only incremental costs are included in the deferral mechanism.

IV. CHANGES IN GAS SYSTEMS AND DISTRIBUTION OPERATIONS COSTS AFFECTING BASE RATE REVENUE REQUIREMENTS

Q. PLEASE SUMMARIZE WHAT YOU WILL BE DISCUSSING IN THIS PART OF YOUR TESTIMONY.

A. First, I will discuss the O&M expenses for the Gas Utility and specifically the Gas Utility transmission and distribution business areas. This includes a discussion of the drivers of the variance between the 2015 Phase I test year, the 12 months ending December 31, 2014 ("2014 HTY"), and the 2016 HTY, the 12 months ending December 31, 2016. I will also touch upon some of the key known and measurable adjustments to the 2016 HTY O&M expenses that form the basis of the 2018-2020 Forward Test Years, provide a brief description of the related activities, and reference key witnesses that go into more detail on these activities. Second, I will describe the capital budget development process and present information on the proposed capital budgets for the MYP period, 2018 through 2020. Finally, I will address the noteworthy plant additions within the Gas Utility.

Q. HOW IS THIS SECTION OF YOUR DIRECT TESTIMONY ORGANIZED?

A. I have broken down this section of my testimony into two parts: O&M expenses and capital costs.

A. Operations And Maintenance Expenses

Q. WHAT ARE THE TYPES OF COSTS THAT THE GAS UTILITY INCURS FOR OPERATIONS AND MAINTENANCE?

A. The Company incurs O&M expenses to provide safe and reliable service of natural gas to our customers. These expenses are incurred across various departments of the Gas Utility including the transmission and distribution business areas and are related to numerous activities that support the gas system. Federal and State codes require significant inspection and maintenance programs for gas utilities, the majority of which is O&M. And integrity management programs at times add O&M costs to mitigate system risks. Examples are ongoing health and condition assessments for gas transmission pipelines as well as accelerated leak survey for known problematic distribution pipes types under renewal programs.

- Internal labor – costs related to the O&M portion of salaries, straight time labor, overtime, premium time, and employee expenses for internal employees.
- Contract labor and consulting – costs related to the use of contract labor and consultants which allows Public Service to increase and decrease staffing levels as workloads require rather than bringing on more full-time staff, and to retain the services of experts as needed for specific tasks or project efforts.
- Materials – costs related to consumables, hardware, and refurbished materials used in maintenance and repair operations, as well as tools and small equipment.

- Transportation – costs for internal fleet assets as directed to O&M accounts on an hourly basis including cars, trucks, construction equipment, and trailers.
- O&M First Set Credits – costs associated with the accounting treatment of meter set expenses.
- Other expenses – costs incurred by the Gas Utility to perform other O&M activities.

Q. DESCRIBE THE LABOR ACTIVITES THAT OCCUR THROUGHOUT THE TRANSMISSION AND DISTRIBUTION BUSINESS AREAS OF THE GAS UTILITY.

A. Labor costs incurred by the Gas Utility are spread across several functional areas:

- Gas Engineering;
- Project Delivery and Technical Services;
- Gas Governance;
- Gas Operations;
- Gas System Strategy and Business Operations; and
- Distribution Operations

These functional areas are focused on the reliability, safety, customer service, operational efficiency, and fiscal oversight necessary to construct, operate, and maintain the gas transmission and gas distribution systems in Colorado.

Gas Engineering provides engineering technical support to ensure safe and compliant operations and maintenance of distribution, transmission, and storage assets.

Project Delivery and Technical Services provides project management, financial management, project controls, records management, and geospatial support.

Gas Governance provides risk management, advocacy, interaction with state and federal agencies, and compliance with codes and standards.

Gas Operations is comprised of the gas emergency response organization for the greater Denver metropolitan distribution system, statewide operation and maintenance of the high pressure gas systems, gas control, corrosion services, technical services and the management of contractors working on certain gas assets.

Gas System Strategy and Business Operations is responsible for strategic direction of the overall gas organization, planning and budgeting of short term and long term projects, and transport customer support.

Distribution Operations is responsible for service changes, design for certain routine customer requested work, distribution system field construction, and the management of contractors working on certain gas assets.

1. <u>Key Drivers Causing O&M Expense to Increase Between the 2014TY and the HTY</u>

Q. WHAT ARE THE O&M EXPENSES INCURRED BY THE GAS UTILITY IN THE 2014TY AND THE 2016 HTY?

A. Expenses have escalated since the 2015 Phase I, just as they have for many other gas utilities throughout the nation. O&M expenses for the Gas Utility business areas for the 2014TY and the 2016HTY actual expenses, adjusted for known and measurable changes, are provided in Table CFC-D-3 below. Also included in Table CFC-D-3 are the key drivers of O&M expense increases from the 2014TY and the 2016 HTY.

Table CFC-D-3 Drivers of O&M Expenses from 2014TY to 2016 HTY

	2014TY	**Driver Amount**	**2016 HTY**
Total O&M (Adjusted)	$92.6 million		
Labor		$3.2 million	
Tools & Materials		$2.1 million	
Design/Engineering		$0.7 million	
Damage Prevention Program		$5.7 million	
Integrity Programs		$4.5 million	
Pipeline System Integrity Adjustment Amortization		($1.8 million)	
Enhanced Gas Emergency Response Program		$6.1 million	
Leak Survey		$1.3 million	
Corrosion Prevention		$1.5 million	
Other		$0.4 million	
	$92.6 million	$23.8 million	$116.4 million

Additional details on the adjustments applied to the O&M expenses in Table CFC-D-3 are provided later in my testimony.

Q. WHAT ARE THE KEY DRIVERS CAUSING THE INCREASE IN O&M EXPENSES BETWEEN THE 2014TY AND THE 2016 HTY?

A. As can be seen in the chart above, 68 percent of the differences are attributable to three areas – Damage Prevention, Emergency Response and Integrity Programs. These are key areas for managing and reducing risk on the gas system. I will discuss key drivers for these and all areas below.

i. Labor

Q. PLEASE EXPLAIN THE KEY DRIVERS RELATED TO LABOR.

A. The variance for labor expenses total approximately $3.2 million from the 2014TY to the 2016 HTY. This increase in labor does not include any incremental positions associated with gas emergency response and dispatch that were approved in the 2015 Phase I. Incremental labor costs associated with gas emergency response have been identified in a separate O&M driver explanation. The increase in labor is attributable to annual merit increases of 3 percent annually and incremental authorized positions since the 2015 Phase I. First, merit increases account for a total of $2.2 million which allow the organization to remain competitive in the labor market in order to attract and retain the skills and talent needed to run a successful gas organization, as explained by Company witness Ms. Koenig.

Second, new positions contributed to the remaining $1.0 million of labor cost increases. These new positions were targeted to areas that facilitate the ongoing risk reduction programs of the Gas Utility. Table CFC-D-4 below sets forth the increase in headcount by position from the 2014TY and the 2016 HTY:

Table CFC-D-4 Increase in Headcount from 2014TY to 2016 HTY

Functional Area	**Number of New Positions**
Quality Assurance/Quality Control	2
Gas Planners	2
Gas Engineers	5
Gas Control	2
Gas Operations Technical Specialist	2
Total	**13**

The two Quality Assurance/Quality Control positions were added since the 2015 Phase I to work with the Company's field staff on ensuring standardized statewide compliance with all gas codes, policies and standards. This small group works with each division annually, reviewing construction, key compliance inspections and maintenance and record keeping ensuring it meets Xcel Energy's standard processes and procedures. The two Gas Planners develop engineering models of the high pressure and IP gas system, ensuring adequate pipeline capacity to meet the peak hourly load of Public Services' firm customers. Five additional Gas Engineers were hired primarily to perform engineering for the Company's pipe replacement projects.

The two Gas Controllers and two Gas Operations Technical Specialist ("GOTS") positions were hired to support the Company's SCADA system. Please see Mr. Litteken's Direct Testimony for additional detail regarding the SCADA/Gas Control Monitoring Improvement program.

ii. Tools & Materials

Q. PLEASE EXPLAIN THE KEY DRIVERS RELATED TO TOOLS AND MATERIALS.

A. The variance for tools and materials is approximately $2.1 million from the 2014TY to the 2016 HTY. The variance is two-fold: an increase in non-capital tools and materials associated with gas meters being set for new business. First, non-capital tools increased approximately $500,000 which included tools such as tapping equipment, pipe hoists, fusion machine parts, and fresh air equipment. The remaining $1.6 million are materials associated with "shop work" that is primarily driven by the uptick in new business meter sets between 2014 and 2016. From the 2014TY to the 2016 HTY approximately 2,400 more gas meters, or 19 percent, were installed. Materials associated with new business meter sets include: meter bars, riser and regulator materials and miscellaneous piping materials. Table CFC-D-5 below forecasts that meter sets will continue to increase in the MYP resulting in increasing costs for materials.

Table CFC-D-5

Year	New Business Gas Meter Sets
2014	12,506
2015	13,470
2016	14,893
2017	14,784
2018	15,129
2019	15,439
2020	16,113

iii. Design/Engineering

Q. PLEASE EXPLAIN THE KEY DRIVERS RELATED TO DESIGN AND ENGINEERING.

A. The variance for design and engineering is approximately $0.7 million from the 2014TY to the 2016 HTY. Similar to the explanation for tools and materials, the increase cost for contract design and engineering is associated with the 19 percent increase in new business. See Table CFC-D-5. An increase in new business drives additional design work for both mains and services. To meet this increase design demand for new business, contract design workforce increased accordingly. While design work itself is highly capital in nature, it does come with an O&M component resulting in this increased O&M contractor expenditures in 2016.

iv. Damage Prevention

Q. PLEASE EXPLAIN THE KEY DRIVERS RELATED TO THE DAMAGE PREVENTION PROGRAM.

A. Damage Prevention Program expenses increased from the 2014TY to the 2016 HTY by approximately $5.7 million. This increase is attributable to an increase in the number of locates and new procedures regarding quality control and supervision. Additionally, as discussed in the 2015 Phase I, the costs for the services of the vendors that perform locate requests has increased.[12] It is important to note that this work is bid out as part of a competitive bid process and the best vendor in terms of quality and cost is selected to perform the work. The Damage Prevention Program is discussed in Mr. Litteken's Direct Testimony.

v. Integrity Program Adjustment

Q. PLEASE PROVIDE DETAILS ON THE KEY DRIVERS RELATED TO INTEGRITY PROGRAMS

A. Integrity management O&M expenses have increased by approximately $2.7 million from the 2014TY to the 2016 HTY. The variance is primarily driven by increased spending related to AMRP, DIMP, and TIMP. The increased spending in these programs is partially offset by decreased CAB and West Main spending. Table CFC-D-6 provides a comparison of 2014TY to the 2016 HTY by program.

[12] Proceeding No. 15AL-0135G, Hearing Exhibit 7, Direct Testimony of Luke A. Litteken, p. 29.l. 9-18.

Table CFC-D-6

Program	2014TY	HTY	Change
AMRP	$2.1M	$5.3M	$3.2M
CAB	$1.4M	$0.00M	($1.4M)
DIMP	$3.9M	$4.2M	$0.3M
TIMP	$9.2M	$11.7M	$2.4M
West Main	$0.01M	$0.00M	($0.01M)
Amortization	$5.4M	$3.6M	($1.8M)
Integrity Program Total	$22.1M	$24.8M	$2.7M

Q. PLEASE EXPLAIN THE KEY DRIVERS RELATED TO AMRP.

A. AMRP spend is associated with meter testing, meter move outs, and select maintenance for pipe types covered by the program. The primary driver for AMRP variance is an increase in the number of meter move outs and the cost of maintenance related activities

Q. PLEASE EXPLAIN THE KEY DRIVERS RELATED PSIA TIMP.

A. The primary drivers of the increased TIMP costs are an increased number of assessments between the two periods and an increased number of repairs.

Q. HOW DID PSIA AMORTIZATION CHANGE FROM THE 2014TY TO THE 2016 HTY?

A. The 2016 HTY was the last year of PSIA amortization. In the final year, the amortization decreased from the 2014 HTY amount of $5.4 million to $3.6 million. This will be zero in the future.

vi. Enhanced Emergency Response Program

Q. HOW MUCH HAVE COSTS INCREASED DURING THE 2016 HTY COMPARED WITH THE 2014 HTY FOR EMERGENCY RESPONSE?

A. Enhanced Emergency Response costs increased during the 2016 HTY compared with the 2014 HTY by approximately $6.1 million. This increase is primarily associated with the implementation of the Enhance Emergency Response Program from the 2015 Phase I. *See Decision No. R15-1204 at 63-64 and* Decision No.C16—123, Ordering ¶6. A breakout of incremental expense for emergency response from the 2014 TY to the HTY are in Table CFC-D-7.

Table CFC-D-7

Expense Category	Amount
Labor/Overtime	$ 4,733,770
Contract Labor	$ 542,221
Employee Expenses	$ 54,354
Materials	$ 192,213
Miscellaneous	$ (3,843)
Transportation/Fleet	$ 614,705
Incremental Emergency Response 2014 TY to HTY	**$ 6,133,420**

The Enhanced Emergency Response Program is discussed in Mr. Litteken's Direct Testimony.

vii. Leak Survey

Q. PLEASE EXPLAIN THE KEY DRIVERS RELATED TO LEAK SURVEY.

A. Leak survey expenses for contract outside vendors increased from the 2014TY to the 2016 HTY by approximately $1.3 million. The two primary drivers are additional number of assets that are leak surveyed and an increase in contract vendor costs.

In 2014, approximately 7,088 miles of pipeline were leak surveyed and in 2016 this rose to 8,236 miles, or an increase of 16 percent. For meters and services, in 2014, the Company surveyed 4,623 meters and in 2016 this rose to 5,377 meters. Although services are surveyed as well, there is minimal difference between 2014 and 2016 for this category of work.

Secondly, unit pricing for the services provided by the contract vendors which perform the Company's leak surveys increased by approximately 4 percent between 2014 HTY and 2016 HTY across several survey activities including pipelines, meters, and services. It is important to note that this work is bid out as part of a competitive bid process and the best vendor in terms of quality and cost is selected to perform the work.

viii. Corrosion Prevention

Q. PLEASE EXPLAIN THE KEY DRIVERS RELATED TO THE CORROSION PREVENTION PROGRAM.

A. Corrosion prevention expenses increased from the 2014TY to the 2016 HTY by approximately $1.5 million. The primary driver is a 119 percent increase in work orders related to corrosion prevention as the Company made adjustments to its corrosion prevention programs. Additionally, in mid-2016 a primary contractor of cathodic protection services increased the unit pricing across several key areas. Most notably, the cost of anode installations has increased by approximately 8 percent. This work is bid out as part of a competitive bid process and the best vendor in terms of quality and cost is selected to perform the work.

Earlier in my testimony I discussed the key risks for Public Service's distribution and transmission system and corrosion was in the top three for both distribution and transmission systems. As we have done more assessment work, we have determined a need to install more corrosion prevention equipment to adequately protect our system to help mitigate this risk.

2. <u>HTY O&M Expenses And Adjustments</u>

Q. WHAT WERE PUBLIC SERVICE'S 2016 HTY O&M COSTS FOR ITS GAS UTILITY?

A. The actual adjusted O&M expenses during the 2016 HTY totaled $116.4 million. Table CFC-D-8 below identifies the amount of overall O&M costs by the categories identified earlier in my testimony. Accounting of these expenditures by FERC account is described below.

Table CFC-D-8 Cost Categories of HTY O&M Expenses

Cost Category	Expenses
Internal Labor	$52.7 million
Contract Labor and Consulting	$47.3 million
Materials	$12.7 million
Transportation	$5.9 million
O&M First Set Credits	($10.4 million)
Other Expenses	$8.2 million
TOTAL	$116.4 million

Q. PLEASE PROVIDE THE EXPENSES FOR THE 2014TY AND 2016 HTY BY FERC ACCOUNT.

A. Table CFC-D-9 below provides a breakdown of the Gas Utility O&M expenses during the 2014TY and the 2016 HTY by FERC account.

Table CFC-D-9 TY versus 2016 HTY Expenses by FERC

	2014 TY	2016 HTY	Variance
810 - Gas for Compressor Stat Fuel Credit	-	(957,509)	(957,509)
850 - Trans Oper - E&S	4,832,020	3,054,890	(1,777,130)
854 - Gas for Compresor Station F	(480,877)	721,303	1,202,180
856 - Trans -Mains Exp	5,606,928	12,927,474	7,320,546
863 - Trans Mtce Mains	8,215,411	4,926,971	(3,288,440)
870 - Dist Oper - E&S	5,640,584	9,967,951	4,327,367
871 - Dist Exp-Dist Load	601,487	1,761,789	1,160,302
874 - Dist Exp-Mains & Serv	14,954,080	20,696,610	5,742,530
878 - Dist Op Meter & House Reg	(2,764,158)	(3,492,891)	(728,732)
879 - Dist Op Customer Install	4,614,375	6,674,843	2,060,468
880 - Dist Oper -Other	12,503,835	16,520,665	4,016,830
887 - Dist - Mtce of Mains	9,592,735	12,912,852	3,320,117
889 - Dist-Mtce of Meas&Regl	28,472	1,267,424	1,238,953
893 - Dist-Mtce of Meters&Hou	7,454,210	8,216,704	762,494
All Other FERCs	21,821,905	21,212,590	(609,314)
Grand Total	92,621,005	116,411,667	23,790,662

The specific FERC accounts identified in Table CFC-D-9 above each have variances of more than $500,000 and these accounts collectively represent over 90 percent of the change in the Gas Utility expenses between the 2014TY and the 2016 HTY. Attachment CFC-10 is a discussion of these FERC accounts. Attachment CFC-11 provides a view of the unadjusted 2016 O&M expenses by Cost Element and Attachment CFC-12 provides a view of the unadjusted 2016 O&M expenses by FERC.

Q. HAVE ANY ADJUSTMENTS BEEN MADE TO THE DATA PRESENTED AS THE HTY O&M EXPENSES IN TABLE CFC-D-2, TABLE CFC-D-8, AND TABLE CFC-D-9?

A. Yes. First, an increase of $1.7 million associated with the incremental forecasted balance of the regulatory asset for December 31, 2017 for Enhanced Emergency Response approved in 2015 Phase I, which is discussed in Mr. Litteken's Direct Testimony. Second, an increase of $0.3 million associated with the incremental forecasted balance for December 31, 2017 for Enhanced Emergency Response Program 2.0, which is discussed in Mr. Litteken's Direct Testimony. All expenses associated with these programs have been included in the amounts presented in Table CFC-D-2, Table CFC-D-8, and Table CFC-D-9.

Q. ARE THE $116.4 MILLION IN 2016 O&M COSTS FOR THE GAS UTILITY BUSINESS AREAS YOU DESCRIBE ABOVE REFLECTED IN THE COST OF SERVICE PRESENTED BY MR. BERMAN?

A. Yes. With respect to O&M, the Company is using an indexing approach that is grounded in the 2016 HTY as explained by Company witness Mr. Brockett. Mr. Brockett explains that this indexing approach applies to non-labor O&M expense and labor O&M expense in similar but not identical ways.

Q. ARE THERE ANY OTHER BUSINESS AREA COSTS YOU ARE SPONSORING OTHER THAN THOSE PREVIOUSLY DISCUSSED?

A. Yes – Energy Supply and Transmission.

B. Capital Costs

Q. HOW ARE CAPITAL EXPENDITURES BUDGETED FOR THE COMPANY'S GAS UTILITY?

A. There is a well-defined process for identifying, ranking, and budgeting gas distribution, transmission, processing, gathering, and storage projects. The key steps necessary to ensure the preparation of a comprehensive five year capital budget are summarized below.

Step 1: - Engineering and operations personnel identify potential problems and solutions.

Step 2: - Each problem (risk) and solution (mitigation) is reviewed for accuracy, completeness, and reasonableness.

Step 3: - As each risk and solution is considered, it is scored based on certain criteria, such as the likelihood of occurrence, and the consequences of not addressing it.

Step 4: - All potential solutions are ranked or prioritized.

Step 5: - After the ranking is completed, business leadership reviews the list, the level of risk associated with the various projects, as well as overall capital levels based on financial criteria.

Step 6: - Projects chosen to be funded are assigned a capital project number based on the type of work. These capital projects are also classified as either "specific" or "routine."

Step 7: - Capital project numbers for large pools of small projects (e.g., main installations, main renewals, etc.) are automatically tied to closing patterns based on the attributes of the work. For larger individual projects, in-service dates are assigned. Project managers then forecast expenditures based on the particulars of a project and its projected in-service date.

Step 8: - All capital projects that are included are reviewed and approved, both at the business area level and at the corporate level.

Step 9; - Work is deployed during the year.

The estimated in-service date of each large project and the closing patterns associated with different types of work pools (noted in Step 7 above) determine the date the project goes from Construction Work In Progress ("CWIP") to Plant-In-Service on the Company's books and becomes a plant addition. The process of moving projects from CWIP to Plant-In-Service is described in more detail by Company witness Ms. Melissa Ostrom. Ms. Ostrom discusses this process as it relates to pulling together the Company's capital budget across all business areas at the corporate level. Since I am representing the Gas Utility business area, the focus of my testimony is on how the capital projects are developed and ultimately become gas distribution, transmission, processing, gathering, and storage assets.

Q. IN SUMMARIZING THE NINE STEPS ABOVE, YOU REFER TO "RISKS," "SOLUTIONS," "MITIGATIONS," AND "PROJECTS." CAN YOU EXPLAIN WHAT YOU MEAN BY THESE TERMS IN THE CONTEXT OF DEVELOPING A CAPITAL BUDGET?

A. "Risks" are potential detrimental impacts or threats to safety, the quality/reliability of our service, environmental quality, our ability to meet our legal obligations, or our financial standing. These identified risks result in initiatives that address the risks. These initiatives, in turn, often require capital expenditures. In the capital budgeting process, potential "solutions" or "mitigations" are essentially "projects;"

i.e., work to be performed that will mitigate a certain risk, or set of risks. These projects are the focus of the capital budget process. Projects are evaluated against each other based on their costs, how effectively they address certain risks, and how critical the risks are.

Q. PLEASE EXPLAIN HOW THE PIPELINE INTEGRITY PROJECTS FOR WHICH THE COMPANY RECOVERS ITS COSTS THROUGH THE PSIA ARE FUNDED THROUGH THE EXISTING CAPITAL BUDGETING PROCESS.

A. Pipeline integrity projects are funded through the normal capital funding process. Integrity assessments and related projects are essential to the overall safety and integrity of the system. Therefore, the work associated with these assessments is considered non-discretionary effectively prioritizing these projects to the top of the project list. The nature of these integrity projects makes it difficult to predict exact expenditures. This is because we often times may find something very different from what was anticipated prior to the completion of an assessment on a pipeline. We may find there are gaps within our current asset information records or the assessment results leads to significantly more repairs than anticipated, or even replacement of pipeline assets.

Q. WHAT IS THE APPROVED 2018-2020 CAPITAL EXPENDITURES BUDGET FOR THE GAS UTILITY BUSINESS AREA AND HOW DOES THAT BUDGET RELATE TO THE PLANT ADDITIONS FOR THE 2018-2020 MYP PERIOD APPLICABLE TO THIS RATE CASE?

A. The approved Gas Utility capital expenditures budget is $325.3 million in 2018, $276.4 million in 2019, and $280.4 million in 2020, including installation and removal expenditures. This amount does not include Allowance for Funds Used During Construction ("AFUDC"), which is a component of plant additions. Each budgeted project has an associated in-service date or closing pattern as described earlier, which determines whether the capital expenditures are converted into plant additions for a given year. Plant additions can result from construction projects started in previous years with a future year in-service date or projects started and completed in that same year and placed in service in the same year.

Q. PLEASE DESCRIBE THE GAS UTILITY CAPITAL EXPENDITURES (EXCLUDING AFUDC) FOR THE 2018-2020 MYP PERIOD BASED ON TYPE OF WORK.

A. As depicted in Table CFC-9 below, I have separated the capital expenditures into three sections. In the first section, I list the capital expenditures by type of work, such as new service, capacity, asset health, etc. However, I have removed six major projects from that section and listed them separately in the second section of the table. The third section shows the proposed integrity programs projects. These pipeline integrity programs or projects represent over half (53 percent) of the overall gas capital budget for 2018-2020, or $463.6 million. Since these integrity programs, including Public Service's proposal for the MYP, have already been addressed in more detail previously, this section will focus on the remaining $418.5 million in capital expenditures – routine work by type and major projects listed in the first two sections of Table CFC-D-10 below.

Table CFC-D-10

Type of Work	2018	2019	2020	Total	Percent of Total
New Service	$35.1	$35.8	$40.4	$111.4	12.6%
Capacity	$1.3	$1.3	$1.4	$4.0	0.5%
Asset Health	$25.3	$25.8	$26.4	$77.6	8.8%
Mandates	$12.3	$11.4	$12.5	$36.2	4.1%
HP Gas	$8.6	$7.7	$7.8	$24.1	2.7%
Equip Purchase	$25.5	$26.0	$26.6	$78.2	8.9%
Fleet	$4.1	$4.3	$4.8	$13.2	1.5%
CIAC	($14.0)	($11.7)	($9.7)	($35.3)	-4%
Other	$14.3	$5.0	$5.1	$24.4	2.8%
Subtotal	**$112.6**	**$105.7**	**$115.3**	**$333.6**	**37.8%**
Major Projects	**2018**	**2019**	**2020**	**Total**	**Percent of Total**
Craig Compressor	$0.4	$0.0	$0.0	$0.4	0.0%
Granby Take-Off	$0.0	$1.6	$8.6	$10.2	1.2%
Gunnison Compressor	$4.1	$0.1	$0.0	$4.1	0.5%
Inside Meter Move-out	$3.3	$3.3	$3.3	$9.8	1.1%
North Metro Reinforcement	$22.4	$2.0	$0.0	$24.4	2.8%
Tungsten to Blackhawk	$24.6	$10.8	$0.5	$35.9	4.1%
Subtotal	**$54.7**	**$17.8**	**$12.3**	**$84.8**	**9.6%**
Integrity Programs	**2018**	**2019**	**2020**	**Total**	**Percent of Total**
AMRP	$38.3	$38.3	$38.3	$114.9	13.0%
DIMP	$42.6	$40.6	$40.6	$123.8	14.0%
TIMP	$77.1	$73.9	$73.9	$224.8	25.5%
Subtotal	**$158.0**	**$152.8**	**$152.8**	**$463.6**	**52.6%**
Total	**$325.3**	**$276.4**	**$280.4**	**$882.0**	**100%**

Q. PLEASE DESCRIBE THE GAS CAPITAL EXPENDITURES CATEGORIZED AS ROUTINE WORK LISTED IN TABLE CFC-D-10, AND EXPLAIN THE DRIVERS FOR EACH TYPE OF WORK.

A. Table CFC-D-10 lists 2018-2020 capital expenditures by work type. Each type of work represents a unique group of like projects. The routine work projects in section one of Table CFC-D-10 represent core, day-to-day gas utility work and include costs associated with new customers, increased capacity requirements, reconstruction or relocation of existing facilities, equipment purchases (such as meters or regulators), and purchases of fleet vehicles. Each of these categories areaddressed below.

New Service: New service projects comprise approximately $111.4 million, or 12.6 percent, of the 2018-2020 capital expenditures. New meter sets are projected to average approximately 15,500 meters per year between 2018 and 2020. This level of forecasted new meter sets remains well below pre-recession levels, which ranged from 25,000 – 30,000 meters per year. Projects required to support this growth can include a combination of the installation of new plastic and steel pipe for mains and service laterals, mainline valves, and regulator stations. New services do not include the meter and service regulators on the meter sets, as they are considered equipment.

Capacity: Pipeline and regulator station capacity projects comprise approximately $4.0 million, or 0.5 percent, of the 2018-2020 capital expenditures. These projects include infrastructure work related to increasing gas main and regulator station (expanded or new installations) capacity to mitigate low-pressure issues. This type of work is driven by increased load, either from existing customers or new customers.

Asset Health: Projects classified as Asset Health are infrastructure that is experiencing equipment failure or leaks that require repair in accordance with

Xcel Energy's Pipeline and Compliance Manual. The 2018-2020 Asset Health projects comprise approximately $77.6 million, or 8.8 percent, of the 2018-2020 capital expenditures. Replacing gas main and services, not covered under the AMRP and PPRP, are included in this category.

<u>Mandates</u>: Mandated projects are required to meet federal, state, or local requirements. This includes relocating facilities that are in direct conflict with street expansions within public rights-of-way and safety-related work required by a governing authority. Mandated projects comprise approximately $36.2 million, or 4.1 percent, of the 2018-2020 capital expenditures. An example of a government-mandated project is the relocation of facilities in support of the "Central 70" Expansion program which will reconstruct 10 miles of Interstate-70 east of downtown Denver. These projects are monitored monthly, and adjustments are made based on stakeholder and governmental requests.

<u>HP Gas</u>: High Pressure ("HP") Gas projects are related to the Company's gas transmission, processing, gathering, and storage assets. HP Gas projects comprise approximately $24.1 million, or 2.7 percent, of the 2018-2020 capital expenditures. These amounts exclude capital expenditures related to the PSIA and the major projects separately identified. Examples include transmission pipeline relocation, new transmission regulator stations, equipment replacement at storage fields, compressor station control systems, or gas processing facilities.

<u>Equipment</u>: Equipment purchases comprise approximately $78.2 million, or 8.9 percent, of the 2018-2020 capital expenditures. While equipment purchases are classified as a type of work, they are routine purchases of gas meters and service regulators. Additionally, this category includes system equipment such as pressure monitoring gauges, process equipment, control equipment and other types of equipment.

Fleet: Fleet purchases comprise approximately $13.2 million, or 1.5 percent, of the 2018-2020 capital expenditures. Fleet units are evaluated for reliability and cost to maintain due to normal wear and tear and general deterioration over time. Fleet units are utilized extensively in day to day operations.

Other: Included within this category are expenditures related to obtaining “rights-of-way” and easements for projects, franchise costs, and special tools and equipment. These expenditures comprise approximately $24.4 million, or 2.8 percent, of the 2018-2020 capital expenditures.

Q. HOW ARE ROUTINE BUDGETS DEVELOPED?

A. Routines are budgets allocated to operational areas and asset types and used to fund projects that are less than $300,000. Projects that are funded under Routines are generally not defined until the current year and are not able to be budgeted years ahead, specifically. The types of projects that are funded under Routines include new residential, commercial and industrial developments, reinforcement projects, and relocation projects. Budgets for Routines are established primarily on historical spend rates while also taking cost escalations into account.

The budget for new gas service routine work is developed using a cost-per-meter methodology. This process begins with forecasting the number of new meter sets for each local operating area. Inputs and assumptions regarding inflation factors are used to determine the assumed cost increase or decrease to the components that constitute the new business costs. These factors (labor, non-labor, contractor, materials, equipment and fleet inflation rates, bargaining labor increases, and corporate overhead rates) reflect both corporate and operating company rates. Historical data is used to determine the major drivers or components that constitute new business costs. These components are labor (both company and contracted), labor loadings, material (excluding meters and regulators), equipment, transportation, overheads, and other costs. Using these components, we then develop a cost-per-meter component matrix for each local operating area. This matrix allows us to apply the related inflation factors to the specific components that make up the overall cost per meter. We also use this data to analyze the various components of the variances between forecasted and actual costs.

The budget for reconstruction routine projects is based on the averages of historical values escalated by the corporate inflation rate (approximately two percent per year). This total budget is then allocated to each service area using the average historical ratio during the past five years. The allocation is adjusted to ensure that unique, one-time projects in a service area do not impact the calculation of the average five-year historical expenditures. Work completed as part of the AMRP and the integrity management programs do not factor into this calculation.

Routine project requests, such as for new business growth, reinforcements, or rebuilds include a five-year expenditure history and estimated in-service date. This routine grouping of projects serves to allocate funding for performing core business functions, such as connecting new customers, reconstructing facilities, and purchasing new meters, regulators, and fleet.

Q. PLEASE DESCRIBE WHAT IS INCLUDED IN THE MAJOR PROJECTS CATEGORY OF Table CFC-D-10 ABOVE.

A. Six major projects make up approximately $84.8 million, or 9.6 percent, of the 2018-2020 capital expenditures proposed in the MYP period. They are:

- Tungsten to Blackhawk ($35.9 million, or 4.1 percent, of the 2018 – 2020 capital expenditures). Load growth in the Southeast and Southwest parts of the Denver/Metro area limit the available pipeline capacity and pressure available to downstream areas, primarily the foothill regions (Georgetown and Blackhawk areas). This project adds pipeline capacity to ensure continued reliable service to both the suburban and foothills communities.
- North Metro Reinforcement ($24.4 million, or 2.8 percent, of the 2018 – 2020 capital expenditures). This project was previously referred to as the Downtown Denver Reinforcement project in the 2015 Phase I case. The project adds an additional source of gas to the Denver/Metro area, improving reliability and meeting load growth in the area.
- Granby Take-Off ($10.2 million, or 1.2 percent, of the 2018 – 2020 capital expenditures). This project addresses load growth in the Granby, Grand Lake, and other mountain areas.

- Gunnison Compressor ($4.1 million, or 0.5 percent, of the 2018 – 2020 capital expenditures). This project meets a capacity request from Atmos Energy for load growth on their system for Crested Butte, Gunnison, and Salida.
- Craig Compressor ($0.4 million, or 0.05 percent, of the 2018 – 2020 capital expenditures). This project meets a capacity request from Atmos Energy for load growth in the Steamboat Springs area. The expenditures depicted in Table CFC-D-10 in FTY 2018 represent project restoration processes. The majority of the expenditures for this project were incurred prior to the 2018 – 2020 timeframe.
- Inside Meter Move-out ($9.8 million, or 1.1 percent, of the 2018 – 2020 capital expenditures). This project moves approximately 1,600 inside meters outside. This is in addition to inside meter move-outs that occur in AMRP and PPRP. The anticipated conclusion of the Inside Meter Move-out project is 2022.

Q. IS THE INSIDE METER MOVE-OUT MAJOR PROJECT MENTIONED ABOVE RELATED TO THE INSIDE METER REPLACEMENT PROJECT PROPOSED IN THE 2015 PHASE I?

A. Yes. In the 2015 Phase I, Public Service proposed a seven year project to move approximately 19,000 meters and connections that were located inside of customer premises to outside locations. Under the proposal, Public Service would replace the old meters and connections with new meters, connections, and regulators with over-pressure protection and relief. Also, in certain instances, the service line from the main to the meter would also have been replaced as these services lines are generally older materials with a high risk of failure under DIMP. The Commission did not approve this project but instead stated: “However, rather than denying the [Inside Meter Replacement Project] outright, the project will be approved for recovery of 2015 costs through base rates."[13]

As result, Public Service undertaken the meter move outs in the ordinary course of business. There are three reasons why it is important for meters to be located at an outside location at a customer premises: cost, customer safety and customer convenience. With meters located on the outside of the premises, Public Service can conduct leak surveys and perform maintenance and inspections without making arrangements for access to be granted. It also eliminates the cost of multiple service calls if appointments are missed. Further, as noted earlier, the safest place for natural gas is in our pipes. However, if there is a leak, it is better for the gas to dissipate outside instead of collecting in a confined space, like a basement, where there are multiple sources of ignition (like a furnace, water heater, dryer or electrical switches).

As reflected in Table CFC-D-11, as of the end of 2016, 3,113 of an identified 11,747 meters have been moved from inside of customer premises to outside locations. Included in this work, is the replacement of the old meters and connections with new meters, connections, and regulators with over-pressure protection and relief. The total amount identified for replacement under this project has been reduced due to improved data and identifying meters that correlate with planned DIMP integrity programs such as AMRP. Beyond 2016,

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[13] See 2015 Phase I, Decision No. R15-1204 at 58, ¶188; Decision No. C16-0123 at 29, Ordering ¶6.

4,937 inside meters are planned to be replaced in DIMP and are not included in the planned Inside Meter Move-out project.

Table CFC-D-11

Meter Move Outs Completed

Inside Meter Move-out	2015A	2016A	2017F	2018B	2019B	2020B
Meters Replaced	1,082	2,031	384	550	550	550

Q. PLEASE PROVIDE ADDITIONAL BACKGROUND REGARDING THE MAJOR CAPACITY PROJECTS THAT AFFECT THE FRONT RANGE OF COLORADO.

A. Two of the six major projects affect capacity in the front range of Colorado.

- Tungsten to Blackhawk improves pressure and capacity on the high pressure system west of Denver. This system serves the towns of Evergreen, Blackhawk, Georgetown, and surrounding areas. New developments in the south and southeast parts of the Denver/Metro area have impacted the system's ability to maintain reliable service into these foothills communities. The Tungsten to Blackhawk project includes approximately thirteen miles of 8-inch high pressure (HP) pipeline from the Tungsten take-off to the Dory Hill regulator station, and approximately two miles of 6-inch HP pipeline from the Dory Hill regulator station to Blackhawk. The project supports continued reliable service in the Georgetown, Blackhawk, Evergreen and other foothills areas, while supporting ongoing growth in the southern parts of the Denver/Metro area.
- The North Metro Reinforcement project supports ongoing growth in the Denver/Metro area while providing another supply line into the area. This improves overall system reliability. The project includes approximately five miles of 24-inch high pressure (HP) pipeline, bringing gas from the terminus of the Cherokee Pipeline (at the Cherokee Power Plant) to the Denver/Metro intermediate pressure

(IP) system at approximately 43rd and Fox Street. The North Metro Reinforcement project also allows access to a more diverse upstream gas supply through the Cherokee pipeline supporting growth on the system. The Cherokee pipeline project was approved in the 2015 Phase I and has been providing reliable service to the Cherokee generation station since 2014.

Q. WHAT HAS THE COMPANY BEEN DOING TO IMPROVE EXECUTION OF CAPITAL PROGRAMS?

A As discussed in the 2015 Phase I, the Company has been working to improve its overall project planning and execution, especially for larger and more complex projects. Examples of our progress include the Cherokee Pipeline Project (completed in 2014), pipeline renewal from Boulder to Louisville and renewal of the East Brighton lateral.

For instance, the Cherokee pipeline project was a 34 mile 24" project to provide service to the Cherokee generation station as well as additional gas into the downtown Denver area. The original budget was $110.0 million with an in-service date of October 30, 2014. The final cost of the project was $112.1 million with an in-service date of October 12, 2014. The project came in at 1.9 percent over cost.

Boulder to Louisville renewal replaced the line from the Boulder valve set to the Louisville valve set, approximately 3.1 miles. The project was estimated at $9.26 million with an in-service date of June 15, 2015. Actual cost was $9.0 million, in-serviced June 30, 2015.

East Brighton lateral replaced 1.5 miles of vintage line with inadequate MAOP records. The project was estimated at $4.45 million prior to construction, with an in-service of October 28, 2016. Actual project cost was $3.58 million and in-service on September 8, 2016.

Q. DID THE COMPANY HAVE INCREASED LOAD REQUIREMENTS IN THE FRONT RANGE OF COLORADO AT THE TIME IT WAS EVALUATING THE TUNGSTEN TO BLACKHAWK AND THE NORTH METRO REINFORCEMENT PROJECTS?

A. Yes. The Company has been aligning its planning process with industry best practices over the last two years. This means that we now utilize 30 year weather to develop peak hour requirements across our system, resulting in some areas requiring reinforcements and other areas showing projects can be pushed out to a later date.

The Company analyzes peak hour load forecasts to ensure the system can adequately meet firm customer deliverability on a design day over a ten year planning horizon. As a result of this analysis, the Company identified the need for additional pipeline capacity to meet the ten year peak hour load requirements for the Front Range area of Colorado. Attachment CFC-13 provides the system peak hour load requirements over the next ten years and the system capacity benefits of the Tungsten to Blackhawk and the North Metro Reinforcement projects.

Q. PLEASE DESCRIBE HOW THE TUNGSTEN TO BLACKHAWK PROJECT RELATES TO THE "FRONT RANGE PIPELINE REINFORCEMENT-DEER CREEK WEST" PROJECT FILED IN THE 2015 PHASE I.

A. The Tungsten to Blackhawk project is an alternative to the Front Range Pipeline Reinforcement-Deer Creek West project which was described in the 2015 Phase I. Prior to incurring any expenditure for the Front Range Pipeline Reinforcement-Deer Creek West project, routine system analysis determined that the Tungsten to Blackhawk project was a better alternative as it improves system capacity over a longer timeframe.

Q. WHAT OTHER ALTERNATIVES DID THE COMPANY IDENTIFY TO THE TUNGSTEN TO BLACKHAWK PROJECT?

A. The Company identified an alternative reinforcement project that included approximately eighteen miles of 12-inch diameter pipe at an estimated cost of $82.0 million. This alternative would have provided increased capacity and pressure into the Georgetown and Blackhawk areas, but it does not provide the same long term system improvements as the Tungsten to Blackhawk project. Given the lower cost as well as the improved long term benefit, Tungsten to Blackhawk was the preferred and selected project.

Q. PLEASE DESCRIBE HOW THE NORTH METRO PROJECT RELATES TO THE DOWNTOWN DENVER REINFORCEMENT PROJECT FILED IN THE 2015 PHASE I.

A. The North Metro Reinforcement project is the same project as the Downtown Denver Reinforcement project that was presented in the 2015 Phase I case. The project name was adjusted for administrative purposes.

Q. PLEASE DESCRIBE ANY DIFFERENCES BETWEEN THE NORTH METRO REINFORCEMENT PROJECT AND THE DOWNTOWN DENVER REINFORCEMENT PROJECT FILED IN THE 2015 PHASE I.

A. The in-service date of the North Metro Reinforcement was originally November of 2018; however, this target in-service date has been revised to November of 2019. The necessary construction permits and pipeline right-of-way will take longer than anticipated, driving the change in project timeline.

Q. WHAT ALTERNATIVES DID THE COMPANY IDENTIFY TO THE NORTH METRO REINFORCEMENT PROJECT?

A. The Company identified an alternative reinforcement project that would bring additional gas supply from the Colorado Interstate Gas ("CIG") East Denver Control receipt point into the Denver/Metro area. This project includes approximately six miles of 16-inch diameter pipe at an estimated cost of $30.0 million, providing increased capacity to the east side of the Denver/Metro area. The system impact has a short term benefit and would have required additional system work from the north. Additionally, customers would have paid incremental upstream supply costs on CIG to increase the delivery capacity from the CIG system. Given the cost differentials, the longer term benefit and the incremental upstream costs, the Company selected the North Metro Reinforcement Project.

Q. PLEASE PROVIDE ADDITIONAL BACKGROUND REGARDING THE MAJOR PROJECTS THAT AFFECT THE MOUNTAIN/SOUTHERN SYSTEM IN COLORADO

A. As part of our utilization of industry best practices to a 30 year weather profile to develop peak hour information, we have made changes to our mountain/southern plans going forward. These changes have pushed out reinforcements for certain areas of the system. However, that analysis has not changed the two major projects listed herein.

- Granby Take-Off improves system reliability and supports load growth in the Granby and Grand Lake areas. The Granby Take-Off project includes approximately five miles of 6-inch high pressure (HP) pipeline from Fraser to Tabernash.
- The Gunnison Compressor project will install a new 740 horsepower compressor station near Gunnison, increasing capacity towards Crested Butte. Atmos Energy, a Local Distribution Company (LDC) serving Crested Butte, Buena Vista and the surrounding areas, contracts with the Company to provide firm gas transportation in these areas. Atmos Energy submitted a request for an additional 2,621 dekatherms (Dth) per day of capacity in these areas. The existing system cannot provide this increased load as well as support load growth on the greater Mountain/Southern system. The lateral serving Crested Butte is constrained, and as such load growth is restricted in the Mountain/Southern gas system areas. The project relieves the

capacity constraint on the Crested Butte lateral and allows additional load growth on the Mountain/Southern system.

Q. DID THE COMPANY HAVE INCREASED LOAD REQUIREMENTS IN THE MOUNTAIN AREAS AT THE TIME IT WAS EVALUATING THE GRANBY TAKE-OFF AND GUNNISON COMPRESSOR PROJECTS?

A. Yes. As part of a routine system analysis, the Company analyzes peak hour load forecasts to ensure the system can adequately meet firm customer deliverability on a design day over a ten year planning horizon. As a result of this analysis, the Company identified the need for additional capacity to meet the ten year peak hour load requirements for the Mountain/Southern system of Colorado.

Q. WHAT ALTERNATIVES DID THE COMPANY IDENTIFY TO THE GRANBY TAKE-OFF PROJECT?

A. The Company identified an alternative reinforcement project that would reinforce the Grand Lake lateral via an alternative route adjacent to Hot Sulphur Springs. This project involves approximately twenty-four miles of 6-inch diameter pipe at an estimated cost of $42.0 million which would have provided a similar capacity benefit into the Granby and Grand Lake areas as the Granby Take-Off project; however, the higher capital costs make this project less practical.

Q. WHAT ALTERNATIVES DID THE COMPANY IDENTIFY TO THE GUNNISON COMPRESSOR PROJECT?

A. The Company identified an alternative reinforcement project that would reinforce the Crested Butte lateral, approximately nineteen miles of 6-inch diameter pipe at an estimated cost of $16.5 million. This alternative project would have provided increased capacity into the Crested Butte, Gunnison, Salida, and other Mountain/Southern system areas. The higher capital costs made this an inferior project.

Q. PLEASE PROVIDE ADDITIONAL BACKGROUND REGARDING THE MAJOR PROJECTS THAT AFFECT THE WESTERN SYSTEM OF COLORADO

A. The Craig Compressor project provides additional capacity in the Steamboat Springs area. Atmos Energy provides distribution service to the Steamboat Springs area with firm transportation from the Company's Western high pressure system. Atmos Energy requested an additional 2,300 Dth per day of capacity in this area to meet increasing requirements in the Steamboat Springs area. The Craig Compressor project installs a new compressor station (two 740 horsepower compressors) near Craig, increasing system capacity in the Steamboat Springs area.

Q. WHAT ALTERNATIVES DID THE COMPANY IDENTIFY TO THE CRAIG COMPRESSOR PROJECT?

A. The Company identified an alternative reinforcement project, which included approximately eighteen miles of 10-inch diameter pipe looping the existing lateral, at an estimated cost of $21.0 million. The higher capital cost makes this a less attractive project.

Q. PLEASE PROVIDE AN OVERVIEW OF THE GAS UTILITY'S KEY CAPITAL ADDITIONS INCLUDED IN THE MYP?

A. The nine routine work types listed in the top section of Table CFC-D-10, previously addressed in my testimony, represent capital expenditures associated with core, day-to-day, gas utility work and including adding new customers, reconstruction or relocation of existing facilities, equipment purchases (such as for meters or regulators) and purchases of fleet vehicles. These expenditures represent nearly half of the capital additions expected during the FTYs, 2018, 2019, and 2020. The remaining portion of capital additions, roughly 50 percent, supports the integrity work performed as part of the PSIA. The key drivers of integrity program capital additions during 2018-2020 are AMRP, the Programmatic Risk-Based Pipe Replacement Program, and TIMP initiatives focused on transmission pipeline assessments and MAOP validation.

Please see Attachment CFC-14 Project Capital Additions: 2018 to 2020 for the capital additions included in the MYP.

Q. ARE THE CAPITAL ADDITIONS PRESENTED IN ATTACHMENT SAB-1 SPONSORED BY MR. BERMAN, AND INCLUDED IN ATTACHMENTS MLO-1 AND MLO-3, SPONSORED BY COMPANY WITNESS MS. OSTROM, REASONABLY REFLECTIVE OF WHAT YOU EXPECT PUBLIC SERVICE TO PLACE IN SERVICE DURING THE MYP?

A. Yes.

Q. PLEASE EXPLAIN THE PROCESS YOU FOLLOW TO MANAGE CAPITAL COSTS AFTER THE CAPITAL BUDGET IS DEVELOPED.

A. The Gas Strategy group within the System Strategy Business Operations organization monitors all distribution and transmission capital dollars to ensure that authorized projects align with the established budget. Detailed monthly reports are produced that compare actual capital expenditures to budgeted levels for programs (routine) and non-routine projects. I meet monthly with this group and key stakeholders within the organization to review program and non-routine project capital expenditures and variances. Adjustments and corrective measures are implemented as needed.

Q. WHAT INCENTIVES ARE IN PLACE TO PROMOTE THE ACCURACY OF THE CAPITAL BUDGET?

A. Management employees that have job responsibilities with a direct impact to capital budget expenditures (e.g. Engineering, Investment Delivery) have specific budgetary goals that are incorporated into their performance evaluations. Performance is measured monthly to ensure adherence to these goals and to address variances. Performance Management Plans for all Directors and Managers include a metric associated with their capital budgets. This metric is aimed at developing accurate budgets and managing to the budgeted levels. The scorecard for Public Service also contains a Key Performance Indicator associated with capital budget accuracy.

Q. HAVE YOU TAKEN ADDITIONAL STEPS TO ENSURE THE ACCURACY OF THE CAPITAL BUDGETS?

A. Yes. I have explained in detail how we follow a rigorous budgeting process that identifies the optimal mix of projects and expenditures for a given year. The up-front inputs into this process need to be accurate to minimize variances between budgeted and actual expenditures. In other words, good up-front planning improves our success in the field. Over the past couple years, we have improved the planning, as well as the accuracy of, our initial cost estimates for projects. We have implemented a more structured and disciplined project management process for larger and/or more complex programs of work. This improvement includes more up-front planning after they have been approved in the capital budgets. The timelines are more accurate, overheads (engineering) are more accurate, and we are less likely to have unexpected occurrences in the field once the project is deployed. Once a project has been deployed and is under way, the project manager meets regularly with the key staff (*i.e.*, siting and land rights, sourcing, construction/operations, etc.). Issues and concerns are identified and solutions developed. The overall goal is to achieve safe and timely completion of the project at no more than the budgeted cost. The practical payoff is that our budget estimates have a higher degree of accuracy.

Q. ARE THERE ANY OTHER REASONS THAT YOUR UP-FRONT ESTIMATES ARE ACCURATE?

A. Yes. We use various thresholds to determine the reviews and approvals required when the projected costs of projects vary from their original budgets. A monthly process is in place to monitor, update, and correct the budgets and forecasts as the projects progress.

Q. IN YOUR OPINION, ARE THE GAS PLANT ADDITIONS SET FORTH IN ATTACHMENTS MLO-1 AND MLO-3 SPONSORED BY MS. OSTROM REFLECTIVE OF WHAT IS EXPECTED TO BE PLACED INTO SERVICE DURING 2018-2020?

A. Yes. The gas plant additions depicted in Attachment MLO-3 of Ms. Ostrom's Direct Testimony reflects what is expected to be placed into service during 2018-2020.

V. OTHER PROGRAMS

A. "Failed Lot" Meter Replacement Program

Q. WHAT ARE METERS ASSOCIATED WITH A FAILED LOT ANALYSIS?

A. The Company's diaphragm gas meters are homogenously grouped based on common characteristics such as meter model, manufacturer and the manufactured date. The Company has implemented a Commission-approved Gas Meter Testing program. Under this program, when performance of the representative samples does not meet statistical accuracy characteristics during the testing cycle, the lot is characterized as "not meeting statistics." Follow up testing is performed whereupon the identified meter lot is tested under normal, and then tightened testing cycles. If the meter lot fails this follow up testing, the lot is identified as "failed", with all meters within the lot to be replaced.

Q. ARE COSTS FOR FAILED LOT METER REPLACEMENT INCLUDED IN THE COMPANY'S MYP PROPOSAL?

A. Specific costs to replace the failed meter lot are not included in the Company's MYP proposal. However, meters within the failed meter lot are being replaced under two pipeline renewal programs, AMRP and PPRP and within the Company's Inside Meter Replacement programs. Approximately 14 percent of the failed meter lot will be replaced through the duration of these three programs. Before proceeding with a larger program to replace the remaining failed meters, the Company plans to evaluate new measurement technologies. New meter technology will be evaluated for capabilities, cost, performance, and compatibility with the Company’s proposed advanced meter infrastructure (AMI), the Company’s field area network strategy and the Company’s advanced grid intelligence and security (AGIS) programs to determine if there is an alternative meter to the traditional gas diaphragm meter. The new meter technology on the horizon may provide customer benefits beyond fundamental metering technology, such as leak detection and/or communicating key operational or inspection information to the Company. These benefits could potentially improve safety and/or reduce ongoing inspection and maintenance costs. A meter replacement plan to replace the meters within the failed lots will developed and shared with the Commission after the Company’s evaluation is completed.

VI. SUMMARY AND CONCLUSION

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY IN THIS PROCEEDING.

A. Public Service has and continues to meet our mission to provide reliable service to our customers. As I described above, the Company has made great strides to enhance the safety and reliability of our gas system and improve customer service. While we face challenges, we have a plan to address those challenges. As such I recommend that the Commission approve:

- if an MYP is approved, the roll-in of the recovery of the costs of PSIA projects into base rates beginning on January 1, 2019, once the recovery of such costs ends under the PSIA on December 31, 2018;
- the Company's request to defer Operations and Maintenance expenses related to the proposed "Transmission Rule" that will likely become final during 2018 and establish a regulatory asset; and
- the Gas Utility's distribution and transmission business areas' capital additions for the MYP Test Years as the related costs will be prudently incurred and reasonable and used an useful in providing customer service

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Statement of Qualifications

Cheryl F. Campbell

I received a Bachelor of Science degree in Chemical Engineering and a Bachelor of Science degree in Business Administration from the University of Colorado in 1983. I received a Master of Science degree in Finance from the University of Colorado in 1990. In August 2014, I was appointed by the United States Secretary of Transportation to the Department of Transportation's Technical Pipeline Safety Standards Committee also known as the Gas Pipeline Advisory Committee.

I was hired by Colorado Interstate Gas ("CIG") as an Associate Engineer in the Design & Evaluation Department in 1984, progressing to department Manager during my tenure in the Department. My experience in Design & Evaluation included transmission system design, economic evaluation, gas balance planning, and both short and long term planning studies.

I transferred to Supply Management in 1990. In this role I was responsible for managing CIG's system supply contracts to ensure adequate purchases to meet contractual obligations. I was also involved in storage and supply planning to meet CIG's market obligations. In late 1993, I began working for CIG Merchant Division, the unbundled merchant arm, and in late 1996, I began working for Coastal Field Services. My experience in these areas includes gas scheduling, allocations, transportation contract management, nominations, imbalance management, full-service agency for small customers, Operational Balancing Agreement management, contract negotiation, budgeting and planning studies. I was promoted to Director of Volume Management for

Coastal Field Services in 1996. In late January of 2001, coincidental with the close of the Coastal/El Paso merger, I joined the Rates Department as Manager of Rate Design for the El Paso Western Pipeline Group. My responsibilities included the preparation of cost allocation and rate design studies for general rate filings and certificate applications with the Federal Energy Regulatory Commission. In addition, I was also responsible for other economic studies and special projects assigned to the Rates Department.

In 2003, I took a position as Vice President of Marketing for a small computer firm based in Dallas, TX. My responsibilities in the role included developing and implementing a marketing and advertising presence for a small computer software company and developing an Energy Services sister company to the main software company.

In 2004, I accepted a position with Xcel Energy as Director of Gas Asset Strategy. In this role, my responsibilities included developing and implementing decision-making and policy-setting processes for engineering, construction, operations, maintenance and retirement (lifecycle) of Xcel's gas delivery assets. We also balanced operational and financial performance with risk to develop strategic direction and policy.

In April 2008, I accepted the role of General Manager, Gas System Design for Public Service Company of Colorado. My responsibilities included strategic leadership in the areas of gas systems engineering, gas control, gas marketing and transportation, operations and maintenance for the high pressure gas transmission pipelines and compressor stations, underground storage operations, and various support functions. In January 2009, I was promoted to Vice President, Gas System Design, Operations and Maintenance for Public Service Company of Colorado. In 2009, Gas Emergency

Response and Repair was transferred to my area. As a result of a corporate wide reorganization, I was promoted in September 2011 to my current position of Vice President, Gas for Xcel Energy Services Inc. (“XES”) the “service company” subsidiary of Xcel Energy, Inc. (“Xcel Energy”), a registered holding company and named Senior Vice President in May 2015. In this capacity, I am responsible for all of Xcel Energy’s regulated natural gas utilities including Public Service Company of Colorado, Northern States Power Company, a Minnesota company, and Northern States Power Company, a Wisconsin company.

I previously have sponsored testimony in CIG’s rate proceedings before the Federal Energy Regulatory Commission in Proceeding Nos. RP90-69 and RP01-350. I also have sponsored direct and rebuttal testimony in Public Service’s rate cases before the Colorado Public Utilities Commission in Proceeding Nos. 05S-264G, 06S-656G, 10AL-963G, 12AL-1268G, and 15AL-0135G. In February 2016, I testified on behalf of the American Gas Association before the Subcommittee on Railroads, Pipelines and Hazardous Materials of the United States House of Representatives’ Committee on Transportation and Infrastructure regarding the reauthorization of the United States Department of Transportation’s Pipeline Safety Program, Protecting Our Infrastructure and Enhancing Safety Act of 2016.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

* * * *

RE: IN THE MATTER OF ADVICE LETTER NO. 912-GAS FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 6-GAS TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE ON 30-DAYS NOTICE.	**) PROCEEDING NO. 17AL-____G**

**AFFIDAVIT OF CHERYL F. CAMPBELL
PUBLIC SERVICE COMPANY OF COLORADO**

I, Cheryl F. Campbell, being duly sworn, state that the Direct Testimony and attachments were prepared by me or under my supervision, control, and direction; that the Testimony and attachments are true and correct to the best of my information, knowledge and belief; and that I would give the same testimony orally and would present the same attachments if asked under oath.

Dated at Denver, Colorado, this Twenty Fourth day of May 2017.

____
Cheryl F. Campbell
Senior Vice President, Gas

Subscribed and sworn to before me this 24th day of May, 2017.

____
Notary Public

My Commission expires 7/30/2018

BARBARA HAMBLIN
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID # 19974007694
MY COMMISSION EXPIRES JULY 30, 2018