BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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IN THE MATTER OF ADVICE NO. 961-GAS OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 6-GAS TARIFF TO INCREASE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL GAS RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE MARCH 7, 2020	**)))))))))**	**PROCEEDING NO. 20AL-____G**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF LUKE A. LITTEKEN</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

February 5, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF COLORADO

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<u>DIRECT TESTIMONY AND ATTACHMENTS OF LUKE A. LITTEKEN</u>

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LIST OF ATTACHMENTS

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
2015 Gas Phase I	Proceeding No. 15AL-0135G
2016 HTY	2016 Historical Test Year adopted in Proceeding No. 17AL-0363G
2017 Gas Phase I	Proceeding No. 17AL-0363G
ALJ	Administrative Law Judge
AMRP	Accelerated Main Replacement Program
API	American Petroleum Institute
Atmos	Atmos Energy Corporation
CCR	Code of Colorado Regulations
CFR	Code of Federal Regulations
CNP	CenterPoint Energy
Commission	Colorado Public Utilities Commission
Company	Public Service Company of Colorado
CWIP	Construction Work in Progress
DIMP	Distribution Integrity Management Program
Dth	Dekatherm
EBB	Electronic Bulletin Board
FERC	Federal Energy Regulatory Commission
GIS	Geospatial Information System
GMS	Gas Management System

Acronym/Defined Term	**Meaning**
HP	High Pressure
HTY	Historical Test Year
IFR	Interim Final Rule
IP	Intermediate Pressure
MAOP	Maximum Allowable Operating Pressure
MSA	Master Service Agreement
NAESB	North American Energy Standards Board
O&M	Operations and Maintenance
PHMSA	Pipeline and Hazardous Materials Safety Administration
PPRP	Problematic Pipeline Replacement Program
PSIA	Pipeline Safety Improvement Act
PSIG	Pounds per Square Inch Gauge
Public Service	Public Service Company of Colorado
Quorum System	Quorum Pipeline Transaction Management System
RP	Recommended Practice
SCADA	Supervisory Control and Data Acquisition
SSSV	Sub-surface Safety Valve
Test Year	12-month Period Ending September 30, 2020

Acronym/Defined Term	**Meaning**
TIMP	Transmission Integrity Management Program
TY	Test Year
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services Inc.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

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DIRECT TESTIMONY AND ATTACHMENTS OF LUKE A. LITTEKEN

I. INTRODUCTION, QUALIFICATIONS PURPOSE OF TESTIMONY, AND RECOMMENDATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Luke A. Litteken. My business address is 1123 West 3rd Avenue, Denver, Colorado 80223.

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. In this position, I am responsible for, among other things, the design, operation, construction, 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, construction, 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, the pipeline safety management system, 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. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR DIRECT TESTIMONY?

A. Yes. I am sponsoring the following attachments:

- Attachment LAL-1: Gas Operations Capital Additions January 1, 2017 – September 30, 2020;
- Attachment LAL-2: Operations and Maintenance Expenses by Cost Element;

- Attachment LAL-3: Operations and Maintenance Expenses by FERC Account;
- Attachment LAL-4: Damage Prevention Regulatory Asset Balance;
- Attachment LAL-5: List of Significant Events & SCADA Field Monitor Device Cost Benefit Analysis;
- Attachment LAL-6: Map of Public Service Gas System with Operational Areas;
- Attachment LAL-7: One-page Descriptions of Discrete Capacity Projects; and
- Attachment LAL-8: One-page Descriptions of Discrete New Business Projects.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to present an operational perspective of Public Service's natural gas business, and detail the major drivers of change in the Company's Gas Operations business and costs since our last gas Phase I rate case in Proceeding No. 17AL-0363G ("2017 Gas Phase I"), which adopted a 2016 historical test year ("2016 HTY"). In order to provide this perspective, I have broken my Direct Testimony into several sections for simplicity.

In Section II of my Direct Testimony, I provide an overview of the Company's Gas Operations and the work Public Service has undertaken over the last several years, as well as progress made with respect to a number of key safety and reliability metrics. I also describe the four primary drivers of work and costs on Public Service's gas system – safety, reliability, new customers, and mandated relocations. I then provide an overview of the Company's capital investments and operations and maintenance ("O&M") expenses included in the Test Year ending September 30, 2020,[1] and describe the Company's budgeting and management processes to support the forecast for capital projects that will be placed in service during the Test Year. In Section II, I also support the Company's request to recover the costs of the Company's updated system to manage its gas transportation business, and foreshadow future issues facing Public Service's Gas Operations.

In Section III of my Direct Testimony, I describe the multiple ways Public Service must attend to maintaining safety as our first priority, including (but not limited to) managing system integrity, damage prevention, gas emergency response, leak surveys, storage integrity, transmission right-of-way maintenance, and pipe inspection and remediation. I support the capital investments and O&M expense necessary to maintain system and public safety since the last rate case, including new projects being placed in service between January 1, 2017 and September 30, 2020, and O&M expense through September 30, 2019 adjusted for certain known and measurable changes. I also support the Company's request to continue the deferral of the costs of our Damage Prevention Program.

In Section IV, I then describe the Company's significant reliability work stemming from our investment in Supervisory Control and Data Acquisition ("SCADA") remote monitoring devices, which has in turn helped us identify areas of reliability and capacity investment needs. As part of this discussion, I identify

[1] As discussed by Company witness Brooke A. Trammell, the Company's proposed test year in this proceeding is the twelve month period ending September 30, 2020, which includes capital additions and revenue through September 30, 2020, and O&M expense based on the twelve-month period ended September 30, 2019 adjusted for known and measurable changes ("Test Year").

capacity projects and key initiatives to improve reliability, including the North Metro Pipeline project and the Tungsten Capacity Project. I discuss other discrete capacity projects and provide support for more routine investments in asset health and capacity.

I then turn, in Sections V and VI of my Direct Testimony, to Public Service's investments to serve new customers, and to undertake required mandated pipeline relocations.

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

A. I recommend that the Colorado Public Utilities Commission ("Commission") approve the Gas Operations capital and O&M expense included in the Company's revenue requirement in this rate case. I further support the recommendation by Company witness Mr. Steven P. Berman for deferral of Damage Prevention Program costs not included in base rates in this proceeding, for further reconciliation in the Company's next Phase I rate case.

II. PUBLIC SERVICE'S GAS BUSINESS

A. Overview of Gas Operations

Q. PLEASE DESCRIBE PUBLIC SERVICE'S GAS OPERATIONS.

A. 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 33 of the 64 counties within the state. A map of our gas service area is provided as Attachment BAT-2 to the Direct Testimony of Ms. Trammell.

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 ("Atmos"), the Town of Center, Colorado Natural Gas, Inc., and Black Hills Energy. 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 Federal Energy Regulatory Commission ("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. WHAT IS THE BASIC MISSION OF PUBLIC SERVICE'S GAS BUSINESS?

A. Our mission is to provide safe, reliable, affordable, and environmentally-responsible service to our approximated 1.4 million Colorado customers. We understand that natural gas service is critical to the State of Colorado and its citizens. When customers need natural gas for home heating, critical industrial processes, and other end uses, 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. To do this, the Company follows federal and state codes and regulations and relies on peer benchmarking. The individual characteristics of infrastructure within Public Service's natural gas system further drive the Company's planning and operation.

In addition, as leaders in clean energy and carbon emissions reductions, Public Service is committed to work to reduce natural gas emissions from 1) our upstream producers and interstate pipelines; 2) the operation of our local distribution system; and 3) our customers at their homes and businesses.

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

A. Yes, through ongoing efforts. There are continually emerging risks that need to be mitigated as the system ages, and we must make ongoing assessments of and investments in our assets, our performance, and our customer service. In fact, like the rest of the gas industry in the United States, Public Service continues to focus on removing operational and safety risks from its system by operating in a proactive manner, while maintaining affordability. This includes replacement of aging assets, responding to emergencies faster, a more frequent leak survey cycle, and standing-by when excavators do work around our critical infrastructure, to name a few.

Q. WHAT ARE THE MAJOR PRINCIPLES, RULES, AND REGULATIONS THAT GUIDE PUBLIC SERVICE'S INVESTMENTS IN ITS GAS SYSTEM ON BEHALF OF CUSTOMERS?

A. At a high level, the basic principle is to ensure that the natural gas (a combustible substance) we deliver to customers remains in our transmission and distribution pipelines until the point of use. While simple in theory, this overarching principle is put into practice through a complex set of rules and regulations that govern our work at the federal, state, and local level.

At a federal level, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") is the primary federal administration for ensuring that pipelines are safe, reliable, and environmentally sound. PHMSA oversees the development and implementation of regulations concerning pipeline construction and maintenance and operations. As discussed below, these responsibilities are shared with the State of Colorado. There are several federal regulations that pertain to Public Service's Gas Operations, including:

- Part 191 - requirements of natural gas pipeline operators to report incidents, safety-related conditions, and annual summary data.

- Part 192 – minimum safety requirements for gas pipeline design and operations. The Distribution and Transmission Integrity Management Programs ("DIMP" and "TIMP") rules are contained in this part, while Underground Storage Interim Final Rule ("IFR") (adopting American

Petroleum Institute ("API") Recommended Practice ("RP") 1171) also applies.

- Part 196 – regulations for protection of underground pipelines from excavation activity.
- Part 199 – programs for preventing alcohol misuse and to test gas employees for the presence of alcohol and prohibited drugs.

Historically, the state generally adopts the federal regulations outlined above and further regulates one-call excavation rules and ensures consumers receive safe, reliable supply and dependable service at a reasonable price.

Federal, state, and local (e.g., city and county) governments are also responsible for overseeing the construction of new distribution infrastructure, including permitting. In addition, some of these local governments provide the Company with franchise agreements that enable us to install our natural gas infrastructure within road rights-of-way through the communities that we serve.

Q. HOW DO THESE RULES AND REGULATIONS AFFECT PUBLIC SERVICE GAS OPERATIONS?

A. These rules and regulations play a large role in how we do business, particularly with respect to the safety of Public Service's Gas Operations. Additionally, PHMSA and API rules and regulations, as well as other state and local requirements, often drive specific investment needs for our system, for both capital and O&M. Throughout my Direct Testimony, I will be describing how these rules drive specific investments the Company is undertaking.

B. <u>Gas Operations Investment Overview</u>

1. Core Areas of Gas Investments

Q. WHAT ARE THE CORE AREAS OF FOCUS FOR PUBLIC SERVICE GAS SYSTEM INVESTMENTS?

A. As previously noted, **<u>safety</u>** and **<u>reliability</u>** are the key areas of focus for Public Service's gas business. In addition, **<u>new business</u>** resulting from new customers and customer growth, along with infrastructure **<u>relocations</u>** mandated by city, state, or federal authorities, require investments on the gas system.

Q. CAN YOU PROVIDE ADDITIONAL DISCUSSION OF THESE FOUR CORE AREAS?

A. Yes. I will discuss each in turn:

1. **<u>Safety</u>** rules and regulations require the Company to establish TIMP and DIMP plans. At a high level, TIMP and DIMP rules require operators to 1) know their assets, 2) identify risks and threats to those assets, and 3) proactively mitigate those risks/threats. For Public Service, the costs to comply with TIMP and DIMP are recovered through either base rates or the Pipeline System Integrity Adjustment ("PSIA").[2]

Since Public Service has Company-owned underground storage facilities, there are also safety rules surrounding those facilities that will be described later in my Direct Testimony. For public safety, the Company is also required to locate

[2] Examples of integrity management costs that are not recovered through the PSIA include leak survey and leak repair on pipe types that are not included in the PSIA.

its underground gas infrastructure free-of-charge to anyone who calls Colorado 8-1-1 and requests a locate. Approximately 85 percent of Public Service's locate costs are incurred on behalf of others and only about 15 percent are related to Xcel Energy's own construction projects. Additionally, every gas operator within the United States is also obligated to respond to customer calls when they think they smell natural gas or have any gas emergency.

2. Our customers need **reliable** service. Customers depend upon natural gas to heat their homes and water, cook their meals, dry their clothes, and support commercial and industrial activities within the state. Consistent with our tariff, Public Service must stand ready to provide our customers with safe and reliable natural gas service. In order to do so, Public Service must adequately maintain, renew, and operate its compressor stations, regulator stations, meters, and every other aspect of the system. When our assets are no longer adequate to meet the customer's safety and reliability needs, the Company must replace, reinforce, or rebuild those parts of our system. Additionally, when safety and service reliability demands exceed the capacity of the human resources needed to operate the system, we must adjust our staffing models accordingly.

3. The Company must serve any **new customer** that requests gas service within its service territory under the rules of its tariff. This includes not only laying the service line and setting the meter to a customer's facility, but also the gas main to which the service line connects. And it does not stop there. Public Service operates an integrated system of both distribution and transmission

assets. Customer growth on the distribution system can cause a capacity shortage on upstream distribution and transmission pipelines and regulating facilities. In order to ensure firm gas service to that customer during a cold peak hour or design day, the Company must have adequate capacity across its entire integrated system.

4. Public Service is also required by state, county, and local government bodies to **relocate** our gas infrastructure that resides in road rights-of-way when that entity's work conflicts with our facilities. Public Service's franchise agreements with the communities it serves require the Company to move or relocate our infrastructure when requested by the government body. This includes, but is not limited to, infrastructure work on water, sewer, transportation, or other major infrastructure. The costs associated with relocating our natural gas infrastructure are born by Public Service and ultimately impact our customers through cost of service ratemaking.

2. Capital and O&M Investments in Core Areas

Q. PLEASE SUMMARIZE THE CAPITAL ADDITIONS IN SAFETY, RELIABILITY, NEW BUSINESS, AND RELOCATIONS THAT ARE INCLUDED IN THIS RATE CASE.

A. Table LAL-D-1 below summarizes the Company's capital additions in these areas included in the Test Year and added to Public Service's system since the end of the 2016 HTY utilized as the basis for setting rates in our 2017 Gas Phase I. In total, Public Service's capital additions placed in service between January 1, 2017 and September 30, 2020, total $830.2 million, as broken out in Table LAL-D-1.

Table LAL-D-1
Gas Operations Capital Additions
January 1, 2017 – September 30, 2020*

	Jan 2017 - Sept 2019	Oct 2019 - Sept 2020	Total
Safety	$25.0	$15.8	$40.8
Reliability	$221.6	$167.0	$388.7
New Business	$244.4	$79.2	$323.6
Relocations	$53.1	$24.0	$77.2
Total	**$544.2**	**$286.1**	**$830.2**

**Differences in sums due to rounding*

Further information regarding the capital additions I support is provided as Attachment LAL-1 to my Direct Testimony.

Q. CAN YOU ALSO PROVIDE AN OVERVIEW OF O&M COSTS THAT ARE INCURRED BY PUBLIC SERVICE'S GAS OPERATIONS?

A. Yes. The Company incurs O&M expenses across various areas within Gas Operations, including the transmission and distribution business functions, that 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 result in O&M expenditures. 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 surveys for known problematic distribution pipe types under renewal programs. We also must perform emergency response and requested damage prevention locates. Other types of O&M expense include internal labor, contract labor, materials, transportation, and other expenses. O&M expense is not approved for recovery in the PSIA, but rather is part of our cost of service for base rates.

Q. CAN YOU ALSO PROVIDE AN OVERVIEW OF O&M COST CHANGES IN PUBLIC SERVICE'S GAS OPERATIONS BUSINESS SINCE THE END OF THE 2016 HTY?

A. Yes. Expenses have escalated since the 2017 Gas Phase I in light of the types of Gas Operations work that is required and the overall cost of doing that work. Table LAL-D-2 walks forward the Company's Gas Operations O&M expense from the 2016 HTY to the Company's Test Year in this case. The incremental O&M expense increase since the 2016 HTY is approximately $7.4 million.

Table LAL-D-2
Key O&M Drivers from 2016 HTY to Current Test Year ($ millions)

		2016 TY	Oct. 1, 2018 - Sept. 30, 2019	Oct. 1, 2019 - Sept. 30, 2020	2020 TY FERC
	Total O&M (Adjusted)	$115.9			
Safety	GER/Gas Trouble		$7.4		879 880 889 892
Safety	Damage Prevention Program		$4.5		407.3
Safety	Leak Survey		$1.0	$0.2	856, 874
Reliability	Compressor Stations		$0.9		864
Safety	Underground Storage		$0.5	$0.2	816 834
Safety	Pipeline System Integrity Adjustment Amortization		($3.6)		863
Safety	MAOP		($4.4)		856 859
Safety	Right of Way Clearing			$1.1	885
Safety	Exposed Pipeline Inspection & Remediation			$1.0	874
	Other		$1.1	$0.6	Various
	Total	**$115.9**	**$7.4**	**$3.1**	**$126.4**

**Differences in sums due to rounding*

Further information regarding the O&M expense I support is provided as Attachments LAL-2 (identifying O&M by cost element) and LAL-3 (identifying O&M by FERC account) to my Direct Testimony.

3. Key Progress Metrics

Q. CAN YOU PROVIDE AN OVERVIEW OF HOW THE COMPANY'S INVESTMENTS IN ITS GAS OPERATIONS SINCE THE 2017 GAS PHASE I HAVE ENHANCED PUBLIC SERVICE'S SYSTEM AND CUSTOMER SERVICE?

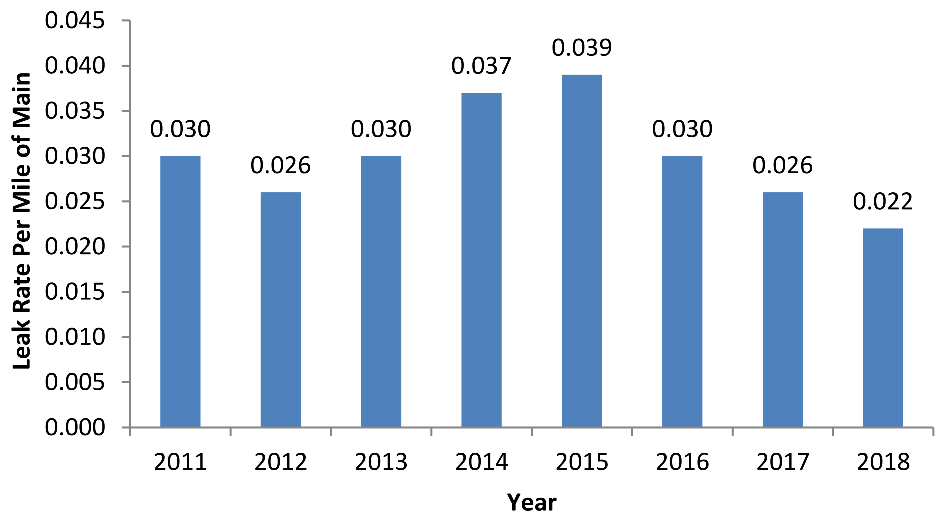
A. Yes. Public Service's investments in the areas summarized above and included in this rate case, plus capital investments for which it receives recovery through the PSIA, enable us to continue providing safe and reliable customer service, while also continually improving in various metrics that are indicators of the health and safety of our system. Such key metrics include leak ratios, quantity of pipeline renewals, number of transmission pipeline assessments, and quality of transmission pipeline records. Overall, improvements in these metrics in recent years help demonstrate the Company's proactive and prudent investments in its gas system.

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

A. Public Service has reduced its distribution leak ratio (that is, the ratio of distribution main leaks per mile of main) by over 43 percent since 2015, which indicates that it is successfully targeting renewal of the highest risk main pipelines through its capital pipeline replacement programs (Accelerated Main Replacement Program ("AMRP") and Programmatic Risk-Based Pipe Replacement Program ("PPRP")) within the PSIA. Figure LAL–D-1 provides annual leak ratios from 2011 through 2018.[3]

[3] Data for 2019 is not yet available.

Figure LAL-D-1
Historical Public Service Distribution Leak Ratios



Q. WHAT IS THE SIGNIFICANCE TO CUSTOMERS OF THE REDUCTION IN PUBLIC SERVICE'S DISTRIBUTION LEAK RATIOS?

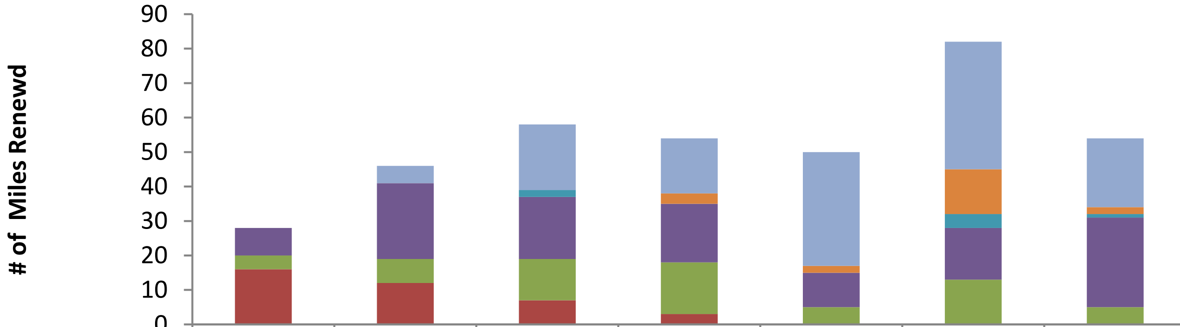
A. A declining leak ratio indicates that more gas is staying in the pipeline where it belongs, providing a benefit to the environment and providing a higher level of safety to our customers.

Q. WHAT PROGRESS HAS BEEN MADE ON PIPELINE RENEWALS?

A. Between 2012 and 2018,[4] Public Service has renewed over 370 miles of main through the PSIA through its pipeline replacement programs, AMRP and PPRP, as demonstrated in Figure LAL-D-2.

[4] Data for 2019 will be available in the 2019 PSIA report, which will be filed with the Commission on April 1, 2020.

Figure LAL-D-2
Public Service Miles of Mains Renewed



	2012	2013	2014	2015	2016	2017	2018
Vintage Steel		5	19	16	33	37	20
Coupled IP		0	0	3	2	13	2
Aldyl A		0	2	0	0	4	1
PVC	8	22	18	17	10	15	26
Bare Steel	4	7	12	15	5	13	5
Cast Iron	16	12	7	3	0	0	0

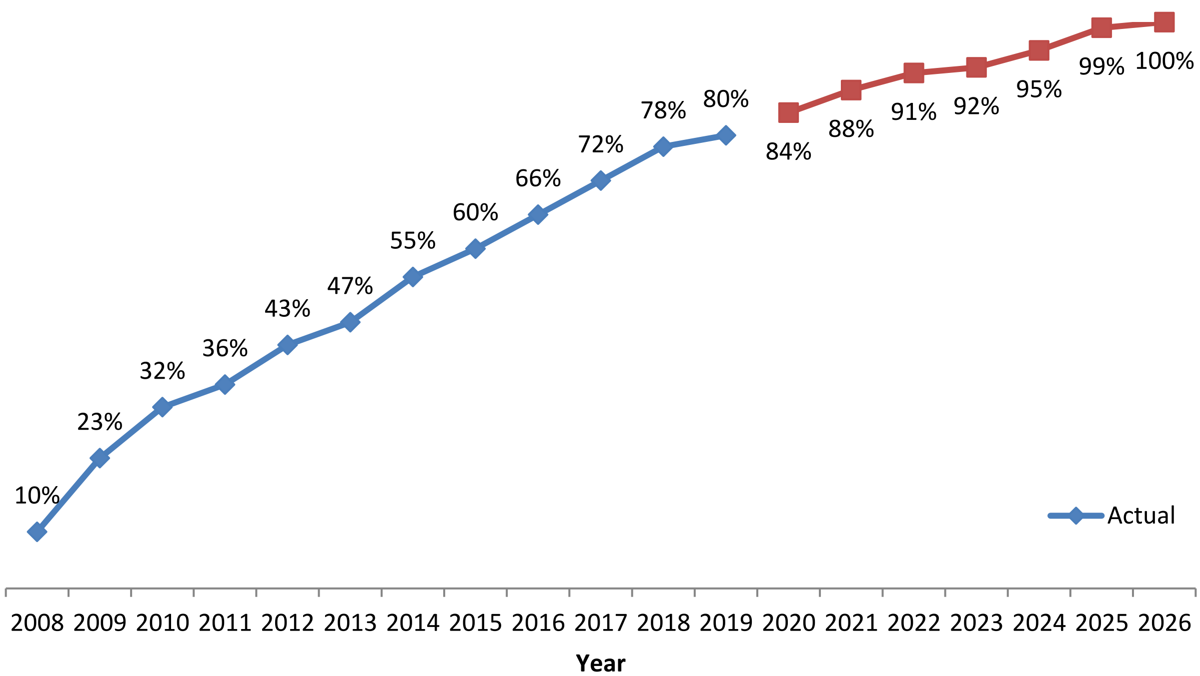
Q. WHAT IS THE SIGNIFICANCE TO CUSTOMERS OF THE PROGRESS ON PIPELINE RENEWALS?

A. The renewal of poor-performing pipe types drives down leak rates and provides a higher level of safety to our customers, as well as lower emissions.

Q. WHAT PROGRESS HAS BEEN MADE ON TRANSMISSION PIPELINE ASSESSMENTS?

A. Public Service has health assessed 80 percent of its transmission pipelines through 2019, and 100 percent completion is forecasted in 2026 via all assessment methods, as set forth in Figure LAL-D-3. Assessments are accomplished through a variety of methods, including in-line inspections, direct current voltage gradient surveys, external corrosion direct assessments, internal corrosion direct assessments, and pressure testing. Capital costs associated with performing transmission assessments are collected through the PSIA, and O&M costs associated with transmission assessments are collected through base rates.

Figure LAL-D-3
Percentage of Transmission Lines Health Assessed



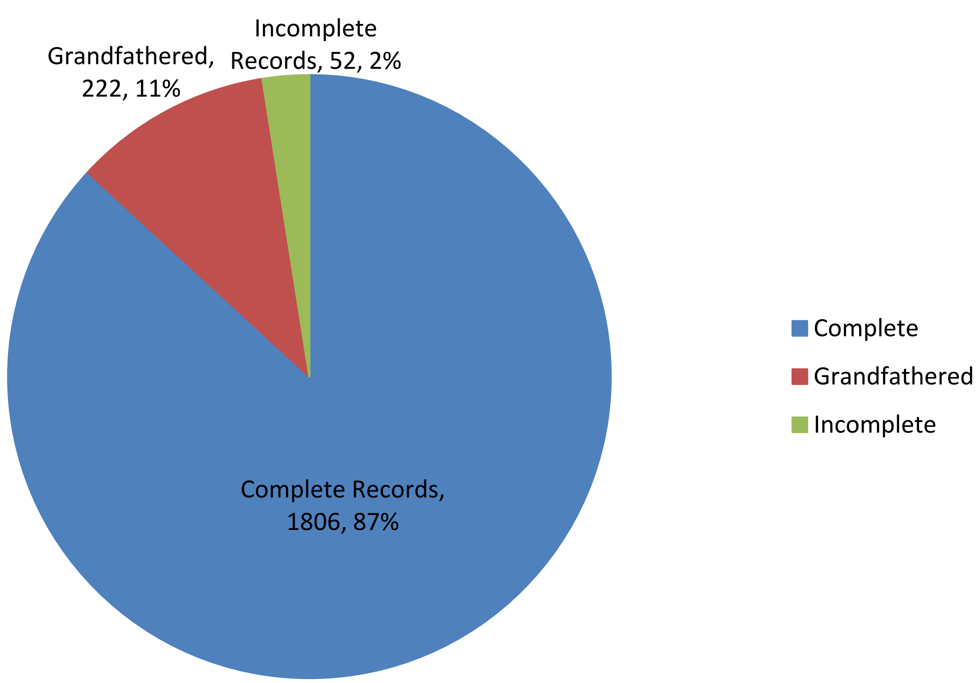
Q. WHAT IS THE SIGNIFICANCE TO CUSTOMERS OF THE PROGRESS ACHIEVED AND ANTICIPATED ON TRANSMISSION PIPELINE ASSESSMENTS?

A. Transmission pipeline assessments provide valuable information about the health and condition of our high-pressure ("HP") transmission lines. Knowing this information allows us to remediate any anomalies discovered, providing a safer environment for our communities and customers that live, work, and play around our transmission pipelines.

Q. WHAT IMPROVEMENT HAS BEEN MADE TO TRANSMISSION PIPELINE RECORDS?

A. The Company has completed the review of all pressure test records on transmission lines for traceability, verifiability, and completeness. Efforts are ongoing to evaluate material records. Figure LAL–D-4 provides the percentage of transmission miles that have incomplete records as defined by 49 CFR Part 192.619 to support the Maximum Allowable Operating Pressure ("MAOP") of the pipeline. In 2018, Public Service had 2,080 miles of transmission pipelines. Of those, 222 miles (11 percent) are grandfathered under Part 192.619(c) of the rule; 87 percent have complete records; and two percent have incomplete records to support the pipelines' MAOP.

Figure LAL-D-4
Percentage of Records to Support Transmission Pipeline MAOP



Q. WHAT IS THE SIGNIFICANCE TO CUSTOMERS OF IMPROVEMENTS IN TRANSMISSION PIPELINE RECORDS?

A. Having complete, traceable, and verifiable pressure test records ensures that our transmission pipelines not only meet PHMSA requirements but also ensure that they are operating at or beneath their MAOP, providing a safer environment for our customers and communities.

Q. WHAT OVERALL CONCLUSIONS CAN BE DRAWN FROM THESE IMPROVEMENTS IN KEY METRICS?

A. These metrics indicate that the Company's investments in safety, reliability, and system integrity are enhancing our overall system health and customer service capabilities. These metrics also support our plan to continue these investments into the future, as our safety and reliability work is not yet done. In fact, we anticipate additional system needs going forward, as described later in my Direct Testimony.

4. Quorum Pipeline Transaction Management System

Q. ARE THERE ANY INVESTMENTS YOU WOULD LIKE TO DISCUSS OUTSIDE OF THOSE LISTED ON ATTACHMENT LAL-1?

A. Yes. Company witness Mr. Sridhar Koneru supports the Company's new gas transportation system management software, which the Company began using in 2019. I provide additional information related to the Gas Operations need for this software, which facilitated many of the transportation operational and tariff changes recently discussed in the Company's 2019 Gas Phase II rate case, Proceeding No. 19AL-0309G.

Q. WHAT IS INVOLVED IN MANAGING TRANSPORTATION OF NATURAL GAS?

A. The natural gas transportation system consists of a vast network of pipelines that run across North America and transport gas from where it is produced to where it will be consumed. The complex movement, or transportation, of gas from gathering systems, interstate pipelines, and local distribution systems requires standardization and coordination. The standardization of transporting gas is accomplished through the North American Energy Standards Board ("NAESB") standard nomination model. This coordination of gas transportation is called gas scheduling.

Q. PLEASE DESCRIBE THE PROCESS OF GAS SCHEDULING.

A. Scheduling of natural gas is a continuous process that occurs 365 days per year, five times per day under the NAESB model. Scheduling of gas can be summarized as involving three steps: nominations (formal requests to transport gas made by a party who manages gas for an end user); scheduling (to ensure nominations received by the Company match available capacity); and confirmation (the process by which pipeline operators confirm nominated volumes at a given location).

Q. WHAT IS PUBLIC SERVICE'S ROLE IN GAS SCHEDULING?

A. Public Service is a Local Distribution Company. Therefore, it is the Company's responsibility to ensure that its system is safe by balancing the system – the gas supply that goes into the Company's pipes should equal what customers use on any given day. This responsibility includes monitoring and assessing gas supply and gas demand and ensuring efficient operational limits so that Public Service can deliver the level of service it has agreed upon with each of its customers. If, on any given day, the Company is not confident that its transportation customers will balance the gas market, Public Service may step in and take action to influence them, to make sure pressure levels remain within acceptable limits.

Q. HOW HAS PUBLIC SERVICE HISTORICALLY MANAGED ITS GAS TRANSPORTATION BUSINESS?

A. For many years, Public Service managed its gas transportation business using internal resources and through a home-grown gas transactional mainframe computer system, called the Gas Management System ("GMS"), that has been in use since the 1990s. This legacy system was used to schedule gas, manage receipts and deliveries of gas, aggregate and manage gas measurement, and prepare volumetric allocations for billing purposes. However, Public Service's legacy gas transportation business was not aligned with NAESB nomination cycles more recently, and updates to align with industry standards and improved operational requirements were needed.

Q. WHY ELSE WAS THE LEGACY GMS SYSTEM INSUFFICIENT TO MANAGE PUBLIC SERVICE'S GAS TRANSPORTATION BUSINESS?

A. In addition to limitations on the legacy system's capabilities, the legacy system was nearing the end of its life. As a result, an extensive Request for Proposal process was undertaken to find the right system to meet the transportation business requirements for the Company. Through that process, the Quorum Pipeline Transaction Management system ("Quorum System") was selected to replace the legacy GMS system. The Quorum System is now managing the gas scheduling, confirmation, and allocation process, as well as gas measurement, beginning in July of 2019. The total plant addition for the Quorum System was approximately $5.0 million and discussed by Mr. Koneru.

Q. CAN YOU DESCRIBE THE BENEFITS OF THE QUORUM SYSTEM?

A. Yes. The Quorum System offers a more modern way to replace the end-of-life system and manage the gas transport business, from measurement to the preparation of the final allocation statement for billing. Perhaps the biggest change that is being realized is the implementation of NAESB five-cycle nominations. The legacy system was unable to accommodate the five-cycle nomination process. Implementing five-cycle nominations allows customers to better manage their nominations compared to their actual gas consumption and is more aligned with other pipeline systems.

In addition, the gas transportation customer is now able to interface with a website called an Electronic Bulletin Board ("EBB"), logging into the EBB to access the Quorum System to make nominations, view gas usage, view contract terms, and generate various reports. While the system is new and the transition is continuing, the web-based platform can be used on a mobile device.

Q. IS THE QUORUM SYSTEM USEFUL FOR CUSTOMERS OTHER THAN TRANSPORTATION CUSTOMERS?

A. No. The Quorum System exists to support and serve our transportation customers, who have unique needs to nominate and balance the gas market that customers who are end-users alone do not have. This obligation applies to all transportation customers, and the Quorum System serves the needs of transportation customers alone. Overall, the upgrade allows our gas transportation business to function consistent with current standards and practices. Costs included in this rate case related to the Quorum System are directly allocated to transportation customers in the class cost of service study, as described by Company witness Mr. Steven W. Wishart.

5. Future Investment Needs

Q. BEYOND THE VARIOUS INVESTMENTS OUTLINED ABOVE, WHAT ADDITIONAL INVESTMENT NEEDS ARE FACING PUBLIC SERVICE'S GAS SYSTEM IN 2020 AND BEYOND?

A. The Company will continue to focus on safety and reliability in the future, as it currently is doing. Much of this focus will involve the same or similar types of work described in my Direct Testimony in this proceeding. In addition, customer requests for new business, along with mandated infrastructure relocations, will also require additional investments on the gas system.

Along with that work, the Company is anticipating incremental investments with the passing of Phase I of the new PHMSA gas transmission rule that was published on October 1, 2019 and is effective on July 1, 2020. The rule includes significant program impacts related to MAOP reconfirmation, material records verification requirements, and establishment of Moderate Consequence Areas for integrity assessments beyond High Consequence Areas. Phase II of the new gas transmission rule is expected to become final in early 2020 and is expected to include significant impacts to anomaly repair criteria, inspection after extreme events, and expanded corrosion control programs. Phase III of this new transmission rule is also expected in 2020 and will expand safety regulations to certain rural gathering lines typically operated by oil and gas producers and processors.

In addition to the transmission rule, PHMSA is expected to propose a rule in 2020 that addresses the installation of remote-controlled valves and rupture detection on transmission lines. Other PHMSA rulemaking topics in progress include integrity of underground storage facilities, expansion of operator qualification, and construction inspection of mains and transmission lines.

Q. DOES THE NEW TRANSMISSION RULE DRIVE ANY OF THE INVESTMENTS IN THIS RATE CASE?

A. No. In the settlement of the extension of the PSIA, Decision No. C18-0983, the parties agreed that Public Service would review the impact of the new transmission rule with the parties and confer regarding the best approach to recover the investments and costs associated with complying with the new rule. The Company anticipates gathering the parties to review this impact around June 2020. However, we believe it is helpful to continue to preview these changes to provide additional context for the overall work being done by the Company's Gas Operations.

C. Gas Operations Budgeting Processes

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

A. In this section, I provide an overview of the Company's budgeting processes and management as additional support for the forecasted capital included in the Company's rate request.

Q. HOW DOES PUBLIC SERVICE BUDGET FOR CAPITAL SPENDING FOR ITS GAS OPERATIONS BUSINESS?

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 risks (issues) and mitigations (solutions).

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

Step 3: - As each risk and mitigation 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 mitigations 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.

<u>Step 6:</u> - 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."

<u>Step 7:</u> - Capital projects for large pools of small projects (e.g., main installations, service 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.

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

<u>Step 9:</u> - Work is deployed during the year, as efficiently and cost-effectively as possible.

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. Laurie J. Wold. Ms. Wold 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 Operations 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 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 and plant in-service to budgeted levels for (1) routine and (2) specific projects. I meet monthly with this group and key stakeholders within the organization to review program and specific 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 and plant in-service (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. This metric is aimed at developing accurate budgets and managing to the budgeted levels.

Q. WHAT ARE ROUTINES?

A. Routines or blankets are budgets used to fund routine small projects that are typically less than $300,000. The Company has four Routine budgets: Asset Health (reliability), New Business, Mandatory Relocations, and Capacity (reliability).

Q. CAN YOU DESCRIBE HOW THE COMPANY BUDGETS FOR ROUTINES?

A. Yes. Because projects that are funded under routines are generally not defined until the current year, the budget is determined based largely on historical actuals. More specifically, routine budgets are based on historical spend and forward-looking growth projections by category, while also taking cost escalations into account.

More individual routine projects, such as for new business growth, reinforcements, or rebuilds, are budgeted based on 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. WHAT ARE DISCRETE PROJECTS?

A. Discrete projects are typically large multi-year projects, greater than $300,000, in which the Company sets up a discrete work order to track the specific cost of the project. Discrete projects are identified through the Company's Builders Call Line (new business), requests from municipal or government agencies (mandatory relocations), or through the Company's planning process (asset health and capacity).

Q. HOW DOES THE COMPANY BUDGET FOR DISCRETE PROJECTS?

A. As mentioned earlier, discrete projects are typically multi-year projects greater than $300,000. During the Company's annual budget cycle, we follow a rigorous budgeting process that identifies the optimal mix of projects and expenditures for a given year. If a discrete multi-year project is known and of high enough priority to be included in the annual budget, it is added to the budget during the regular budget cycle.

However, discrete projects can arise outside of the Company's normal budget process. In order to account for these projects that arise outside of the normal budget process, the Company reviews historical spend and will place funding in a working capital fund. These working capital funds appear in the discrete project lists, contained within my testimony, under the project name “other” along with additional projects that do not fall into a broader project name category. For example, in Table LAL-D-33 later in my Direct Testimony, the Mandated Relocations – Other category is comprised of 33 projects, of which one is the working capital fund. This represents approximately one percent of the total capital additions from January 1, 2017 through September 30, 2019, and approximately one percent of total forecasted capital additions from October 1, 2019 through September 30, 2020, capital additions.

Q. IN GENERAL, HOW DOES THE COMPANY DETERMINE COST ESTIMATES FOR INDIVIDUAL DISCRETE PROJECTS?

A. Given the nature of our business, the Company must estimate the costs of large multi-year projects that contain unknown variables that may impact the final cost of these projects. Initial budgets are based on either unit pricing, or (for larger projects) more specific details such as the scope of the project, timelines, historical costs, anticipated labor and material costs, and the like. Historically, the Company has also added a level of contingency to help account for unanticipated variables to minimize the impacts to the overall budget.

In an effort to further refine the estimation process over the last several years, the Company has been focusing on enhancing the planning and accuracy of our initial cost estimates. Additionally, we have recently piloted and are now implementing a gated project development and execution approach, which has resulted in a more structured and disciplined project management process for larger and/or more complex programs of work. The project development process is a tiered approach with prescribed planning requirements at each gate within a project's lifecycle. This requires that project managers develop a more holistic registry of project risks including materials availability, contractor resourcing strategy, operational schedules, and public impact. Overall, these improvements enable more up-front planning which supports the accuracy of our capital budgets. As a result, the contingencies are refined as a project goes through the process.

Finally, once a project is under way, the project manager meets regularly with the key staff (i.e., siting and land rights, sourcing, construction/operations, etc.) where issues and concerns are identified and solutions are developed. The overall goal is to achieve safe and timely completion of the project at no more than the budgeted cost.

Q. WITH THAT BACKGROUND, CAN YOU PROVIDE ADDITIONAL SUPPORT FOR THE GAS OPERATIONS CAPITAL AND O&M EXPENSE INCLUDED IN THIS RATE CASE?

A. Yes. In Sections III, IV, V, and VI of my Direct Testimony, I will walk through each of these four areas of investment (Safety, Reliability, New Customer Business, and Mandated Relocations), identifying in more detail how they affect the operations of Public Service's gas system. I will also walk through key projects and primary drivers of O&M expense, and provide attachments supporting other capital projects of approximately $1 million or more.

III. SAFETY OF THE GAS SYSTEM

Q. WHAT ARE THE KEY COMPONENTS OF MAINTAINING THE SAFETY OF THE PUBLIC SERVICE GAS SYSTEM?

A. As previously noted, customer, system, and public safety are at the core of the mission of Public Service's Gas business. Maintaining safety requires a multi-faceted approach that takes into account the complex nature of the system and the multiple risks that face any natural gas system. Much of the safety work is focused on maintaining the integrity of the Public Service gas system assets so they can function as intended and provide safe and reliable service to customers.

In addition to overall integrity efforts, key areas I will address in turn in this section of my Direct Testimony include: 1) Damage Prevention; 2) Emergency Response; 3) Leak Surveys; 4) Storage Integrity Programs; 5) Transmission Right-of-Way Clearing; and 6) Exposed Pipe Inspection and Remediation. I also support discrete safety capital investments.

Q. PLEASE PROVIDE AN OVERVIEW OF THE SAFETY CAPITAL ADDITIONS BETWEEN ROUTINE AND DISCRETE PROJECTS.

A. While many of our capital investments in safety remain in the PSIA, Table LAL-D-3 identifies the Safety plant additions that the Company has invested in, outside of the PSIA, since the last rate case and forecasted through September 30, 2020:

Table LAL-D-3
Gas Operations Safety Capital Additions
Routines vs. Discrete Projects ($ millions)

Safety	Jan 2017 - Sep 2019	Oct 2019 - Sep 2020	Total
Routines	$0.0	$0.0	$0.0
Discrete	$25.0	$15.8	$40.8
Total	**$25.0**	**$15.8**	**$40.8**

**Differences in sums due to rounding*

Q. PLEASE IDENTIFY THE INDIVIDUAL DISCRETE SAFETY PROJECTS THAT WERE ADDED BETWEEN JANUARY 1, 2017 AND SEPTEMBER 30, 2019.

A. Table LAL-D-4 lists the key discrete safety projects that were in-serviced between January 1, 2017 and September 30, 2019. In addition, the table also contains a brief description of each of these safety projects.

Table LAL-D-4
Discrete Safety Plant Additions ($ millions)

Project Name	Jan 1, 2017 - Sept 30, 2019	Description
Inside Meter Move-out	$9.1	Move-out of inside gas meters
Leak City Training Center	$2.4	Installation of center to support training and repair of leaks
Capitalized Locating Costs	$2.4	Ongoing capitalized component of damage prevention locates
Tools	$4.3	Tools and equipment for construction and maintenance activities
Asbury Wellhead Filters	$1.0	Six well-head filter separators at Asbury to protect recently installed dehydrators
Underground Storage	$3.3	Various underground storage activities
SSSVs	$1.3	Installations of 17 subsurface safety valves
Safety - Other	$1.2	Various activities to support safety
Total Safety Discretes	**$25.0**	

**Differences in sums due to rounding*

Q. PLEASE DESCRIBE THE DISCRETE SAFETY PROJECTS THAT ARE BEING ADDED FROM OCTOBER 1, 2019 THROUGH SEPTEMBER 30, 2020.

A. Table LAL-D-5 lists the key discrete safety projects that will be in service between October 1, 2019 and September 30, 2020. In addition, the table also contains a brief description of each of these safety projects.

Table LAL-D-5
Discrete Safety Plant Additions ($ millions)

Project Name	Oct 1, 2019 - Sept 30, 2020	Description
Capitalized Locating Costs	$1.6	Ongoing capitalized component of damage prevention locates
Tools	$8.2	Tools and equipment for construction and maintenance activities
Asbury Wellhead Filters	$0.5	Six well-head filter separators at Asbury to protect recently installed dehydrators, and completion of filter separator at Asbury
Underground Storage	$4.4	Various underground storage activities
SSSVs	$0.4	Installations of 17 subsurface safety valves, and close out efforts involving installation of sub-service safety valves
Safety - Other	$0.7	Various activities to support safety
Total Safety Discretes	**$15.8**	

**Differences in sums due to rounding*

I provide additional detail regarding key safety capital plant additions later in this section of my Direct Testimony.

Q. PLEASE IDENTIFY THE SAFETY O&M COSTS INCURRED SINCE THE COMPANY'S 2017 GAS PHASE I.

A. Table LAL-D-6 identifies the Safety O&M costs incurred since Public Service's last rate case, as well as known and measurable expense increases through September 30, 2020, proposed for inclusion in base rates.

Table LAL-D-6
Gas Operations Safety O&M Expenses ($ millions)

	Oct. 1, 2018 - Sept. 30, 2019	Oct. 1, 2019 - Sept. 30, 2020	Total
GER/Gas Trouble	$7.4		$7.4
Damage Prevention Program	$4.5		$4.5
Leak Survey	$1.0	$0.2	$1.2
Underground Storage	$0.5	$0.2	$0.7
Pipeline System Integrity Adjustment Amortization	($3.6)		($3.6)
MAOP	($4.4)		($4.4)
Right of Way Clearing		$1.1	$1.1
Exposed Pipeline Inspection & Remediation		$1.0	$1.0
Other	$1.1	$0.6	$1.7
Total	**$6.5**	**$3.1**	**$9.6**

**Differences in sums due to rounding*

Q. CAN YOU PROVIDE SUPPORT FOR EACH OF THESE AREAS OF SAFETY INVESTMENTS IN PUBLIC SERVICE'S GAS SYSTEM?

A. Yes. Above I have identified the capital and O&M costs of the work completed and ongoing in each of these major categories of safety investment. Below, I explain why this work is important for the system and necessary to provide safe natural gas service to customers. I begin with individual programs, which consist mainly of O&M for base rates, and then move to the larger discrete capital projects.

A. Damage Prevention

Q. ARE UNDERGROUND DAMAGES A SIGNIFICANT RISK TO PUBLIC SERVICE'S GAS DISTRIBUTION SYSTEM?

A. Yes. Damage to Public Service's underground facilities continues to be a significant risk to our gas distribution system. In fact, the largest cause of leaks on Public Service's gas mains has been third-party damage.[5] As a result, Public Service continues to institute a variety of outreach efforts to excavators regarding the importance of utilizing Colorado 811, as well as the Common Ground Alliance and Gold Shovel Association, for best excavation practices.

Specifically, it is critical that the Company's mains and services are located accurately before excavating to ensure safety for the workers, as well as the public, around the work site. To that end, Public Service continually re-evaluates its damage prevention programs to increase their effectiveness. The Company also provides leadership in several industry organizations where it obtains and shares information about best practices for reducing public damage.

Q. HOW IS PUBLIC SERVICE PERFORMING WITH RESPECT TO DAMAGE PREVENTION?

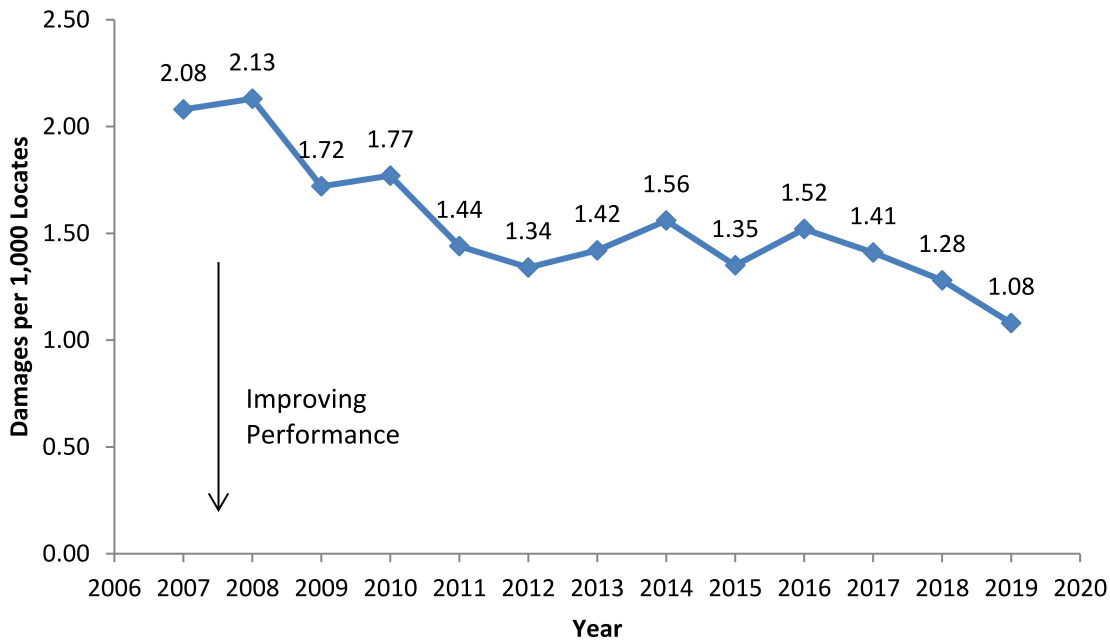
A. As a result of the efforts outlined above and described in more detail later in my testimony, Public Service continues to maintain our industry leading, top quartile position on damage prevention. A proactive and top quartile damage prevention

[5] U.S. D.O.T. – PHMSA. Annual Report for Calendar Year 2018 Gas Distribution System – Public Service Company.

program also contributes to the Company's journey to improve response times to gas emergency calls.

Figure LAL-D-5 illustrates the number of gas and electric damages per 1,000 locates from 2007 through 2019. As indicated by this figure, the Company has seen almost a 50 percent reduction in damages per 1,000 locates on our system since 2007.

Figure LAL-D-5
Public Service Damages per 1,000 Locates



Q. HOW ARE LOCATES PERFORMED BY PUBLIC SERVICE?

A. The Company is required by law to perform locate services for its facilities when requested. To meet this requirement, the Company participates in Colorado 811, utilizes five contracted outside vendors to perform locate requests, and utilizes one vendor who performs support and audit services.

First, Colorado 811 provides a centralized phone center for customers to call to request locates. The Company is required to participate in Colorado 811 per Colorado Revised Statutes section 9-1.5-105, which fulfills federal mandate 49 CFR Part 198.37 that requires states with underground pipeline facilities to adopt a one-call damage prevention program. The cost for this service is free to customers; however, the Company pays Colorado 811 a cost per ticket.

Second, the Company contracts with vendors to perform actual production locates, specialty locates, and provide field support and audit services. This work is bid out as part of a competitive bid process and the Company selects the best vendor in terms of quality and cost. Public Service is currently under contract with five out of the six vendors until 2021, with the remaining vendor's contract expiring in 2023.

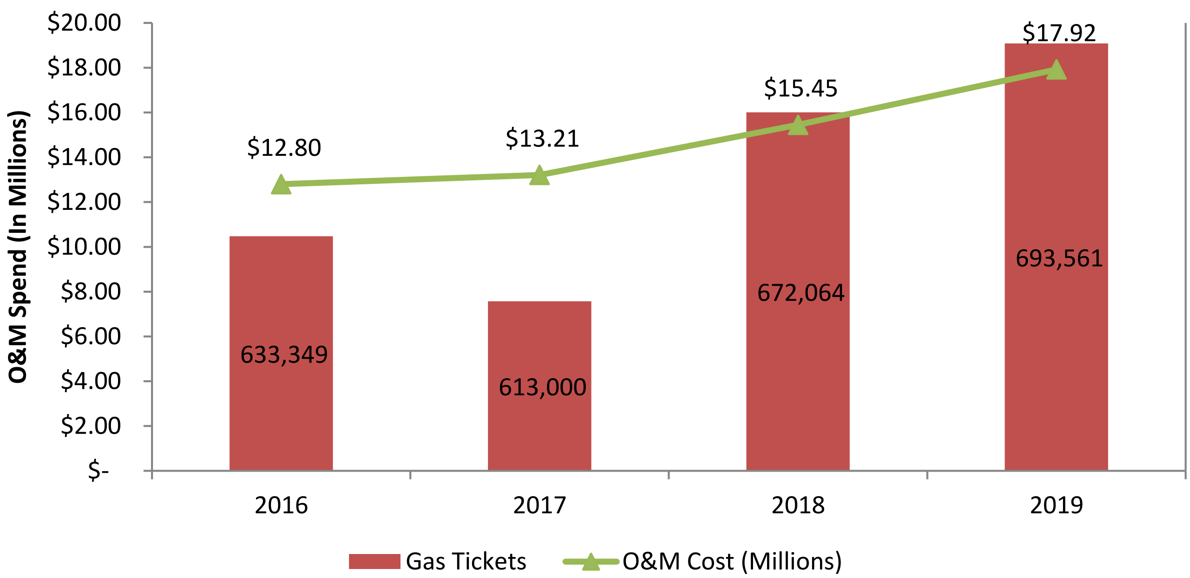
Q. DOES THE COMPANY HAVE A DEFERRED ACCOUNTING MECHANISM FOR LOCATE REQUESTS?

A. Yes. The Commission first approved deferred accounting for Public Service's damage prevention costs in the Company's 2015 Phase I gas rate case in Proceeding No. 15AL-0135G ("2015 Gas Phase I"), because these are significant O&M costs, are unanticipated, and are outside of Public Service's control. See Decision No. R15-1204 and Final Order Exhibit 3 in the 2015 Gas Phase I. In the 2017 Gas Phase I, the Commission approved $12,763,072 to be included in the 2016 HTY and further approved the Company's deferred accounting mechanism.

Q. WHAT WERE THE ACTUAL COSTS ASSOCIATED WITH LOCATE REQUESTS SINCE THE 2016 HTY?

A. Figure LAL-D-6 provides the annual actual O&M costs incurred since the 2016 HTY. From 2016 to 2019, the volume of gas locate requests have increased approximately ten percent, while O&M costs during this period have increased twelve percent. This cost increase is largely attributed to additional safety needs related to increased horizontal directional drilling requests to install 5G facilities near the Company's critical gas infrastructure.

Figure LAL-D-6
Annual O&M Spend – Public Service Gas Locates



Year	Gas Tickets	% Increase
2016	633,349	
2017	613,000	-3%
2018	672,064	10%
2019	693,561	3%
Average Ticket Increase		**3%**

Q. HOW MUCH IS THE REGULATORY ASSET AS OF SEPTEMBER 30, 2019?

A. As shown in Attachment LAL-4, the balance of the regulatory asset at September 30, 2019 is $7.3 million.

Q. WHAT IS YOUR CONCLUSION REGARDING THE NEED TO RECOVER PREVIOUSLY INCURRED DAMAGE PREVENTION COSTS?

A. This work is required by state and federal code and is variable and largely outside the Company's control. Costs are managed to the extent possible in the manner described above. As a result, the Company's damage prevention program is prudent, and these O&M expenses were reasonable and necessary and should be recovered through base rates. Public Service therefore requests that the deferred balances for 2018 and 2019 related to the regulatory assets for locate requests ($2.7 million, and $4.6 million, respectively) be approved for cost recovery. Mr. Berman discusses the Company's proposed amortization of the deferral balances that have been included in the revenue requirement provided as Attachment DAB-1 to the Direct Testimony of Ms. Deborah A. Blair.

Q. ARE THERE ANY CAPITAL INVESTMENTS ASSOCIATED WITH PERFORMING LOCATE REQUESTS?

A. Yes, a small portion of locate requests are allocated to capital. As mentioned previously, approximately 15 percent of locate requests are performed for Public Service capital projects for new business, main renewals, capacity projects, etc. The costs for these locate requests for Public Service capital projects are capitalized. From January 1, 2017 through September 30, 2019. the Company capitalized $2.4 million, and forecasts capitalizing an additional $1.6 million from October 1, 2019 through September 30, 2020.

Q. LOOKING AHEAD, DOES THE VOLUME OF LOCATE REQUESTS CONTINUE TO REPRESENT A CHALLENGE FROM A SAFETY AND BUDGET PERSPECTIVE?

A. Yes. Responding to locate requests is a critical safety activity, as noted above. Further, Figure LAL-D-6 depicts the actual number of gas locate requests the Company has completed by year since 2016. The number of locate requests is driven by economic conditions in new construction and by local city, county, and state project activity. In fact, in 2019, approximately 85 percent of locate requests were not Public Service projects at all, but other entities excavating around our infrastructure. As such, it is difficult to predict ticket volume on an annual basis. O&M expenses related to this type of locating requests vary considerably, depending on the requested work and its relation to the Company's key facilities.

Q. WHAT IS PUBLIC SERVICE'S PROPOSAL IN THIS PROCEEDING FOR RECOVERY OF THE COST OF FUTURE DAMAGE PREVENTION PROGRAM LOCATE REQUESTS?

A. Public Service is proposing to reset the amount of damage prevention costs included in the Test Year, and then continue the deferred accounting mechanism to account for additional and future O&M costs. In particular, the Company proposes to (1) set the annual base O&M level at $17.3 million, which represents the total actual O&M expense from October 1, 2018, to September 30, 2019; and

(2) defer the costs incurred above or below the base amount going forward and establish a regulatory asset for such costs through the Company's next Phase I or combined rate case. For a more detailed discussion of the deferred accounting mechanism, please see the Direct Testimony of Mr. Berman.

B. <u>Gas Emergency Response</u>

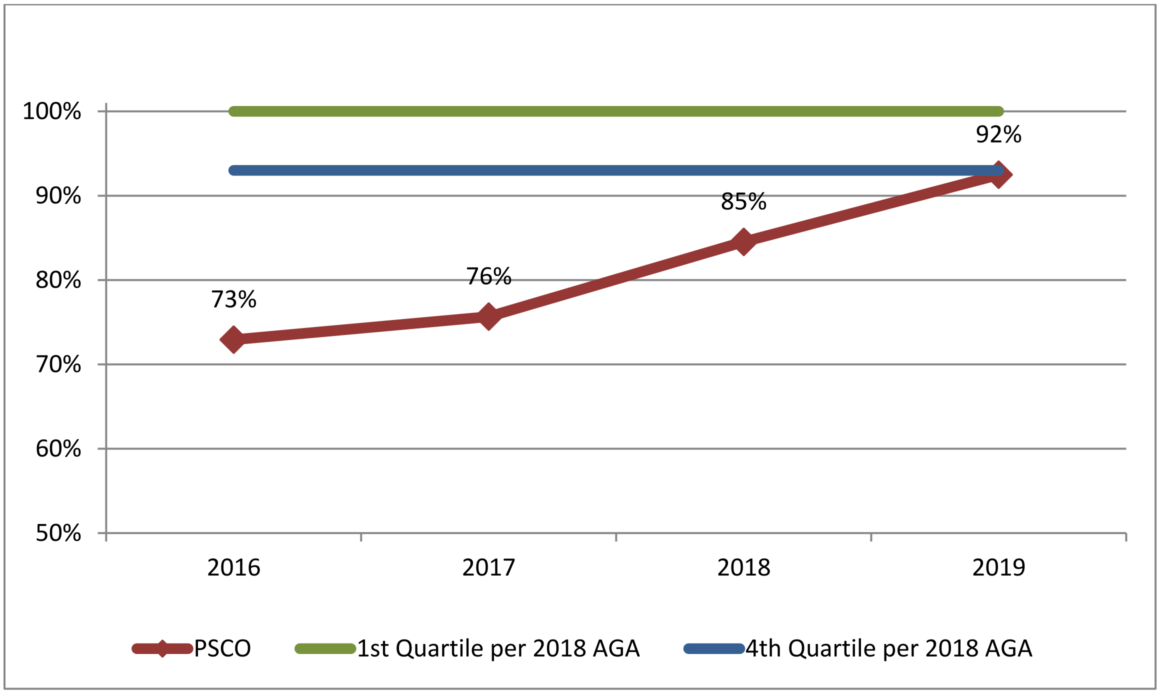
Q. WHAT IS INVOLVED IN GAS EMERGENCY RESPONSE?

A. Calls for gas leaks, an odor of gas, damaged gas lines, fire, and carbon monoxide symptoms are all considered gas emergencies. The Company's response to these emergency situations are critical to providing safe and reliable natural gas to our customers. Gas emergency responders are dispatched quickly to the scene of the emergency after the phone call is received by the Company, with the primary goal of making the situation safe. Based on the situation, the gas emergency responder may also call in others to help make repairs.

Q. HOW HAS THE COMPANY PERFORMED WITH RESPECT TO GAS EMERGENCY RESPONSE TIMES?

A. While Public Service has additional work to do, the Company has made remarkable improvements in its gas emergency response times. The industry measures gas emergency response times as the percentage of all emergency calls responded to within 60 minutes. Figure LAL-D-7 shows the improvements made since the 2017 Gas Phase I rate case.

Figure LAL-D-7
Percentage of Gas Emergency Calls Responded to in < 60 Minutes



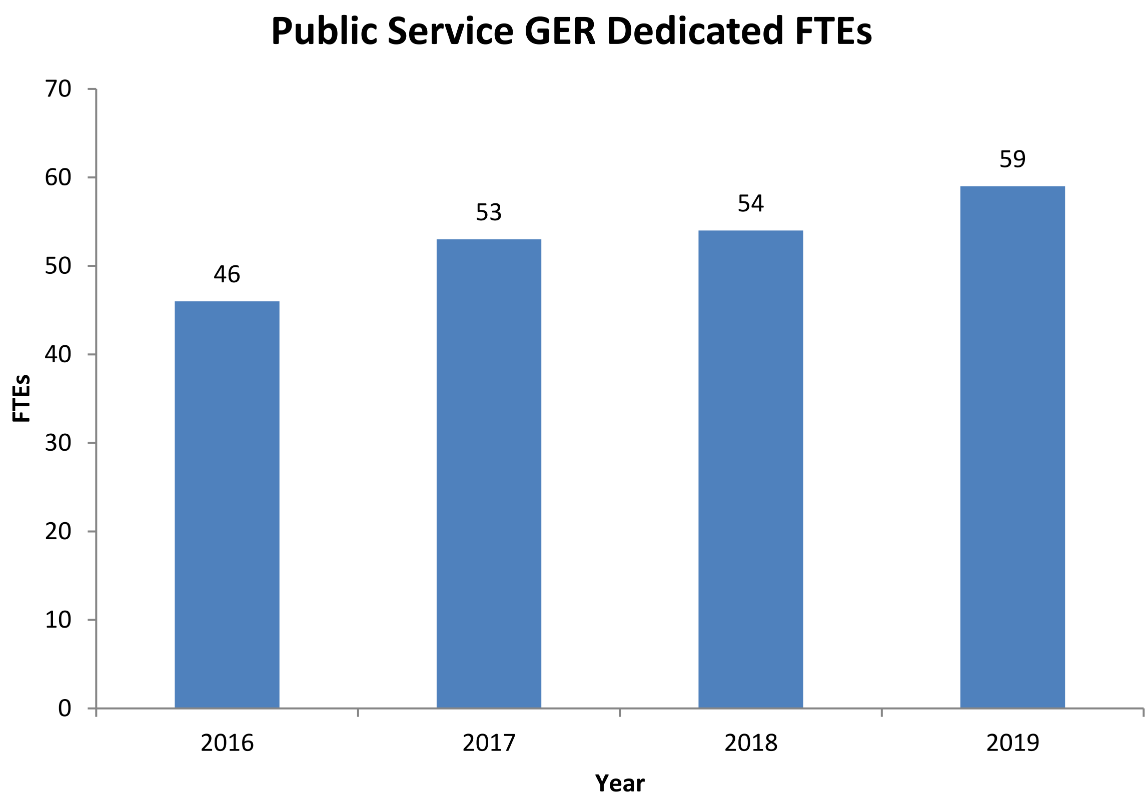
Q. WHAT WERE THE MAIN DRIVERS FOR THE SIGNIFICANT IMPROVEMENTS IN RESPONSE TIME SINCE 2016?

A. There are three main drivers that contributed to the 25 percent increase in gas emergency response times since 2016: (1) number of employees responding to emergencies, (2) amount of overtime employees worked, and (3) efficiency improvements in how the work is performed.

Q. HOW HAVE THE NUMBER OF EMPLOYEES RESPONDING TO GAS EMERGENCIES CHANGED SINCE 2016?

A. The Company has increased the number of employees who are dedicated to responding to gas emergencies. Since 2016, the Company has hired an incremental 13 dedicated gas emergency responders. Figure LAL-D-8 shows the number of dedicated gas emergency responders from 2016 to 2019.

Figure LAL-D-8
Public Service Dedicated Gas Emergency Responders



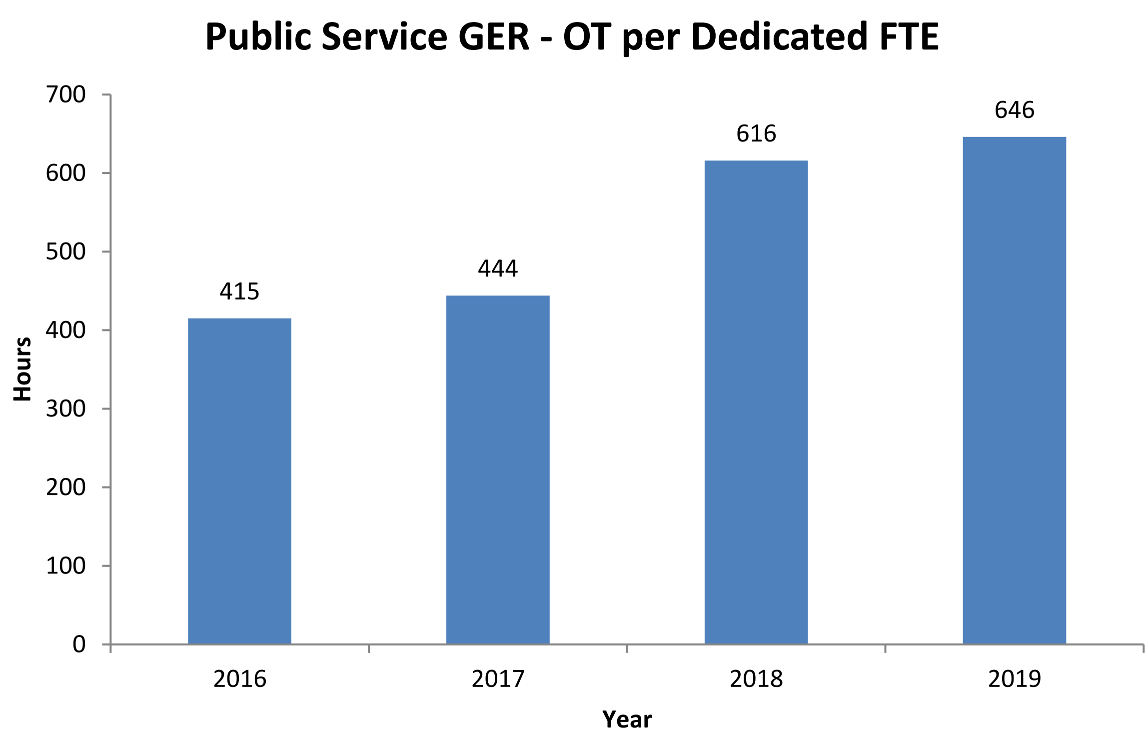
Q. HAS THE COMPANY MADE ANY OTHER ORGANIZATIONAL CHANGES TO ALLOW OTHER CLASSES OF EMPLOYEES TO RESPOND TO GAS EMERGENCIES?

A. Yes. The Company combined the employees from the meter shop (38 FTE) and gas emergency response departments, effective October 1, 2019 to increase the number of available resources to respond to emergencies in the Denver Metro area. Both classifications of employees are fully qualified to perform all associated tasks when responding to gas emergency calls.

Q. HAS OVERTIME ALSO INCREASED SINCE 2016 FOR THE DEDICATED EMERGENCY RESPONDERS?

A. Yes. The amount of overtime performed by the dedicated emergency responders has also increased. Figure LAL-D-9 shows how the average number of overtime hours for dedicated gas emergency responders have increased by approximately 60 percent from 2016 to 2019, despite the increase in the number of responders. This has been necessary to meet the demand for gas emergency response while improving response times to ensure the safety of the public.

Figure LAL-D-9
Average Overtime per Year per Dedicated Responder



Q. HAS THE NUMBER OF GAS EMERGENCY CALLS INCREASED SINCE THE 2017 GAS PHASE I?

A. Yes, slightly. When comparing the number of emergency calls in 2016 with those received in 2019, the Company received 816 more calls in 2019 than 2016 or an increase of 1.9 percent. Figure LAL-D-10 shows the annual number of emergency calls received from 2016 to 2019.

Figure LAL-D-10
Annual Number of Emergency Calls

Q. DID THE COMPANY ALSO IMPLEMENT ANY EFFICIENCY MEASURES?

A. Yes. Earlier in 2019, an effort was launched to strategically review the end-to-end gas emergency response process, looking for opportunities to further improve response times. The employee group identified several initiatives across four work streams that it will focus on through the end of 2020 to further increase response time. These work streams include:

1. **Resource Strategy** – predictive analytics for emergency call volumes to optimize planning efforts, strategic geographic placement of responders to shorten response times, and utilization of meter shop employee to respond to gas emergencies.

2. **Field Execution** – development of standard operating procedures, streamlined paperwork, and reduced idle time.

3. **Performance Management** – daily meetings (huddles) with employees to review response performance, the development of an analytics hub, and implementation of a recognition system.

4. **Dispatch** – improved training programs and updating the dispatch system to simplify emergency orders.

Q. WHAT COSTS ARE INCLUDED IN THIS PROCEEDING FOR GAS EMERGENCY RESPONSE?

A. One of the key O&M expense drivers in this proceeding is the incremental $7.4 million in spend for gas emergency response (gas emergency response does not result in specific capital additions). These costs include increased labor and overtime to further meet increasing gas emergency response needs and continue to improve response times, as set forth in Table LAL-D-7:

Table LAL-D-7
Incremental Gas Emergency Response O&M ($ millions)

Expense Category	Amount
Labor/Overtime	$5.6
Tools	$1.5
Miscellaneous	$0.3
Incremental Emergency Response 2016 TY to 2020 TY	$7.4

**Differences in sums due to rounding*

C. <u>Leak Surveys</u>

Q. WHAT ARE LEAK SURVEYS?

A. A leak survey is a federally-mandated requirement on operators to systematically survey their gas system to locate leaks. Gas leak surveys are performed to detect potentially hazardous leaks and ensure the safety of people, property, and environment. When gas leakage is detected, the surveyor will determine the probable location of the leak and classify the level of hazard. Leaks identified through the leak survey process are then remediated consistent with the Company's Pipeline Compliance and Standards manual.

Additionally, operators are also required to regularly conduct atmospheric corrosion checks on their above-ground facilities. When possible and practical, it is appropriate to perform both routine patrolling and atmospheric corrosion monitoring during the performance of leak surveys. During these inspections, abnormal operating conditions are also identified, documented, and remediated.

Q. WHY ARE THE LEAK SURVEYS IMPORTANT?

A. Regular leak surveys are not only required by code, but they also detect gas leaks that could result in personal injury and/or property damage if not addressed. Thus, these surveys ensure not only the safety and integrity of our gas system, but the safety of our customers and protection of the environment from unnecessary methane releases.

Q. HOW MANY LEAK SURVEYS DOES PUBLIC SERVICE PERFORM?

A. The number of leak surveys performed can vary from year to year. Historically, Public Service has operated on a five-year leak survey cycle for some assets and a three-year survey cycle for other assets, using survey intervals that were set in 2006. However, Public Service is transitioning to a three-year leak survey cycle that aligns the survey program with the atmospheric corrosion program and will improve system safety and reliability. Within the Company's service territory, the Pueblo and Alamosa service centers have already updated to a three-year cycle. The Lipan service center has converted a third of its work to a three-year cycle and other areas are on a five year-cycle.

Q. HOW OFTEN IS PUBLIC SERVICE REQUIRED TO PERFORM LEAK SURVEYS?

A. Pursuant to 49 CFR Part 192.723(b)(2), Public Service is required to conduct leak surveys once every five years at intervals not exceeding 63 months for facilities outside of business districts. Pursuant to 49 CFR Part 192.723(b)(1), facilities within business districts[6] must be surveyed at intervals not to exceed every 15 months, but at least once each calendar year.

[6] A "business district" is an area marked by the distinguishing characteristic of being used in the conducting of buying and selling commodities and service, and related transactions. A "business district" would normally be associated with the assembly of people in shops, offices, and the like, and in the conduct of such business. It is the responsibility of the operator to determine if an area is a "business district."

Q. WHAT IS PUBLIC SERVICE'S PROPOSAL REGARDING LEAK SURVEYS WITHIN ITS SYSTEM?

A. In order to shift from a five-year to a three-year cycle, there will need to be additional surveys performed in the Test Year ending September 30, 2020. Public Service anticipates that it will take approximately three to four years to get everything fully transitioned to a three-year cycle and proposes to include the level of costs in the Test Year that are necessary to progress along this timeline.

Q. WHAT ARE THE BENEFITS OF MOVING TO A THREE-YEAR CYCLE WHEN THE CODE REQUIRES A FIVE-YEAR CYCLE?

A. Transitioning leak surveys from a five-year cycle to a three-year cycle creates the ability to perform both leak surveys and atmospheric corrosion inspections simultaneously, which in turn will reduce the number of individual trips. Surveying the area multiple times in one year (for different survey activities) could result in multiple leak notifications for one leak. This has the potential to cause recordkeeping errors and additional work while investigating the leak. As previously discussed in my Direct Testimony, leak ratios per mile of main are decreasing. Moving to a three-year leak survey interval would also reduce risk and reduce the release of methane to the environment; when leaks occur they will be found more quickly due to the increased frequency of survey.

Q. WHAT INCREMENTAL O&M EXPENSE DID THE COMPANY INCUR FROM THE 2016 HTY TO THE ACTUAL PERIOD ENDED SEPTEMBER 30, 2019 FOR THE LEAK SURVEY PROGRAM?

A. The Company has incurred an incremental $1.0 million of O&M expense for the leak survey program in the twelve-month period ended September 30, 2019 compared to the 2016 HTY. The two primary drivers are increases in contract vendor costs and overtime. In 2016, leak surveys were conducted almost entirely by a contract vendor. The leak surveys performed in 2019 were conducted by a combination of contract vendor and internal labor. The increase in contract vendor costs was $0.5 million due to a combination of a rate increase, as well as differences in the units of survey completed. The balance of the $1.0 million related to increased internal overtime labor. The Company anticipates that the increased costs for leak surveys experienced from 2016 to 2019 will reflect the change in the Colorado labor market, and that costs will remain at 2019 levels as evidenced by recent contractor bids for the leak survey contract for 2020 through 2022.

Q. WHAT INCREMENTAL KNOWN AND MEASURABLE O&M EXPENSE IS THE COMPANY FORECASTING FOR THE LEAK SURVEY PROGRAM FROM OCTOBER 1, 2019 TO SEPTEMBER 30, 2020?

A. In the 2020 calendar year, Public Service plans to survey approximately 7,900 main and service miles. The total estimated incremental O&M expenses for this program for the Test Year are approximately $0.2 million. The O&M expenses are related to the expected incremental contract outside vendor expenses required for the program.

Q. ARE THERE ANY CAPITAL COSTS ASSOCIATED WITH LEAK SURVEY IN THIS RATE CASE?

A. No.

Q. WHAT DO YOU CONCLUDE REGARDING THE LEAK SURVEY PROGRAM?

A. Consistent with industry peers, the Company views the leak survey cycle as fundamental to public safety and reducing the impact of methane on the environment. This program should be continued given the importance of the work under both code requirements and to protect the overall safety of our customers and the costs associated with the program should be found to be reasonable. This program continues to ensure and improve the safety and reliability of Public Service's natural gas system.

D. Storage Integrity Program

Q. PLEASE DESCRIBE COMPANY-OWNED STORAGE FACILITIES.

A. Public Service has three underground gas storage facilities, which are depleted natural gas fields – Roundup, Asbury, and Fruita. The purpose of underground gas storage fields is to provide supply flexibility, to ensure reliable deliveries, and to mitigate the risk associated with seasonal price movements. With respect to these gas storage fields, wells are used to inject gas into a field and to withdraw gas when needed. Roundup has 33 total wells, Asbury has 10 wells, and Fruita has one well. Of these, 23 are active wells for injection and withdrawal.

Q. PLEASE PROVIDE SOME BACKGROUND ON THESE UNDERGROUND STORAGE FACILITIES.

A. The Roundup field was discovered in 1967 and converted into storage in 1979, with well vintages ranging from 1979 to 1990. Asbury was discovered in 1948 and converted into storage in 1979, with well vintages ranging from 1969 to 2003. Fruita was developed in 1961 and converted to storage in 1971. Original wellheads, casings, and well bore tubing have been replaced occasionally as necessary, due to leaks and/or age. Additionally, the Company replaced active wellhead separators between 2011 and 2018, and Asbury and Fruita dehydrating units in 2016.

Q. WHAT IS THE PURPOSE OF THE STORAGE INTEGRITY PROGRAM WITH RESPECT TO THESE UNDERGROUND STORAGE FACILITIES?

A. The purpose and benefits of the storage integrity program are two-fold. First, the program will enhance the safety and reliability of Public Service's gas storage fields, especially given their ages as described above. It will prevent gas escaping into domestic water wells, possibly resulting in injury or damage to persons and/or property, thus protecting public health and safety.

Second, it will allow Public Service to manage its storage field prudently and to avoid gas escaping into areas of the underground storage fields where it cannot be recovered. Maintaining the performance of these wells will continue to keep bills low for our customers as we can purchase gas in the cheaper summer months and withdraw gas in the winter when gas prices are typically more expensive.

Q. HAVE THERE BEEN ANY RECENT INDUSTRY INCIDENTS THAT HAVE CAUSED PUBLIC SERVICE TO MAKE IMPROVEMENTS TO ITS GAS STORAGE FACILITIES?

A. Yes. On October 23, 2015, SoCal Gas discovered a massive gas leak from its Aliso Canyon storage facility. Gas was escaping from a well at the facility near Los Angeles. It took SoCal Gas until February 11, 2016, to get the storage leak under control. During this time, an estimated 97,100 tonnes (metric tons) of methane and 7,300 tons of ethane were released into the atmosphere. This incident was widely reported to have been the worst single natural gas leak in the U.S. history in terms of its environmental impact.

Following this incident, PHMSA came out with the IFR in December 2016 that applies to all gas storage operators. With the IFR, PHMSA adopted many of the recommendations from the Aliso Canyon incident and incorporated API RP 1171 by reference. It recommends installation of tubing, packers, and sub-surface safety valves in both gas injection and withdrawal wells, providing double barrier protection against gas escape. Since 2016, 23 sub-surface safety valves (“SSSVs”) and 23 downhole well packers have been installed at Company storage facilities.

Q. DOES THE COMPANY HAVE A STORAGE MAINTENANCE PROGRAM?

A. Yes, the Company has always maintained its storage wells carefully; however, after the Aliso Canyon incident, the Company made improvements to its storage maintenance plan to test and further support the integrity of gas wells and compressor stations associated with the Company's storage fields. The Company also has begun a regular and systematic program of installing and maintaining SSSVs and downhole packers to ensure integrity of its storage fields and ensure continued reliable deliverability. Further, due to naturally-occurring water aquifers contained in the storage reservoirs, as gas is withdrawn, the water produced with the gas, referred to as produced water, is separated by wellhead separators and dehydrators. As a result, the Company has installed wellhead filters to prevent salt contamination of the Asbury dehydration system. The produced water has a high salt content and has potential to foul the gas stream and dehydration unit itself.

Q. WHAT STANDARDS APPLY TO UNDERGROUND STORAGE MAINTENANCE?

A. The Company completes on-going maintenance activities in accordance with PHMSA's double barrier safety recommendation in case of well integrity failure, as well as API RP 1171. API RP 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs," provides recommendations for depleted oil and gas reservoirs used for natural gas storage. This recommendation covers the functional integrity in maintenance, monitoring, operation, documentation practices, and also suggests operators manage integrity of facilities through practices of monitoring, maintenance and remediation, with case-by-case applications based on specific integrity assessments. The Company has also developed a formal Well Control Emergency Response Plan that addresses the provisions of API RP 1171.

Q. DOES THE COMPANY HAVE SSSVS INSTALLED ON ITS 44 STORAGE WELLS AT THE ASBURY, FRUITA, AND ROUNDUP STORAGE FACILITIES?

A. Currently, the Company has 23 SSSVs installed on all active injection withdrawal storage wells. The Company installed 17 of the 23 SSSVs since the 2016 HTY in our 2017 Gas Phase I.

Q. WHAT UNDERGROUND STORAGE PLANT ADDITIONS HAS THE COMPANY MADE FROM THE LAST PHASE I TO THE BEGINNING OF THE TEST YEAR IN THIS PROCEEDING?

A. The Company has in-serviced approximately $5.6 million of plant additions at underground storage facilities between the end of the 2016 HTY and September 30, 2019. Table LAL-D-8 describes the plant additions at underground storage facilities since the 2016 HTY.

Table LAL-D -8
Storage Facility Plant Additions since 2016 HTY ($ millions)

Project Name	Jan 1, 2017 - Sept 30, 2019	Description
Asbury Wellhead Filters	$1.0	Six well-head filter separators at Asbury to protect recently installed dehydrators
Underground Storage	$3.3	Various underground storage activities
SSSVs	$1.3	Installations of 17 subsurface safety valves
Total Underground Storage	**$5.6**	

**Differences in sums due to rounding*

Q. WHAT PLANT ADDITIONS IS THE COMPANY FORECASTING FOR UNDERGROUND STORAGE DURING THE TEST YEAR ENDING SEPTEMBER 30, 2020?

A. The Company is forecasting $5.3 million of plant additions between October 1, 2019 and September 30, 2020. Table LAL-D-9 provides a list of forecasted projects at underground storage facilities from October 1, 2019 to September 30, 2020.

Table LAL–D-9
Storage Facility Forecasted Plant Additions ($ millions)

Project Name	Sept 30, 2020	Description
Asbury Wellhead Filters	$0.5	Project is continuing from the prior year. Six well-head filter separators at Asbury to protect recently installed dehydrators, and completion of filter separator at Asbury
Underground Storage	$4.4	Various underground storage activities
SSSVs	$0.4	Project is continuing from the prior year. Installations of 17 subsurface safety valves, and close out efforts involving installation of sub-service safety valves
Total Underground Storage	**$5.3**	

**Differences in sums due to rounding*

Q. WHAT INCREMENTAL O&M DID THE COMPANY INCUR FROM THE 2016 HTY THROUGH SEPTEMBER 30, 2019?

A. The Company spent an incremental $0.5 million of O&M for the storage maintenance program in the twelve-month period ended September 30, 2019, compared to the 2016 HTY. The Company continues to improve gas underground storage field maintenance to test and further support the integrity and reliability of gas wells and compressor stations associated with the Company's storage fields. The Company also has begun a regular and systematic program of SSSV and downhole maintenance to ensure integrity of its storage fields and to ensure continued reliable deliverability, in accordance with PHMSA's double barrier safety, outlined in API RP 1171.

Q. WHAT INCREMENTAL KNOWN AND MEASURABLE O&M EXPENSE IS THE COMPANY FORECASTING FOR THE STORAGE PROGRAM FROM OCTOBER 1, 2019 TO SEPTEMBER 30, 2020?

A. Approximately $0.2 million of incremental O&M expense will be incurred from October 1, 2019 to September 30, 2020 in order to complete on-going maintenance on SSSVs and downhole packer equipment. This equipment provides integral storage well integrity management via prevention of uncontrolled release of gas. As discussed earlier, these maintenance activities are required per PHMSA's double barrier safety recommendation and, as a result of the Aliso Canyon incident, specifics are outlined in API RP 1171.

Q. WHAT DO YOU CONCLUDE REGARDING THE UNDERGROUND STORAGE PROGRAM?

A. The underground storage program is necessary, required, and well-managed, and the related O&M expense and capital additions are consistent with industry-recommended practices. The underground storage program further enhances the safety and reliability of Public Service's gas system and reduces the likelihood of an environmental emergency, while providing supply price stability to help keep customer bills low.

E. Transmission Right-of-Way Program

Q. WHAT IS INVOLVED WITH TRANSMISSION RIGHT-OF-WAY MANAGEMENT?

A. Public Service deploys a variety of methods to patrol and clear surface conditions on and adjacent to transmission line rights-of-way for indications of leaks, construction activity, and other factors affecting safety and operation. Patrolling and clearing access to our transmission rights-of-way gives us efficient access to both view and repair the pipeline in the event of an emergency, by allowing Public Service to bring in the appropriate vehicles and equipment to make pipeline repairs. In addition, clearing vegetation from our rights-of-way reduces the damage to our transmission pipelines from roots from trees, shrubs, bushes, and other vegetation.

Q. WHAT ARE THE COSTS OF PUBLIC SERVICE'S TRANSMISSION RIGHT-OF-WAY CLEARING PROGRAM INCLUDED IN THIS RATE CASE?

A. Public Service is working to ensure clearance of a 20-foot path within the right-of-way (10 feet on each side of the pipeline) on 300 miles in the Colorado mountains, which requires incremental investment. For the Test Year, this results in a $1.1 million known and measurable adjustment to O&M.

Q. WHAT IS THE REQUEST OF THE COMMISSION WITH RESPECT TO THIS PROGRAM?

A. Public Service recommends approval of the additional known and measurable costs associated with clearing and patrolling around transmission pipelines and associated rights of way during the Test Year.

F. <u>Exposed Pipe Inspection and Remediation</u>

Q. WHAT IS AN EXPOSED PIPELINE INSPECTION IN A GAS SYSTEM?

A. Public Service's Exposed Pipeline Atmospheric Corrosion Inspections review each pipeline or portion of pipeline that are exposed to the atmosphere. These pipeline segments are often located in difficult to reach locations such as under bridge decks or suspended high above river and creek beds and require the use of special equipment such as trucks with side booms, cranes, or scaffolding. Facilities are inspected during the leak survey process for coating damage and are evaluated to determine the area and extent of atmospheric corrosion.

Q. WHAT INCREMENTAL O&M IS THE COMPANY FORECASTING FOR EXPOSED PIPELINE INSPECTION AND REMEDIATION WORK FROM OCTOBER 1, 2019 TO SEPTEMBER 30, 2020?

A. In the Test Year, the forecasted incremental O&M expense is $1.0 million, which includes both inspection and remediation work performed by outside contractors and materials.

Additionally, Public Service will also remediate damaged pipelines by removing all damaged coating from the exposed pipeline segments, repairing with Wax Tape products, and making structural repairs to supports and end seals, as needed. The number of pipe segments needing remediation will be determined as inspections occur, and remediation costs vary based on the extent of the repairs needed on an exposed pipe segment.

Q. WHAT BENEFITS WILL RESULT FROM THE EXPOSED PIPELINE INSPECTION AND REMEDIATION PROGRAM?

A. Regular atmospheric corrosion inspections on exposed pipe segments help prevent and/or detect gas leaks, which, if not addressed, could result in personal injury and/or property damage. Our efforts will increase pipeline safety and integrity. The remediation of exposed pipeline segments will also result in a longer life span for the pipeline segment as the new coating will prevent corrosion. Public Service therefore recommends approval of the costs associated with this work.

G. <u>Inside Meter Move-Out</u>

Q. WHAT IS THE INSIDE METER MOVE-OUT PROJECT?

A. This project involves moving meters currently inside customer premises to external locations. This is largely capital work.

Q. WHY IS THIS WORK IMPORTANT?

A. There are three reasons why it is important for meters to be located outside a customer premise: customer safety, customer convenience, and cost. With meters located outside of the premises, Public Service can conduct leak surveys and perform maintenance and inspections as required without making arrangements with the Customer 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 the customer's home 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).

Q. HOW WAS THE INSIDE METER MOVE-OUT PROJECT ADDRESSED IN PRIOR COMPANY RATE CASES?

A. In Public Service's 2015 Gas Phase I, the parties discussed whether the program should be approved for PSIA cost recovery. While the program was not ultimately approved for PSIA recovery, the Administrative Law Judge ("ALJ") recommended (and it was not contested) that the costs be recovered through base rates. The program has been ongoing since that time.

Q. HAVE THERE BEEN ANY CHANGES TO THE INSIDE METER MOVE-OUT PROJECT SINCE THE 2017 GAS PHASE 1?

A. No. This project is continuing in the same vein as first identified in the 2015 Gas Phase I and continuing into the 2017 Gas Phase I. Consistent with the Commission's Decision No. C16-0123 in the 2015 Gas Phase I, Public Service has undertaken and paced the meter move outs as part of the ongoing program. Going forward, the Company intends to continue to replace inside meters in the ordinary course of business.

H. Tools and Equipment

Q. CAN YOU PROVIDE INFORMATION RELATED TO THE FORECASTED CAPITAL ADDITIONS RELATED TO TOOLS AND EQUIPMENT?

A. Yes. The capital addition related to tools and equipment in the Test Year is primarily a large order of blowing gas policy tools received in the fourth quarter of 2019 for $5 million. The tools include stopple and gas detection equipment for service centers across Public Service's territory. Additional tools supporting general operations, such as squeeze-off tool system, air compressor, and air hammer drill, were purchased in late 2019, and will be purchased in early 2020 related to typical tool spend.

I. <u>Other Safety Investments</u>

Q. WHAT OTHER SAFETY PLANT ADDITIONS HAS THE COMPANY MADE FROM THE LAST PHASE I TO THE BEGINNING OF THE TEST YEAR IN THIS PROCEEDING?

A. While the above safety discussion addresses the large majority of safety-related capital and O&M investments included in the Test Year, the Company has also in-serviced approximately $6.0 million of other safety plant additions between the end of the 2016 HTY and September 30, 2019, as identified and described in Table LAL-D-10.

Table LAL –D-10
Other Safety Plant Additions
($ millions)

Project Name	Jan 1, 2017 - Sept 30, 2019	Description
Leak City Training Center	$2.4	Installation of center to support training and repair of leaks
Capitalized Locating Costs	$2.4	Ongoing capitalized component of damage prevention locates
Safety - Other	$1.2	Various activities to support safety
Total Other Safety	**$6.0**	

**Differences in sums due to rounding*

Q. WHAT PLANT ADDITIONS IS THE COMPANY FORECASTING FOR OTHER SAFETY DURING THE TEST YEAR?

A. The Company is forecasting $2.4 million of plant additions between October 1, 2019 and September 30, 2020. Table LAL-D-11 provides a list of the forecasted other safety additions, as well as a brief description of each.

Table LAL –D-11
Other Safety Forecasted Plant Additions ($ millions)

Project Name	Oct 1, 2019 - Sept 30, 2020	Description
Capitalized Locating Costs	$1.6	Ongoing capitalized component of damage prevention locates
Safety - Other	$0.7	Various activities to support safety
Total Other Safety	**$2.4**	

**Differences in sums due to rounding*

Q. IS THERE ANY OTHER ASPECT OF CAPITAL INVESTMENTS IN SAFETY YOU WISH TO HIGHLIGHT?

A. Yes. Maintaining physical security is an additional focus of Public Service's overall safety efforts. While a small portion of the costs of physical security are included in the Gas Operations budget, other costs are included in the Company's Shared Services budgets addressed by Company witnesses Mr. Adam Dietenberger and Mr. Koneru.

Indeed, the Company employs a variety of security measures depending upon the nature of the facility, including lighting, signage, gates, perimeter fencing, barriers, cameras, locking mechanisms, and facility access control. The Company has a full-time staff of trained security professionals who operate two security operations centers and the Alarm Response Center, which monitor cameras, access control equipment, monitoring points, and alarms. Xcel Energy Physical Security coordinates with local, state, and federal law enforcement agencies to reduce risk to Xcel Energy facilities to ensure timely incident response, investigation, and notification that may affect the gas system. Physical Security also provides on-site training to these agencies on an annual basis along with educational training programs in the classroom. Recurring drills and exercises are conducted at the local, state, and national levels to test and enhance our response procedures and lessons learned from the exercise are applied to improve capabilities.

Q. HAS THE COMPANY INCURRED ANY INCREMENTAL O&M EXPENSE SINCE THE 2016 HTY RELATED TO SAFETY?

A. Yes. In addition to damage prevention, gas emergency response, leak survey, storage integrity, transmission right-of-way clearing, and exposed pipe inspection and remediation, the Company has incurred incremental and expected ongoing O&M expense related to safety since the 2016 HTY. Table LAL-D-12 summarizes these incremental safety O&M costs both in the Test Year ended September 30, 2019 and forecasted through September 30, 2020, along with a short description of these items.

Table LAL-D-12
Incremental Safety O&M Costs ($ millions)

	Oct. 1, 2018 - Sept. 30, 2019	Oct. 1, 2019 - Sept. 30, 2020	Total	Description
Pipeline System Integrity Adjustment Amortization	($3.6)		($3.6)	2016TY final year of PSIA amortization.
MAOP	($4.4)		($4.4)	In 2017 all records had been collected and properly filed, the Company decreased the contract staff.
Gas Reorganization		$0.4	$0.4	
High Risk Commercial/Industrial Regulator Inspections		$0.1	$0.1	The total estimated O&M expenses for the TY period are $0.1 million annually, which is comprised of materials and labor associated with implementing the regulator inspection program.
Appliance Studies		$0.1	$0.1	The variance for Appliance studies is approximately $0.1 million from the 2016 HTY to the 2020 TY.
Other	$1.0		$1.0	
Total	**($7.0)**	**$0.6**	**($6.4)**	

**Differences in sums due to rounding*

Q. PLEASE DESCRIBE THE O&M EXPENSE REDUCTION FOR THE PSIA AMORTIZATION.

A. The 2016 HTY was the last approved year of the PSIA amortization for previously-incurred O&M expense. In the final year, the amortization amount was $3.6 million.

Q. PLEASE DESCRIBE THE O&M EXPENSE REDUCTION FOR MAOP.

A. The variance for MAOP is approximately $4.4 million less in the 2020 Test Year, as compared to the 2016 HTY. Prior to 2017, the MAOP project developed a process to collect, organize, and assess historic records relevant to a pipeline's MAOP in order to ensure all pipelines have traceable, verifiable, and complete records associated with them. In 2017, once all records had been collected and properly filed, the Company decreased the contract staff that had been performing the records review due to the uncertainty associated with PHMSA's Pipeline Safety "mega rule." The Company continues to collect, review, and validate records for the remaining pipelines.

Q. PLEASE DESCRIBE THE GAS REORGANIZATION AND THE FORECASTED INCREMENTAL O&M SPEND FROM OCTOBER 1, 2019 THROUGH SEPTEMBER 30, 2020.

A. As part of the Company's continuous improvement processes, it relies on industry benchmarking, peer reviews, and lessons learned from industry events. Xcel Energy gas has historically had a decentralized organizational structure, meaning that employees with gas responsibility have been split between gas and distribution electric, and it has had its management span of control (employees per supervisor) that was significantly higher than our peers. Both the way the Company has historically been organized and its span of control are inconsistent with similarly-sized peer companies, and also inconsistent with lessons learned following the San Bruno gas event in 2010.

Following the San Bruno event, a Blue Ribbon Panel that was tasked to review the event noted that a contributing factor to the event was the company's organizational effectiveness. Among many findings, one cited that the company's gas transmission operations were spread over several integrated electric and gas organizational units such that there were not clear divisions of responsibility.

In addition, Xcel Energy gas's leadership span of control in some areas exceeded 55 front line employees to managers. Industry peer benchmarking span of control ranges from 10-20 employees per manager/supervisor.

As a result, the Company is moving toward a centralized gas organization to drive consistency in its operations and depth in its gas organization in a way that will reduce field span of control to 25 or less, and better position the Company to operate more safely and in compliance with federal and state code. The Company is in the process of hiring 12 incremental managers and supervisors to achieve a centralized gas organization. The Gas Reorganization costs included in the Test Year are intended to address these needs.

Q. PLEASE DESCRIBE THE HIGH RISK COMMERCIAL AND INDUSTRIAL REGULATOR INSPECTION PROGRAM AND THE FORECASTED INCREMENTAL O&M SPEND FROM OCTOBER 1, 2019 THROUGH SEPTEMBER 30, 2020.

A. When supplying gas to large commercial and industrial customers, the volumes of gas and delivery pressures are typically significantly higher than for residential customers. In order to deliver the gas in a safe and reliable manner, the Company regulates the gas pressure with equipment known as regulators. As system pressures fluctuate and customer gas demand fluctuates, these regulators ensure gas is delivered at a consistent pressure.

Public Service is proposing the High Risk Commercial/Industrial Regulator Station Inspection Program as part of its risk reduction obligations under its DIMP which is mandated by Subpart P of 49 CFR Part 192. The intent of this program is to improve safety and service reliability for commercial and/or industrial pressure regulators by inspecting the internal components for signs of wear that may lead to failure. These stations serve facilities that include hospitals, schools, universities, and commercial establishments that may experience substantial interruption to their operations should the pressure regulator fail. This program will establish a prioritized risk-based inspection program based on risk factors. The total estimated O&M expenses for the Test Year are $0.1 million annually and are comprised of materials and labor associated with implementing the regulator inspection program.

Q. PLEASE DESCRIBE THE APPLIANCE STUDIES AND THE FORECASTED INCREMENTAL O&M SPEND FROM OCTOBER 1, 2019 THROUGH SEPTEMBER 30, 2020.

A The Company receives natural gas from many sources (including renewable gas sources) with variations in properties such as heating value and specific gravity. The Company will be testing gas appliances in the Denver metropolitan area for performance characteristics in order to assist in ensuring that the gas being supplied from different sources is interchangeable for safe and efficient use.

The variance for appliance studies is approximately $0.1 million from the 2016 HTY to the Test Year. Expenditures support ongoing natural gas appliance studies that will enable the Company to enhance our understanding of appliance performance to ensure that gas quality continues to be interchangeable as stated in Section 4202(c) of 4 CCR 723-4 (Code of Colorado Regulations). The Company anticipates spending the majority of this O&M within the Test Year.

Q. HAS PUBLIC SERVICE MADE OTHER INVESTMENTS IN SAFETY SINCE THE 2016 HTY IN THE COMPANY'S 2017 GAS PHASE I?

A. Yes. As discussed earlier in my Direct Testimony and in the Direct Testimony of Ms. Blair, a number of the Company's safety and integrity investments are reflected in the PSIA, which is ongoing for specified projects through the end of 2021. Only those projects that have been completed and have been through the Company's April Annual Filings process have been transferred into base rates in a rate case; therefore, additional costs remain in the PSIA.

IV. RELIABILITY OF THE GAS SYSTEM

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

A. In the following section of my Direct Testimony, I discuss the Company's work to maintain system reliability for our customers. I explain how our SCADA system is our primary tool to monitor system reliability, and Public Service's recent investments in adding SCADA monitoring devices on the system to better identify and manage system reliability and capacity needs. I then explain how SCADA monitoring capability has helped Public Service identify and address capacity and reliability needs in an increasingly proactive manner that is beneficial to our customers. I also support the capital and O&M costs associated with reliability and capacity projects and programs, as well as routine asset health and capacity investments.

Q. WHAT ARE THE MAJOR COMPONENTS OF THE COMPANY'S RELIABILITY WORK SINCE THE 2016 HTY THAT ARE INCLUDED IN THE COMPANY'S RATE PROPOSAL?

A. In addition to, and in several cases as a result of, the additional remote SCADA monitoring devices, the Company identified a number of additional capacity needs requiring pipeline reinforcements on the system. After discussing the addition of SCADA monitoring devices, I walk through the need for capacity additions, and then turn to several discrete reliability projects that will be completed by the end of the Test Year ending September 30, 2020.

Q. PLEASE IDENTIFY PUBLIC SERVICE'S OVERALL CAPITAL ADDITIONS RELATED TO RELIABILITY SINCE THE COMPANY'S LAST GAS RATE CASE.

A. Table LAL-D-13 identifies the reliability capital costs incurred since Public Service's last rate case that the Company proposes to include in base rates:

Table LAL-D-13
Gas Operations Reliability Capital Additions
Routines vs. Discrete Projects ($ millions)

Reliability	Jan 2017 - Sep 2019	Oct 2019 - Sep 2020	Total
Routines	$100.0	$32.2	$132.2
Discrete	$121.6	$134.9	$256.5
Total	**$221.6**	**$167.0**	**$388.7**

**Differences in sums due to rounding*

Q. PLEASE DESCRIBE THE DISCRETE RELIABILITY PROJECTS THAT WERE ADDED BETWEEN JANUARY 1, 2017 AND SEPTEMBER 30, 2019.

A. Table LAL-D-14 lists the key discrete reliability projects that were in-serviced between January 1, 2017 and September 30, 2019. In addition, the table contains a brief description of each reliability project.

Table LAL-D-14
Discrete Reliability Plant Additions ($ millions)

Project Name	Jan 1, 2017 - Sept 30, 2019	Description
Obsolete Regulators	$5.9	Ongoing replacement of 1,200 obsolete regulators at regulator stations
Compressor Station Maintenance	$1.8	Various activities in support of compressor station maintenance
ERX Installations	$1.1	Ongoing ERX installations to support system monitoring through SCADA system
Yosemite South Compressor	$1.2	Various activities in support of Transmission Regulator and Meter Station activities
CO/50th and Kipling Leak	$1.1	Main renewal of 150' of 16" main due to leak. Main renewal required additional scope due to depth of main.
Reliability - Capacity	$100.5	Various projects to support system capacity
Reliability - Other	$10.0	Various projects in support of system reliability
Total Reliability Discretes	**$121.6**	

**Differences in sums due to rounding*

Q. PLEASE DESCRIBE THE DISCRETE RELIABILITY PROJECTS THAT ARE BEING ADDED BETWEEN OCTOBER 1, 2019 THROUGH SEPTEMBER 30, 2020.

A. Table LAL-D-15 lists the key discrete reliability projects that will be in service between October 1, 2019 and September 30, 2020. In addition, the table contains a brief description of each reliability project.

Table LAL-D-15
Discrete Reliability Plant Additions ($ millions)

Project Name	Oct 1, 2019 - Sept 30, 2020	Description
Obsolete Regulators	$1.3	Ongoing replacement of 1,200 obsolete regulators at regulator stations
Compressor Station Maintenance	$2.1	Various activities in support of compressor station maintenance
ERX Installations	$0.6	Ongoing ERX installations to support system monitoring through SCADA system
CO/Yosemite/Replace VFD Switchgear	$2.6	Replacement of electrical switchgear at Yosemite Compressor Station
Reliability - Capacity	$111.6	Various projects to support system capacity
Reliability - Other	$16.7	Various projects in support of system reliability
Total Reliability Discretes	**$134.9**	

**Differences in sums due to rounding*

Q. PLEASE PROVIDE THE INCREMENTAL RELIABILITY O&M EXPENSE SINCE THE COMPANY'S LAST GAS RATE CASE.

A. Since Public Service's last rate case, the Company's O&M expense has increased approximately $0.9 million, related to compressor station maintenance. I describe the Company's investments in more detail below.

A. <u>SCADA Monitoring Devices</u>

Q. HOW DOES PUBLIC SERVICE MONITOR ITS SYSTEM TO PROVIDE RELIABLE SERVICE TO ITS CUSTOMERS?

A. Public Service, like most utilities across the United States, monitors its gas system through a SCADA system. This SCADA system collects real time data from across the system and converts it into useful, actionable data that is used in our Gas Control center. Here, Gas Controllers review such data as flow rates, pressures, and equipment statuses to make informed decisions ensuring proper system operation. Staffed 24 hours a day, seven days a week, Public Service's Gas Controllers proactively manage the system and identify problems as they arise (e.g., pressure drops/surges, odorization levels, and gas flow rates) and can make changes to the system through the SCADA program or by dispatching field personnel. Public Service's SCADA system has the capability to remotely monitor and control the flow of natural gas into and throughout our transmission and distribution systems. As the Company continues to increase these capabilities, it has increasing ability to improve the safety and reliability of the system.

Q. PLEASE DESCRIBE THE COMPANY'S SCADA/GAS CONTROL MONITORING IMPROVEMENT PROGRAM.

A. In both its 2015 Gas Phase I and 2017 Gas Phase I, Public Service proposed to increase the number of SCADA pressure monitoring points at regulator stations and other strategic locations on our gas transmission and distribution systems. The purpose of this proposal was to create system visibility, identify unknown operational risks and enhance public safety and system reliability through early identification of abnormal operating pressures, avoid overpressure events and gas outages, and identify areas of the system that need incremental gas supply or pipeline reinforcements. Day to day, the remote field monitoring devices provide advanced warning of situations and allow an opportunity for Public Service to operate the system from the control room or dispatch crews proactively to make the appropriate adjustments or repairs before they put the public or system at risk. Equally important, a robust SCADA system is crucial for long-term system reliability planning purposes.

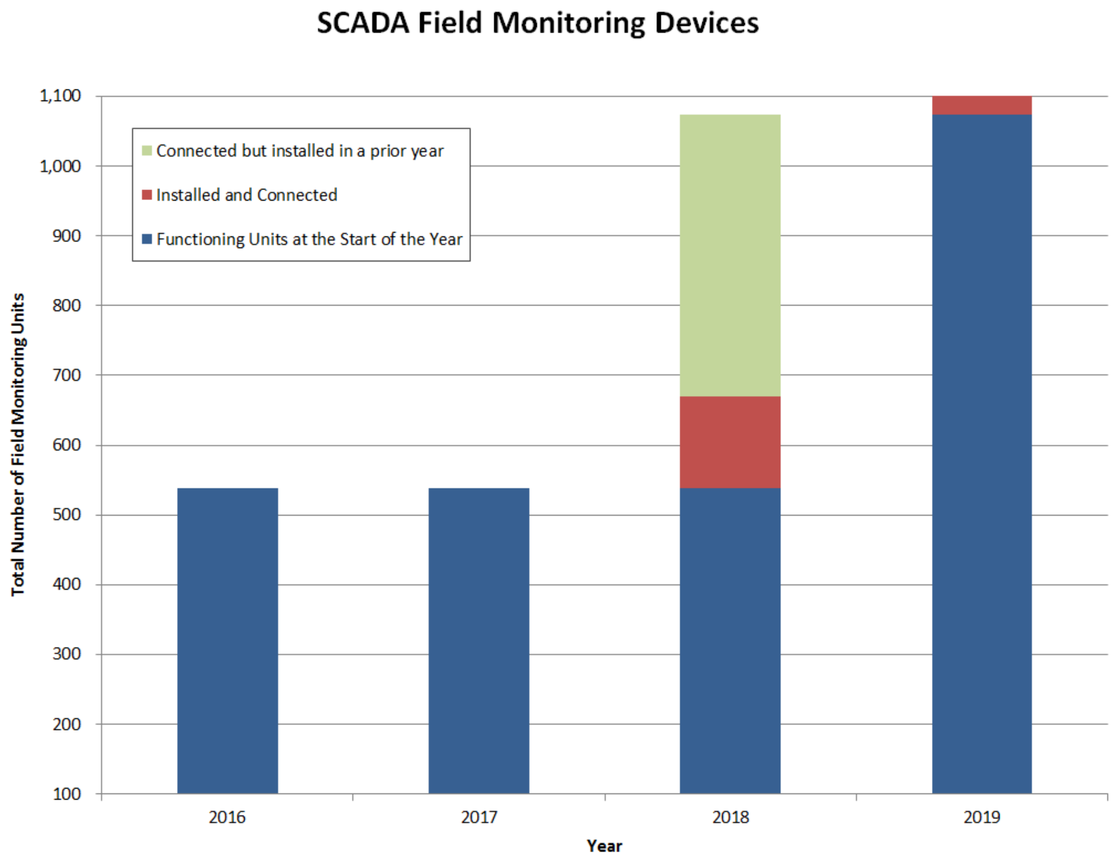
Q. HAS THE COMMISSION PROVIDED DIRECTION ON THE COMPANY'S SCADA/GAS CONTROL MONITORING PROGRAM IN THE PAST?

A. Yes. In the 2015 Gas Phase I, the Commission reversed the Recommended Decision of the ALJ and approved *pro forma* adjustments of $1.7M to the 2014 HTY to permit cost recovery related to the SCADA/Gas Control Monitoring program. Further, the Commission stated the "Public Service is not barred from future cost recovery of SCADA project costs incurred in the ordinary course of business." However, the Commission stated that the "ALJ properly determined that the Company's qualitative analysis for the proposed project was inadequate" in the context of the 2015 Gas Phase I, and the Company "must conduct a thorough quantitative cost benefit analysis for project justification for future cost recovery of any additional upgrades." *See* 2015 Gas Phase I, Decision No. C16-0123 at 24.

Q. DID THE COMPANY IMPLEMENT THE SCADA/GAS CONTROL MONITORING IMPROVEMENT PROGRAM IN THE ORDINARY COURSE OF BUSINESS?

A. Yes. Figure LAL-D-11 shows the progress it has made on the installation of SCADA monitoring devices in the field since 2015.

Figure LAL-D-11
Number of Gas SCADA Field Monitoring Devices



Q. HAS THE COMPANY UNDERTAKEN A COST-BENEFIT ANALYSIS OF SCADA WORK UNDERGONE AFTER 2015, AS ORDERED BY THE COMMISSION?

A. Yes. In the Company's 2017 Gas Phase I, I provided a discussion in Direct Testimony of the SCADA/Gas Control Monitoring Program, including a cost-benefit analysis. This analysis identified the major system events that were proactively avoided by Gas Control personnel responding to system issues; the likely outages that would have resulted if not for the Company's proactive response; and therefore, the actual costs and benefit of avoided customer outages. The results of the cost-benefit analysis illustrated that the Company's SCADA/Gas Control Monitoring program was an effective risk and system issue mitigation tool.

Q. DID THE COMPANY REFRESH THE COST BENEFIT ANALYSIS FOR THE DEVICES INSTALLED IN 2019?

A. Yes. This analysis is performed in a Company system known as "Workbook." The Company refreshed its Workbook analysis with actual costs of the SCADA work compared to known benefits resulting from avoiding system events and customer outages.

In the twelve-month period ended December 31, 2019, the Company identified approximately 41 unique events where a potential outage was avoided using information from field monitoring devices installed in 2018 and 2019. The new units helped prevent approximately 81,000 potential customer outages over the two-year period. The capital expenditures to install those units was approximately $1.5 million, or approximately $19 per avoided outage. In comparison, the relight cost is approximated at $45 per customer. Attachment LAL-5 provides a list of these 41 events and illustrates the results of the cost benefit analysis with the actual costs versus the benefit of over 81,000 avoided customer outages. Attachment LAL-5 also provides the cost-benefit analysis results. Given the high risk to public safety inherent in outage events, the result of the analysis is a positive cost benefit.

Q. NOW THAT THE COMPANY HAS OVER 1,100 SCADA FIELD MONITORING DEVICES ON ITS SYSTEM, WHAT IS THE COMPANY'S PLAN FOR THE FUTURE OF THIS PROGRAM?

A. The Company's current plan is to install approximately 160 additional remote SCADA monitoring devices at critical locations on its system in 2020 and 2021. These critical locations are determined by a cross functional team of engineers and operations personnel that prioritize work based on the number of customers connected, system integration, and location within the system. These additional points will supplement the existing 1,139 SCADA field monitoring devices that Public Service currently has on its system. The increase in units will provide a high level of visibility across high and intermediate pressure systems allowing operators to manage these systems safely and reliably. Additionally, the Company is also reviewing expanding the program to install remote SCADA monitoring devices on distribution regulator stations and at the tail end of distribution systems. These distribution field monitoring units will increase visibility into the gas mains that directly tie to homes across the state. The Company expects that the ideal number of field units will continue to change as new pipelines are built to serve new customers. This build-out is crucial to understanding broader capacity constraints and allows for system planning that ensures reliable service.

Q. HOW DOES THE COMPANY DETERMINE WHERE IT NEEDS TO INSTALL A SCADA FIELD MONITORING DEVICE?

A. The Company uses a multi-faceted approach in determining locations for field monitoring devices. Traditionally, monitoring devices are installed at the beginning or at the end of a system. This approach allows operators to know how much gas is entering the system, at a supply receipt point, interconnect or regulator station, and how much gas is left at the "tail end" of the system. Monitoring tail end points on the gas system ensures that the system has enough pressure to serve our firm customers.

Many factors are used to determine where a new device is needed including system location, number of customers in a gas system, if the system has a secondary feed or if it is isolated, etc. The list of proposed locations is then ranked and reviewed by Distribution and Transmission Engineering, Gas Control, and Management.

Q. WHAT PLANT ADDITIONS FOR SCADA MONITORING DEVICES ARE INCLUDED IN THIS RATE PROCEEDING?

A. Plant additions for SCADA monitoring devices from the 2016 HTY through September 30, 2019 are approximately $1.3 million, with an additional $1.4 forecasted from October 1, 2019 to September 30, 2020. These additions have resulted in additional data that is vital to the safe and reliable operation of the system, as well as to identify capacity needs and constraints. As a result, this program has not only enhanced the safety and reliability of Public Service's gas system, but it has also preserved and improved customer service.

B. <u>System Capacity Needs</u>

Q. WHAT DOES PUBLIC SERVICE DO WITH THE DATA RECEIVED FROM THE SCADA REMOTE MONITORING DEVICES?

A. In addition to providing real time data into our SCADA system, which allows our Gas Controllers to operate and monitor the system real-time, the data is utilized by our Gas Capacity engineers for system modeling for project determination and evaluation purposes. Specifically, the data is reviewed to ensure that there is enough capacity to service our firm customers during the coldest peak design hour, which typically occurs during the early morning hours on a cold winter day. The design peak design hour is determined by analyzing the last 30 years of system operation to determine the coldest day in that timeframe and the highest hourly gas usage on that day. If it is determined that capacity on a specific location is becoming constrained, the engineer then determines the appropriate project necessary to alleviate the constraints to ensure reliable service to firm customers. This process of reviewing weather, customer counts, and the operation of the system is reviewed yearly to ensure firm customers will be serviced reliably on that cold winter morning.

Q. PLEASE DESCRIBE HOW SCADA MONITORING FEEDS INTO PUBLIC SERVICE'S SYSTEM MODELING PROCESS.

A. Long-term system planning of the Company's transmission and distribution pipelines is performed on an annual basis that encompasses a ten-year capacity forecast for the four operational areas. These plans are updated to include changes in operating conditions received from the SCADA remote monitoring points along with forecasted customer growth on the system. The capacity planning process evaluates increased demand by modeling potential system constraints at times of peak capacity needs and analyzing potential operational solutions to provide reliable service to our firm customers.

Q. HOW IS THE SYSTEM MODELING PERFORMED TO REFLECT BOTH PUBLIC SERVICE CAPACITY NEEDS AND SYSTEM AVAILABILITY?

A. Computer-aided system modeling allows for accurate simulation of the Company's system in four different regions, from the numerous supply interconnects, through the pipeline networks, to customer end points. The Company's Geospatial Information Systems ("GIS") contains the most current records of pipe and facilities, with important system attributes that include pipe material, pipe diameter, date of installation, and operating pressure. Through the use of GIS, SCADA data and user input information, Public Service is able to create system models with hydraulic modeling software called Synergi®. The modeling software then simulates natural gas gathering, transmission, and local distribution systems to represent current pressure and flow conditions based on customer growth. The software therefore identifies, predicts, and helps address the system's operational challenges, enabling day-to-day efficiency of gas distribution and transmission networks.

Q. IS PUBLIC SERVICE'S SYSTEM PEAK DAY MODELING IN ALIGNMENT WITH OTHER GAS UTILITIES ACROSS THE U.S.?

A. Yes. Public Service uses the industry standard probabilistic modeling approach to determine the coincidence of a 1-in-30-year cold weather event (i.e., "peak-day") occurring in each of the four operational areas on Public Service's system. A "1-in-30" event is based on the likelihood of the extreme weather event that will occur within 30-years of weather occurrence. The peak-hour analysis, which is a subset of the peak day, is used for the Public Service system modeling. The peak hour load forecast is the goal for system design planning that must be met by the capacity of the Company's piping network.

Q. CAN YOU PROVIDE MORE INFORMATION ABOUT THE OPERATIONAL AREA S IN PUBLIC SERVICE'S SYSTEM?

A. Yes. Since Public Service's system is so vast, ranging from the Wyoming border on the north, to the New Mexico border on the south, to the Utah border on the west, we model our system in four operational areas that contain unique characteristics and operational requirements. Attachment LAL-6 contains a map of the system with the four operational areas. The Front Range system encompasses the Denver Metro area north to the Wyoming border east of the foothills, the Mountain Southern system stretches from Boulder west of Marshall to Bayfield, including the ski areas of Breckenridge and Winter Park along with the towns located centrally in the state. The Western system encompasses Grand Junction with pipelines extending up to Steamboat Springs and east to Vail. The final system is the Pueblo system which encompasses the area directly surrounding the city of Pueblo.

Q. WHAT ARE THE 1-IN-30 PEAK DAY TEMPERATURES FOR EACH OF THE FOUR REGIONS ON PUBLIC SERVICE'S GAS SYSTEM?

A. Table LAL-D-16 provides the peak day temperatures by operational area that occur once every 30 years on the Company's gas system.

Table LAL-D-16
Peak Day Temperatures by Operational Area

Operational Area	Design Day
Front Range	-25°F
Mountain Southern	-39°F
Pueblo	-26°F
Western	-18°F

Q. CAN YOU EXPLAIN IN MORE DETAIL HOW THE DATA FROM THE SCADA REMOTE MONITORING DEVICES IS USED IN THE SYSTEM MODEL?

A. Yes. Data from the SCADA remote monitoring devices is used to verify the various models' output, which is required to continually improve the model's accuracy. Verification is performed by comparing actual operating data with predicted model values for peak-hour and peak-day demands. System models with a noticeable difference between predicted and actual pressures are reviewed in detail for significant changes annually and recalibrated to ensure the model is as accurate as possible.

Q. OVERALL, WHAT INSIGHT INTO THE SYSTEM HAS THE COMPANY ACHIEVED BY INSTALLING SCADA MONITORING POINTS?

A. As a result of the cold winter temperatures from the winter of 2018-2019, along with the information received from the SCADA monitoring points located across the system, the Company discovered through its annual capacity modeling efforts that there were several areas on the system where there was not enough capacity in the pipeline to deliver gas to our firm customers on a peak day. This information is driving additional capacity projects identified for the next ten years that are designed to deliver the requirements of our customers on a peak hour.

Q. PLEASE IDENTIFY THE CAPACITY PROJECTS THAT HAVE RESULTED FROM SUCH ANALYSES.

A. Table LAL-D-17 below lists all the major capacity projects in excess of $1.0 million that were in-serviced from January 1, 2017 to September 30, 2019 to address identified capacity limitations.

Table LAL-D-17
Capacity Project Plant Additions
January 1, 2017 to September 30, 2019 ($ millions)

Project Name	Jan 1, 2017 - Sept 30, 2019	Description
North Metro Reinforcement	$51.7	Installation of five miles of 24" high pressure main in the Denver metro area
Lancaster to Fort Lupton	$14.7	Installation of four miles of 24" high pressure main
Stapleton Phase III Reinforcement	$11.3	Installation of 10,000' of 16" high pressure main in Denver
Tungsten to Blackhawk	$8.2	Installation of two miles of 6" high pressure main and 13 miles of 8" high pressure main to reinforce Idaho Springs, Black Hawk, Central City, Empire, and Georgetown areas.
CO\PBLO\Reinforce pipe feeding X-59	$3.4	Install 6,300' of 6" main in Pueblo
Stroh Rd HP Reinforcement	$2.7	Installation of 3,400' of 6" high pressure main in Parker
CO/NMR/F555/IP Reinforcement 4"	$2.6	Installation of 100' of 4" IP main and 3,800' of 8" IP main in Arvada
CO-Outage risk for Pueblo County	$1.9	Installation of 8,000' of 4" distribution main in Pueblo
CO/Pueblo West/Dist Reinforcement	$1.1	Installation of 2,755' of 4" distribution main and 1,000' of 6" distribution main in Pueblo.
CO/MNTN/Ski Hill Rd Dist Mains	$1.2	Installation of 5,500' of 6" distribution main in Breckenridge
Total Capacity Projects	**$98.7**	

**Differences in sums due to rounding*

Further, Table LAL-D-18 below identifies the major capacity projects over $1.0 million that are forecasted to be in-serviced from October 1, 2019 to September 30, 2020.

Table LAL-D-18
Forecasted Capacity Project Plant Additions
October 1, 2019 to September 30, 2020 ($millions)

Project Name	Oct 1, 2019 - Sept 30, 2020	Description
Tungsten to Blackhawk	$55.7	Installation of remaining 6" high pressure main and 8" high pressure main to reinforce Idaho Springs, Black Hawk, Central City, Empire, and Georgetown areas.
Granby T-O to YMCA VS 6"	$9.5	Installation of ~five miles of 6" high pressure main between Fraser and Tabernash
Upsize pipe for Boulder 285#	$9.4	Install 11,400' of 12" high pressure main in Broomfield
CO/GJ/ River Road, W-55-A Reinforcement TME	$8.6	Install two miles of 8" high pressure main along River Road in Grand Junction
CO/Ft Lupton/Ione NF-18 Reinforcement	$7.5	Install 1,700' of 2" high pressure main and 5,300' of 4" IP main in the Ft. Lupton area
F-400 Install New IP Main	$6.7	Install 11,000' of 6" IP main in Morrison
CO/SEMR/F481 & F872/ IP Reinforcement	$2.7	Install a new high pressure to IP regulator station in Aurora
CO/MNTN/BRECK/Breckenridge Reinforcement	$2.2	Installation of seven reinforcements in the Breckenridge area.
CO\PBLO\Reinforce pipe feeding X-31	$1.5	Installation of 1,600' of 4" IP into X-31 in Pueblo
CO/Bldr/E-119 Reinforcement	$1.3	Installation of 2,200' of 6" IP in Boulder
CO/Reinforce Rifle with 4" PE and 2	$1.3	Installation of 410' of 2" distribution main and 9,000' of 4" distribution main in Rifle
CO/SEMR/F715/Inlet Reinforcement	$1.3	Installation of 1,100' of 4" high pressure main in Centennial
CO/SEMR/F352/Inlet Reinforcement	$1.2	Installation of 1,400' of 4" IP main in Greenwood Village
CO/DMO/Stn 165/Rebuild/Mains	$1.2	Rebuild of regulator station in Denver
CO/BLDR/EN-8 IP Reinforcement	$1.0	Installation of 2,000' of 4" IP main in Boulder
Total Capacity Projects	**$110.8**	

**Differences in sums due to rounding*

Q. HAS THE COMPANY INCURRED ANY ADDITIONAL INCREMENTAL O&M EXPENSE SINCE THE 2016 HTY RELATED TO CAPACITY?

A. No.

Q. CAN YOU PROVIDE MORE INFORMATION ABOUT THE COMPANY'S CAPITAL PROJECTS?

A. Yes. Attachment LAL-7 contains project-specific information for each of the capacity projects listed in Tables LAL-D-17 and LAL-D-18. In addition, in the next segments of my Direct Testimony, I discuss four of the largest capacity projects in these periods, which include the North Metro Pipeline Project, the Tungsten to Blackhawk Project, the Stapleton Phase 3 Project, and the Lancaster Capacity Project.

C. <u>Key Reliability and Capacity Projects</u>

1. North Metro Pipeline Project

Q. WHAT IS THE NORTH METRO PIPELINE PROJECT?

A. The North Metro Pipeline Project increases capacity in the Denver metropolitan area as part of its normal business operations. During the normal annual process of modeling capacity of the pipeline system in 2012, the Company identified the need for increased capacity to meet the long-term peak hour and peak day load requirements, together known as design day requirements, beginning in the winter of 2015/2016 for the Denver metro area. Given this timing, Table LAL-D-19 provides the shortfall of peak hour and peak day load requirements as stated in the 2015 Gas Phase I in Table CFC-R-1 included on page 42 of the Rebuttal Testimony of Cheryl F. Campbell filed in that case.

Table LAL-D-19
Denver Metro Capacity Shortfalls from 2015 Gas Phase I

Winter	Peak Day Dth/day)	Peak Hour (Dth/hr)
Winter 2014/2015	**0**	**0**
Winter 2015/2016	**8,280**	**460**
Winter 2016/2017	**20,880**	**1,160**
Winter 2017/2018	**30,600**	**1,700**
Winter 2018/2019	**48,600**	**2,700**
Winter 2019/2020	**64,800**	**3,600**
Winter 2024/2025	**119,736**	**6,652**

Q. HAS THE COMPANY IDENTIFIED THE NORTH METRO PIPELINE PROJECT IN OTHER PROCEEDINGS BEFORE THE COMMISSION?

A. Yes. The North Metro pipeline project was previously referred to as the Downtown Denver reinforcement project in the 2015 Gas Phase I proceeding and was identified as the preferred Company project to address capacity shortfalls in the Denver metro area.

Q. PLEASE PROVIDE AN OVERVIEW OF THE WORK INVOLVED IN COMPLETING THE NORTH METRO PIPELINE PROJECT.

A. The 24-inch North Metro pipeline project involved the construction of an HP pipeline, operating at 700 pounds per square inch gauge (“psig”), in the course of business to deliver gas to support the load growth requirements in the Denver metro area. The project includes approximately five-miles of 24-inch HP pipeline routed through an urban area. Designed to transport gas from the terminus of the

Cherokee Pipeline Project, the pipeline follows city streets from the Cherokee Generating Station to approximately 43rd and Fox Street. At this location, the gas is reduced to a pressure of 150 psig where it is delivers 125,000 Dth/day of capacity into the intermediate pressure ("IP") distribution system that supplies the downtown Denver and surrounding areas.

Q. HOW HAS THE COMPANY BEEN MEETING THE DESIGN DAY REQUIREMENTS OF THE DENVER METRO AREA SINCE THE WINTER OF 2015/2016 UNTIL THE MAY 2019 IN-SERVICE DATE OF THE NORTH METRO PIPELINE PROJECT?

A. Supply into the Denver metro area has been strategically increased over the years in anticipation of the installation of the North Metro Pipeline. Starting in 2015, a valve was installed that allowed two adjacent IP systems to be connected during peak hours. The connection allowed gas to flow from a system with higher capacity into the Denver Metro system during peak hours. In 2017, the Stapleton Phase 3 project was completed that brought in a new 16-inch 285 psig pipeline into the Metro system and replaced the valve installed in 2015. This pipeline provided a consistent delivery pressure out of a new regulator station into the Denver metropolitan area. This pipeline is still in use today and provides a valuable supply to the area around East 36th Ave and Quebec Street in Denver.

The North Metro Project was completed in 2019, connecting the Cherokee Pipeline to the Denver Metro System.

Q. WHAT ALTERNATIVES TO THE NORTH METRO PIPELINE PROJECT DID THE COMPANY CONSIDER?

A. The alternative route was 6 miles of 16-inch HP, operating at 285 psig, pipeline that extends from approximately East 36th Avenue and Ulster to approximately 38th Street and Blake Street. This alternative was estimated at approximately $30 million, in 2015; however, it was ruled out because it only provided approximately 76,000 Dth/day of gas supply into the downtown area, which would already be out of capacity in 2020, unlike the North Metro pipeline project that provides for 10 years of load growth. Additionally, this cost estimate did not include any work at the receipt point with Colorado Interstate Gas, called East Denver Control, which would be needed to supply the pipeline.

Q. HOW HAS THE NORTH METRO PIPELINE PROJECT CHANGED SINCE THE 2015 GAS PHASE I AND 2017 GAS PHASE I PROCEEDINGS?

A. As previously noted, the project was initially referred to in the 2015 Gas Phase I as a planned extension of the Cherokee Pipeline via the Downtown Denver Reinforcement project. As originally outlined, the North Metro pipeline is designed to supply an additional 125,000 Dth/day or 6,944 Dth/hour of natural gas into the Denver metro area.

The project was expanded upon in the Company's 2017 Gas Phase I, where the Company provided a conceptual planning level estimate of $41 million, with approximately $24.4 million to be incurred during the 2018-2020 multiyear plan proposed in that proceeding.

Q. HAS THE NORTH METRO PIPELINE BEEN COMPLETED?

A. Yes, the pipeline was completed in May of 2019 at a final scope and cost of $51.7 million. This final cost is within the final project estimate of $53 million that I discuss below.

Q. PLEASE OUTLINE THE DRIVERS OF THE FINAL PROJECT COST IN THIS PROCEEDING.

A. The detailed design and engineering of the project as it has developed over time has led to further refinement of cost estimates and ultimately the final cost of the project. The Company started with a $41 million planning level estimate that is considered accurate within +/- 30 percent. Prior to construction, the Company completed the engineering on the project and established a detailed engineering level estimate with an accuracy of +/- 10 percent. This detailed engineering estimated the project cost at $53 million. During this project estimate refinement process, the Company collected competitive bids and incorporated them into the final estimates. The updated scope, route, and estimate were then vetted by a diverse group of senior engineers, project managers, and leaders prior to establishing the revised budget and moving forward. A notice of construction was also sent to the Commission's pipeline safety group on September 20, 2017, outlining this $53 million estimate. The project was then managed to the final estimate of $53 million and came in under the budget at $51.7 million.

Q. PLEASE FURTHER DISCUSS WHAT DROVE THE INCREASED COST ESTIMATE FOR THIS PROJECT.

A. After the project engineering was complete, the detailed design identified considerable amounts of ground water, higher numbers of conflicting underground utilities, and rocky soil along the route contributing to the estimate increase. Typically, detailed project engineering only begins after the planning estimate is reviewed and approved by leadership. In this case, the planning estimate included a phase 1 environmental survey and a groundwater study. These studies indicated a high potential for shallow ground water but identified a clean utility corridor through a contaminated area. Additionally, a more detailed utility survey discovered many more underground utilities that increased the number of difficult depth offsets and horizontal direction drills. The difficulty for the additional depth was exacerbated by the presence of shallow bedrock and groundwater. These construction difficulties resulted in higher construction bids.

Furthermore, material changes were made that allowed for the pipeline to maintain its 1,000 psig MAOP even with customer growth along the pipeline route. Pipelines are constructed with a safety factor that takes into account the number of residences along a given route, called a class location. With the growth in Denver, and the proximity of that growth to the pipeline, it was determined that using the highest safety factor was the prudent choice. It is expected that Denver will continue to grow and, without the higher-grade materials, the pressure within the pipeline would need to be lowered. In turn, this would reduce the pipeline's capacity and potentially create the need for additional capacity through the development of another pipeline into the same area to maintain adequate capacity to the Denver metro area. An example of these material changes includes pipe and fittings with thicker walls.

Q. WAS THE NORTH METRO PIPELINE PROJECT COMPETITIVELY BID?

A. Yes, as mentioned earlier, and in keeping with Company policy and normal course of business for such projects, the construction portion was competitively bid with the bids being reviewed and approved by a sourcing department outside of the direct control of Gas operations. Additionally, third party inspection and construction management resources were engaged to monitor the progress of the construction contractor to ensure cost prudency and work quality consistent with the Company's Pipeline Compliance and Standards manual. Technical design was completed by an engineering firm with expertise in this type of construction, and the firm's fees were competitively bid specifically for this project and closely managed.

Q. WAS THE CHANGE IN THE OVERALL PROJECT ESTIMATE REVIEWED AND VETTED PRIOR TO THE WORK CONTINUING?

A. Yes, the project followed the financial governance process that is used in the ordinary course of business for all major projects within Public Service. The detailed engineering estimates that updated the earlier planning estimates were subject to financial governance review prior to the work being released to construction. The project was allowed to proceed based on the need for the work and the changes in circumstance that reasonably affected the overall cost.

Q. CAN YOU POINT TO FURTHER INFORMATION REGARDING THIS PROJECT?

A. Yes. Attachment LAL-7, page 1 provides additional concise information regarding the route, scope, cost, and additional details regarding the project. Overall, this was a necessary project that is providing system benefits to deliver natural gas to our firm customers on the coldest winter morning.

2. Tungsten Capacity Project

Q. WHEN DID THE COMPANY FIRST IDENTIFY THE NEED FOR THE TUNGSTEN CAPACITY PROJECT?

A. During the normal annual process of modeling capacity of the pipeline system in 2013, the Company identified a need for increased capacity in the Front Range System to meet the long-term peak hour and peak day load requirements beginning in the winter of 2017/2018 in the Front Range area. Analysis indicated that without the Tungsten pipeline, the existing gas system may begin experiencing customer outages if temperatures fall below -22ºF, increasing to up to 3,600 customer outages as the system approaches design day.

Q. PLEASE PROVIDE AN OVERVIEW OF THE TUNGSTEN PIPELINE CAPACITY PROJECT.

A. The Tungsten pipeline is a 6-inch and 8-inch pipeline that is designed to reinforce the HP gas supply to the communities of Idaho Springs, Black Hawk, Central City, Empire, and Georgetown. The pipeline provides additional capacity to the Front

Range HP systems by better utilizing the existing capacity on the Littleton Lateral for growth in Lakewood, Highlands Ranch, and Littleton in southwest Denver. The pipeline contains approximately two miles of 6-inch steel pipe and 13 miles of 8-inch steel pipe of which both sections are planned to operate at an MAOP of 1000 psig. The route is through a very rocky section of the foothills, roughly between the towns of Nederland and Black Hawk.

Overall, this project is a normal course of business pipeline project needed to meet growing capacity needs and ensure that the Company can meet design day requirements. More information on the route, scope, cost, and additional details regarding the project is found in Attachment LAL-7 to my Direct Testimony.

Q. DID THE COMPANY CONSIDER ANY ALTERNATIVE TO THIS PROJECT?

A. Yes. An alternate route was investigated that replaced approximately 18 miles of 8-inch high pressure main with 12-inch high pressure main. This alternate route would have commenced outside of Golden, Colorado terminating west of Evergreen Colorado on Santa Fe Mountain. This alternative was ruled out due to its length and higher estimate of $82 million.

Q. HOW WAS THE TUNGSTEN PIPELINE REFERENCED IN PREVIOUS RATE CASES?

A. The project was first discussed during the 2017 Gas Phase I as part of the Company's proposed multiyear plan, wherein the scope was outlined and an initial estimate of $35.9 million was provided. During the course of that case, the Company provided a directional planning estimate of approximately $42.2 million.

However, detailed engineering studies had not been completed at that time, and the project was not yet in the physical construction phase. Consequently, this project was not included in the 2016 HTY because it was not in service during 2016.

Q. DID THE COMPANY OBTAIN ADDITIONAL INFORMATION DURING THE COURSE OF THE PROJECT?

A. Yes. When detailed engineering and geotechnical studies were completed during 2018, they showed there would be significant cost additions due to stone along the route. As a result, the estimate was increased to approximately $62 million, which was provided to the Commission in February of 2019 with a notification of a major project.

Q. HOW WAS THE ORIGINAL DETAILED ENGINEERING PROJECT ESTIMATE OF $62 MILLION COMPLETED?

A. During the project estimate refinement process, the Company collected competitive bids and incorporated them into the final estimates. The updated scope, route, and estimate were then vetted by a diverse group of senior engineers, project managers, and leaders prior to the work being released to construction. The project followed the financial governance process that is used for all major projects within Public Service.

Q. WHEN DID PROJECT CONSTRUCTION BEGIN?

A. The actual construction of the pipeline commenced in the second quarter of 2019 after which the full nature of the rock conditions began to present themselves. The

Company tested rock samples in June 2019 as a result of construction challenges, and these tests indicated that the route contained sections of particularly-hard gneiss rock. Specifically, the samples showed that the bedrock has a compressive strength of 13,718 psi to 19,648 psi.[7]

Q. DID ANY OTHER CONSTRUCTION ISSUES ARISE?

A. Yes. Compounding the rock issues identified during the engineering process and then again during construction was the unexpected presence of building materials such as "I-beams" in the streets of Black Hawk that had to be removed by the contractor. As previously noted, the original estimates were based on more typical fill conditions. Consequently, while the estimate provided to the Commission in February of 2019 did contain an adder for bedrock, the difficulty of construction identified during subsequent construction further increased costs. The estimated aggregate capital addition for this project is approximately $63.9 million.

Q. HAS THE TUNGSTEN PIPELINE BEEN COMPLETED?

A. A portion of the project was in-service on September 2019 for $8.2 million. This section of pipe was in-serviced before the winter of 2019/2020 to serve the Dory Hill Station, a supply point to Colorado Natural Gas. The remaining project cost, totaling $55.7 million, will be in-serviced by September 30, 2020, for the 2020/2021 heating season.

[7] In comparison, the typical compressive strength of structural concrete ranges from 4,000 psi to 6,000 psi.

Q. WHAT PROGRESS HAS THE COMPANY MADE TOWARD PLACING THE REMAINING PORTION OF THE PROJECT IN SERVICE?

A. As illustrated in Attachment LAL-7, page 4, the cost estimation and design phases of the project have been completed, and construction is in progress. Additionally, as also illustrated on page 4 of Attachment LAL-7, the Company has spent approximately $30.4 million on the project. This is an important multi-year project to provide necessary additional capacity to our customers, with an expected completion in September 2020.

3. Stapleton Phase 3 Capacity Project

Q. WHAT IS THE STAPLETON PHASE 3 PIPELINE PROJECT?

A. Through the Company's business annual planning process, it was determined that the Downtown Denver IP system was at capacity due to new customer additions in the area. The Company further determined that customers would likely experience outages during cold winter mornings if additional capacity was not added.

Q. PLEASE PROVIDE AN OVERVIEW OF THE WORK INVOLVED IN COMPLETING THE STAPLETON 3 CAPACITY PROJECT.

A. The scope of the Stapleton Phase 3 capacity project was to install approximately 10,000 feet of 285 psig HP steel main predominately along Smith Road from Peoria Street to Ulster Street. Additionally, a new regulator station at approximately East 36th Avenue and Ulster Street was built to reduce the pressure from 285 psig to 150 psig so it could be delivered into the Downtown Denver IP system.

Q. HOW MUCH ADDITIONAL CAPACITY DID THE STAPLETON PHASE 3 PROJECT PROVIDE TO THE DOWNTOWN DENVER IP SYSTEM?

A. The Stapleton project was designed to provide 43,000 Dth/day of capacity into the Downtown Denver IP system. By the 2019 heating season, the capacity created by the Stapleton Phase 3 project was fully consumed to serve firm customers. Overall, the combination of Stapleton Phase 3 and the North Metro Pipeline provide sufficient capacity to meet the design day requirement of our firm customers.

Q. WHAT ALTERNATIVES TO THE STAPLETON PHASE 3 CAPACITY PROJECT DID THE COMPANY CONSIDER?

A. The Company considered an alternate project that contained approximately two miles of 16-inch IP pipeline inside the Downtown Denver IP system. The alternate option and the Stapleton Phase 3 projects were very similar in scale and approximately the same cost. However, the Stapleton Phase 3 project was chosen because it provided more capacity and increased reliability by creating an additional supply point into the Denver Downtown IP system.

Q. WAS THE STAPLETON PHASE 3 PIPELINE PROJECT COMPETITIVELY BID?

A. Yes; the construction and engineering portions were competitively bid in the same manner as described above for the North Metro and Tungsten capacity projects.

Q. HAS THE STAPLETON PHASE 3 CAPACITY PROJECT BEEN COMPLETED?

A. Yes, the Stapleton Phase 3 Capacity Project was in-serviced in June 2017.

4. Lancaster Capacity Project

Q. WHAT IS THE LANCASTER PROJECT?

A. The Lancaster Project is a new pipeline that connected a new supply point into the Company's HP gas system. Specifically, the pipeline ties the Lancaster Gas Residue plant into the Cherokee Pipeline, which transports gas to the Denver metropolitan area. The additional supply provides sufficient gas supply for firm customer growth on the Cherokee and Downtown Denver IP systems.

Q. PLEASE PROVIDE AN OVERVIEW OF THE WORK INVOLVED IN COMPLETING THE LANCASTER CAPACITY PROJECT.

A. The Lancaster project involved the construction of 4.1 miles of 24-inch HP pipe operating at 1,000 psig. The Lancaster project runs from an Anadarko processing plant to the inlet of the Cherokee pipeline near Fort Lupton. The pipeline provides an additional 120,000 Dth/day of supply into the metro area.

Q. WHAT ALTERNATIVES TO THE LANCASTER CAPACITY PROJECT DID THE COMPANY CONSIDER?

A. The Company reviewed an extension of the Stapleton Phase 3 project from approximately East 36th Avenue and N Ulster Street to 38th Street and Blake Street. The project would have included six miles of 16-inch HP (285 psig) pipeline. The project was ruled out because it was more expensive due to the urban route, despite the smaller diameter.

Q. WAS THE LANCASTER PIPELINE PROJECT COMPETITIVELY BID?

A. Yes; the construction and engineering portions were competitively bid in the same manner as described above for the North Metro and Tungsten capacity projects.

Q. HAS THE LANCASTER CAPACITY PROJECT BEEN COMPLETED?

A. Yes, the Lancaster Project was in-serviced in April 2018.

D. Compressor Station Maintenance Program

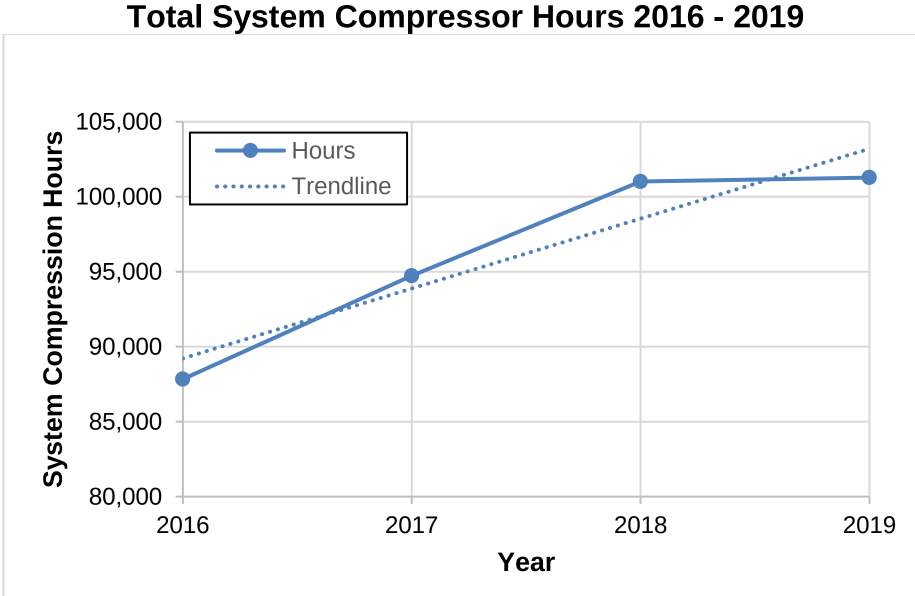
Q. PLEASE DESCRIBE PUBLIC SERVICE'S COMPRESSOR STATIONS.

A. Public Service has 19 compressor station facilities, all of which are important to the Company's integrated gas system. Transmission compressor stations are strategically placed along the Company's gas transmission pipelines to maintain pressure and the flow of gas. In addition, the Company has compressors at our gas processing plant and storage facilities where they serve an important role as well. As throughput on Public Service's systems continues to increase due to the addition of new customers, the reliance on the Company's compressor stations to deliver gas to firm customers on cold winter mornings increases.

Q. WHAT BENEFITS TO CUSTOMERS RESULT FROM THE MAINTENANCE OF COMPRESSOR STATION EQUIPMENT?

A. Periodic testing and maintenance expenditures support safe and efficient operations of the overall gas system, given the steadily increasing system demands experienced in recent years. Increased load demands require that compressor units be highly reliable since pipeline pressures can drop dramatically over very short peak demand periods. Larger magnitude peak loads require that some transmission pipelines be kept pressurized continuously at near-MAOP pressures to be prepared for peak demand. Under 49 CFR 192.739, downstream pressure regulating equipment is required to be supplied at the documented minimum required inlet pressure to meet the anticipated peak customer loads, and this condition can only be met on the Company's system with reliable compression equipment. Operating hours on the compressor fleet continue to increase on a 4.7 percent annual basis based on recent data, indicating an increasing use and reliance on these compressor units as system loads increase. Figure LAL-D-12 presents total annual compressor hours of operation from 2016 to 2019.

Figure LAL-D-12
Total System Compressor Hours 2016 - 2019



Equipment failures must be addressed immediately as reserve capacity may not be available during peak periods. Spare parts inventories must be maintained at each facility to enable timely repair of failed equipment. These inventories include full cylinder head assemblies, pistons, connecting rods, ignition control components, etc. Spare parts requirements can exceed $100,000 for a single large compressor unit.

Q. DOES THE COMPANY HAVE A COMPRESSOR STATION MAINTENANCE PROGRAM?

A. Yes, the Company has always maintained its compressor stations on a regular basis in order to enhance the safety and reliability of the gas system while keeping pace with increasing system loads. Compressor equipment is operated under federal (49 CFR Part 192.165, 49 CFR Part 192.167, 49 CFR Part 192.169, 49 CFR Part 192.171), state, and local compliance requirements, ranging from air emissions to ambient noise restrictions, and Public Service is committed to adhere to all applicable compliance requirements.

Q. PLEASE ELABORATE ON THE FEDERAL CODE REQUIREMENTS RELATED TO COMPRESSOR STATION MAINTENANCE.

A. Under 49 CFR Part 192.165, Liquid Removal, compressors must be equipped with scrubbers and/or filter separators to protect equipment from being damaged by liquids in the gas stream. The dump valves and other instrumentation associated with liquid removal must be inspected and tested on regular intervals and accumulated liquids must be periodically removed from site by truck. Under 49 CFR Part 192.167, Emergency Shutdown, compressors are required to be equipped with emergency shutdown systems that safely shut down the unit, shut off the fuel gas, and blow down the station piping in the event of an emergency like a fire. These systems must be inspected and tested on an annual basis. Under

49 CFR Part 192.169, Pressure Limiting Devices, compressors must be equipped with overpressure protection devices that prevent overpressure of the downstream pipeline. These devices must be tested and inspected on an annual basis. Under 49 CFR Part 192.171, Additional Safety Equipment, compressor units are required to have devices that prevent over-speed of the driver, over-temperature shutdowns, lubrication failure shutdowns, and fire protection equipment that are tested and inspected on an annual basis.

Q. PLEASE EXPLAIN HOW STATE AND LOCAL REQUIREMENTS DIFFER FROM FEDERAL REQUIREMENTS.

A. While federal code covers specific compressor station equipment requirements and the respective maintenance of such equipment, state and local requirements can range from air emissions to ambient noise restrictions. State and local requirements can be more restrictive than federal requirements. In 2015, the Colorado Air Quality Control Commission adopted “Regulation Number 7” which imposed additional leak inspection and record keeping requirements with the goal of “regulating hydrocarbon emissions from oil and gas on a state-only, state-wide basis.” State requirements also include compliance with site-specific air (emissions) permit which require quarterly testing and reporting. In late 2019, the Colorado Air Quality Control Commission was considering even more intensive emissions reductions to address diminishing air quality in the Front Range areas of Colorado. Local compliance covers any special noise restrictions, fire system inspection, and reporting, as well as any other requirements set forth by the local government entities.

Q. WHAT DOWNSTREAM ASSETS ARE IMPACTED BY THE MAINTENANCE OF COMPRESSOR STATION EQUIPMENT?

A. All downstream transmission and distribution facilities are dependent on sufficient inlet pressures to properly operate pressure and flow control equipment that serves industrial, commercial, and residential customers. If compressor discharge pressures fall below minimum thresholds, cascading downstream system failures are possible if the next compressor station in the chain shuts down due to low suction pressure.

Q. WHAT PLANT ADDITIONS HAS THE COMPANY MADE BETWEEN THE END OF THE 2016 HTY IN THE COMPANY'S 2017 GAS PHASE I AND SEPTEMBER 30, 2019?

A The Company has in-serviced approximately $3.9 million of compressor station plant additions, including larger projects detailed in Table LAL-D-20.

Table LAL-D-20
Compressor Station Plant Additions
($ millions)

Project Name	Jan 1, 2017 - Sept 30, 2019	Description
CO/East/Yosemite South Compressor S	$1.2	Yosemite Compressor Unit Overalls (Units #4, #6, & #7)
Compressor Station	$2.7	Various projects in support of system reliability
Total Compressor Station Projects	**$3.9**	

**Differences in sums due to rounding*

Q. WHAT PLANT ADDITIONS IS THE COMPANY FORECASTING FOR COMPRESSOR STATION MAINTENANCE FROM OCTOBER 1, 2019 TO SEPTEMBER 30, 2020?

A. The largest driver of the forecasted $4.7 million in plant additions is the $2.6 million replacement of the electrical switchgear and variable frequency drive equipment at the Yosemite compressor facility. The larger forecasted compressor station projects are shown in Table LAL-D-21.

Table LAL-D-21
Forecasted Compressor Station Plant Additions
($ millions)

Project Name	Oct 1, 2019 - Sept 30, 2020	Description
CO/EAST/Replace Switchgear/VFD Yose	$2.6	Yosemite Compressor Electrical Switchgear and Variable Frequency Drive Replacement
Compressor Station	$2.1	Various projects in support of system reliability
Total Compressor Station Projects	**$4.7**	

**Differences in sums due to rounding*

Q. HAS THE COMPANY INCURRED ANY ADDITIONAL INCREMENTAL O&M EXPENSE SINCE THE 2016 HTY RELATED TO RELIABILITY?

A. Yes, the variance for maintenance of compressor station equipment is $0.9 million. This increase is driven by increased maintenance on the Company's Yosemite, Marshall, Tiffany, Hunter Canyon, Gunnison, Chalk Bluffs, Craig, Greasewood, and Pagosa Compressor Stations, in order to enhance the safety and reliability of the gas system while keeping pace with increasing system loads.

Q. HOW LONG WILL IT TAKE TO COMPLETE THE MAINTENANCE OF COMPRESSOR STATION EQUIPMENT?

A. Maintenance on compressor equipment is a continuous activity involving periodic performance testing, monitoring, and inspection. As discussed earlier, Public Service is committed to adhere to all applicable federal, state, and local compliance requirements. Maintenance of compressor station equipment is also a critical component of the Company's efforts to further enhance the safety and reliability of Public Service's gas system. As such, we expect compressor equipment maintenance to be an ongoing activity during and beyond the Test Year.

E. <u>Obsolete Regulator Replacement Program</u>

Q. HOW MANY REGULATOR STATIONS ARE LOCATED THROUGHOUT THE COMPANY'S SERVICE TERRITORY?

A. There are approximately 2,300 regulator stations located throughout the Company's gas system.

Q. WHAT FUNCTION DO REGULATOR STATIONS SERVE IN THE PUBLIC SERVICE GAS SYSTEM?

A. Regulator stations control the flow of gas from higher pressure gas systems to lower pressure systems through a series of regulators. As gas flows into a regulator station, a regulator senses when gas pressure drops below a pre-determined set point and then opens to allow more gas to move downstream to the lower pressure system. When the downstream system pressure rises above a pre-determined set point, the regulator will then close. Alternately, the Company may install a relief valve instead of the second regulator which also prevents over-pressurization of the gas system. In summary, regulator stations serve a critical function on the gas system as they protect the gas system from over-pressurization and maintain appropriate delivery pressures to customers. Figure LAL-D-13 presents single run regulator station with dual regulators and Figure LAL-D-14 presents a single run regulator station with a regulator and relief valve.

Figure LAL-D-13
Regulator Station with Regulators in Series with the regulators both working to cut the pressure in steps.

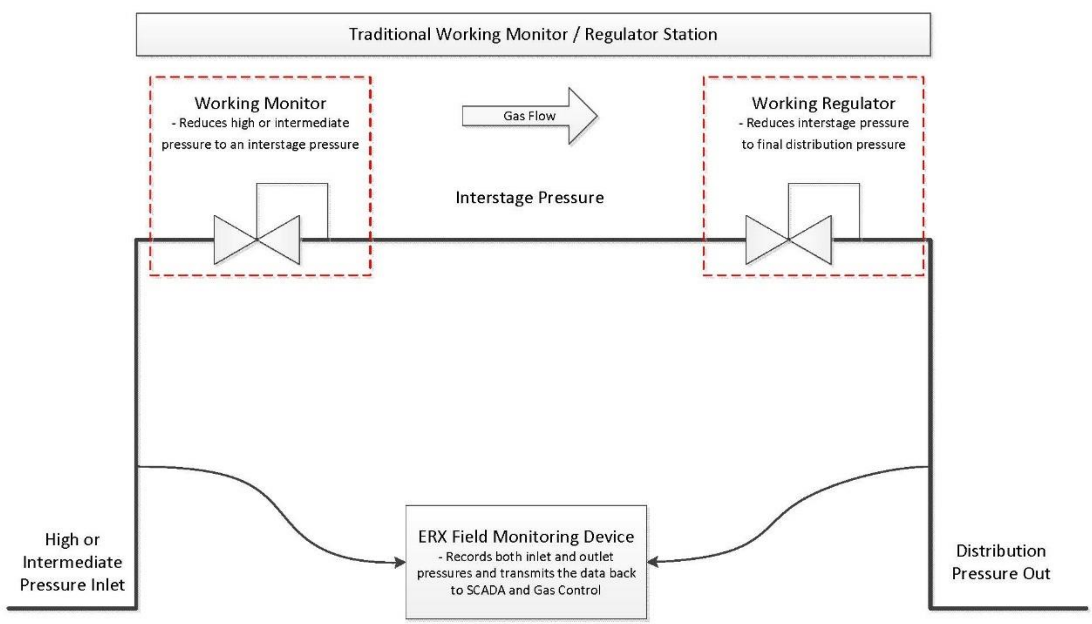
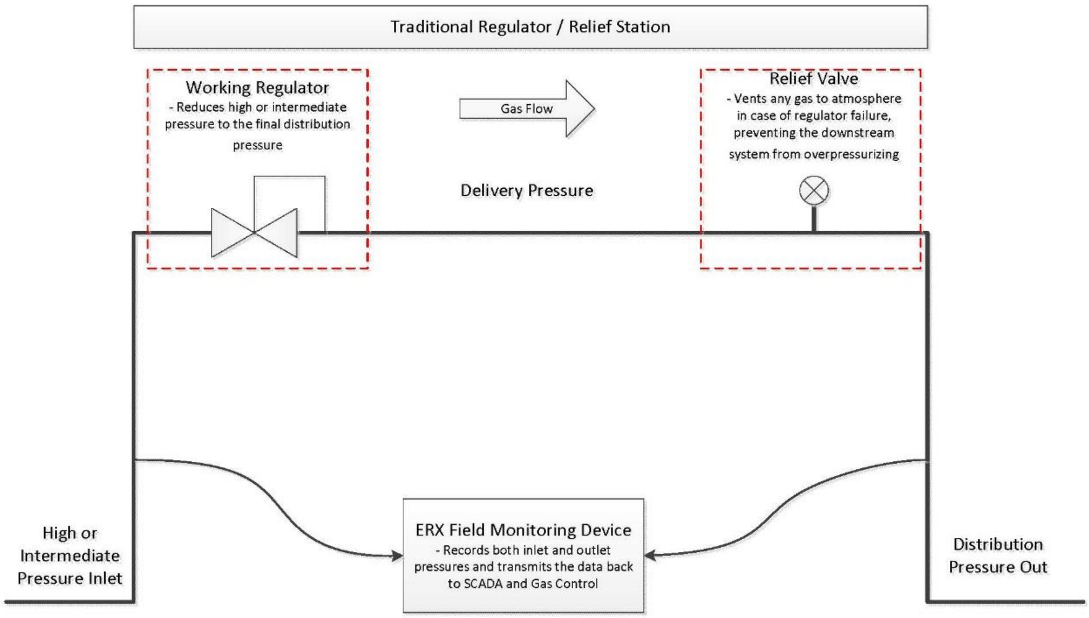


Figure LAL-D-14
Regulator Station with Relief Valve



Q. WHAT ARE OBSOLETE REGULATORS ON PUBLIC SERVICE'S GAS SYSTEM?

A. In the Company's 2015 Gas Phase I, the Company identified approximately 1,200 obsolete regulators that are comprised of older equipment where there are limited or no replacement parts available. A number of those obsolete regulators were replaced prior to January 1, 2017. From January 1, 2017 through September 30, 2019, the Company replaced approximately 398 more obsolete regulators and relief valves. There are approximately 250 remaining obsolete regulators on Public Service's gas system.

Q. HOW DID THE COMMISSION ADDRESS THE COMPANY'S REGULATOR STATION PROGRAM IN THE 2015 GAS PHASE I?

A. In that rate case, the Company proposed a specific program to recover the costs of regulator replacements. While the ALJ initially did not approve that program, the Commission concluded that "Public Service is not barred from future cost recovery of regulator station program costs made in the ordinary course of business. However, we agree with the ALJ that, when Public Service considers expenditures on regulatory station improvements to achieve a 'higher level of service,' the Company must conduct a thorough quantitative cost benefit analysis for project justification."

Q. OF THE 398 REGULATORS REPLACED FROM JANUARY 1, 2017 THROUGH SEPTEMBER 30, 2019, HOW MANY OF THOSE WERE ROUTINE REPLACEMENTS?

A. Of the regulators replaced in this timeframe, 386 were simply to replace obsolete equipment with newer equipment that provided the same level of service. During the Company's annual capacity review of regulators, it was determined that 12 regulators would need to be replaced to comply with 49 CFR Part 192.201(a), entitled Required Capacity of Pressure Relieving and Limitation Stations.

Q. WHAT ANALYSIS DID THE COMPANY PERFORM TO DETERMINE HOW TO ADDRESS THE OBSOLETE REGULATORS AND THE REQUIREMENTS OF 49 CFR PART 192.201(A)?

A. The Company assessed its options. Because the regulators were still needed to provide service and were obsolete, there was not an option to allow them to fail or simply retire them. That meant the only options were to replace the obsolete regulators and upgrade their capacity to meet code requirements, or else replace the obsolete regulators and also upgrade different regulators to meet mandated capacity requirements. The latter option would have been duplicate work, such that the most efficient approach was to upgrade the capacity of the 12 obsolete regulators, in compliance with 49 CFR Part 192.201(a).

Q. HOW MANY OBSOLETE REGULATORS DOES THE COMPANY PLAN TO REPLACE FROM OCTOBER 1, 2019 THROUGH SEPTEMBER 30, 2020?

A. The Company plans to replace 13 regulators from October 1, 2019 through September 30, 2020. All 13 will be replaced with like-for-like regulators that are newer and have replacement parts.

Q. WHAT ARE THE PLANT ADDITIONS IN THIS RATE CASE FOR THE OBSOLETE REGULATOR PROGRAM?

A. Table LAL-D-22 provides the capital additions for this rate case.

Table LAL-D-22
Obsolete Regulator Station Plant Additions January 1, 2017 to September 30, 2020 ($ Millions)

Project Name	Jan 1, 2017 - Sept 30, 2019	Oct 1, 2019 - Sept 30, 2020	Total	Description
Obsolete Regulators	$5.9	$1.3	$7.2	Ongoing replacement of 1,200 obsolete regulators at regulator stations

**Differences in sums due to rounding*

There is no O&M expense associated with the obsolete regulator program. Because the cost of these regulator replacements is part of maintaining reliable operation of the Company's Gas system, they are important investments to serve the public interest.

F. Routine Asset Health Investments

Q. WHAT ARE ASSET HEALTH ROUTINES?

A. Asset health routines are budgets used to fund routine small Asset Health or compliance projects that are typically less than $300,000. Projects classified under the asset health routine include replacements of failed equipment or leaks that require repair in accordance with the Company's Pipeline and Compliance Manual. Renewals of gas main and services not covered under the PSIA are also included in asset health routines.

Q. CAN YOU PROVIDE MORE DETAIL REGARDING THE KINDS OF PROJECTS COVERED BY ASSET HEALTH ROUTINES IN 2017, 2018, AND THE FIRST NINE MONTHS OF 2019?

A. Yes. The kinds of projects included in the asset health routines are: condition-based main and/or service replacements, leak repairs, removal of services due to structure removal, replacement/removal of services in support of main reinforcements or main relocations, and customer-requested relocation of service due to building modifications. Table LAL-D-23 shows the plant additions in the asset health routine from January 1, 2017 to September 30, 2019, along with the amount of main, in feet, renewed during this time period:[8]

Table LAL-D-23
Asset Health Routines Plant Additions
January 1, 2017 to September 30, 2019 ($ millions)

Routine Description	2017	2018	Jan 1, 2019 - Sept 30, 2019	Total
Service Renewal/Cutoff Additions ($M)	$14.0	$14.2	$20.5	$48.7
Main Renewal Additions ($M)	$5.2	$10.4	$13.1	$28.7
Main Renewal Additions (feet)	50,429	46,792	55,897	153,118

**Differences in sums due to rounding*

Table LAL-D-24 shows, the forecasted plant additions in the asset health routine from October 1, 2019 to September 30, 2020 in support of the project types described above:

Table LAL-D-24
Forecasted Asset Health Routines Plant Additions
October 1, 2019 to September 30, 2020 ($millions)

Routine Description	Oct 1, 2019 - Sept 30, 2020	Total
Service Renewal/Cutoff Additions ($M)	$16.5	$16.5
Main Renewal Additions ($M)	$7.5	$7.5

**Differences in sums due to rounding*

Q. WHY IS THE BUDGET FOR ASSET HEALTH ROUTINES FOR THE TEST YEAR REASONABLE?

A. First, the work to maintain asset health is necessary to the reliability of Public Service's gas system. Second, the budget levels for the Test Year are prudent. As we have previously discussed, our budget for asset health routines are based

[8] The Company tracks main renewals in feet on an ongoing basis, rather than in terms of plant additions. Therefore, there may be a timing difference with respect to plant additions and feet of main renewed in a given year. This also applies to main reinforcements, new main, and main relocations.

on historical data. For the 2020 Test Year, the Company has budgeted $24.0 million in plant additions or an average of $2.0 million per month for main and/or service replacements, leak repairs, removal of services due structure removal, replacement/removal of services in support of main reinforcements or main relocations, and customer requested relocation of service due to building modifications. From January 1, 2017 through September 30, 2019, the Company's actual plant additions for the asset health routine was $77.4 million or $2.3 million per month. The monthly forecasted plant additions for asset health routines is thirteen percent less than the actual amount in-serviced from January 1, 2017 through September 30, 2019; therefore, the Company has conservatively forecasted plant additions for the asset health routine in the Test Year.

G. Routine Capacity Investments

Q. WHAT ARE CAPACITY ROUTINES?

A. Projects included in capacity routines are infrastructure work related to increasing gas main capacity to mitigate low-pressure, customer outage related risks based on design day modeling. This type of work is driven by increased load, either from existing customers or new customers.

Q. WHAT KINDS OF PROJECTS WERE COVERED BY CAPACITY ROUTINES IN 2017, 2018, AND THE FIRST NINE MONTHS OF 2019?

A. Capacity routines are comprised of smaller (less than $300,000) projects involving the replacement of existing main assets with larger diameter pipe. Table LAL-D-25 shows the plant additions in support of capacity routines for the project types described above from January 1, 2017 to September 30, 2019, along with the number of feet of replaced main.

Table LAL-D-25
Capacity Routines Plant Additions and Footages
January 1, 2017 to September 30, 2019 ($ millions)

Routine Description	2017	2018	Jan 1, 2019 - Sept 30, 2019	Total
Main Reinforcement Additions ($M)	$2.8	$8.7	$11.0	$22.6
Main Reinforcement Additions (feet)	14,528	29,955	55,242	99,725

**Differences in sums due to rounding*

Table LAL-D-26 below contains the forecasted plant additions in support of capacity routines for the project types described above from October 1, 2019, to September 30, 2020:

Table LAL-D-26
Forecasted Capacity Routines Plant Additions
October 1, 2019 to September 30, 2020 ($millions)

Routine Description	Oct 1, 2019 - Sept 30, 2020	Total
Main Reinforcement Additions ($M)	$8.2	$8.2

**Differences in sums due to rounding*

Q. WHY IS THE BUDGET FOR CAPACITY ROUTINES FOR THE TEST YEAR REASONABLE?

A. Like asset health routine plant additions, capacity routines are necessary to maintain service levels for our customers. Further, the cost forecasts included in the Test Year are reasonable. As previously noted, our budget for capacity routines is based on historical data. For the Test Year, the Company has budgeted $8.2 million in plant additions, or an average of $683,300 per month, for the replacement of existing main assets with larger diameter pipe. From January 1, 2017, through September 30, 2019, the Company's actual plant additions for the

Capacity Routines was $22.6 million or $684,800 per month. The monthly forecasted plant additions for capacity routines are roughly one percent lower than the actual amount in-serviced from January 1, 2017 through September 30, 2019 on a monthly basis; therefore, the Company has conservatively forecasted plant additions for the capacity routines in the Test Year.

V. NEW CUSTOMER BUSINESS

Q. HOW DOES PUBLIC SERVICE RECEIVE REQUESTS FOR NEW BUSINESS?

A. Public Service receives requests from individuals and developers for new gas service through the Company's Builders Call Line. The Builders Call Line is the customer's first point of contact when requesting new gas and electric service from the Company and is intended to be a single call department to simplify the customer's experience. The Company supports new business customers through five key phases of installing and connecting new service through the Builders Call line: 1) Application, 2) Design, 3) Payment, 4) Scheduling and 5) Construction and meter set. The Builders Call Line delineates which tasks within the five phases are the customer's responsibility, the Company's responsibility, and joint responsibility between the customer and the Company.

Q. WHAT IS PUBLIC SERVICE'S OBLIGATION UPON RECEIPT OF REQUESTS FOR SERVICE FROM NEW CUSTOMERS WITHIN THE COMPANY'S SERVICE TERRITORY?

A. Public Service has an obligation to provide natural gas service to new customers within areas in the State of Colorado where the Company has received approval from the Commission to build and operate a gas system. These areas are known as certificated service territories. These territories provide boundaries to gas utilities to ensure that duplicate assets are not built to serve customers. Another advantage to certificated territories is customers and emergency personnel, like fire departments, know what gas utility is responsible for gas odors, gas leaks, and gas line location services.

Q. HOW DOES PUBLIC SERVICE DESIGN, ENGINEER, AND OBTAIN A COST ESTIMATE FOR THE PROJECT ONCE IT OBTAINS A REQUEST FOR NEW BUSINESS?

A. The design phase begins when a customer submits building plans and a request for service to the Company's Builders Call Line. During that initial call, information such as address, customer contact information, building type, and any available load data is collected by the Company and compiled into a standardized form. That data is then assigned to a designer, who will contact the customer and arrange a meeting to cover any specifics related to the project.

After that initial meeting, the designer uses a program called Bentley Expert Designer to start outlining the project scale, route, and required materials to meet the customer's needs. Bentley Expert Designer allows the designer to determine the pipeline route, select the required materials, and factor in installation and restoration costs. If the request for new gas service is large in nature, and served from our HP system, the request for new business is transferred from the designer to a gas engineer. That list of materials and labor is then populated into the Company's Work and Asset Management system and sent to local design and engineering management for review and approval before a quote is issued. From that point, the system generated cost estimates are valid for 90 days before a refresh is required. If the customer accepts the quote by signing the service agreement, payment is collected, and the project is moved to construction.

Since Bentley Expert Designer is built into the Company's GIS, all location and material information is captured and added to the Company's mapping system and serves as the Company's asset system of record. The design process is the same for both gas and electric and a customer can start the process for both gas and electric services concurrently, with one application.

Q. HOW DOES THE COMPANY DETERMINE IF THE PARTY REQUESTING NEW SERVICE NEEDS TO BE CHARGED CONTRIBUTION IN AID OF CONSTRUCTION?

A. New business customers are subject to the Gas Extension Policy process as outlined in Public Service's Gas Tariff. The policy was updated in 2019 as part of Commission Proceeding No. 18AL-0826G. That policy determines customer versus Company contributions to new gas line extensions.

Q. HOW ARE NEW BUSINESS PROJECTS ACCOUNTED FOR?

A. All costs associated with new business are capital, including labor and materials. As with other parts of the Gas Operations projects, there are two types of capital project funding types: 1) discreet projects, and 2) routines. Discrete projects typically are more complex projects in excess of $300,000 that may include transmission mains, transmission regulator stations, larger diameter distribution mains, distribution regulator stations, and land or easement purchases. New business discrete projects are tracked individually under separate work orders and have a high likelihood of having expenditures in more than one budget year.

New business projects that are funded under routines are generally simpler in nature, like a new service and new meter, and not defined until the current year because the Company will receive many requests for new service in any given year but cannot necessarily predict exactly when those calls will be received.

Q. HOW ARE CONSTRUCTION COSTS TYPICALLY DETERMINED FOR NEW BUSINESS WORK AT PUBLIC SERVICE?

A. New business projects are primarily installed by qualified contractors where the Company has a negotiated Master Service Agreement (“MSA”) with each contractor. These MSAs have per-unit pricing. For example, within the negotiated MSA, the cost per service and the cost to install gas mains is set based on pipe diameter and the required installation technique (e.g., trench, bore, etc.).

Q. HOW MANY NEW CUSTOMERS DID PUBLIC SERVICE CONNECT FROM JANUARY 1, 2017 THROUGH SEPTEMBER 30, 2019?

A. According to the Direct Testimony of Company witness Ms. Jannell E. Marks, Public Service customer counts increased an average of 15,604 customers per year, for an average annual growth rate of 1.1 percent.

Q. WHAT WERE THE RESULTING PLANT ADDITIONS TO SUPPORT THIS AVERAGE ANNUAL NEW CUSTOMER GROWTH?

A. Public Service added $244.4 million in plant additions to support these additional customers and the load growth for existing customers. The Company is forecasting to add $79.2 million in plant additions from October 1, 2019 through September 30, 2020 for the 15,590 new customer connections during this time period. Table LAL-D-27 identifies the new business plant additions between discrete and routine projects.

Table LAL-D-27
Gas Operations New Business Capital Additions
Routines vs. Discrete Projects ($ millions)

New Business	Jan 2017 - Sep 2019	Oct 2019 - Sep 2020	Total
Routines	$204.9	$63.8	$268.7
Discrete	$39.5	$15.4	$54.9
Total	**$244.4**	**$79.2**	**$323.6**

**Differences in sums due to rounding*

Q. PLEASE DESCRIBE THE DISCRETE NEW BUSINESS PROJECTS THAT WERE ADDED FROM JANUARY 1, 2017 AND SEPTEMBER 30, 2019.

A. Table LAL-D-28 lists the key discrete new business projects that were in-serviced between January 1, 2017 and September 30, 2019. In addition, the table also contains a brief description of each new business project.

Table LAL-D-28
Discrete New Business Plant Additions ($ millions)

Project Name	Jan 1, 2017 - Sept 30, 2019	Description
Craig Compressor	$9.7	Installation of new compressor to support New Business in Steamboat Springs area.
Gunnison Compressor	$8.2	Installation of new compressor to support New Business in Gunnison and Crested Butte area.
Sterling Ranch Subdivision	$14.5	Installations of main and regulator station to feed 13,000 premise subdivision in Douglas County.
Transmission Reg. and Meter Stations	$2.6	Various activities in support of Transmission Regulator and Meter Station activities
Amazon - 144th & Washington IP	$1.9	Installation of 1,470' of 4" Main in order to serve new Amazon warehouse
Harmony Ridge Subdivision	$1.5	Installation of 860' of 6" IP main and 29,150' of 2", 4", & 6" main in support of new subdivision
CO/Prologis Park	$1.4	Installation of 6,000' of 6" main to serve new warehouse development
Transmission Main Installation Projects	$1.4	Various activities in support of Transmission Main Installation
CO Gas System Reg/Meter Install	$1.5	Various activities in support of Regulator Station and Meter Stations
New Business - CIAC	-$22.0	Contribution in aid of construction payments to the Company
New Business - Other	$18.6	Various other New Business activities
Total New Business Discretes	**$39.5**	

**Differences in sums due to rounding*

Q. PLEASE DESCRIBE THE DISCRETE NEW BUSINESS PROJECTS THAT ARE EXPECTED TO BE ADDED FROM OCTOBER 1, 2019 THROUGH SEPTEMBER 30, 2020.

A. Table LAL-D-29 below lists the key discrete new business projects that will be in service between October 1, 2019 and September 30, 2020. In addition, the table also contains a brief description of each new business project.

Table LAL-D-29
Discrete New Business Plant Additions ($ millions)

Project Name	Oct 1, 2019 - Sept 30, 2020	Description
Transmission Reg. and Meter Stations	$0.7	Various activities in support of Transmission Regulator and Meter Station activities
Transmission Main Installation Projects	$0.6	Various activities in support of Transmission Main Installation
CO Gas System Reg/Meter Install	$1.2	Various activities in support of Regulator Station and Meter Stations
CO/DMO/Highlands PL/W Colfax/IP	$2.3	Installation of 3,000' of 6" IP Main, 4,000' of 6" Main, Regulator Station due to new customers on western sections of Colfax Ave.
CO/Painted Prairie	$1.8	Installation of 150' Transmission Main, Two Regulator Stations for new subdivision
CO/DMR/Auraria Campus Steam Conversion	$0.9	Installations of 4,300' of 4" Main in support of campus conversion from steam
New Business - CIAC	-$4.0	Contribution in aid of construction payments to the Company
New Business - Other	$11.8	Various other New Business activities
Total New Business Discretes	**$15.3**	

**Differences in sums due to rounding*

Q. CAN YOU PROVIDE MORE INFORMATION ABOUT THESE PROJECTS?

A. Yes. Attachment LAL-8 contains a one-page project description for key discrete new business projects in tables LAL-D-28 and LAL-D-29. In addition, below I describe the largest of the discrete projects, which are the Sterling Ranch subdivision projects and the Craig and Gunnison compressors.

Q. HAS THE COMPANY INCURRED ANY ADDITIONAL INCREMENTAL O&M EXPENSE SINCE THE 2016 HTY RELATED TO NEW BUSINESS?

A. No.

Q. HOW DOES THE NEW CUSTOMER BUSINESS BUDGET FOR THE TEST YEAR COMPARE TO ACTUAL CAPITAL ADDITIONS IN RECENT YEARS?

A. Table LAL-D-27 above illustrates that the Company has forecasted $63.8 million in routine new business projects and $15.4 million in discrete new business projects for the twelve months ending September 30, 2020. From January 1, 2017 through September 30, 2019, the average plant addition per month is $7.4 million.

In the Test Year, the average new business plant addition per month is $6.6 million or a reduction of almost 11 percent. The Company believes that it has conservatively estimated the plant additions for new business in the period from October 1, 2019 through September 30, 2020.

A. <u>Gunnison and Craig Compressor Projects</u>

Q. PLEASE DESCRIBE THE INDIVIDUAL COMPRESSOR PROJECTS INCLUDED IN THE COMPANY'S RATE REQUEST.

A. The compressor projects consist of the Gunnison and Craig compressors. The Gunnison compressor was needed to meet the capacity request from Atmos for load growth on their system in Crested Butte, Gunnison, and Salida. The Craig compressor was also used to meet a capacity request for Atmos for load growth in the Steamboat Springs area. Additional information about these compressors is included in Attachment LAL-8 to my Direct Testimony.

Q. WERE THESE COMPRESSORS DISCUSSED IN A PREVIOUS COMMISSION PROCEEDING?

A. Yes. Public Service sought recovery of the compressors in the 2017 Gas Phase I, as part of its request for a multiyear plan involving future test years. While neither the need for the compressors nor their cost was contested, there was some debate whether to allocate the compressors solely to Atmos via a surcharge, or across the system. Public Service supported allocating the costs across the system based on the overall system benefits the compressors provide. Staff supported a surcharge and argued that an overall cost of service allocation would subsidize Atmos customers based on the remote locations of the compressors.

Q. WHAT WAS THE COMMISSION'S DECISION REGARDING ALLOCATION OF THESE COSTS?

A. In Decision No. R18-0318 (mailed date May 11, 2018) in the 2017 Gas Phase I, the ALJ approved allocation of the compressor costs across the system based on the system-wide benefits they provided. Because that portion of the ALJ's decision was not contested, it became the decision of the Commission.

Q. WHY ARE THE COMPRESSOR PROJECTS INCLUDED AS NEW BUSINESS PLANT ADDITIONS IN THIS RATE CASE?

A. The compressor projects were not in service within the 2016 HTY the Commission ultimately used to set rates for the 2017 Gas Phase I. As a result, the Company has been receiving offsetting revenues for these projects, which will end when the projects are placed in service (as discussed in more detail by Company witness Ms. Blair). Because both projects are now in service, they are included as new business plant additions in Public Service's cost of service in this rate case.

B. Sterling Ranch Subdivision Project

Q. WHAT IS THE STERLING RANCH SUBDIVISION PROJECT?

A. The new Sterling Ranch subdivision is located south of the Chatfield Reservoir and will contain approximately 13,000 new homes and businesses when fully built out. The current project is designed to bring sufficient gas into the area to provide service to these customers. As the development expands, additional mains and regulator stations will be required to transport the gas from the HP system to the individual customers' homes.

Q. PLEASE PROVIDE AN OVERVIEW OF THE WORK INVOLVED WITH PROVIDING NATURAL GAS TO THE STERLING RANCH SUBDIVISION.

A. A new HP regulator station (650 psig to 285 psig) provides a feed into a new four-mile segment of 12-inch HP main operating at 285 psig and approximately 2.8 miles of 8-inch HP main.

Q. DID THE COMPANY CONSIDER ANY OTHER ALTERNATIVE TO PROVIDING GAS TO THE STERLING RANCH SUBDIVISION.

A. Yes. The Company considered an alternate route that involved installing 7.2 miles of 12-inch 285 psig HP pipeline and a regulator station down Highway 85 from Mill Vista Road to North Roxborough Park Road and West Titan Road. The alternative was not used due to increased length and the challenging route down Highway 85.

Q. WAS THE STERLING RANCH SUBDIVISION PROJECT COMPETITIVELY BID?

A. Yes; the construction and engineering portions were competitively bid in the same manner as the discrete reliability and capacity projects described earlier in my Direct Testimony.

Q. HAS THE STERLING RANCH SUBDIVISION PROJECT BEEN COMPLETED?

A. Yes, the Sterling Ranch Subdivision project was in-serviced in January 2019. Additional information about the Sterling Ranch project is included in Attachment LAL-8 to my Direct Testimony.

C. New Business Routines

Q. WHAT ARE NEW BUSINESS ROUTINES?

A. These routines cover the purchase of new meter and service regulators and the installation of new distribution mains and services for projects less than $300,000, in order to serve new customers.

Q. WHAT KINDS OF WORK WAS COVERED BY NEW BUSINESS ROUTINES IN 2017, 2018, AND THE FIRST NINE MONTHS OF 2019?

A. New business routines involved the purchase of new meters and service regulators and the installation of new distribution mains and services. The drivers for these types of projects are outlined previously in this section. Table LAL-D-30 below shows the plant additions in support of new customer additions along with the number of feet of new main additions to support customer growth.

Table LAL-D-30
New Business Routines Plant Additions and Footages for Period ending September 30, 2019 ($ millions)

Routine Description	2017	2018	Jan 1, 2019 - Sept 30, 2019	Total
New Meter and Regulator Purchases	$25.0	$27.1	$23.0	$75.2
New Service Additions ($M)	$16.9	$21.5	$19.5	$58.0
New Main Additions ($M)	$19.2	$30.8	$21.8	$71.8
New Main Additions (feet)	394,900	2,296,909	898,737	3,590,546

**Differences in sums due to rounding*

Q. WHAT METHODOLOGY DID PUBLIC SERVICE USE TO FORECAST NEW BUSINESS ADDITIONS FROM OCTOBER 1, 2019 THROUGH SEPTEMBER 30, 2020?

A. First, the forecast for the number of customers that will request new gas service is obtained from the Sales, Energy, and Demand Forecasting department. This department is forecasting new customer additions of 15,590 from October 1, 2019 through September 30, 2020. The budget for new business routines is then developed using a cost-per-customer from historical actuals. Further, inputs and assumptions regarding inflation factors are used to determine the assumed cost increases or decreases. These inflation factors include but are not limited to labor, non-labor, contractor, materials, equipment and fleet inflation rates, and bargaining labor increases. Table LAL-D-31 shows the plant additions for new business routines.

Table LAL-D-31
New Business Routines Plant Additions and Footages for Twelve-Month Period ending September 30, 2020 ($ millions)

Routine Description	Oct 1, 2019 - Sept 30, 2020	Total
New Meter and Regulator Purchases	$26.0	$26.0
New Service Additions ($M)	$21.8	$21.8
New Main Additions ($M)	$16.0	$16.0

**Differences in sums due to rounding*

Q. WHY IS THE NEW BUSINESS ROUTINE BUDGET FOR THE TEST YEAR REASONABLE?

A. As with the Company's other routine budgets, the work covered by these budgets is necessary to serve customers and the budgeted amounts for the Test Year are reasonable. As previously discussed, the Company's budget for new business routines is based on the customer additions forecast and assumptions from Ms. Marks and the cost-per-customer from historical actuals. The historical customer addition actuals and Ms. Marks' forecast are then used to develop the new business routine budgets.

For the Test Year, the Company has budgeted $63.8 million in plant additions or an average cost per customer of $4,092. From January 1, 2017 through September 30, 2019, the Company's actual plant additions for the new business routines was $205 million or $4,773 per customer. Therefore, the forecasted cost per customer for new business routines is fourteen percent less the average actual amount per customer in-serviced from January 1, 2017 through September 30, 2019. In sum, the Company has conservatively forecasted plant additions for the new business routines in the Test Year.

VI. MANDATED RELOCATIONS

Q. WHAT ARE MANDATORY RELOCATION PROJECTS?

A. Mandated Relocations are capital projects that require Public Service to move existing infrastructure in order 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. An example is the CO/Platteville/WCR 34 – WCR 13 relocation, which was required by Weld County in 2019 due to road and associated drainage culvert reconstruction and included the relocation of approximately 1,200 feet of 12-inch transmission main, valve set relocation, and lowering of 4-inch and 2-inch transmission main. The total cost of this project was $2.2 million.

Q. WHAT WERE THE RESULTING PLANT ADDITIONS TO SUPPORT THE MANDATORY RELOCATIONS?

A. Table LAL-D-32 identifies the mandatory relocations plant additions between discrete and routine projects.

Table LAL-D-32
Mandatory Relocation Plant Additions
Routines vs. Discrete Projects ($ millions)

Relocations	Jan 2017 - Sep 2019	Oct 2019 - Sep 2020	Total
Routines	$29.6	$6.9	$36.6
Discrete	$23.5	$17.1	$40.6
Total	**$53.1**	**$24.0**	**$77.2**

**Differences in sums due to rounding*

A. Discrete Mandated Relocations

Q. WHAT ARE THE PLANT ADDITIONS FOR MANDATORY RELOCATION PROJECTS FROM THE 2016 HTY TO THE PERIOD ENDED SEPTEMBER 30, 2019?

A. The Company implemented $23.5 million of discrete mandatory relocation plant additions from the 2016 HTY to the actual period ended September 30, 2019. Several larger, individual projects were included in that total, as shown in Table LAL-D-33. Table LAL-D-33 also provides a description of each project.

Table LAL-D-33
Mandatory Relocations Plant Additions
($ millions)

Project Name	Jan 1, 2017 - Sept 30, 2019	Description
Central 70	$0.4	Ongoing main, service, and regulator station relocations in support of 10 miles of Interstate 70 reconstruction in central Denver area.
Two Basins	$4.9	Ongoing main relocations in support of Two Basins project by the City of Denver in conjunction with the Central 70 project.
Stapleton Phase 3 Reroute	$2.5	Installed 3,500' of 16" pipe due to road expansion efforts
CO/Platteville/WCR 34-WCR 13	$2.2	Relocated ~1,640' of 12" high pressure main, one valveset, and lowered ~600' of 4" and 2" high pressure main
CO/NMR/McIntyre Relocation	$4.2	Relocated ~2,000' of 20" main as requested by Jefferson County
CO/SWMO/SanteFe/US85 @C470 Relocat	$1.8	Relocated 6,500' of 6" high pressure main, 1,200' of 3" high pressure main, and 200' of 24" high pressure main due CDOT widening of US Highway 85
Flood Main Renewal	$1.7	Main relocation and renewal in Boulder area of 1,490' of main in support of flood recovery efforts
Relocation - Other	$5.9	
Total Relocation Discretes	**$23.5**	

**Differences in sums due to rounding*

Q. WHAT ARE THE FORECASTED PLANT ADDITIONS FOR MANDATORY RELOCATION PROJECTS FROM OCTOBER 1, 2019 TO SEPTEMBER 30, 2020?

A. For the period of October 1, 2019 to September 30, 2020, the Company is forecasting $17.1M of discrete mandatory relocations, including several large projects shown in Table LAL-D-34.

Table LAL-D-34
Forecasted Mandatory Relocation Plant Additions
($ millions)

Project Name	Oct 1, 2019 - Sept 30, 2020	Description
Central 70	$8.3	Ongoing main, service, and regulator station relocations in support of 10 miles of Interstate 70 reconstruction in central Denver area.
Two Basins	$2.4	Ongoing main relocations in support of Two Basins project by the City of Denver in conjunction with the Central 70 project.
CO/SWMO/SanteFe/US85 @C470 Relocat	$0.1	Relocated 6,500' of 6" high pressure main, 1,200' of 3" high pressure main, and 200' of 24" high pressure main due CDOT widening of US Highway 85, and completion efforts related to relocation of high pressure main
CO/CAMP/Picadilly & 64th Relocation	$2.2	Relocation of 6,100' of 8" high pressure main due to road expansion efforts in Aurora.
CO/FR/Miner St Idaho Spring Reloc	$1.3	Relocation of 2,700' of 1 1/4" distribution main with 2" main in Idaho Springs due to reconstruction of road
Relocation - Other	$2.8	
Total Relocation Discretes	**$17.1**	

**Differences in sums due to rounding*

Q. HAS THE COMPANY INCURRED ANY ADDITIONAL INCREMENTAL O&M EXPENSE SINCE THE 2016 HTY RELATED TO MANDATORY RELOCATIONS?

A. No.

Q. DOES THE COMPANY REQUEST PAYMENT OR REIMBURSEMENT FOR MANDATORY RELOCATIONS FROM PARTIES WHO MAKE THE REQUEST?

A. Yes, whenever we can. The Company seeks reimbursements from entities for relocations where the Company holds the appropriate land rights (fee or easement) for assets. A recent of example of this is the CO/North/Kendall Parkway Relocation where the Company had 2,100 feet of 4” main in conflict with a proposed development. The Company held the land rights to the location of the conflict, so the developer reimbursed the Company the entire cost of the $0.3

million project. This protected other customers from funding non-mandated relocations.

Q. DO CUSTOMERS RECEIVE THE BENEFIT OF REIMBURSEMENTS?

A. Yes. Customers receive the benefit of the reimbursements because those reimbursed projects are not recovered through rates since the specific requestor of the relocation reimbursed the Company directly.

<u>Routine Relocations</u>

Q. WHAT ARE ROUTINE RELOCATIONS?

A. Routine relocation projects are mandated to meet federal, state, or local requirements and are typically less than $300,000. This includes relocating pipelines that are in direct conflict with street expansions within public rights-of-way and safety-related work required by a governing authority.

Q. HOW DOES THE COMPANY BUDGET FOR RELOCATIONS?

A. The budget for main relocation routines is based on the averages of historical values escalated by the corporate inflation rate (approximately two percent per year).

Q. WHAT KINDS OF PROJECTS WERE COVERED BY RELOCATION ROUTINES IN 2017, 2018, AND THE FIRST NINE MONTHS OF 2019?

A. Relocation routines are comprised of smaller (less than $300,000) projects involving the renewal of mains due to relocations. Tables LAL-D-35 and LAL-D-36 below show the plant additions for routine mandatory relocations in support of the project types described above.

Table LAL-D-35
Routine Mandatory Relocations Plant Additions and Footage
2016 HTY to Actual Period ending September 30th 2019 ($ millions)

Routine Description	2017	2018	Jan 1, 2019 - Sept 30, 2019	Total
Main Relocation Additions ($M)	$9.3	$10.0	$10.3	$29.6
Main Relocation Additions (feet)	154,293	120,531	41,223	316,047

**Differences in sums due to rounding*

Table LAL-D-36
Mandatory Relocations Routine Plant Additions
October 1, 2019 to September 30, 2020 ($ millions)

Routine Description	Oct 1, 2019 - Sept 30, 2020	Total
Main Relocation Additions ($M)	$6.9	$6.9

**Differences in sums due to rounding*

Q. WHY IS THE BUDGET FOR THE TEST YEAR REASONABLE?

A. As we have previously discussed, our budgets for mandated relocations routines are based on historical data. For the Test Year, the Company has budgeted $6.9 million in plant additions or an average of $575,000 per month for projects that require Public Service to move existing infrastructure in order to meet federal, state, or local requirements. From January 1, 2017 through September 30, 2019, the Company's actual plant additions for the mandated relocations routines was $29.6 million or $897,000 per month. The monthly forecasted plant additions for mandated relocations routines is over 35 percent less than the actual monthly average amount in-serviced from January 1, 2017 through September 30, 2019. Therefore, the Company has conservatively forecasted plant additions for the capacity routines in the Test Year.

VII. CONCLUSION

Q. WHAT DO YOU RECOMMEND IN THIS PROCEEDING?

A. I recommend that the Commission approve the Gas Operations capital additions and O&M expense included in the Company's revenue requirement in this rate case. I further support the recommendation by Mr. Berman for deferral of Damage Prevention Program costs not included in base rates in this proceeding, for further reconciliation in the Company's next Phase I rate case.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Statement of Qualifications

Luke A. Litteken

I received a Bachelor of Arts in Business Administration and a Master of Business Administration from Augsburg College. I have an Associate of Technology in Heating, Cooling and Refrigeration from Ranken Technical Institute in St. Louis, Missouri. I also hold the following professional licenses: Master Gasfitter license, Master Refrigeration license, and Master Warm Air license.

I was hired by CenterPoint Energy ("CNP") as a Service Technician in the Field Operations Department in 1989 and was promoted to Supervisor, Field Operations in 1995. I was responsible for a team of emergency responders and service technicians for a geographic territory in Minnesota.

In 2000, I became Manager of Subcontractor Services & Sales Administration for CNP. In this position, I developed the Company's quality program, credit policy, credit administration, records retention, and sales administration to support the retail sales business. I also developed and implemented the processes to rollout the SAP business platform for CNP's Home Service Plus retail sales business.

From 2005 to 2009, I was promoted to Manager of Field Operations in Minnesota for CNP. In this position, in addition to managing CNP's Field Operations, I negotiated non-union and union subcontractor agreements, led the team that worked on reducing bad debts, and co-led the Minnesota CNP Emergency Response team that focused on improving the promptness and efficiencies of CNP's emergency response program.

From 2009 until the time that I joined XES in 2014, I served as Director of CNP's South District and North District. In this position, in addition to overseeing the provision of safe and reliable service to approximately 400,000 customers, my responsibilities included safety, emergency response, community relations, franchise negotiations, new customer growth and the development of district budgets. I also acted as incident commander for several significant CNP gas events. I led the efforts that improved emergency response times for CNP's second responders. Further, I led the team that developed common processes and identified best practices across CNP's jurisdictions.

In 2014, I joined XES as Area Vice President, Gas Operations. In this position, I had oversight of the operations and maintenance of the gas distribution and HP systems in the seven states in which Xcel Energy operates, including gas control center operations. My responsibilities included system reliability, emergency response, damage prevention and compliance with federal and state rules and regulations. I also provide leadership over Xcel Energy's Gas operations including bargaining and non-bargaining employees, contractors and other outside vendors. I was promoted in 2018 to my current position of Senior Vice President, Gas for XES. 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.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * *

IN THE MATTER OF ADVICE NO. 961-GAS OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 6-GAS TARIFF TO INCREASE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL GAS RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE MARCH 7, 2020.	) PROCEEDING NO. 20AL-_____G

AFFIDAVIT OF LUKE A. LITTEKEN
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO

I, Luke A. Litteken, being duly sworn, state that the Direct Testimony and attachments were prepared by me or under my supervision, control, and direction; that the Direct 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 31st day of January 2020.

Luke A. Litteken

Luke A. Litteken
Senior Vice President, Gas

Subscribed and sworn to before me this 31st day of January 2020.

Diane K Duresky
Notary Public Diane K. Duresky

DIANE K DURESKY
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20064044236
MY COMMISSION EXPIRES NOVEMBER 22, 2022

My Commission expires November 22, 2022