BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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RE: IN THE MATTER OF ADVICE NO.	**)**	
1797-ELECTRIC OF PUBLIC SERVICE	**)**	
COMPANY OF COLORADO TO REVISE	**)**	
ITS COLORADO P.U.C. NO. 8-	**)**	**PROCEEDING NO. 19AL-______E**
ELECTRIC TARIFF TO IMPLEMENT	**)**	
RATE CHANGES EFFECTIVE ON	**)**	
THIRTY-DAYS' NOTICE.	**)**	

DIRECT TESTIMONY AND ATTACHMENTS OF CHAD S. NICKELL

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

May 20, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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RE: IN THE MATTER OF ADVICE NO. 1797-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8-ELECTRIC TARIFF TO IMPLEMENT RATE CHANGES EFFECTIVE ON THIRTY-DAYS' NOTICE.	**)))))))**	**PROCEEDING NO. 19AL-______E**

DIRECT TESTIMONY AND ATTACHMENTS OF CHAD S. NICKELL

TABLE OF CONTENTS

SECTION **PAGE**

LIST OF ATTACHMENTS

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
2014 Electric Rate Case	Proceeding No. 14AL-0660E
ADMS	Advanced Distribution Management System
AGIS	Advanced Grid Intelligence and Security
AGIS CPCN Settlement	Proceeding No. 16A-0588E
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
ANSI	American National Standards Institute
CIAC	Contribution in Aid of Construction
CDOT	Colorado Department of Transportation
Commission	Colorado Public Utilities Commission
Company	Public Service Company of Colorado
CPCN	Certificate of Public Convenience and Necessity
CPCN Projects	AMI, IVVO, and the components of the FAN that support these components
CPE	Customer Premise Equipment
CSG	Community Solar Gardens
DA	Distribution Automation
DER	Distributed Energy Resources
Distribution	Distribution Business Area
DSM	Demand Side Management
ECT	Electric Continuity Threshold

Acronym/Defined Term	Meaning
ENGO	Edge of Network Grid Optimization
ERT	Electric Restoration Threshold
FAN	Field Area Network
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location Isolation System Restoration
FLP	Fault Location Prediction
FPIP	Feeder Performance Improvement Program
GB CMD	Green Button Connect My Data
GFCI	Ground Fault Circuit Interrupter
GIS	Geospatial Information System
HAN	Home Area Networks
HTY	Historical Test Year
IEEE	Institute of Electrical and Electronics Engineers
IT	Information Technology
IVVO	Integrated Volt-VAr Optimization
kVAr	Kilovolt-Amperes Reactive
kW	Kilowatt
kWh	Kilowatt Hours
LED	Light-Emitting Diode
LTCs	Load Tap Changers
MHT	Mountain Hazard Tree
NIC	Network Interface Cards

Acronym/Defined Term	Meaning
NREL	National Renewable Energy Laboratory
OH	Overhead
O&M	Operations and Maintenance
OMS	Outage Management System
OpCos	Xcel Energy Operating Companies
PMO	Project Management Office
PTMP	Point-to-Multipoint
PTT	Productivity Through Technology
Public Service	Public Service Company of Colorado
QSP	Quality Service Plan
RFP	Request for Proposal
RFx	Request for Information and Pricing
ROW	Right of Way
RWT	Reliability Warning Threshold
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
Settlement Agreement	Non-Unanimous Comprehensive Settlement Agreement
SMS	Sensor Management System
SVC	Secondary Static VAr Compensators
TOU	Time-of-Use

Acronym/Defined Term	Meaning
UG	Underground
WAN	Wide Area Network
WiMAX	Worldwide Interoperability for Microwave Access
WiSUN	802.15.4g Standard
Xcel Energy	Xcel Energy, Inc.
XES	Xcel Energy Services Inc.
XLPE	Non-Jacketed Cross-Linked Polyethylene

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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RE: IN THE MATTER OF ADVICE NO. 1797-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8-ELECTRIC TARIFF TO IMPLEMENT RATE CHANGES EFFECTIVE ON THIRTY-DAYS' NOTICE.	**)**	**PROCEEDING NO. 19AL-______E**

DIRECT TESTIMONY AND ATTACHMENTS OF CHAD S. NICKELL

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, AND RECOMMENDATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Chad S. Nickell. My business address is 1123 West 3rd Avenue, Denver, Colorado 80223.

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

A. I am employed by Xcel Energy Services Inc. ("XES") as Manager, System Planning and Strategy—South. 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 utility operating company subsidiaries of Xcel Energy on a coordinated basis.

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

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As the Manager of Distribution System Planning & Strategy—South, I am responsible for providing strategic direction for building the Company's distribution plan, and for ensuring a reliable and cost-effective electric distribution system. My duties include developing and leading a system modernization and renewal strategy and managing the Distribution capital budget for Public Service and Southwestern Public Service Company, one of the other Xcel Energy operating companies ("OpCos"). A description of my qualifications, duties, and responsibilities is set forth after the conclusion of my testimony in my Statement of Qualifications.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is multi-fold. First, in Sections IV through VI I support the $1.294 billion of the Company's Distribution Business Area ("Distribution") plant in-service additions since the last rate case (not including Advanced Grid Intelligence and Security ("AGIS")) as well as forecasted Distribution plant-in-service additions for calendar year 2019 of $205.9 million (not including AGIS or Wildfire Mitigation), which are appropriately allocated to Public Service retail electric and included in the 2018 Historical Test Year ("HTY") cost of service that is presented by Company witness Ms. Deborah A. Blair. Company witness Ms. Laurie J. Wold has calculated the monthly plant balances to develop the plant-related roll forward, which in turn is used by Company witness Ms. Blair to incorporate the year-end plant in service balances into the 2018 HTY cost of service. I also support the $105.4 million in 2018 Operations and Maintenance ("O&M") expense (pre-adjustment) included in the 2018 HTY cost of service. These dollar figures also do not include costs associated with the AGIS initiative, which I discuss below. As part of my support for Distribution's O&M expenses, I support the proposed adjustment to remove the Company's incremental Distribution O&M expenses associated with providing mutual aid to Puerto Rico after Hurricane Irma in 2018. The Company's last rate case was Proceeding No. 14AL-0660E ("2014 Electric Rate Case"), in which a 2013 HTY was approved, therefore I am supporting the incremental capital investments from year-end 2013 through year-end 2019 with my testimony here.

Second, in Section VII of my Direct Testimony, I support the recovery of capital and O&M costs associated with Distribution's updated Wildfire Mitigation Plan, including planned capital additions and O&M costs for 2019 included as an adjustment in the 2018 HTY cost of service. I also discuss Distribution's Wildfire Mitigation activities going forward.

Next, in Section VIII, I discuss and support the technical strategy for implementation of the AGIS initiative, and the activities undertaken by the Company, which will result in an advanced electric distribution grid in the Company's service territory. I explain how Distribution has started moving forward from the Commission approved settlement of the Certificate of Public Convenience and Necessity ("CPCN") for AGIS ("AGIS CPCN" or "Grid CPCN") in Proceeding No. 16A-0588E ("AGIS CPCN Settlement") to implement the AGIS

CPCN projects, while also implementing those components of AGIS that are being conducted in the ordinary course of business. Through my discussion of the AGIS projects in Section VIII, I support Distribution's capital additions related to AGIS projects through 2018 of $13.8 million, and the Company's forecasted 2019 capital additions of $71.4 million.

In Section IX, I support Distribution's AGIS-related O&M expenses for 2018 as well as an adjustment to account for the known and measurable O&M that the Company anticipates for its AGIS-related Distribution O&M in 2019, which are included in the Company's 2018 HTY cost of service presented by Ms. Blair.

I note that Company witness Ms. Brooke A. Trammell introduces the proposed cost recovery methodology related to the AGIS programs and discusses the policy aspects of the AGIS initiative for this rate review, and that Company witness Mr. David C. Harkness provides support for the Business Systems organization's implementation of the Information Technology ("IT") for the AGIS projects.

Finally, in Section X, I discuss the Company's distribution reliability achievements to date and its plans for additional enhancements in the years ahead.

Q. WHAT IS "AGIS"?

A. We have visited with this Commission and interested stakeholders on various occasions previously about AGIS, but for those that haven't had the opportunity to engage on this topic or are new interested parties, AGIS is a long-term strategic initiative that will transform the Company's electrical distribution business by enhancing security, efficiency, and reliability, which will enable us to safely integrate more distributed resources, and improve customer products and services. The technical capabilities of the current grid are limited compared to more advanced grid technologies, and the overall system as presently configured is opaque—meaning the Company has little near real-time insight into the grid beyond the substation level. AGIS seeks to take advantage of existing advanced technology to increase grid reliability, transparency, efficiency, and access. Overall, the AGIS platform consists of multiple programs that will ultimately work together to support improved distribution technology, empowered customer choice, and improved energy management and savings. Consistent with related initiatives by utilities around the country, it is the natural next step in the development of our distribution grid.

The advanced grid that will be achieved through the Company's AGIS initiative involves the following key programs, commonly referred to as "foundational" programs: Advanced Distribution Management System ("ADMS"); the Geospatial Information System ("GIS"); Advanced Meter Infrastructure ("AMI"); a Field Area Network ("FAN"); and advanced applications—such as

Integrated Volt-VAr Optimization ("IVVO"), Fault Location Isolation and Service Restoration ("FLISR"), and Fault Location Prediction ("FLP")—that will utilize intelligent field devices. In addition, there are several projects and programs in development that will become part of the AGIS initiative beyond 2019. As a result, Public Service is not including those costs or forecasts as part of this rate review.

As noted above, in Section VIII of my testimony, I provide an overview of the AGIS initiative and discuss the implementation of the individual AGIS programs, detailing the type of work Distribution will complete, particularly where Distribution is taking the lead on budget development, planning, and deployment. I also support Distribution's AGIS-related capital plant-in-service additions. In Section IX, I discuss Distribution's AGIS-related O&M expenses.

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

A. Yes, I am sponsoring Attachments CSN-1 through CSN-5, which were prepared by me or under my direct supervision. The attachments are as follows:

- Attachment CSN-1: Distribution Capital Additions 2014–2018;
- Attachment CSN-2: Distribution Capital Additions 2019;
- Attachment CSN-3: Distribution O&M Expenses by Cost Element;
- Attachment CSN-4: Distribution O&M Expenses by Federal Energy Regulatory Commission ("FERC") Account; and
- Attachment CSN-5: Illustration of the principal components of the FAN.

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

A. As part of approving the cost of service developed by Ms. Blair, I recommend that the Colorado Public Utilities Commission ("CPUC" or "Commission") approve the 2014-2019 Distribution Business Area capital additions and 2018 Distribution Business Area O&M expenses, including the AGIS capital additions and O&M set forth below. I also recommend the Commission approve the Company's request related to recovery of Distribution-related Wildfire Mitigation Plan O&M expenses, which comprise an adjustment to the 2018 O&M expenses for known and measurable expenses.

II. DISTRIBUTION FUNCTIONS AND ACTIVITIES

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

A. In this section, I describe the functions of the Distribution Business Area, including its key aspects and services. I also provide an overview of Public Service's distribution system.

Q. PLEASE DESCRIBE THE DISTRIBUTION BUSINESS AREA.

A. The Distribution Business Area is responsible for the construction and operation of Public Service's distribution system, which is the portion of its electric system that delivers electricity to the vast majority of our customers. The Distribution Business Area is comprised of the following functional areas: (1) Electric Distribution Design, Construction, and Maintenance; (2) Electric Distribution Engineering; (3) Business Operations; and (4) Planning and Performance. There are a total of approximately 1,132 operating company and XES Distribution employees assigned to provide services to the Public Service distribution system. Of those employees, approximately 1,055 are Public Service employees.

Q. PLEASE DESCRIBE THE KEY FUNCTIONS AND SERVICES OF THE DISTRIBUTION BUSINESS AREA.

A. The key services provided by the Distribution Business Area include developing infrastructure to serve new customers, restoring service after outages, performing routine maintenance, and making capital improvements when necessary to improve the performance and reliability of the distribution system.

To deliver these services, the Distribution Business Area is structured around four key functions:

- *Operations:* Includes the design, construction, and maintenance of the distribution system, as well as monitoring and operating the distribution system from the Electric Control Center, responding to electric distribution trouble calls, and coordinating emergency response.
- *Engineering:* Includes technical support and system planning, design, construction, and material standardization, reliability planning, and addressing distribution-related customer service issues.
- *Business Operations:* Includes vegetation management, outdoor lighting, metering systems and support, facility attachments, and the builder's call line.
- *Planning and Performance:* Includes business planning, consulting, and analytical services and performance governance and management.

Q. PLEASE PROVIDE AN OVERVIEW OF PUBLIC SERVICE'S DISTRIBUTION SYSTEM.

A. To reliably and efficiently serve our approximately 1.5 million Colorado customers, Public Service owns and operates an extensive electric distribution system. Our electric distribution system has assets in 25 counties and provides service to both rural and urban customers. The distribution system consists of approximately 151 distribution-level substations that support a network of 785 distribution feeders necessary to serve our customers. Our distribution system is further comprised of 9,569 circuit miles of overhead distribution lines, 13,202 circuit miles of underground distribution lines, and over 400,000 poles. To operate and maintain this extensive system, the Distribution Business Area has wide-ranging control center operations and a fleet of over 330 support vehicles.

III. DISTRIBUTION CAPITAL BUDGET, PROJECT SELECTION, AND FUNDING

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

A. The purpose of this section of my Direct Testimony is to provide an overview of the Distribution Business Area's capital budgeting process, project development, and budget management processes.

Q. WHAT ARE THE PRIMARY DRIVERS AFFECTING PUBLIC SERVICE'S DISTRIBUTION UTILITY CAPITAL ADDITIONS?

A. System growth, capacity expansion, and replacement for normal wear and tear of our electric distribution assets and fleet vehicles drive the need for capital additions to the system in order to: (1) ensure safety, quality of service, and financial prudence, while also (2) satisfying environmental and other legal and regulatory requirements. These business drivers in turn influence the amount and type of infrastructure we need to provide service to our customers, including: poles, wires, cross-arms, protective equipment, meters, transformers, switches, and street light equipment. To ensure the health of our distribution system and to meet the needs of our new and existing customers, as a general matter the Distribution Business Area undertakes projects to either (1) support existing customers, or (2) provide electric service to new customers.

Q. WHAT ARE THE CORE CAPITAL BUDGET GROUPINGS THAT REFLECT THE DISTRIBUTION BUSINESS AREA'S GOALS AND DETERMINE ITS DISTRIBUTION INVESTMENTS?

A. The Distribution Business Area has a well-defined process for identifying and determining electric distribution investments within five capital budget groupings encompassing our business area responsibilities. These categories include:

- *Asset Health and Reliability:* Projects classified as Asset Health and Reliability are related to infrastructure that is reaching the end of its useful life and is experiencing high failure rates – and that, as a result, negatively impact reliability of service while increasing O&M expenses. It also includes public damage and efficiency programs. Distribution assets are monitored to ensure that they provide reliable service throughout the year. When poor-performing assets are identified, projects that will improve asset performance are included in the budget. Examples of these types of projects include replacing underground tap and feeder cable, Feeder Performance Improvement Program ("FPIP") projects along with other projects to address equipment and customers experiencing multiple interruptions. This category also includes replacement of wood poles and overhead lines that have reached the end of their useful life, replacing failed substation equipment, and replacing substation transformers and switchgear, and public damage.
- *Capacity:* This category includes all distribution system equipment associated with upgrading or increasing capacity to handle system load

growth and serve load under single contingency outage conditions (i.e., when one element of the distribution system is out of service). The work includes installation of new or upgraded substation transformers and distribution feeders. Capacity projects generally span multiple years and are necessitated by increased load either from existing customers or new customers. The investment varies between years depending on the type of work being completed. The installation of a brand new substation or the reconfiguration of an urban substation can be significantly more costly than additions to existing suburban substations. The Company prioritizes projects based on system need – which is defined as having enough available capacity to maintain the ability to serve additional load and the ability to provide backup support and switching capability when there is an outage. The Company will fund projects over its five-year budget period based on when a project is needed, the cost of projects, and actual spend. For instance, a capacity project in a high growth area could be funded sooner than a capacity project in a low growth area as the need is more immediate.

- *New Business:* This work includes new overhead and underground extensions and services associated with extending facilities to new customers, purchases of transformer and metering equipment, street lighting, and light-emitting diode ("LED") street lights. Projects required to support this growth include the installation of feeders, primary and secondary extensions, street lights and service laterals.

- *Mandates:* This category includes poles, wire, labor, and other costs associated with both the relocation of existing plant and the location of certain new plant, to meet federal, state, or local requirements. These projects include relocating facilities that are in direct conflict with street expansions within public right-of-ways ("ROW"), undergrounding of facilities as required by franchise agreements or other authority, and safety-related work required by a governing authority. These projects are normally identified during planning meetings with local communities. Examples of these projects include relocations for state and local governments such as the Central 70 project, which involves relocation across the I-70 corridor. These projects are monitored monthly and adjustments are made based on customer requests and any changes in operational mandates.
- *Fleet, Tools, and Equipment:* The Fleet, Tools, and Equipment category includes fleet, tools, ROW, land, communications, and locate costs associated with modifications or additions to the distribution system or supporting assets. Fleet costs represent the necessary replacement of vehicles and equipment that have become less reliable over time and more costly to maintain. ROW costs include capital additions associated with obtaining ROW and easements.

Within each of these categories, we identify both routine and individual projects based on the nature of the work we anticipate undertaking to continue to serve existing customers, and to meet the needs of new customers on our distribution system.

Q. PLEASE OUTLINE HOW THE DISTRIBUTION BUSINESS AREA IDENTIFIES AND FUNDS PROJECTS.

A. First, we prioritize, fund, and undertake those projects that are necessary to maintain Public Service's distribution system to enable Public Service to provide safe and reliable electric service to our existing customers. As noted above, Public Service's distribution system is extensive and it is necessary to make regular investments that support the ongoing health and reliability of the system. These projects can be routine or individual. Examples of individual projects include the Proactive Cable Replacement program, where we systematically replace cables that have failed, and Overhead Rebuild projects, including the conversion of 4 kV feeders to 13.2 kV. This allows us to increase the efficiency and reliability of our feeder level network. We also monitor, fund and undertake reconstruction investments for road moves, as necessary.

Second, we make investments necessary to expand our system to serve new customers on the system. These investments include equipment purchases and installation. Expansion of our distribution system may involve both overhead and underground extensions, and substation and distribution line projects.

To support continued reliable service to existing customers and extension of service to new customers, we also incur costs for fleet purchases, tool and equipment purchases, street lighting, ROW work, and facility locates.

Q. WHAT PROCESS DOES PUBLIC SERVICE FOLLOW TO MANAGE AND CONTAIN ITS DISTRIBUTION CAPITAL COSTS?

A. The engineering department within the Distribution Business Area monitors all Distribution capital dollars to ensure that authorized projects align with the established budget. We perform a monthly project forecasting exercise to ensure we have a steady and dependable flow of financial information regarding capital expenditures. We then compare our monthly expenditures to our budgets, and any variances are addressed. Any project that may be outside of allowed variances is reevaluated, and may be escalated to management or the corporate level as appropriate. Reviews are also performed to compare year-to-date actual performance with year-to-date and year-end forecasts. Deviations are identified and recommendations to meet financial targets are reviewed and approved.

There is often emergent work in the distribution area, due to storm damage or other unforeseeable circumstances. Given that, it is important that we have the flexibility to shift funding to meet changing circumstances that arise each year. When we have unexpected projects that require completion in a certain year, we fund these projects by deferring less urgent projects. This allows us to stay within our annual capital budget, while ensuring the safety and reliability of the distribution system – which is a top priority.

IV. DISTRIBUTION 2014-2018 CAPITAL ADDITIONS

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

A. The purpose of this section of my Direct Testimony is to discuss the major non-AGIS capital investments the Distribution Business Area has made since the Company's 2014 Electric Rate Case, in which a 2013 HTY was approved, that were placed into service through the end of 2018. I discuss the Company's 2019 actual and forecasted capital additions in Section V, below.

Q. WHAT IS THE TOTAL DOLLAR AMOUNT OF NON-AGIS DISTRIBUTION CAPITAL ADDITIONS THAT PUBLIC SERVICE IS REQUESTING IN THIS CASE?

A. As reflected in Attachment CSN-1, the Company placed into service approximately $1.294 billion (Total Company) for non-AGIS related Distribution Business Area capital additions for 2014-2018 (Total Company). Note that Attachment CSN-1 contains Distribution capital additions inclusive of the AGIS-related capital additions as well.

Q. PLEASE PROVIDE AN OVERVIEW OF PUBLIC SERVICE'S DISTRIBUTION PLANT ADDITIONS FROM 2014 THROUGH 2018.

A. The Table below reflects Distribution capital additions, placed in service from 2014 through 2018, broken down by budget grouping. I discuss these capital additions by budget group below.

Table CSN-D-1
Distribution Capital Additions 2014-2018
(Total Company)
(Dollars in Millions)

Distribution Capital Additions 2014–2018*					
Category	**2014**	**2015**	**2016**	**2017**	**2018**
Asset Health and Reliability	$83.8	$111.5	$119.0	$100.8	$87.7
Capacity	$79.4	$50.4	$31.2	$31.4	$62.5
New Business	$55.2	$50.3	$64.7	$74.3	$95.6
Mandates	$18.2	$16.7	$22.0	$18.5	$26.2
Fleet, Tools, and Equipment	$12.9	$22.9	$14.4	$18.5	$26.0
Total**	$249.5	$251.8	$251.2	$243.4	$298.0

* This table does not include Distribution's AGIS-related capital additions, which are discussed separately in Section VIII and shown in Table CSN-D-7.
** There may be differences between the sum of the individual category amounts and Total amounts due to rounding.

These figures are stated on a Total Company (Public Service) basis, meaning that they include both electric utility-specific projects and common electric/gas projects stated at the total Public Service level.

Below I discuss the Company's 2014–2018 capital additions by driver category. I address the Company's 2019 planned capital additions in Section V, below.

A. Asset Health and Reliability

Q. PLEASE DISCUSS THE PRIMARY DRIVERS OF DISTRIBUTION CAPITAL ADDITIONS RELATED TO ASSET HEALTH AND RELIABILITY SINCE THE 2013 HTY.

A. The primary drivers affecting the Company's capital additions related to Asset Health and Reliability since the 2013 HTY fall into two categories – "routine in nature," and "larger specific projects." Over several years prior to and through 2014, the Company reviewed the age profile and overall reliability performance of key components of the distribution system (substation transformers and circuit breakers, overhead lines, wood poles, and underground cables). As a result of this review, we concluded that Public Service must increase the level of annual replacements of these key components to maintain the existing condition and reliability of the distribution system. We then developed replacement plans for these key components and utilized this data to develop our budget to address the long-term asset health of these components. This work has helped to enable a systemic, efficient replacement program.

Q. ARE THERE OTHER FACTORS THAT HAVE IMPACTED CAPITAL ADDITIONS IN THIS AREA?

A. Yes. Instances of more severe weather events have increased and, with it, capital expenditures associated with storm-related damage. For instance, the Company's 2016 storm-related capital spend was about $6 million above Public Service's annual average, and these expenditures were largely placed in service in 2017. Likewise, the Company replaced several substation transformers (Substation Category) in 2016 due to failures, which were completed and went into service in early 2017. This had the effect of raising 2017 capital additions in these categories above the levels we have historically experienced.

Within the Asset Health Budget group, capital additions can be further classified into the following categories: Overhead Rebuild/Poles, Cable Replacement and Assessment, Substation, and Underground Conversions. I will address each in turn.

Q. PLEASE DESCRIBE CAPITAL ADDITIONS RELATED TO OVERHEAD REBUILD/POLES SINCE THE 2014 ELECTRIC RATE CASE.

A. Public Service's distribution system has nearly 9,600 miles of overhead lines and over 400,000 poles serving our distribution customers. The Overhead Rebuild/Poles category refers to the replacement, rebuild, and refurbishment of overhead feeder, tap and secondary lines. This may include replacing a single pole or cross-arm, or completely rebuilding a section of line. The grouping contains a program to proactively rebuild aged and overhead lines that are reaching their end of life to improve service and reliability to our customers. The specific rebuild projects are determined by an engineering review of previous line performance and reliability measures, as well as visual inspection by qualified line personnel to evaluate the condition of the equipment. This category also includes storm costs incurred as a result of weather events that impact service to our customers. In 2018, for example, the Company placed $19.5 million in capital additions in service related to Overhead Rebuild/Poles.[1]

Q. CAN YOU DESCRIBE THE COMPANY'S POLE REPLACEMENT PROGRAM IN MORE DETAIL?

A. Yes. Public Service owns over 400,000 distribution poles in the state of Colorado. The average useful life of a pole is around 80 years. The goal is to replace poles prior to failure, but at or near the end of their useful life.

Q. HOW DOES PUBLIC SERVICE DETERMINE WHAT POLES TO REPLACE?

A. The Company tests its poles on a 12-year inspection cycle, which amounts to approximately 8.3 percent of our poles each year. Actual poles inspected each year can vary depending on a variety of factors including the rate of poles rejected in each region of the Company. In 2018, the Company experienced a reject rate (referring to a pole that has failed testing and needs to be either replaced or reinforced to ensure the physical integrity of the pole) of around 6.8 percent.

Q. WHAT IS INCLUDED IN THE CABLE REPLACEMENT AND ASSESSMENT CATEGORY LISTED IN ATTACHMENT CSN-1?

A. Public Service's distribution system has over 13,000 miles of underground cable. The Cable category refers to the replacement of portions of this underground cable that have failed and thus reached the end of their useful life. The specific sections of cable selected for replacement are chosen based on reliability date,

[1] These are labeled as "OH Rebuilds" in Attachment CSN-1.

failure history, and in some cases, by historical performance of similar types and vintages of cable.

Q. PLEASE DESCRIBE THE COMPANY'S CABLE REPLACEMENT PROGRAMS.

A. The Company has three main cable replacement programs, the replacement of what is referred to as URD cable or tap level cable, the proactive replacement of feeder or mainline cable, and the emergency replacement of feeder or mainline cable. Cable failures are a main contributor to outages for customers who are served by underground facilities. As part of the Company's asset renewal program, the replacement of underground cable is one of the key targeted assets. Nearly one-fifth of the Company's underground cable is a type of cable (non-jacketed cross-linked polyethylene ("XLPE") cable) and vintage (installed prior to 1990) that is more prone to failures and has shorter useful life (approximately 45 years) than newer cable types. Since 2012 the Company has been able to reduce the number of cable failures when compared to predicted failures with its continued investment in cable replacement.

Given the critical nature of the service we provide and the disruptive impact an outage can have, we intend to continue to invest in our cable replacement programs with the aim of improving reliability for our customers. In 2018, for example, the Company placed more than $43.4 million in capital additions into service related to replacing underground cable[2] that reached the end of its useful life.

Q. PLEASE DESCRIBE THE COMPANY'S SUBSTATION CAPITAL ADDITIONS.

A. Replacing substation equipment can mitigate some of the greatest reliability risks to our customers. Public Service has 151 substations that have distribution equipment and 278 transformers that include other substation equipment like breakers and switchgear. The substation category refers to the replacement of transformers, breakers, switchgear, and other substation equipment that has either failed or has reached the end of its useful life. The specific equipment that is chosen to be proactively replaced is managed by our Substation System Performance group based on the age, condition, and by historical performance of similar types of equipment. The 2018 capital additions, for instance, included replacement of transformers at the Arvada Substation, Romeo Substation (located in San Luis Valley area), substation breakers that reached the end of their useful lives, and renewal of other general substation equipment.

Q. PLEASE DESCRIBE THE COMPANY'S UNDERGROUND CONVERSION CAPITAL ADDITIONS.

A. Public Service has over 9,500 miles of overhead line and more than 13,000 miles of underground line serving our distribution customers. The Underground Conversion category primarily refers to the conversion of distribution lines from overhead to underground. This category is also used to describe work to

[2] These are labeled as "Cable Replacement and Assessment" in Attachment CSN-1.

upgrade and replace underground equipment based on the age, performance, and condition. The need for conversion may be driven by customer request, redevelopment requirements, franchise requirements, or the condition of the equipment. In this way, these capital additions are often outside of the Company's control. That said, the Company also has a program to proactively replace aged network protectors and isolation boxes that have reached the end their useful life in our Downtown Denver underground network system. Proactively replacing these pieces of equipment helps maintain safe working conditions for our employees, and also avoids reliability risk to network customers. Another program within this category is the replacement of switch cabinets. These cabinets typically serve customer load in residential areas, and failure may result in extended outages to many customers. As an illustrative example, the Company placed $18.1 million in capital additions in service related to Underground Conversions in 2018.[3]

B. <u>Capacity</u>

Q. PLEASE DISCUSS THE PRIMARY DRIVERS OF DISTRIBUTION CAPITAL ADDITIONS RELATED TO CAPACITY SINCE THE 2013 HTY.

A. The primary drivers of the Company's capital additions related to Capacity projects since the 2013 HTY include new substations, expansion of existing substations, addition of new feeders, and upgrades of existing equipment. Capacity projects generally involve fewer projects and are typically the

[3] These are labeled as "UG Conversions" in Attachment CSN-1.

Company's largest distribution capital expense. As a result, there is some variation year over year in capital additions, based on the cost and magnitude of projects and when projects go in-service. The annual capital expenditures from 2014-2018 have been relatively flat, typically in the $50-60 million range; however, these capital additions can fluctuate annually due to the size and duration of each project. Below are illustrative examples of some of the Capacity projects Public Service placed into service in 2018.

- *Sullivan #3 Project:* The Sullivan #3 Project included the addition of a third transformer and associated substation equipment and feeders at Sullivan Substation in Denver. The purpose of the project was to resolve existing system risks and to provide additional capacity to serve future load growth. The Company placed $16.8 million in service in 2018 for the distribution portion of the project, of which $11.1 million includes a substation transformer and the associated substation equipment, and $5.8 million in feeder costs.
- *Moon Gulch Substation Project:* The Moon Gulch Project is a new distribution substation in Arvada. The purpose of the project was to provide additional capacity to serve load growth and development and to provide back-up and load transfer services to other substations in the area. The Company filed a CPCN application on November 25, 2015 in Proceeding No. 15A-0929E, and the Commission granted the CPCN on January 20, 2016. The Company placed $14.5 million of capital additions in service in 2018, which consists of

the new substation, a 50 Mega Volt Amp ("MVA") transformer and the associated substation equipment, and two new feeders.

- *Arrowhead Lake # 2 Project:* The Arrowhead Lake #2 Project included the addition of a second transformer and the associated substation equipment and feeders at Arrowhead Lake Substation in Greeley. The project was designed to add capacity and support the removal and decommissioning of a 44 kV substation called Highlands. The Company placed $11.9 million in capital additions in service in 2018, which consists of the new substation, a 50 MVA transformer and the associated substation equipment, and two new feeders. The project is part of the overall Greeley master plan and removal of the 44 kV system which is needed to increase the reliability and load serving capability in and around the Greeley area.[4]

C. <u>New Business</u>

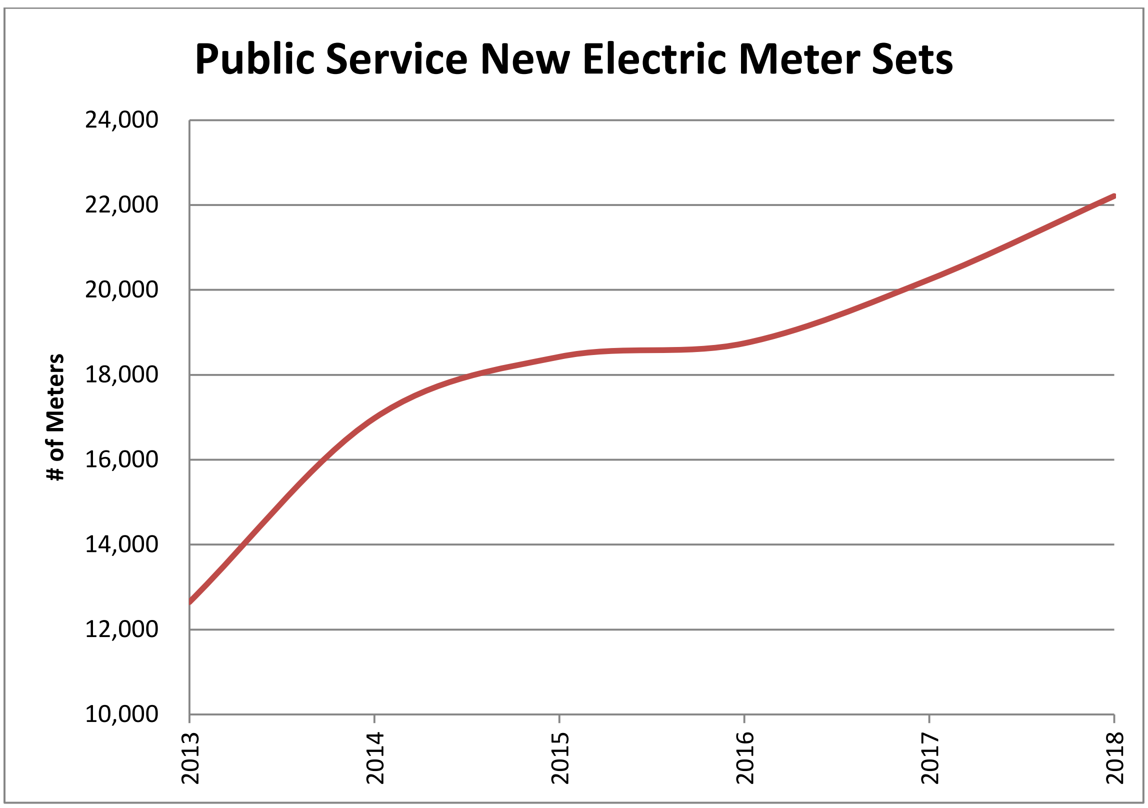
Q. PLEASE DISCUSS THE PRIMARY DRIVERS OF DISTRIBUTION CAPITAL ADDITIONS RELATED TO NEW BUSINESS FROM THE 2013 HTY THROUGH 2018.

A. The primary drivers of the Company's capital additions related to New Business projects since the 2013 HTY fall into four main categories – extensions, contribution in aid of construction ("CIAC"), street lights, and purchases of meters and transformers to support new business and replacements. New business

[4] See, e.g. Proceeding No. 17A-0146E, *In Re Public Service Application for Order Granting a Certificate of Public Convenience and Necessity for the Northern Greeley Area Transmission Plan Project* (filed Mar. 9, 2017).

needs are highly dependent on the state of the economy which, in turn, drive the number of requests for new service. Over the past several years, our new business investments have steadily increased. This increase is driven by growth in new housing construction, which is largely driven by strong economic conditions in Colorado. As reflected in Figure CSN-D-1 below, between 2014 and 2018, the number of annual new meter sets has risen from 16,978 to 22,211 respectively, representing a 30 percent increase over a four-year period.

Figure CSN-D-1
Public Service New Meter Sets – 2013-2018



Other factors that have driven capital additions from 2014 include a decrease in CIAC credits from expiring extensions which has decreased 2014 levels by more than $13 million or by about 55% (as explained in more detail below) and increases due to inflation and new customers requesting service within the Company's service territory.

Q. PLEASE DESCRIBE IN MORE DETAIL THE COMPANY'S CAPITAL ADDITIONS FOR EXTENSIONS AND "EXPIRING EXTENSIONS."

A. New housing growth necessitates new overhead and underground line extensions and associated service materials to serve new customers (including projects required to support this growth include the installation of feeders, primary and secondary extensions, and service laterals). Regarding the reduction in credits from expiring extensions, as described in the Company's electric tariffs, the "open extension period" is a ten-year span during which the Company calculates and pays refunds of customer construction payments according to provisions of this extension policy. At the end of the ten-year period, any remaining open extensions not credited back to customers are credited back to Distribution capital and offset some of the investments the Company makes on an annual basis. In recent years, there has been a decrease in credits for expiring extensions from a reduction in CIAC collected due being ten years out from the global recession and economic downturn starting in 2008.

Q. PLEASE DESCRIBE THE COMPANY'S CAPITAL ADDITIONS RELATED TO STREET LIGHTING.

A. The street lighting category includes any new street or area lights placed into service in 2018, as well as the reconstruction or rebuilding of street or area lights. Streetlight reconstruction or rebuild may include street lights that require replacement due to adverse weather impacts, public damage, or failed equipment.

Q. PLEASE DESCRIBE THE COMPANY'S CAPITAL ADDITIONS RELATED TO TRANSFORMERS.

A. The transformers category includes the purchase and installation costs of any distribution transformer and voltage regulator necessary to serve new or existing customers. Transformer purchases are primarily needed to serve new customers. Transformers in some instances require replacement due to increased customer demand, load, or in the event an existing transformers fails or malfunctions.

Q. PLEASE DESCRIBE THE COMPANY'S METER CAPITAL ADDITIONS.

A. The meters category includes the purchase and installation costs of distribution meters necessary to serve new or existing customers. Meter purchases are primarily for new customers in order to measure demand and energy at the point of delivery. Meters in some instances require replacement due to increased customer demand, load, or in the event an existing meter fails or malfunctions.

D. Mandates

Q. PLEASE DISCUSS THE PRIMARY DRIVERS OF DISTRIBUTION CAPITAL ADDITIONS RELATED TO MANDATES SINCE THE 2013 HTY.

A. The primary drivers of the Company's capital additions related to Mandate projects since the 2013 HTY generally fall into two main categories – relocating facilities that conflict with street expansions within public ROW and undergrounding facilities as pursuant to franchise agreements or other authorities. Similar to the New Business category, the volume of facility relocation projects is directly correlated to the state of the economy, which has been strong over the past five years. Examples of relocations include relocations of facilities in coordination with the Colorado Department of Transportation ("CDOT") Central 70 project and electric distribution facilities that need to be relocated to accommodate the new alignment of I-70. Expenditures for undergrounding facilities pursuant to franchise agreements have generally remained flat year over year. Along with meeting our franchise requirements, these projects provide benefits to our customers in the form of a more reliable, resilient system, renewal of existing assets, and improved aesthetics.

Q. PLEASE EXPLAIN WHAT UNDERGROUNDING PROJECTS ARE.

A. Through franchise agreements the Company signs with local jurisdictions, the Company will underground existing overhead lines at the request of the local jurisdiction. As an illustrative example, the Company placed $14.7 million of capital additions in service related to undergrounding projects pursuant to franchise agreements in 2018.

Q. PLEASE DESCRIBE RELOCATION PROJECTS.

A. This category includes routine projects that consist of poles, wire, labor, and other costs associated with both the relocation of existing plant and the location of certain new plant, to meet federal, state, or local requirements. These projects include relocating facilities that are in direct conflict with street expansions within public ROWs, undergrounding of facilities as required by franchise agreements or other authority, and safety-related work required by a governing authority.

E. Fleet, Tools, and Equipment

Q. PLEASE DISCUSS THE PRIMARY DRIVERS OF DISTRIBUTION CAPITAL ADDITIONS RELATED TO FLEET, TOOLS, AND EQUIPMENT SINCE THE 2013 HTY.

A. The primary drivers of the Company's capital additions related to Fleet, Tools, and Equipment since the 2013 HTY generally fall into five categories – fleet purchases, tools purchases, substation communication equipment, electric locates, and acquisition of ROW for distribution equipment. The capital expenditures within this category have generally been flat year over year, though the timing of in-servicing some of the larger fleet vehicles (such as bucket trucks) occasionally leads to variances. For example, the primary increase within this category is based on timing on fleet vehicles that were purchased at the end of

2017, but not in-serviced until 2018 (once the vehicles were "road ready") along with the fleet vehicles that were purchased and in-serviced in 2018.

Q. WHAT DO YOU CONCLUDE REGARDING THE COSTS FOR THE DISTRIBUTION BUSINESS AREA CAPITAL PROJECTS THAT WENT INTO SERVICE BETWEEN 2014 AND 2018?

A. I conclude that these capital additions have been prudently incurred, reasonable in cost, and used and useful in supporting Public Service's ability to provide safe and reliable electric service to its customers.

V. DISTRIBUTION 2019 CAPITAL ADDITIONS

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

A. The purpose of this section of my Direct Testimony is to provide an overview of the Distribution Business Area's forecasted capital additions not related to AGIS or the Company's Wildfire Mitigation Plan for 2019.

Q. PLEASE DESCRIBE THE 2019 DISTRIBUTION CAPITAL ADDITIONS YOU AER SUPPORTING FOR INCLUSION IN THIS RATE REVIEW.

A. I am supporting $205.9 million in Distribution-related capital additions not related to AGIS or the Wildfire Mitigation Plan for inclusion in the 2018 HTY cost of service. Table CSN-D-2 below provides a breakdown of these capital additions by budget group.

Table CSN-D-2
Distribution Capital Additions 2019
(Total Company)
(Dollars in Millions)

Distribution Capital Additions 2019*	
Category	**2019**
Asset Health and Reliability	$96.1
Capacity	$79.2
New Business	$0.0
Mandates	$24.3
Fleet, Tools, and Equipment	$6.4
Total**	$205.9

* This table does not include Distribution's AGIS-related capital additions, which are discussed separately in Section VIII and shown in Table CSN-D-7.
** There may be differences between the sum of the individual category amounts and Total amounts due to rounding.

Below I describe these capital additions by budget group (using the same budget groups as above, in Section IV, for the period 2014–2018), and describe approximately 90 percent of the portfolio of the Company's 2019 Distribution capital additions requested in this proceeding.

A. Asset Health and Reliability

Q. PLEASE DESCRIBE THE COMPANY'S DISTRIBUTION CAPITAL ADDITIONS RELATED TO ASSET HEALTH AND RELIABILITY IN 2019.

A. As discussed above in Section IV.A, within the Asset Health budget group, most capital additions fall into the following categories: Overhead Rebuild/Poles, Cable Replacement and Assessment, Substation, and Underground Conversions. The activities undertaken by Distribution for each of these categories is described above in Section IV.A.

Total capital additions for Asset Health and Reliability projects for 2019 will be $96.1 million, which is in-line with previous years and is representative of the continued execution on the Company's asset health and reliability programs. Capital additions by category include $23.4 million for Overhead Rebuild/Poles, $41.2 million for Cable Replacement and Assessment, $11.3 million for Substation, $18.0 million Underground Conversions, and $2.2 million for Network Protectors.

B. <u>Capacity</u>

Q. PLEASE DISCUSS THE COMPANY'S DISTRIBUTION CAPITAL ADDITIONS RELATED TO CAPACITY IN 2019.

A. The primary categories of the Company's capital additions related to Capacity projects include: new substations, expansion of existing substations, addition of new feeders, and upgrades of existing equipment. As noted above in Section IV.B, Distribution generally has fewer capacity projects at any given time, and these projects are typically the Company's largest distribution capital expenses. As a result, there is some variation year over year in capital additions, based on the cost and magnitude of projects and when projects go in-service.

Total capital additions for Capacity projects in 2019 will be $79.2 million. Key projects related to Capacity in 2019 include:

- *Thornton Project:* The Thornton Project is a new distribution substation in Thornton. The project includes the construction of a new substation in Thornton and the extension of the Fort-Lupton – Cherokee 115 kV transmission line to feed the substation.

  The distribution portion of the project consists of installing a single 115 kV/13.8 kV 50 MVA distribution transformer and the associated substation equipment, and will ultimately include two new distribution feeders. The purpose of the project is to provide additional capacity to serve load growth and development and to provide back-up and load transfer services to existing substations in the area.

  The new substation site is located on the southeast corner of 120th and Holly Street, and the Company closed on the land on July 31, 2017, which placed the land in service in 2017. When complete, the site will include landscaping and an architectural wall that will have a similar architectural look as the Anything Library across the street.

  The Company filed a CPCN on October 3, 2014 in Proceeding No. 14A-1002E and the CPCN was granted on April 29, 2015. For the distribution portion of the project, the Company is forecasting $22.7 million in capital additions to be placed into service in 2019.

- *Ennis Substation Project:* The Ennis Substation Project includes the addition of a new transformer and associated substation equipment and feeders at Ennis Substation in Keensburg. The purpose of the project is to provide additional capacity to serve a single large oil and gas customer in the area. The Company is planning to place $7.9 million in service in 2019 for the distribution portion of the project, of which $7.1 million includes a substation transformer and the associated substation equipment, and $0.8 million in feeder costs.

- *Rosedale #3 Project:* The Rosedale #3 Project included the addition of a new transformer and associated substation equipment and feeders at Rosedale Substation in Greeley. The purpose of the project was to resolve existing system risks, to provide additional capacity to serve future load growth, and to support the removal and decommissioning of a 44 kV substation Evans. The Company is planning to place $11.0 million in service in 2019 for the distribution portion of the project, of which $6.6 million includes a substation transformer and the associated substation equipment, and $4.4 million in feeder costs.
- *Picadilly #2 Project:* The Picadilly #2 Project includes the addition of a new transformer and associated substation equipment and feeders at Picadilly Substation in Aurora. The purpose of the project is to resolve existing system risks and to provide additional capacity to serve future load growth. The Company is planning to place $5.2 million in service in 2019 for the substation transformer and the associated substation equipment.
- *Pleasant Valley Substation Project:* The Pleasant Valley Substation Project includes a new 115kV substation called Cloverly Substation and is part of the

Northern Greeley Area Plan that received a CPCN from the Commission in Proceeding No. 17A-0146E. The purpose of the project is to support the decommissioning of the existing 44 kV Pleasant Valley substation and transmission lines which ultimately will improve the reliability and load serving capabilities in the area. The Company is planning to place $6.0 million in service in 2019 for the substation transformer, the associated substation equipment, and the distribution feeders.

- *Alamosa Terminal Substation Project*: The Alamosa Terminal Substation Project includes a new transformer and associated substation equipment and feeders at Alamosa Terminal Substation in Alamosa. The purpose of the project is to resolve existing system risks, replace existing substation equipment that is nearing the end of useful life, and to provide additional capacity to serve future load growth. The Company is planning to place $3.9 million in service in 2019 for the substation transformer and the associated substation equipment.

Q. HOW WERE COSTS FOR THE THORNTON PROJECT ADDRESSSED IN THE COMPANY'S CPCN FILING?

A. In its CPCN Application filed in Proceeding No. 14A-1002E, the Company estimated project costs at $32.7 million, plus or minus 30 percent for the substation, transmission, and distribution feeders, with siting and land costs excluded. Highly Confidential Attachment JDL-1, attached to the Direct Testimony of John Lupo filed in Proceeding No. 14A-1002E, included the total cost of the project which included land costs. The costs were highly confidential as the Company was still in negotiations to acquire the property at the time. This information is no longer highly confidential as the property for the substation has been acquired. With siting and land costs included, the Company estimated project costs to be $34.2 million, plus or minus 30 percent.

Q. HAS THE THORNTON PROJECT INCREASED IN COST SINCE THE COMMISSION ISSUED A CPCN?

A. Yes. The project costs have increased for several reasons. As Company witness Ms. Kelly Bloch explained in her Direct Testimony (page 14 lines 7-17) in the CPCN proceeding (Proceeding No. 14A-1002E), the costs estimated in the CPCN were highly dependent on the location of the substation site. The Company's cost estimates in the CPCN application were based on its preferred siting area, which was located on the southeast corner of 136th Avenue and Holly Street. After receiving its CPCN, the Company encountered local opposition from the adjacent neighborhood, and was simultaneously approached by a nearby landowner about an opportunity to purchase a nearby parcel being annexed to the City of Thornton. Accordingly, the Company decided not to pursue local land use permits at its preferred site. The new site has resulted in higher land costs and higher site development costs that include landscaping, a detention pond, and other general development costs. This has increased the project cost by approximately $5.5 million. The other major driver has been the engineering, staff, and consulting support for siting the new substation. The project spend for siting and engineering support (excluding the land costs of the 136th Avenue and Holly Street site) was approximately $5 million through the end of 2016.

Q. CAN YOU PROVIDE AN UPDATE ON THE THORNTON PROJECT?

A. Yes. The Company's local land use permits for the 120th Avenue and Holly Street site were approved by the Thornton City Council on July 11, 2017, the Company successfully acquired the land on July 31, 2017, and the Company's local land use permits for the transmission transition structures were approved by Adams County on August 24, 2017. The Company has received all the necessary approvals, started construction in 2018, and is anticipating the substation will be placed in service in June 2019.

C. <u>New Business</u>

Q. ARE YOU SUPPORTING ANY CAPITAL ADDITIONS FOR DISTRIBUTION NEW BUSINESS IN 2019?

A. No. The New Business category contains projects that are revenue-producing, such as new overhead and underground extensions, extensions to serve new customers, purchases of transformer and metering equipment, and streetlighting. As explained in more detail in the Direct Testimony of Ms. Trammell, the Company is not including 2019 New Business capital additions that are revenue-producing in our 2019 capital reach request as an attendant impact of the Company's requested capital reach. This adjustment to the capital reach recognizes and accounts for the fact that certain new capital additions can be directly attributed to incremental revenue.

D. <u>Mandates</u>

Q. PLEASE DESCRIBE THE DISTRIBUTION CAPITAL ADDITIONS RELATED TO MANDATES IN 2019.

A. The Company's capital additions related to Mandate projects in 2019 generally fall into two main categories: relocating facilities that conflict with street expansions within public ROW and undergrounding facilities as pursuant to franchise agreements or other authorities. Similar to the New Business category (discussed in Section IV above), the pervasiveness of facility relocation projects are generally dependent on the state of the economy, which has been strong over the past several years. The activities undertaken by Distribution for each of these categories is described above in Section IV.D.

Total capital additions for Mandates projects for 2019 will be $24.3 million, which is down by $1.9 million from 2018 levels. Capital additions by categories include $13.0 million for undergrounding facilities pursuant to franchise agreements, and $11.3 million for relocation of facilities in conflict with street expansions projects (including $2.2 million of relocations for the Central 70 project, which is described above in Section IV.D).

E. Fleet, Tools, and Equipment

Q. PLEASE DISCUSS THE CATEGORIES OF DISTRIBUTION CAPITAL ADDITIONS RELATED TO FLEET, TOOLS, AND EQUIPMENT FOR 2019.

A. The categories of the Company's capital additions related to "Fleet, Tools, and Equipment" have changed in 2019. Starting this year, Fleet purchases were moved from individual business unit budgets (such as Distribution) to Operations Services (which falls within the Shared Corporate Services Business Area) to gain efficiencies across the Xcel Energy operating companies for Fleet purchases. Accordingly, 2019 capital additions for Fleet purchases are supported in the Direct Testimony of Mr. Adam R Dietenberger. The remaining categories remain unchanged and include: tools purchases, substation communication equipment, electric locates, and acquisition of ROW for distribution equipment. As discussed above in Section IV.E, these expenditures have generally been flat year over year, though the timing of in-servicing some of the larger fleet vehicles (such as bucket trucks) occasionally had resulted in variances in the timing of plant additions.

Total capital additions for Tools, and Equipment for 2019 will be $6.4 million. Of the decrease from 2018 levels, $16.1 million can be attributed to Fleet purchases, which have been moved from the individual business areas (such as Distribution) to Operations Services.

Q. HAS THE COMPANY, AND WILL THE COMPANY, MANAGE ITS PROJECTED DISTRIBUTION BUSINESS AREA-RELATED CAPITAL ADDITION PROJECTS IN 2019 TO ENSURE THE FINAL, ACTUAL COSTS ARE REASONABLE AND PRUDENT?

A. Yes.

VI. DISTRIBUTION O&M

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

A. The purpose of this section of my testimony is to provide an overview of the Distribution Business Area non-AGIS O&M expenses, followed by a discussion of the 2013 HTY compared to actual 2018 Distribution Business Area O&M expenses, which the Company proposes to utilize as the primary basis for establishing Distribution O&M levels included in rates going forward. I also describe the drivers of O&M cost increases between 2013 and 2018, if applicable.

Q. WHAT ARE THE TYPES OF COSTS THAT THE DISTRIBUTION BUSINESS AREA INCURS FOR O&M?

A. To support the Company's Distribution assets, a variety of O&M work is performed by the Distribution Business Area. Distribution's O&M expenses includes labor costs associated with maintaining, inspecting, installing, and constructing distribution facilities such as poles, wires, transformers, and underground electric facilities. It also includes labor costs related to programs that include vegetation management, pole inspection, cable repairs, and damage prevention. Finally, it includes transportation costs and miscellaneous materials and minor tools necessary to build out, operate and maintain our electric distribution system. Specifically, the O&M component of fleet includes those expenses necessary to maintain our existing fleet. This includes annual fuel costs plus the allocation of fleet support to O&M based on the proportion of the distribution fleet utilized for O&M activities as compared to capital projects.

The O&M expenses can be further broken down into the following six categories:

- *Internal Labor*: Internal labor costs are the employee costs associated with maintaining, inspecting, installing, and construction distribution facilities such as poles, wires, transformers, and underground electric facilities.
- *Contract Labor*: Contract labor costs are the costs associated with the use of contractors to support more specialized or seasonal tasks such as tree trimming, pole inspections, storm response, and underground facility location.
- *Materials*: Material costs are the material costs for maintaining and operating the distribution system such as braces, insulators, cross-arms, and splices.
- *Transportation*: Transportation costs are the costs associated with the use and maintenance of our fleet vehicles that is necessary to operate and maintain our electric distribution system.
- *Other*: Other costs include costs associated with employee expenses and miscellaneous expenses.
- *First Set Credits*: Consistent with general utility practice, Public Service capitalizes its transformers and meters when they are purchased (including the labor and transportation to install them). When the transformers and meters are purchased a credit is applied to O&M upon purchase to account for the expenses to install this equipment later. By providing this O&M credit,

we mitigate the double-counting that would occur for the installation of the equipment.

As I describe in more detail below, over 83 percent of the 2018 Distribution O&M expenses are related to employee and contract labor. The remaining portions are comprised of fleet, materials, tools, employee expenses, and first set credits as explained above.

Q. PLEASE PROVIDE AN OVERVIEW OF PUBLIC SERVICE'S DISTRIBUTION O&M EXPENSES SINCE ITS LAST 2014 ELECTRIC RATE CASE, WHICH WAS BASED ON A 2013 HTY.

A. Table CSN-D-3, below, identifies the amount of overall O&M costs by the categories I listed above. Attachment CSN-3 and Attachment CSN-4 provide an accounting of these expenses by Cost Element and by FERC account (not including AGIS), respectively.

Table CSN-D-3:
Distribution 2018 versus 2013 Actual O&M Expenses
Public Service Electric
(Dollars in Millions)

Distribution 2018 versus 2013 Actual O&M Expenses (Dollars in Millions)*			
Cost Category	**2013**	**2018**	**Difference**
Internal Labor	32.5	39.1	6.6
Contract Labor	42.7	60.7	18.0
Materials	8.9	7.4	(1.5)
Transportation	7.5	8.3	0.8
Other	3.7	4.9	1.2
First Set Credits	(7.4)	(15.0)	(7.6)
Total*	**87.9**	**105.4**	**17.5**

*There may be differences between the sum of the individual category program amounts and Total amounts due to rounding.
** Dollar figures in this Table do not include AGIS-related O&M expenses.

Q. WHAT IS THE TOTAL DOLLAR AMOUNT OF DISTRIBUTION O&M THAT YOU ARE SUPPORTING IN THIS CASE?

A. As reflected in Attachment CSN-3, I support $105.4 million of O&M expenses (pre-adjustments) not related to AGIS. Attachment CSN-3 provides an accounting of these expenses by Cost Element and Attachment CSN-4 provides the O&M by FERC account.

Q. IS THE $105.4 MILLION (PRE-ADJUSTMENTS AND EXCLUDING AGIS) IN 2018 O&M COSTS YOU DESCRIBE IN TABLE CSN-D-3 ABOVE REFLECTED IN THE 2018 HTY COST OF SERVICE PRESENTED BY MS. BLAIR?

A. Yes.

Q. WHAT ARE THE MAJOR DIFFERENCES BETWEEN THE DISTRIBUTION BUSINESS AREA'S 2013 HTY AND 2018 ACTUALS?

A. Three major drivers explain the increase of $17.5 million in O&M expenses from 2013 to 2018. These are:

- Internal Labor has increased by $6.6 million from 2013 to 2018. The average annual internal labor wage increase has been approximately 3 percent and is the primary driver of the 2013 to 2018 increase.
- Contract Labor has increased by $18.0 million from 2013 to 2018. Approximately $7 million is representative of the increase of the contract labor necessary to install transformers and meters, which is offset by the increase in credits for first set credits. Other increases include general inflation over the five-year period (around $6.8 million) and the O&M expenses associated with contract designers necessary to meet the increased amount of work the Company is conducting on an annual basis, particularly to serve new customers.
- Material costs have decreased by $1.5 million from 2013 to 2018. Material costs incurred tend to fluctuate year over year dependent on the type of O&M activities and the materials necessary to maintain and operate the electric distribution system.
- Transportation costs have increased by $0.8 million from 2013 to 2018. Transportation costs tend to fluctuate year over year dependent on the cost of fuel and maintenance of fleet vehicles that is required in a given year.

- Other costs have increased by $1.2 million from 2013 to 2018 and includes costs for employee expenses, safety equipment, and miscellaneous costs.
- First Set Credits have increased by $7.6 million from 2013 to 2018, which is representative of the increase in meters and transformer purchases needed to meet an increased number of meter sets (and the number of new customers) between 2013 and 2018. The number of meter sets increased by over 9,500 meters during this time period due to the strong economic growth in Colorado, as described in more detail in the New Business section of my Direct Testimony.

Q. IS THE COMPANY PROPOSING KNOWN AND MEASURABLE ADJUSTMENTS TO ITS 2018 TEST YEAR COST OF SERVICE?

A. Yes. The Company is proposing an adjustment of $5.3 million to eliminate the incremental Distribution O&M expenses associated with Mutual Aid to Puerto Rico the Company provided after Hurricane Irma in 2018. The expenses included contract labor, employee expenses, internal over-time labor, materials, and fleet as part of the Company's effort to help restore Puerto Rico's electric grid after Hurricane Irma. Adjustments related to aid to Puerto Rico are discussed by Company witness Ms. Blair. I discuss the Company's proposed Wildfire Mitigation adjustment in Section VII below, and AGIS O&M in Section VIII below.

Q. IS THERE ANYTHING ELSE YOU WOULD LIKE TO DISCUSS RELATED TO THE COMPANY'S 2018 DISTRIBUTION O&M?

A. Yes, there is one compliance item from a previous proceeding I would like to mention. In accordance with the Non-Unanimous Comprehensive Settlement Agreement ("Settlement Agreement") approved in consolidated Proceeding Nos. 16AL-0048E, 16A-0055E, and 16A-0139E, Public Service committed to developing a study (the "Red Light / Green Light" demarcation study) to make available possible interconnection points on its system for Community Solar Gardens ("CSG").[5] The Settling Parties believed that certain constraints on the Company's distribution system may create an opportunity for Public Service to assist CSG developers in siting CSG facilities. Under the terms of the Settlement Agreement, the Settling Parties agreed that Public Service should receive deferred accounting treatment for the monies needed to complete the study, the cost of which would be capped at $250,000. The Settling Parties further agreed that the recovery methodology would be determined at the time the Company requested recovery through rates.

Public Service initiated the Red Light / Green Light demarcation study in June 2017 and presented the results of the study on its website and introduced it to certain stakeholders in June 2018. The Red Light / Green Light study was completed internally by the Company meaning that there were no incremental

[5] Proceeding Nos. 16AL-0048E, 16A-0055E, and 16A-0139E, Non-Unanimous Comprehensive Settlement Agreement, pp. 61–62 (filed Aug. 15, 2016).

costs incurred to produce the study. Therefore, the Company is not requesting separate treatment for the internal costs to produce the study.

Q. IS THE 2018 DISTRIBUTION O&M, SUBJECT TO ADJUSTMENTS YOU IDENTIFIED, A REASONABLE BASIS ON WHICH TO ESTABLISH O&M COSTS FOR THE TEST YEAR?

A. Yes.

Q. ARE THESE O&M EXPENSES REASONABLE AND NECESSARY TO CARRY OUT THE DISTRIBUTION BUSINESS AREA'S KEY FUNCTIONS YOU DESCRIBED ABOVE?

A. Yes. These O&M expenses are necessary to ensure that the Distribution Business Area is able to deliver safe and reliable electric service to our Colorado customers.

VII. WILDFIRE MITIGATION

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

A. The purpose of this section of my Direct Testimony is to provide an overview of the Distribution Business Area's Wildfire Mitigation Plan, including planned capital additions and O&M costs for 2019, and also address planned capital and O&M costs for 2020-2023.

Q. PLEASE SUMMARIZE THE COMPANY'S OVERALL REQUEST WITH RESPECT TO ITS DISTRIBUTION WILDFIRE MITIGATION EFFORTS.

A. As discussed in the Direct Testimony of Ms. Trammell, the Company is seeking recovery of 2019 Distribution capital and O&M costs associated with its updated Wildfire Mitigation Plan in this rate review, and requesting deferred accounting treatment for incremental Distribution capital and O&M associated with these efforts.

Q. WHY IS THE COMPANY MAKING A SPECIFIC REQUEST FOR WILDFIRE MITGATION?

A. The Colorado region has seen drought and decreased snow pack in the mountains in recent years. These conditions can increase the risk and effects of wildfires in areas already prone to risk throughout the hottest and driest months of the year. Coupled with the Mountain Pine Beetle infestation several years ago that impacted Public Service's service territory only increases this risk. Public

Service owns and operates Distribution assets in high risk areas[6] that include the foothill and mountainous areas along the Front Range area, in the mountains along the I-70 corridor, outside of the Grand Junction area, and the more mountainous areas in the San Luis Valley. In total, the Company estimates that approximately 70,000 of the 400,000-plus distribution poles that the Company owns and operates are located within the at-risk area.

Q. WHAT DOES THE COMPANY PROPOSE WITH RESPECT TO DISTRIBUTION'S UPDATED WILDFIRE MITIGATION PROGRAMS IN THIS RATE REVIEW?

A. The Company is currently undertaking activities in its Wildfire Mitigation Plan and is requesting in this rate review to recover the related O&M and capital costs incurred in 2019 in the Company's cost of service as this work will continue in the future. These costs are shown below in Tables CSN-D-4 and CSN-D-5 and 2019 capital additions are included in Attachment CSN-2. The Company has requested deferred accounting treatment for accelerated wildfire mitigation activities that the Company plans to perform in 2020-2023. Ms. Trammell discusses this further in her testimony.

[6] As identified by the Colorado State Forest Division at https://csfs.colostate.edu/wildfire-mitigation/

Q. WHAT ARE PUBLIC SERVICE'S PROJECTED DISTRIBUTION O&M EXPENSES ASSOCIATED WITH ITS WILDFIRE MITIGATION INITIATIVE IN 2019 AND 2020-2023?

A. As shown in Table CSN-D-4 below, the Company is seeking a total of $8.3 million in incremental Distribution Wildfire Mitigation Plan O&M expense for 2019. With respect to 2020 through 2023, for which we are seeking deferred accounting treatment for incremental Distribution Wildfire Mitigation Plan O&M expense, the Company is forecasting approximately $11.4 million in 2020, $8.7 million in 2021, $9.3 million in 2022, and $9.4 million in 2023.

Table CSN-D-4:
Wildfire Mitigation Programs – Distribution O&M
Public Service (Electric)

Wildfire O&M (Dollars in Millions)					
Category	**2019**	**2020**	**2021**	**2022**	**2023**
Corporate	$0.3	$0.9	$0.9	$0.9	$0.9
Inspection and Modelling	$2.7	$3.6	$1.7	$1.7	$1.7
Protection	$0.5	$0.7	$0.1	$0.0	$0.0
Replace	$4.2	$4.7	$4.5	$5.2	$4.6
Vegetation	$0.6	$1.4	$1.5	$1.5	$2.2
Total*	**$8.3**	**$11.4**	**$8.7**	**$9.3**	**$9.4**
*There may be differences between the sum of the individual category program amounts and Total amounts due to rounding.					

Q. WHAT ARE PUBLIC SERVICE'S PROJECTED DISTRIBUTION CAPITAL ADDITIONS ASSOCIATED WITH ITS WILDFIRE MITIGATION PLAN IN 2019 AND 2020-2023?

A. Table CSN-D-5 below contains the Company's projected Distribution capital additions associated with its Wildfire Mitigation Plan for 2019-2023. Attachment CSN-2 includes the 2019 capital additions.

Table CSN-D-5:
Wildfire Mitigation Programs – Distribution Capital Additions
Public Service (Electric)

Wildfire Capital Additions (Dollars in Millions)					
Category	**2019**	**2020**	**2021**	**2022**	**2023**
Corporate	$0.1	$0.1	$0.1	$0.1	$0.1
Inspection and Modelling	$0.6	$0.3	$0.1	$0.1	$0.1
Protection	$7.9	$12.2	$6.2	$0.0	$0.0
Replace	$20.3	$21.3	$20.3	$23.8	$19.1
Total*	**$29.0**	**$33.9**	**$26.7**	**$23.9**	**$19.3**
*There may be differences between the sum of the individual category program amounts and Total amounts due to rounding.					

Q. WHAT DO TABLE CSN-D-4 AND TABLE CSN-D-5 SHOW?

A. As I discuss below, many of the Company's wildfire mitigation activities have historically been completed as part of Distribution's existing programs. The dollar figures shown in the Tables above, as well as in Attachment CSN-2, reflect amounts above the Company's normal expenditures for these activities.

Q. WHAT SORT OF WILDFIRE MITIGATION PROGRAMS DOES DISTRIBUTION MAINTAIN?

A. Distribution programs with respect to the Wildfire Mitigation Plan can generally be divided into five categories: corporate, inspection and modeling, protection, replacement, and vegetation management.

Q. DOES THE COMPANY ROUTINELY MAINTAIN THESE PROGRAMS?

A. Yes. The Company historically has maintained several of these programs. Other programs have been identified and initiated as part of the Company's Wildfire Mitigation Plan. However, as explained by Ms. Trammell, the Company believes it would be prudent to accelerate certain activities in the coming years, particularly because the risk of wildfires continues to grow and the Company needs to ensure it can continue to provide safe and reliable power to the communities we serve that are in high wildfire risk areas.

Q. PLEASE DESCRIBE THE BUDGET AREAS WITHIN DISTRIBUTION'S CORPORATE PROGRAM.

A. The Corporate program includes $0.1 million in capital additions and $0.3 million in O&M costs in 2019 for following budget areas: Leadership Positions and Community Relations. These budget areas are described below:

- *Leadership Positions*: Leadership positions will be responsible to coordinate, initiate and complete all the Wildfire Mitigation Plan activities.
- *Community Relations*: Partnership with public agencies, communities, and the general public are critical for ensuring the success of planned work in wildfire risk areas.

Q. PLEASE DESCRIBE THE ACTIVITIES WITHIN DISTRIBUTION'S INSPECTION AND MODELING PROGRAMS.

A. The Inspection and Modeling program includes $0.6 million in capital additions and $2.7 million in O&M costs in 2019 for the following activities: pole inspections, infrared inspections, and wind strength review. The Company's inspection results inform the activities that the Company will need to undertake as part of the replacement program.

An overview of these activities is provided below:

- *Pole inspections*: The primary focus for the Company's pole inspection program for 2019 and 2020 will be in the wildfire risk areas and is an acceleration of the Company's routine 12-year inspection plan to ensure all poles in the wildfire area are inspected as soon as possible. For efficiency purposes, additional poles near the wildfire area will also be inspected in 2019 and 2020. Once all the poles are inspected in the wildfire area, the pole inspection program is assumed to follow the routine inspection plan but will account for the results of the accelerated inspections in 2019 and 2020.
- *Infrared inspections*: Infrared inspections are routinely performed using thermal imaging technology (infrared) to identify problem areas on distribution facilities. This inspection allows detection of certain defects that are difficult or impossible to identify during visual inspection. These inspections will be more extensive and focused on equipment located in high risk areas and equipment that is nearing the end of its useful life. Distribution plans are based on completing infrared inspections in 2019 and 2020. We will evaluate the need and frequency of future infrared inspections at a later date, considering the results of the inspections in 2019 and 2020.
- *Wind strength review*: Wind strength review involves modeling distribution facilities located within the wildfire risk zones using software to evaluate their wind strength capacity against high-wind load cases. It is not commonly part of the Company's routine maintenance activities although it is reviewed as one of the requirements when defining construction standards for new

installations. The planned forecasted spend was developed by funding of an initial pilot program to determine the characteristics and condition of different parts of the infrastructure population. The funding forecast is projected based on a sustained effort to manage resources and address the infrastructure population over several years.

Q. PLEASE DESCRIBE THE ACTIVITIES WITHIN DISTRIBUTION'S PROTECTION PROGRAM.

A. The Protection Program includes $7.1 million in capital additions and $0.5 million in O&M expense in 2019 and is a comprehensive effort that includes a protection study of all distribution feeders in the wildfire risk area and upgrades to reclosing devices such as breakers and reclosers that will leverage technologies being deployed as part of AGIS which include the Field Area Network and ADMS.

An overview of these activities is provided below:

- *Protection study for feeders*: Modern protection equipment can provide improved ability to provide reliable service and mitigate the potential for starting a wildfire. All circuits within the wildfire risk areas are being reviewed for protection improvements in 2019. Capital work based on this engineering review is planned to be completed from 2019-2021.
- *Recloser communications*: Reclosers are pole-mounted remote supervisory reclosing and switching devices. The recloser communication includes the cost for communications at each individual recloser device while leveraging

the existing deployment of the FAN already planned as part of the AGIS initiative.

- *Substation relay upgrade for remote non-reclosing*: Upgrades to substation relay equipment will also be required to allow for adaptive protection schemes that is not possible with more mature relays like electromechanical relays. The relay upgrades will be identified in coordination with the protection studies. While these upgrades are similar to those we will implement for FLISR as part of the AGIS initiative, the upgrades identified here are for safety purposes, rather than for reliability (which is the purpose of the FLISR-related upgrades).
- *ADMS enhanced circuit breaker functionality*: The ADMS enhanced circuit breaker functionality is part of the protection upgrade work and will allow for different protection settings depending on the fire risk. The ADMS enhanced circuit breaker functionality includes two modules within the ADMS platform that were not planned as part of the AGIS deployment.
- *Design and Installation of New Protective Devices*: The design and installation of new protective devices will follow the protection reviews and include such devices as reclosers.

Q. CAN YOU DESCRIBE HOW THE PROTECTION PROGRAM WILL HELP TO MITIGATE THE RISK OF WILDFIRES?

A. Yes. Wildfires related to utility equipment are often caused from sparks from a failure on a line. Failures can be caused by a number of issues including vegetation falling into lines, lightning, high winds, animals, failed equipment, and other types of failures. Protective equipment like reclosers and breakers are designed to open when a failure is detected and close after a few seconds and remain closed if the failure is temporary (resulting in a momentary outage for customers) or open if the failure is permanent requiring a crew to be dispatched for repairs. The protective equipment program will include upgrades to protective equipment that for example will allow the Company to modify settings for reclosers on high wildfire risk days and limit the risk of sparks caused by failures on lines.

Q. PLEASE DESCRIBE THE ACTIVITIES IN DISTRIBUTION'S REPLACEMENT PROGRAM.

A. The Replacement program includes $20.3 million in capital additions and $4.2 million in O&M costs in 2019 for the replacement of equipment that is identified during the during the inspection process that is described in more detailed above. An overview of these activities is provided below:

- *Pole Replacements*: Pole Replacements are identified through the pole inspection process and through the wind and condition assessments. The pole inspection and replacement process is the same process the Company undertakes on an annual basis, but the Company plans to accelerate these activities in 2019 and 2020 on the nearly 70,000 poles within at risk wildfire areas. The Company's 2019 plans include the inspection of approximately 40,000 poles in wildfire risk areas and the planned pole replacements are based on a projected reject rate of 8 percent, meaning the Company anticipates that it will need to replace 8 percent of inspected poles in the wildfire risk areas. As noted above, the Company plans to identify an initial pilot area for wind and condition assessments which will be used to supplement and enhance information gathered during pole inspections. Pole replacement activities will continue in 2021 and beyond based on the results of the Company's inspection and modeling programs.

- *Pole Top Reinforcements:* Pole top reinforcements are the replacement of equipment near the top of the pole, such as cross-arms and switches identified as needing replacement during pole inspections and infrared inspections. Identification of pole top degradation historically has been considered a small reliability risk and minor degradation was not pursued as aggressively for mitigation. We have learned, however, that pole top degradation may not only be a small reliability risk, it can also contribute to a potential ignition. As a result, we are reviewing and accelerating the replacement of pole top equipment.
- *Equipment Upgrades:* Equipment Upgrades include changing out equipment, primarily fuses and arresters that meet the California Exclusion Criteria. The

replacement equipment is superior because it does not spark when operating, thereby preventing a potential ignition. This equipment replaces industry standard equipment that is typically used in areas that are not at risk for wildfires.

Q. CAN YOU DESCRIBE HOW THE REPLACEMENT PROGRAM WILL MITIGATE THE RISK OF A WILDFIRE?

A. Yes. California utilities have identified vegetation contact with lines as the greatest risk for causing a wildfire. While our vegetation management program includes activities for minimizing this risk, it is unrealistic we can eliminate this risk entirely. By pairing vegetation management with the replacement of poles and the equipment on the tops of poles, we can incorporate industry best practices aimed at increasing the resiliency of our system and reducing the likelihood of failure and sparking. Increasing the resiliency of our system also results in reliability benefits to customers in the form of reducing the risk of failures and outages on the system.

Q. PLEASE DESCRIBE THE VEGETATION MANAGEMENT PROGRAMS.

A. Vegetation management activities include $0.6 million in O&M expenses for the Mountain Hazard Tree Program, pole brushing, and secondary voltage line clearance. An overview of these activities is provided below:

- *Mountain Hazard Tree Program:* The Company's Mountain Hazard Tree ("MHT") Program involves the mitigation of hazard trees adjacent to both electric distribution and transmission facilities in areas that have been impacted by the mountain pine beetle epidemic. The enhanced mitigation is an expansion of the Company's existing program in both scope and scale to include more primary voltage line miles as well as the addition of patrolling secondary distribution lines.

- *Pole Brushing:* Pole brushing includes maintaining a 10 foot vegetation clear zone around poles that have overhead devices such as fuses in selected areas that could emit sparks and ignite a fire should there be an expulsion fuse operation. The planned activity is based on completing clearing activities on a four year cycle.
- *Secondary Voltage Line Clearance:* Secondary Voltage Line Clearance expands the Company's current Vegetation Management Guidelines to include dedicated vegetation inspections and to proactively prune vegetation around distribution lines with only secondary voltages, street lights and service lines within the defined zone. Implementing the additional line segments will be added into the scope of work for Vegetation Management's planned scope moving forward.

Q. PLEASE DESCRIBE THE PEER REVIEW PROCESS THE COMPANY HAS UNDERTAKEN AS PART OF UPDATING ITS WILDFIRE MITIGATION PLAN.

A. The Company has undertaken several efforts to collaborate with peers and industry leaders in this space. Most notably, the Company has actively participated in conferences on this topic and engaged in discussions with vendors and peer utilities experienced in developing wildfire mitigation strategies.

Importantly, we have spent time engaging with representatives from San Diego Gas & Electric, a utility considered an industry leader for wildfire mitigation, to identify industry best practices and identify programs appropriate to integrate into Public Service's wildfire mitigation strategy.

Q. HAS THE COMPANY, AND WILL THE COMPANY, MANAGE ITS PROJECTED WILDFIRE MITIGATION PLAN COSTS RELATED TO CAPITAL ADDITION AND O&M COSTS IN 2019 TO ENSURE THE FINAL, ACTUAL COSTS ARE REASONABLE AND PRUDENT?

A. Yes.

VIII. AGIS CAPITAL ADDITIONS

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

A. In this section of my Direct Testimony, I support Distribution's capital additions for which the Company seeks recovery in this rate review with respect to the AGIS initiative, including actual capital additions placed into service through 2018 as well as capital additions forecasted for 2019, as introduced by Ms. Trammell and explained in more detail by Ms. Blair, who supports the Company's cost of service.

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. Immediately below, I provide an introduction to each of the AGIS foundational programs and describe the division of work between the Distribution Business Area and Business Systems (IT). I also provide an overview of Distribution's capital additions through 2018 and forecasted 2019 capital additions that are proposed to be included in the 2018 HTY cost of service.

In Sections VIII.A through VIII.F, I discuss each of the foundational programs in detail. In each Section, I first outline the reasons why Public Service is implementing the AGIS programs and explain their capabilities. I then discuss the deployment and implementation of the foundational components of AGIS, including activities that were carried out from 2016 to 2018, and the implementation that will continue going forward, consistent with the AGIS CPCN Settlement.

Q. PLEASE PROVIDE AN INTRODUCTION TO EACH OF THE AGIS FOUNDATIONAL PROGRAMS.

A. Below is an introduction to each of the AGIS foundational programs:

- *Advanced Distribution Management System* ("ADMS"): ADMS will provide an integrated operating and decision software and hardware support system to assist control room, field personnel, and engineers with the monitoring, control, and optimization of the electric distribution system. It will manage the complex interaction of Distributed Energy Resources ("DER"), outage events, feeder switching operations, and the advanced applications utilizing intelligent field devices, such as IVVO and FLISR, discussed below. ADMS gives access to real-time and near real-time data to provide all information on operator console(s) at the control center in an integrated manner, which means the different operating systems and technologies will communicate with and update each other in the ADMS platform. ADMS is the fundamental platform that will utilize the updated data that is being gathered as part of the GIS project (described below), and manages each of the other AGIS components described below.
- *Geospatial Information System* ("GIS"): The GIS provides location information about all physical assets that make up the Company's electric distribution system. The records also include specification information regarding the physical assets, such as a distribution feeder's size. While the Company already has a GIS, the Company is engaging in a data gathering

effort to validate and update the information in GIS because the ADMS model needs accurate information to operate effectively. ADMS will use the GIS' location and specification information to maintain the as-operated electrical model and advanced applications.

- *Advanced Meter Infrastructure* ("AMI"): AMI meters are able to measure and transmit voltage, current, and power quality data and can act as a "meter as a sensor," enabling ADMS to engage in near real-time monitoring of the distribution system. These meters provide information about customer usage and will enhance the Company's ability to send price signals to customers, allow for new rate structures that will enable customers to manage their energy usage with near real-time energy usage data available through a customer web portal, identify outages without customer reporting, respond efficiently to metering and usage issues, and allow remote service disconnects and reconnects. AMI meters will replace existing Automated Meter Reading ("AMR") meters with more advanced technology to improve service and reliability.
- *Field Area Network* ("FAN"): The FAN is the communications network that will enable communications between the communications infrastructure that already exists at the Company's substations, the ADMS, the new AMI meters, and the new intelligent field devices associated with advanced applications as described immediately below. The FAN may provide benefits to all AGIS

projects, but is designed and built according to the needs of various specific components, and each has different communication network requirements.

- *Advanced Applications that Utilize Intelligent Field Devices*: The following advanced applications and associated field devices will support a more advanced grid:
    - *Integrated Volt-VAr Optimization* ("IVVO") is an application that automates and optimizes the operation of the distribution voltage regulating and VAr control devices to reduce electrical losses, electric demand, and energy consumption, and provides increased distribution system injection capacity to host DER.
    - *Fault Location Isolation and Service Restoration* ("FLISR") uses software and automated switching devices to decrease the duration of, and number of customers affected by, any individual outage. The automated switching devices detect feeder mainline faults, isolate the fault by opening section switches, and restore power to un-faulted sections by closing tie switches to adjacent feeders as necessary.
    - *Fault Location Prediction* ("FLP"), is a subset application of FLISR that leverages sensor data from field devices to locate a faulted section of a feeder line and reduce patrol times needed to physically locate the fault.

Q. WHAT KINDS OF ACTIVITIES WILL THE DISTRIBUTION BUSINESS AREA PERFORM TO IMPLEMENT THE AGIS FOUNDATIONAL PROGRAMS?

A. At a high level, the work that the Distribution Business Area will undertake falls into four primary categories: (1) installing field devices (advanced meters, and devices to implement IVVO, FLISR, FLP); (2) data collection (ADMS/GIS); (3) determining appropriate business processes to manage the system; and (4) determining employees' roles and responsibilities in implementing and operating the new programs that are part of the AGIS initiative. The last two categories I identified (3 and 4) are both part of Program and Change Management to ensure a successful implementation, which are discussed separately in Section VIII.F and comprise a part of each AGIS project.

Q. HOW IS THE COMPANY SUPPORTING ITS AGIS COSTS IN THIS RATE REVIEW FILING?

A. AGIS costs are incurred by both the Distribution Business Area and the Business Systems (IT) organization for each of the AGIS programs. In the remainder of my testimony, I describe each of the AGIS foundational programs in more detail and explain Distribution's work to forecast and implement the AGIS projects

I provide the primary support for the costs and implementation related to the GIS data collection effort for ADMS, the AMI meters, the procurement and installation of pole-mounted FAN devices, the advanced applications utilizing intelligent field devices (i.e., IVVO, FLISR and FLP), and additional elements of the AGIS implementation process including Program and Change Management efforts.

Business Systems has primary responsibility for the ADMS IT components, the IT integration of AMI (but not the meters themselves) and the AMI head-end application, the IT integration and deployment of the FAN, and the forecast development for the FAN. As explained by Mr. Harkness, Business Systems is the centralized IT organization for the Xcel Energy operating companies and provides technology services to support all aspects of the operations of the Xcel Energy OpCos, including Public Service. For this rate review, Mr. Harkness provides the primary support for the costs related to the components of the AGIS programs identified above.

In summary, Mr. Harkness and I support the costs and forecasts of the AGIS components as follows:

Table CSN-D-6: AGIS Program Witness Support

AGIS Foundational Program	Component	Witness
ADMS / GIS	System Development	Harkness
	GIS Data Collection	Nickell
AMI	IT Integration	Harkness
	Head end application	Harkness
	Meters and deployment	Nickell
FAN	IT Integration and deployment	Harkness
	Procurement and installation of pole-mounted devices	Nickell
IVVO	Application deployment	Harkness
	Advanced application and field devices	Nickell
FLISR / FLP	Application deployment	Harkness
	Advanced application and field devices	Nickell

Q. WHAT TYPES OF EXPENDITURES FOR AGIS ARE CLASSIFIED AS CAPITAL COSTS?

A. Capital costs include expenses for new equipment like meters and intelligent field devices, costs to modify existing equipment, and related installation and labor costs. This is an illustrative list, but it is not exhaustive.

Q. WHAT TYPES OF CAPITAL COSTS IS DISTRIBUTION INCURRING TO IMPLEMENT THE AGIS PROJECTS?

A. Capital costs Distribution is incurring to implement AGIS include the capital cost of installing additional equipment on the distribution system for IVVO, FLISR and FLP, and the capital costs to install AMI meters (including the costs of the devices, meters, and equipment themselves), the costs required to make capital modifications to equipment in distribution substations and at various points on the electric distribution system ("make-ready work"), and the costs to collect and build the GIS data additions required to operate ADMS. Together, these costs include equipment and device costs, labor, contractor and vendor services, transportation, material and stores expenses, permitting, traffic control, restoration, disposal costs, etc.

Q. WHAT ARE DISTRIBUTION'S ACTUAL AND PROJECTED CAPITAL COSTS FOR AGIS IMPLEMENTATION THAT THE COMPANY SEEKS TO RECOVER IN THIS RATE REVIEW?

A. Distribution's AGIS capital additions that Public Service seeks to recover in this rate review, are shown below in Table CSN-D-7 below.

Table CSN-D-7:
AGIS Distribution - Capital Additions
(Total Company)

(Dollars in Millions)

AGIS Program	2016	2017	2018	2019
ADMS	0.0	0.0	11.7	8.6
AMI	0.0	0.0	0.2	10.1
FAN	0.1	0.1	0.0	11.1
FLISR	2.0	3.2	(4.0)	17.4
IVVO	0.0	0.0	0.6	24.2
Total*	**2.1**	**3.2**	**8.5**	**71.4**

*There may be differences between the sum of the individual AGIS program amounts and Total amounts due to rounding.

Distribution's AGIS-related capital additions are also set forth in Attachments CSN-1 and CSN-2. I provide additional support for the capital costs, organized by AGIS component, in Sections VIII.A-VIII.F of my testimony, below.

Q. HOW DO THE IVVO, AMI, AND FAN COSTS COMPARE TO THE AGIS CPCN SETTLEMENT APPROVED IN PROCEEDING NO. 16A-0588E?

A. The Company's deployment costs are consistent with the AGIS CPCN Settlement amounts, and Recommended Decision R18-0590 approving the uncontested (amended) application in Proceeding No. 18A-0194E, which includes an additional $2.8 million to implement an AMI network that includes HAN capabilities.

Q. ARE DISTRIBUTION'S CAPITAL COSTS PRESENTED ABOVE CONSISTENT WITH THE INFORMATION PROVIDED IN PUBLIC SERVICE'S COMPLIANCE FILINGS IN PROCEEDING NO. 16A-0588E?

A. The actual capital costs, which include the costs incurred through 2018, are consistent with the cost information filed by the Company in its Annual Actuals Report for 2017 filed in May 2018 in Proceeding No. 16A-0588E.

Distribution's capital costs forecasted for 2019 are slightly lower than was reported by Public Service in the Grid CPCN 2019 Forecast Report filed in October 2018 in Proceeding No. 16A-0588E due to some adjustments in the timeline of implementation activities for AMI and IVVO.

Q. IS THE COMPANY INSTITUTING CONTROLS TO ENSURE AGIS IMPLEMENTATION IS CONDUCTED EFFECTIVELY, AND WITHIN FORECAST?

A. Yes. The AGIS program has established standard program governance processes, which were developed based on established Xcel Energy Enterprise methods. Project Management Office ("PMO") services include management of processes, governance structures, metrics and reporting. The core PMO function provides Program Governance which includes Program Management, Resource Management, and Financial Management. A dedicated team has been established to develop, manage and ensure quality and compliance to all governance processes.

Q. HOW DOES THE AGIS PROGRAM ENSURE EFFECTIVE COST CONTAINMENT RELATED TO THE AGIS PROJECTS?

A. The Company's AGIS governance includes Program Management, Resource Management, and Financial Management. Program Management includes Scope Change, Risk/Issue Management, and Work and Schedule Management. Resource Management includes on-boarding and off-boarding of AGIS personnel, resource demand and capacity planning, and resource forecasting. Financial Management includes financial forecasting, budget management, cost benefit analysis, and contract management. Controls are established to ensure that processes with appropriate approval levels are adhered to.

A. Advanced Distribution Management System (ADMS) and Geospatial Information System (GIS)

1. ADMS and GIS Functions and Capabilities

Q. WHAT IS THE ADMS?

A. As mentioned above, ADMS is a foundational system that consists of a collection of hardware and software applications designed to monitor and control the entire electric distribution system safely, efficiently, and reliably. An ADMS acts as a centralized decision support system that assists the control room, field operating personnel, and engineers with the monitoring, control, and optimization of the electric distribution system. The multiple applications within ADMS will constitute a single system that will enable the optimization of each application by using one operating model and the same power flow measurements and calculations.

Q. WHAT IS GIS?

A. A GIS is a system or program that captures, stores and manages geographic data / geographically referenced information. For Public Service, GIS is, in essence, a digital map of the Company's distribution system. GIS data is critical to the ADMS to provide location and specification information for all of the physical assets that make up the distribution system.

Q. HOW WILL ADMS IMPROVE THE WAY THE COMPANY CURRENTLY MONITORS THE DISTRIBUTION SYSTEM?

A. ADMS will enable access to real-time and near real-time data to provide all information on operator console(s) at the control center in an integrated manner and make adjustments for real-time grid conditions and topology that are impacted by each application. Some of the Company's key objectives for ADMS include optimizing switching sequences, improving the distribution system's reliability and quality of service in terms of reducing outages and minimizing outage time (through FLISR), maintaining acceptable voltage levels on the system (through IVVO), and maintaining awareness of DER impacts to power flow on the grid.

Q. HOW WILL ADMS ACHIEVE THESE IMPROVEMENTS?

A. ADMS will utilize an enhanced distribution grid model that will include substations, feeders, taps, and services in one user interface, to more accurately represent the entire distribution grid. Because GIS will provide the nominal geospatial electrical model to ADMS, accuracy of the GIS model including impedance data will be essential, as this data will improve the model when operating advanced applications like IVVO and FLISR. ADMS will maintain the as-operated GIS electrical model and advanced applications in near real-time. This model will provide the Company with greater visibility into the distribution system and provide information about the system at a more granular level. Historically, the Company has not had the ability to track the level of detail that ADMS will require in order to operate the distribution system effectively. Therefore, the Company is in the process of updating all of its physical asset records to ensure that the information available complies with the necessary level of detail needed for ADMS. In addition, Public Service's ADMS will integrate existing Supervisory Control and Data Acquisition ("SCADA") system measurements with the enhanced model. This will allow the Company to monitor and control power flow from substations to the edge of the grid, enabling multiple grid performance objectives.

Q. HOW IS THE COMPANY ASSESSING THE LEVEL OF GIS DATA NEEDED IN ORDER TO EFFICIENTLY OPERATE ADMS?

A. The Company has entered in to a Technology Partnering Agreement with the National Renewable Energy Laboratory ("NREL") to assist in analyzing what specific GIS data is needed to enable ADMS functionality. As a member of the Department of Energy sponsored ADMS "testbed", NREL maintains a demonstration laboratory that will allow the Company to model how ADMS will interact with various levels of data. This partnership, which also includes Schneider Electric (the provider of Public Service's ADMS platform), will allow the Company to efficiently collect the data necessary to operate the system effectively and enable the AGIS program functions. NREL has provided a preliminary report of its findings and the Company is reviewing the report and assessing next steps.

Q. PLEASE DESCRIBE THE FUNCTIONS OF ADMS.

A. ADMS will have core applications, which will make up the foundation of ADMS, as well as advanced applications. The core applications include distribution network modeling, network topology processor, impedance calculation, unbalanced load allocation, unbalanced load flow, state estimation, and distribution SCADA. These applications provide the basis for running load flow and state estimation on the distribution system providing near real-time calculations of the state of the network including factors such as voltages, currents, real and reactive power, amps, voltage drops, and losses.

The ADMS advanced applications will utilize the core applications and provide additional capability. Public Service will utilize two such advanced applications: IVVO and FLISR (and FLP). These applications will rely on accurate power flow calculations to determine the power flow at points on the grid where sensor information does not exist. For example, if there are no sensors on a feeder, the Unbalanced Load Flow core application will apply power flow measurements taken at the substation to calculate power flow throughout the feeder.

Although sensors are not a component of ADMS itself, ADMS will utilize sensor and equipment information, located at strategic points on the grid, to continuously improve upon the power flow calculations made by the power flow application. For example, AMI meters will measure and transmit voltage, current, and power quality data and can act as a "meter as sensor" providing near real-time monitoring information to ADMS. Where sensor data is available, power flow results will be refined and utilized through the ADMS application.

Q. CAN YOU PROVIDE EXAMPLES OF HOW ADMS WILL PROVIDE THE CAPABILITY TO ENABLE OTHER APPLICATIONS AND OBJECTIVES?

A. Yes, the IVVO and FLISR functions (discussed in more detail below) will be applied to the same feeders in a given portion of the distribution grid. FLISR will facilitate fault isolation and service restoration activities. IVVO technology will be able to manage voltage and power quality objectives both before and after fault isolation and service restoration activities are carried out by automatic FLISR and manual switching operations. IVVO and FLISR systems could be implemented independently, but with reduced efficiency. By implementing IVVO and FLISR in ADMS, the applications are integrated and coordinated to realize the full benefits of each application.

Q. DO YOU FORESEE FURTHER USES FOR ADMS IN THE FUTURE?

A. Yes. ADMS will provide a dynamic model and real-time power flow information that will facilitate increased penetration and integration of DERs, energy storage, integration of micro-grids, and future customer choice. The need for ADMS arose, at least in part, because of the increase in two-way power flow resulting from the growth of DERs, including renewable resources, on Public Service's distribution system. The visibility enabled by ADMS will provide the Company with information about these resources and their impacts that will be necessary to manage the system. The ADMS platform's ability to monitor, incorporate, and manage the higher penetration levels of DER, storage, and micro-grids, will also enable ADMS to implement actions to limit the potential negative impacts of these technologies on traditional electric customers, such as higher-than-necessary voltage that results from greater penetrations of solar on the distribution feeders. As DER penetration levels continue to rise, and as new storage and micro-grid technologies emerge and need to be connected to the grid, other ADMS applications will be necessary to study and manage the behavior of the grid to ensure maintained reliability.

2. ADMS and GIS Implementation and Costs

Q. WHAT WILL BE THE PHYSICAL COMPONENTS OF ADMS?

A. ADMS will be composed of hardware, software, distribution SCADA, and an impedance model, which is an accurate electrical representation of the distribution grid, including substations, core, and advanced applications.

Q. WHAT WORK IS DISTRIBUTION UNDERTAKING TO IMPLEMENT THE ADMS AND GIS PROJECT?

A. Although Distribution will be the business area that utilizes ADMS, Business Systems is responsible for the implementation of ADMS—building the ADMS model, including hardware, software, and Information Technology integration—and its ongoing maintenance, as discussed by Mr. Harkness.

Distribution is involved in three components of ADMS implementation. First, the GIS data collection effort, for which Distribution has primarily responsibility, will require collecting (a) data that will validate the physical characteristics of the current system, and (b) additional data that defines the electrical characteristics necessary to enable the ADMS model. The second category includes implementation of select intelligent field devices to test ADMS and ensure it has the necessary operating information. Third, all components of AGIS will have Program and Change Management efforts. I discuss the work that will be done related to Program and Change Management in Section VIII.F below.

Q. WHAT WORK WILL DISTRIBUTION COMPLETE REGARDING THE GIS DATA COLLECTION EFFORT TO ENABLE THE ADMS MODEL?

A. The Company is currently validating asset information pertaining to physical characteristics of the system. Since the ADMS is dependent on a robust dataset, Distribution will leverage system and data knowledge and confirm the accuracy and completeness of the electric distribution grid model. This is accomplished by verifying the information contained in the corporate GIS via the performance of a physical data verification and capture effort to determine the level of readiness to support the ADMS application. Distribution will also ensure the representations of customer load profiles and generation are accurate to meet the needs of advanced applications. Finally, we will use SCADA development for new device configuration requirements and alignment with current SCADA systems.

Q. PLEASE PROVIDE SOME EXAMPLES OF THE DATA DISTRIBUTION WILL COLLECT.

A. Examples of the data we will collect include the size of distribution system wiring, the size and location of equipment such as transformers, switches, poles, phasing and connectivity, and device control settings. This process validates the various data attributes contained in the corporate GIS system. As a result, the physical plant and the electrically connected model are reflective of one another.

Q. HOW IS THE COMPANY GATHERING THE GIS DATA?

A. Public Service has selected Cyient, a third-party vendor, to complete the work of collecting the GIS data. Cyient was selected through a competitive Request for

Proposals ("RFP") process. Specifically, Cyient will perform field verification of electric distribution assets. This involves confirming information contained in the corporate GIS platform, verifying equipment attributes and documenting differences. Information is then quality control checked prior to updating the corporate GIS, which interfaces with the ADMS to support grid optimization analysis. The Company has completed the data gathering process for approximately 55 percent of its distribution feeders. The Company anticipates completing the data gathering in the fourth quarter of 2021.

Q. HOW WILL DISTRIBUTION TEST THE ADMS SYSTEM?

A. Because ADMS is a foundational system that will control the advanced applications, ADMS must be functional upon deployment of the field devices and advanced meters. To ensure that ADMS is operating efficiently and effectively, the Company must complete end-to-end testing of the system, including with some intelligent field devices that will be utilized by the advanced applications like IVVO and FLISR. By deploying some of these devices for testing, Public Service's Distribution Business Area will be able to provide and validate use cases and test cases so we can ensure the software performs consistently with our needs for managing the electric distribution grid. These devices are not temporary and will be used as part of the intelligent field device deployment. In addition, the 2019 capital additions for ADMS reflect costs for the Company's testing lab, which performs testing of devices to implement the AGIS programs, but that will not be installed in the field. We will also use this testing to configure and maintain ADMS performance with the substations and advanced applications. We will also participate in software testing to validate that the software is able to manage the electric distribution grid and deliver the application performance required to meet corporate commitments.

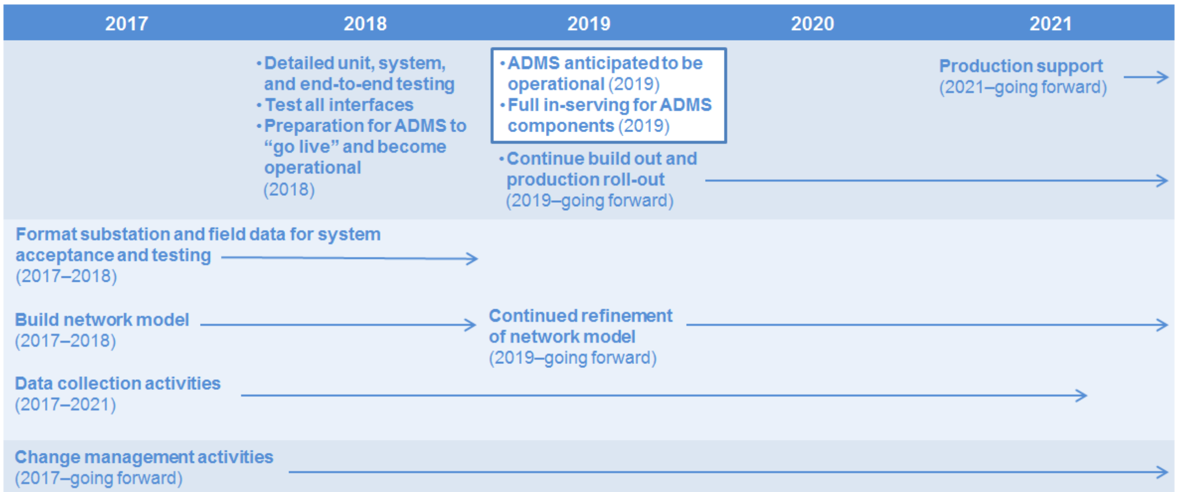
Q. PLEASE PROVIDE DISCUSS THE IMPLEMENTATION OF ADMS ITSELF.

A. Public Service began the design and implementation of ADMS in the second quarter of 2016, and expects ADMS to be operational later in 2019. ADMS implementation will occur in three stages. The first involves standing up the ADMS software which will permit the IVVO advanced application to be enabled. In the next phase, ADMS will “go live” at the control center with respect to a limited number of feeders and field devices later in 2019. The third phase will enable the IVVO application on additional feeders and continues through 2022.

Although the primary ADMS work, including work related to the hardware, software and labor associated with the design and build of the ADMS system and interfaces, is conducted by Business Systems, and described in detail by Mr. Harkness, Distribution and Business Systems have conducted their ADMS implementation activities in partnership with each other.

Figure CSN-D-2 shows a timeline of ADMS implementation activities.

Figure CSN-D-2



Q. WHAT ARE THE PRIMARY ELEMENTS OF THE DISTRIBUTION BUSINESS AREA'S ADMS AND GIS CAPITAL FORECAST?

A. The primary components of the Distribution Business Area's ADMS and GIS capital forecast, shown in Table CSN-D-7 and Attachments CSN-1 and CSN-2, are: (1) field audit of distribution pole data and data collection, and (2) substation data collection and loading.

Q. HOW DID THE DISTRIBUTION BUSINESS AREA DERIVE THE FORECAST FOR THESE ACTIVITIES?

A. Two vendors (Cyient and Ramtech) participated in a data collection pilot effort in 2017. Their RFP responses provided expected costs for data collection by pole and substation. The Company used those per unit costs and extrapolated them using greater Public Service system information.

In addition, in order to create a project forecast for the GIS collection activity, the Company engaged in scoping activities:

- Conducting a gap analysis to determine what additional information was needed in the Company's GIS data model for ADMS to run successfully.
- Identification of changes required to the GIS data model to support ADMS.
- Identification of data to be captured from other sources (such as substation equipment databases) and how this will be provided to ADMS.
- Assessing the quality of data already held in the GIS and external sources and determination whether additional data cleanup activities are required.
- Identification of data attributes that are to be field verified and updated in the GIS.

Q. CAN YOU PROVIDE ADDITIONAL DETAIL REGARDING THE DEVELOPMENT OF THE DISTRIBUTION BUSINESS AREA'S ADMS COST FORECAST?

A. Yes. In general, the processes used to develop the ADMS cost forecasts were the same for both Distribution and Business Systems. Prior to beginning the sourcing process, in 2013 a cross-functional Xcel Energy team began identifying and visiting United States utilities that had either implemented, or were in the process of implementing, an ADMS. These site visits provided information that was used in the internal planning process. Based on this benchmarking effort, an RFP was issued in 2014 and an extensive sourcing selection process was utilized to determine the successful vendor—Schneider Electric.

In 2015 the Company initiated a "blue print and design" phase with the selected ADMS vendor and other key business partners to develop extensive business and integration requirements for the project. This effort was used to negotiate key contracts with the vendor. To assist in the negotiation process, the Company hired consulting firm ICG to act as a trusted advisor due to ICG's detailed industry knowledge of ADMS to ensure that contract terms and deliverables were reasonable and appropriate. In 2016, following contract negotiations, the Company and the successful vendor, Schneider Electric, began detailed design of the project and completed the design in April of 2017. Based on this extensive effort, detailed budgets were developed and updated in June of 2016. After detailed design, Distribution has supported the implementation and functionality testing of ADMS, which has included testing and commissioning of FLISR and IVVO devices, verifying functionality of load flow and state estimation, and commencement of testing IVVO and FLISR algorithms in support of ADMS.

Q. WILL ADMS AND THE GIS PROJECT PROVIDE BENEFITS TO THE COMPANY AND ITS CUSTOMERS?

A. Yes. Enhancing the Company's GIS and implementing ADMS by itself may not provide direct benefits to customers that they can see. However, as the centralized system it enables these programs to work with the applications that provide customer-facing benefits.

Q. WHY ARE THE DISTRIBUTION BUSINESS AREA'S ADMS AND GIS COSTS REASONABLE FOR CUSTOMERS TO SUPPORT?

A. Of the various data elements required to support the ADMS, GIS is the most critical data source. For ADMS to perform its calculations and provide accurate results, the GIS model must be enhanced. The calculations will drive the operation of IVVO and FLISR, and provide a means of tracking the FAN assets. These are reasonable and necessary expenses to enable the ADMS capabilities, which in turn provide the customer benefits.

Further, the Company has gone through an extensive process to select an ADMS vendor that will be able to deliver the overall business requirements that are necessary to operate a modern electric distribution grid. ADMS is not only a foundational tool, it is a critical part—the "engine"—of the overall package of tools necessary to deliver reliable energy efficiency measures and to enable the integration of increasing quantities of DERs without compromising reliability and power quality. Finally, the forecasts for ADMS were also developed using the Company's thorough and extensive process in which information was collected from other utilities, industry experts, consultants, and a rigorous sourcing process.

B. Advanced Metering Infrastructure (AMI)

1. AMI Functions and Capabilities

Q. WHAT IS AMI?

A. AMI is an integrated system of advanced meters, communications networks, and data management systems that enables two-way communication between the utility's business data systems and customer meters. Advanced meters are the key endpoint component of an AMI system that measures, stores, and transmits metering quantities, including energy usage information at customer locations.

Q. WHY IS PUBLIC SERVICE TRANSITIONING TO AMI TECHNOLGY?

A. As detailed in our approved CPCN, advanced meters can provide substantial near real-time data that can be used to improve the Company's ability to monitor, operate, and maintain the distribution grid. Advanced meters can be used to verify power outages and service restoration, functionality the Company currently does not have. Improved monitoring can lead to improved outage response, proper protection system analysis and ultimately reduce outages. Advanced meters can also provide improved voltage monitoring and management, support better load studies and analysis resulting in improved planning and design, and be used to support additional systems such as an ADMS with applications like IVVO that will promote energy efficiency and peak shaving. The functionality enabled by advanced meters will also be able to support new rate designs that cannot be supported by the Company's current AMR meters.

Q. HOW WILL ADVANCED METERS WORK WITH THE OTHER COMPONENTS OF THE AGIS INITIATIVE?

A. The advanced meters will collect the data that will be communicated through the FAN, which I describe in more detail below, to the AMI head-end system which will have an interface to ADMS to allow the Company to more efficiently manage the distribution system.

2. AMI Implementation, Costs, and Benefits

Q. PLEASE PROVIDE AN OVERVIEW OF THE PROCESS THE COMPANY HAS UNDERTAKEN TO IMPLEMENT AMI.

A. The Company began detailed planning for AMI in 2016 and issued a Request for Information and Pricing ("RFx") with respect to advanced meters and the AMI head-end system (and the FAN's WiSUN mesh network) in 2016. The Company selected a vendor and contractor for the AMI head-end and the mesh network (i.e., the communication component), and issued a separate RFP to select the meter vendor. The Company is currently in negotiations to finalize a single meter vendor.

Distribution and Business Systems will work together to manage the logistics for AMI installation and removal of existing AMR meters. I provide an overview of the AMI development and the AMI meter vendor selection process and forecasting. Company witness Mr. Harkness discusses AMI head-end and integration development and provides support for the associated costs.

Q. PLEASE DESCRIBE THE WORK THE DISTRIBUTION BUSINESS AREA IS PERFORMING TO SUPPORT AMI IMPLEMENTATION.

A. In 2017, Distribution and Business Systems participated in contract awards (from RFPs) for AMI system integration and for a network vendor to support WiSUN (the mesh network portion of the FAN that will utilize the advanced meters' communications modules). We also commenced design and planning processes for AMI and began qualification of various advanced meters as part of the AMI meter RFP process. Distribution also began to develop its business processes for AMI and started its Program Management efforts.

In 2018, we engaged in detailed meter installation planning, completed the advanced meter testing qualification testing, and started contract negotiations for the advanced meters and deployment. The Distribution Business Area has continued to work on its business processes. No AMI components were placed in service in 2017 or 2018.

Q. PLEASE DESCRIBE THE WORK THE DISTRIBUTION BUSINESS AREA WILL UNDERTAKE GOING FORWARD TO SUPPORT AMI IMPLEMENTATION, PARTICULARLY METER DEPLOYMENT.

A. Public Service plans to deploy approximately 1.6 million advanced meters in Colorado between 2019 and 2024. The first meters are planned to be installed in 2019, in conjunction with the implementation of the WiSUN mesh network that will support IVVO. The Distribution Business Area will be primarily responsible for the deployment of advanced meters. Meter deployment includes AMI hardware evaluation, testing, acquisition, configuration, and the physical deployment of electric meter assets. The AMI deployment also includes hardware for customer HAN capabilities.

In 2019, the Distribution Business Area will continue testing the AMI meters and data for operational use, prepare for the meter acquisition, and begin initial deployment. We will continue to conduct additional testing of meters for both electric distribution and customer operational requirements. Testing covers meter specifications (including the meters' network information communication card and internal disconnect switch), as well as the ability of the meters to integrate with products, applications, and platforms involved with AMI.

Distribution will coordinate closely with the meter vendor and engage in joint planning and scheduling processes. We will also help support the process for the removal, retirement, and disposal of the non-AMI meters, which will be performed by the meter installation vendor. The Company is also developing business tools to enable electric meter communications with customers' HANs, and will develop customer communication plans to support the mass meter rollout that complements our wider corporate strategy for the overall customer engagement experience.

Q. WHAT ARE THE PRIMARY COMPONENTS OF DISTRIBUTION'S AMI CAPITAL FORECAST?

A. The primary components of the Distribution's AMI capital forecast, shown in Table CSN-D-7 and Attachments CSN-1 and CSN-2, are: (1) meters, (2) meter installation, (3) vendor project management, and (4) AMI Operations (internal and external personnel). It should be noted that costs related to Change Management constitute a portion of each AGIS program's forecast. Change Management is discussed separately below. Lastly, the AMI forecast includes HAN cost estimates, consistent with the AGIS CPCN Settlement.

Q. HOW DID DISTRIBUTION DERIVE ITS CAPITAL FORECAST FOR THE AMI METER COSTS?

A. The forecast for the meter costs was developed from the information provided from each vendor from its RFx for residential and commercial type meters. Meter costs were separated into two categories—residential and commercial. The total price for meters for each category was divided by the number of meters in that category to arrive at an average per-meter cost per category for each vendor, and the results of each category from each vendor were then averaged to arrive at an overall estimated unit cost.

Q. HOW DID DISTRIBUTION DERIVE ITS CAPITAL FORECAST FOR AMI METER INSTALLATION?

A. The forecast for meter installation was developed from the average cost provided from the vendors that responded to the Company's RFx. Because responding vendors did not provide sufficient detail to determine if they met the Company's required installation procedures for commercial meters, the Company's present contractor installation costs for commercial meters were weighted proportionally to develop a per unit commercial meter installation cost. The Company developed a weighted average of residential and commercial meter installation cost per meter for its overall meter installation forecast.

Q. HOW DID DISTRIBUTION DERIVE ITS CAPITAL FORECAST FOR AMI VENDOR PROJECT MANAGEMENT?

A. The forecast for AMI vendor project management was developed from the average pricing provided by respondents to the RFx. In addition to project management, this cost estimate includes training, integration assistance, and system testing.

Q. HOW DID DISTRIBUTION DERIVE ITS CAPITAL FORECAST FOR AMI OPERATIONS RELATED TO INTERNAL AND EXTERNAL PERSONNEL?

A. Internal personnel included roles such as AMI Analyst, Billing Analyst, Project Operations Manager, Meter Supervision, Meter Engineering, and Inventory Analyst. The forecast for these positions was developed using average internal wage scales for these positions and estimating when the roles would be needed throughout the AMI deployment. External personnel include the roles of Billing Contractor, Scheduling Contractor, and Temporary Office Contractor. The forecast for these positions was also developed using average costs for these positions and estimating when the roles would be needed throughout the AMI deployment. Additionally, external personnel costs include an Electrical Contractor and a General Repair Contractor. The forecast for these is an estimate of costs that we may incur as a result of the Company needing to repair customer property that may be damaged during the meter exchange.

Q. WHY ARE DISTRIBUTION'S AMI COSTS REASONABLE FOR CUSTOMERS TO SUPPORT?

A. AMI is a foundational component of AGIS. As discussed above, AGIS is a long-term strategic initiative to transform our electrical distribution system to enhance security, efficiency, and reliability, to safely integrate more DERs, including those that are customer owned, and to enable improved customer products and services. The AMI forecast put forward is reasonable in enabling technologies that improve customer products and services.

Q. ARE ANY COSTS INCLUDED IN THE REQUEST YOU ARE SUPPORTING FOR AMI METERS BEYOND THOSE INSTALLED FOR THE PURPOSES OF IVVO?

A. No. The costs, both capital and O&M, that I am supporting in this proceeding reflect only those costs associated with the 2019 meter deployments for the purposed of IVVO deployment. In the approved CPCN I mention above, full deployment of AMI was not scheduled to commence until 2020. Recently, the Company has identified an alternative deployment plan due to evolving technologies that we will bring back to the stakeholders of the AGIS CPCN, as addressed by Ms. Trammell.

3. AMI Benefits

Q. WILL AMI PROVIDE QUANTITIVE BENEFITS TO THE COMPANY, AND THROUGH THE COMPANY, TO ITS CUSTOMERS?

A. Yes. AMI will provide quantifiable capital savings in the areas of distribution system management, outage management, and avoided meter purchases. AMI will also provide O&M savings, particularly with respect to meter reading costs, field and meter service costs, improvements in customer care, and distribution management and outage management activities. We also expect some savings with respect to reductions in energy theft, reduced consumption on inactive premises, and reduced uncollectible and bad debt expense. We anticipate that these quantitative benefits will begin to be realized starting in 2021 and will enhance the customer experience by improving the information available to customers, improving the information available to the Company and how we interact with customers (i.e. not requiring customers to report outages and being able to notify customers more precisely when power is restored), improved reliability for customers, and customer bill savings realized through cost savings.

Public Service also anticipates a number of benefits that are not readily quantifiable. These non-quantifiable benefits were discussed extensively by Company in the approved CPCN.

Q. DOES THE COMPANY ANTICIPATE THAT AMI WILL PROVIDE THE SAME BENEFITS AS THOSE THAT WERE PRESENTED IN PROCEEDING NO. 16A-0588E?

A. Yes. The Company anticipates that AMI will provide the same benefits as what the Company presented in Proceeding No. 16A-0588E. However, as part of the AGIS CPCN Settlement, the Company agreed to modify its meter deployment schedule, with meter installations not beginning until late 2019, and taking place over a longer period of time. At this time, meter installations are scheduled to be completed in 2024. Benefits are expected to be realized when a critical mass of meter installations have taken place, thus in the latter years of the deployment schedule. These benefits will assist the Company in managing the distribution system and provide our customers with an enhanced electric service experience.

Q. PLEASE DESCRIBE THE CAPITAL BENEFITS IN MORE DETAIL.

A. As mentioned above, AMI will provide quantifiable capital savings in the areas of distribution system management, outage management, and avoided meter purchases. These types of benefits are described below.

- *Distribution System Management*: AMI data can be aggregated at varying levels of the distribution system that include the tap, transformer, and service lines among other distribution system equipment. This data will be used to prioritize distribution grid improvements and more efficiently plan and design the system. This data can then be used to determine optimum installation and replacement of distribution assets as well as optimizing inventory levels.

The Company estimates that a one percent capital benefit will be achieved in reducing distribution capital expenditures through more efficient installation and replacement of distribution assets related to reliability and capacity projects. This will benefit customers because the Company will avoid capital expenditures that would otherwise go into rate base, and also assist in ensuring that distribution grid improvements will be made where and when they will impact the grid (and our customers) most effectively.

- *Outage Management Efficiency*: AMI will enable increased outage management efficiencies by providing automated outage notification and restoration confirmation (power-on information) to the Company's Outage Management System ("OMS"). Power loss information is identified by an AMI meter's last gasp. Outage notification from the AMI meters will provide the Company with a more timely and accurate scope of an outage without relying on customers to report an outage. The restoration confirmation that will be provided by AMI meters also enables the Company to focus and optimize its restoration efforts on active outages, minimizing field trips where outages do not exist—also known as "Okay on Arrival" outage calls. The automated outage information provided by the AMI meters will then assist the Company in restoring power more quickly because the Company will no longer be dependent upon customers notifying the Company of a power loss. These increased outage management efficiencies will enhance the customer experience by enabling quicker response and restoration to customer outages and will limit requirements on the customers as they will not have to report outages as they have to today and will enable enhanced communication by being able to notify them more precisely when power is restored. We estimate that AMI will contribute a ten percent efficiency gain from storm-related capital costs.

- *Avoided Meter Purchases*: The estimated benefits of avoided meter purchases were derived by comparing costs of a "business as usual" scenario, which includes business operations with existing installed meters, to the costs of implementing a new AMI meter population. Under the business as usual scenario, the Company would continue to replace and retire meters due to failures, performance, and age at projected costs. The AMI meter scenario assumes replacing the existing meters with meters that have a lower retirement rate.

Q. PLEASE DESCRIBE THE O&M EXPENSES-RELATED BENEFITS THAT AMI WILL PROVIDE.

A. As noted above, AMI will also provide savings to O&M expenses, particularly with respect to meter reading costs, field and meter service costs, improvements in customer care, and distribution management and outage management activities. The reductions in Company costs will be experienced by customers through their bills for electric service.

Q. PLEASE DESCRIBE THE REDUCTION IN METER READING EXPENSES IN MORE DETAIL.

A. The benefits related to meter reading expenses will be realized through the elimination of contracted manual meter reading and the reduction of 31 full-time-equivalent positions and their associated fleet costs specific to meter reading. Public Service's goal is to reduce headcount is through natural attrition, which includes position reassignments and expected retirements.

Q. PLEASE DESCRIBE THE REDUCTION IN FIELD AND METER SERVICES IN MORE DETAIL.

A. AMI meters equipped with internal service switches can be operated remotely, thereby reducing the need to deploy personnel to manually connect or reconnect customers, or to take special meter readings at customer premises. Customers will benefit because the Company will be able to switch meters on or off nearly instantaneously and Company personnel will be able to perform trouble-shooting activities remotely. Customers will not have to wait for Company personnel to arrive on-site in order to resolve issues. And customers will not need to experience the inconvenience or nuisance of a visit to their premises. We estimate that these capabilities will benefit the Company through a reduction in O&M costs generally in proportion to the cumulative number of meters installed to the Company's total number of customers, in the following areas:

- *Reduction in manual disconnection and reconnection of meters*: Manual disconnects and reconnects of residential meters occur for reasons including credit, customer requests, and revenue assurance. We estimate a reduction of approximately 90 percent of manual disconnections and reconnections through remote-controlled capabilities.

- *Reduction in manual off-cycle and special meter reads*: The Company estimates an annual reduction in nearly all of these types of manual reads. This benefit will begin to be realized proportionate to the number of AMI meters installed.
- *Reductions in nuisance stopped meter orders*: These are meter exchange orders that are system-generated because there was no energy consumption on the meter since the last billing meter reading. These orders may also be system-generated because the energy consumption reported is lower than expected as compared to Company-established data validation criteria for high or low consumption. In either of these two situations, there may be valid reasons for low or no energy consumption such as the premise being vacant, the meter being installed on seasonal load such as cabins, sprinklers, or ballparks, or the customer may be disconnected at the transformer or ahead of the meter. The diagnostic and analytical tools available through AMI are estimated to eliminate approximately 60 percent of these types of field trips.
- *Reduction in customer equipment problem outages*: Remote read access to meters will enable the Company to determine if an outage exists on the Company side of the meter, which is expected to significantly reduce costs associated with field trips that are not associated with company equipment

problems. For this analysis, the Company conservatively estimates a 50 percent reduction in such field trips.

- *Reduction in "Okay on Arrival" outage field trips*: Public Service estimates a 50 percent reduction in "Okay on Arrival" outage field trips due to better data through AMI.
- *Reduction in field trips for voltage investigations*: The Company estimates a reduction of approximately 60 percent of these types of field trips due to voltage investigations that will be able to be completed remotely.

Q. PLEASE DESCRIBE THE ESTIMATED BENEFITS RELATED TO COSTS FOR CUSTOMER CARE.

A. Public Service anticipates a reduction in customer call volumes and a corresponding reduction in the Company's back-office costs related to customer accounts due to the deployment of advanced meters and the implementation of AMI. The reduction in customer call volumes corresponds to the reduced need for customers to have to contact the Company to resolve electric service issues because the advanced meters will provide information to the Company directly, enabling the Company to proactively address service issues. Public Service anticipates that these improvements in customer care will provide financial benefits.

Q. ARE THERE OTHER O&M EXPENSE BENEFITS THAT WILL BE PRODUCED BY AMI?

A. Yes. The outage management efficiency that I discussed above will also produce O&M expense benefits.

Q. ARE THERE ADDITIONAL QUANTIFIABLE BENEFITS THAT CUSTOMERS AND THE COMPANY WILL REALIZE AS A RESULT OF AMI IMPLEMENTATION?

A. Yes. The timely reporting by the AMI meters of specific conditions in need of evaluation will allow the Company to correct these conditions more quickly and more quickly respond to customers. The availability of this information will also enable Public Service to detect and reduce meter tampering and energy theft, and to differentiate those instances more quickly from dead and malfunctioning meters. The Company has estimated a 0.25 percent gain in residential and small commercial customer (base rate) revenue due to these added capabilities of AMI meters.

Additionally, the Company will be able to remotely disconnect service on inactive residential and small commercial meters. The Company estimates a 50 percent reduction in consumption on inactive residential meters.

Also, the Company estimates an eight percent reduction in residential customer bad debt. This information is consistent with data provided to the FERC based on other utilities' pre- and post-AMI deployment.

C. The Field Area Network (FAN)

1. FAN Functions and Capabilities

Q. WHAT IS THE FAN?

A. The FAN is a wireless communications network that provides connectivity between substations and field devices up-to and including the customer meter. Through the substation's connectivity to the Company's existing Wide Area Network ("WAN"), the FAN enables back-office applications[7] to directly communicate with field devices providing near real-time usage information for both customers and the Company. The WAN is an intermediate link in the Company's communication system that provides high-speed, two-way communications capabilities and connectivity in a secure and reliable manner between Public Service's core data centers and its service centers, generating stations, and substations. The FAN's connections to the WAN will be primarily at substations on the distribution system.

Q. WHY IS PUBLIC SERVICE IMPLEMENTING FAN TECHNOLOGY?

A. Public Service's FAN will be a resilient communications network that enables two-way communication of information and data between the Company's existing infrastructure located at its substations and new or planned field devices, including reclosers, feeders, electric meters, capacitor banks, and virtually any other endpoint field device capable of communications, as those devices are installed or upgraded with communications modules. The FAN will securely and

[7] "Back office" applications and systems are those that actually use and manipulate the data and perform specific business functions, including energy management system applications.

reliably address the need for increased communication capacity that arises from grid advancements.

Q. WHAT ARE THE PRINCIPAL COMPONENTS OF THE FAN?

A. The FAN will consist of two separate wireless technologies: (a) a lower-speed Wireless Smart Utility Network ("WiSUN") mesh network; and (b) a high-speed point-to-multipoint ("PTMP") Worldwide Interoperability for Microwave Access ("WiMAX") network. Attachment c-5 provides an illustration of the principal components of the FAN. The WiSUN and WiMAX technologies are discussed in more detail by Company witness Mr. Harkness.

The WiSUN mesh network will communicate directly with the AMI infrastructure (such as the advanced meters) and the Distribution Automation ("DA") field devices used for the IVVO advanced application. The flow of communications between field devices, meters, and WiSUN access points through a mesh-styled network is illustrated in Attachment CSN-5. The term "mesh" refers to the network's topology, which resembles the interlaced design of mesh material.

The WiMAX network will provide redundant, reliable, and secure connectivity between the WiSUN mesh network and the Company's WAN. The DA field devices and WiSUN access points connect to the WiMAX base stations (located largely at the Company's substations) via wireless communication modules that are integral to those devices.

Through the substation's connectivity to the WAN, the FAN (including the WiMAX network and the downstream WiSUN mesh network) will enable the Company's advanced applications (such ADMS and AMI, and sub-applications, including IVVO, FLISR, and FLP) to communicate with the field devices that implement those applications and sub-applications.

Q. PLEASE DESCRIBE THE INFRASTRUCTURE AND DEVICES THAT WILL BE INSTALLED AS PART OF THE WISUN MESH NETWORK TO SUPPORT AMI AND IVVO.

A. The core mesh infrastructure will consist of three main device types:

- *Access Points*: device that will link the Company's endpoint devices that are enabled with wireless communication modules with the rest of the Company's communications network; located primarily on distribution poles and other similar structures.
- *Repeaters*: range extenders and are used to fill in coverage gaps where devices would be otherwise unable to communicate; located primarily on distribution poles and other similar structures.
- *Endpoint Devices*: include AMI meters and DA field devices, such as the intelligent FLISR and IVVO field devices, that have built-in mesh radios. The former will be located on customer premises; the latter will be co-located with either pole-mounted or pad-mounted distribution devices.

Q. PLEASE DESCRIBE THE INFRASTRUCTURE AND DEVICES THAT WILL BE INSTALLED AS PART OF THE WIMAX NETWORK.

A. The WiMAX network will consist of two main components: (1) base stations, and (2) customer premise equipment ("CPE")[8].

Base stations will serve as the key communication points between the substation WAN and the WiSUN (mesh) network. Base stations will communicate with CPEs in the field and, through the substations' connection to the WAN, enable end-to-end communication between the intelligent field devices and the Company's advanced applications and other back office applications.

At substations, there will be a base station with up to three radios that will communicate multi-directionally with CPEs out in the field of operations. Where possible, the base stations at the substations will be mounted on existing poles or structures in order to ensure an appropriate height. In some cases, new poles may need to be deployed if a structural analysis of the designated existing poles indicates that added weight would cause a stability issue. CPEs will be mounted on distribution poles in the field of operation.

Q. HOW WILL THE FAN TECHNOLOGIES BE CONNECTED TO AND INTERFACE WITH EACH OTHER AND THE COMPANY'S EXISTING WAN?

A. The WiMAX network and WiSUN mesh network will communicate wirelessly as the WiSUN mesh access points communicate with the CPEs that make up the

[8] CPE is a common term in the network industry that refers to specific equipment. In the term "CPE", the "customer" refers to Public Service (or a similarly-situated entity using this equipment), which is a customer of the equipment manufacturer. It does not refer to any specific customers of Public Service, or to Public Service's customers generally.

WiMAX network, and the CPEs in turn communicate back to the base stations at the substation.

The WiMAX base stations will be connected to the pre-existing WAN connections at the substation, which, in turn, will enable connectivity back to the data center locations.

Q. HOW WILL THE FAN SUPPORT OR INTERACT WITH ADMS?

A. The FAN infrastructure will ultimately provide data from endpoint devices, such as meters and field devices to the WAN, which will then deliver data to ADMS, and also enables commands to be transmitted to the field devices from ADMS.

Q. HOW DOES THE FAN SUPPORT OR INTERACT WITH AMI AND IVVO?

A. An AMI system is an integrated communication system that involves the FAN and the advanced meters. The WiSUN integrates with the advanced meters because each meter includes a communication module, and these communications modules form the majority of the mesh network. The mesh network allows the advanced meter to communicate its measurement data, power status, voltage current, usage history, and demand information back to the Company.

Additionally, the FAN integrates with IVVO because voltage information collected by the advanced meters is communicated to the Company via the FAN. Receiving this information allows the Company to increase or decrease voltage to the optimum level on a system-wide basis while ensuring all customers are within the acceptable voltage range allowable under the Company’s tariffs.

Q. HOW WILL THE FAN SUPPORT OR INTERACT WITH FLISR (AND FLP)?

A. The FLISR/FLP distribution equipment (*i.e.*, feeder-level devices) will have embedded communication modules that will communicate with access points in the mesh network or directly to WiMAX base stations. The FAN will enable two-way communication between these advanced field devices and ADMS.

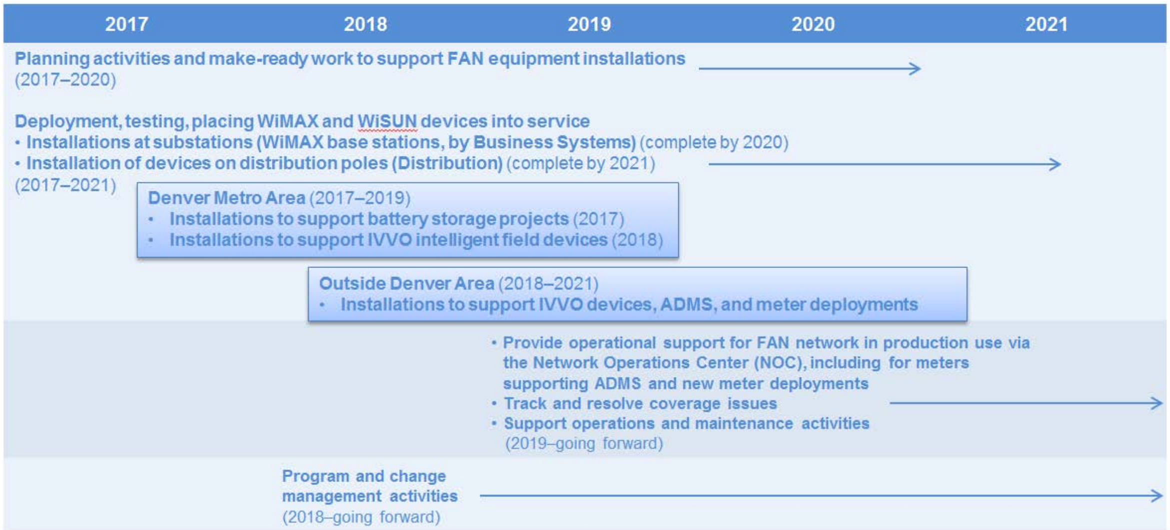
2. <u>FAN Implementation and Costs</u>

Q. WHAT WORK IS DISTRIBUTION UNDERTAKING TO IMPLEMENT THE FAN?

A. The Company engaged in comprehensive planning for implementation of the FAN beginning in 2016. This task is a joint effort between Business Systems and Distribution, with Business Systems primary responsible for the installation of WiMAX base stations and Distribution resources responsible for the installation of devices that will be located on Distribution poles (CPE's, AP's and repeaters primarily). For the Distribution Business Area, preparations for the FAN consist largely of make ready work for the devices to be placed on the distribution system, and the procurement and installation of hardware—that is, pole-mounted devices. An example of make-ready work includes situations where a pole needs to be modified or replaced in order to support a particular piece of communications hardware; in these situations, Distribution is responsible for modifying or replacing the pole. The Company began make-ready work in 2017 and equipment installations in 2018. The FAN infrastructure must be in place in order for the intelligent field devices needed for IVVO to communicate with ADMS, and for the AMI meters to communicate to the AMI head-end and ADMS.

Figure CSN-D-3 shows a timeline of activities for implementation of the FAN.

Figure CSN-D-3



Q. WHAT ARE THE PRIMARY COMPONENTS OF DISTRIBUTION'S CAPITAL FORECAST FOR THE FAN?

A. The primary components of the Distribution Business Area's capital forecast, shown in Table CSN-D-7 and Attachments CSN-1 and CSN-2, for the FAN are (1) make ready work (labor and hardware), and (2) FAN device hardware and installation (labor and hardware).

Q. HOW WAS THE CAPITAL FORECAST FOR THE FAN DERIVED?

A. Although Distribution is supporting the FAN deployment through the installation of certain devices, Business Systems was primarily responsible for developing the forecast for the components of the FAN. Accordingly, Company witness Mr. Harkness discusses the development of the FAN forecast.

Q. WILL THE FAN PROVIDE BENEFITS TO THE COMPANY AND ITS CUSTOMERS?

A. Yes. The FAN is an essential component of our AGIS initiative, so customers will benefit from the FAN's support of, and interaction with, other programs and technologies.

D. Integrated Volt-VAr Optimization (IVVO)

1. IVVO Functions and Capabilities

Q. WHAT IS IVVO?

A. As mentioned above, IVVO stands for Integrated Volt-VAr Optimization. IVVO is an advanced application that automates and optimizes the operation of the distribution voltage regulating devices and VAr control devices. Enhanced voltage control will help achieve the following benefits to the operation of the distribution system and our customers:

- Reduction of distribution electrical losses;
- Reduction of electrical demand;
- Reduction of energy consumption; and
- Increased ability to host DER.

Fundamentally, IVVO can be characterized as a demand-side management ("DSM") tool that allows the utility to control voltage without requiring behavioral changes from customers.

Q. WHY IS PUBLIC SERVICE IMPLEMENTING IVVO TECHNOLOGY?

A. The current distribution system has the capability to monitor voltages at the substation but does not have the capability to allow the Company to constantly monitor voltage levels throughout its feeders. As a result, the Company must often operate the system at a higher voltage than what would otherwise be required to ensure the appropriate voltage at the end of a long feeder.

The Company's proposed IVVO application will allow voltage to be monitored along the entire length of the feeder and at selected end points (rather than only at the substation). This insight into the voltage levels will allow the Company to utilize lower voltages across the entire feeder at most times.

Maintaining proper voltage levels throughout the electric distribution system is one of the most important challenges utilities face. Utilities seek to provide electric service to customers within a specific voltage range because customer equipment, appliances, and devices may not operate satisfactorily when electricity is supplied at voltages outside of the appropriate range. Customer demand for electricity changes throughout the day, which means the power flowing through distribution systems and voltage levels on feeders increase and decrease throughout the day to meet changing loads.

Q. HOW WILL THE TECHNOLOGY OPTIMIZE VOLTAGE?

A. Voltage optimization is accomplished by "flattening" a feeder line's voltage profile—or, in other words, narrowing the bandwidth of the voltage from the head-end of the feeder (at the substation) to the tail-end in concert with capacitors and other voltage-regulating devices (discussed below) for voltage support. In the Company's IVVO model, voltage will be monitored along the feeder and at select end points (rather than only at the substation), allowing the head-end voltage to be significantly lower at most times.

Voltage optimization (i.e., managing the overall voltage profile of the feeder) will reduce demand and energy consumption while still ensuring that voltage levels are adequate for providing safe and reliable power to customers at all points along the distribution feeders, including the end of the feeders. IVVO will also reduce the electrical losses on the distribution system.

Q. WHAT WILL BE THE PHYSICAL COMPONENTS OF IVVO?

A. There will be four principal utility equipment components of IVVO:

- Capacitors;
- Secondary static VAr compensators ("SVCs");
- Voltage sensing devices; and
- Load Tap Changers ("LTC").

Q. PLEASE DESCRIBE THE CAPACITORS.

A. Electric loads, like motors, require two types of power to operate: active and reactive power. Distribution line capacitors are located at various points on a distribution feeder and provide local static VAr support or reactive power. By doing so, they help to limit both voltage drop and line losses across the distribution system. Capacitors are currently switched on and off based only on local conditions. The Company will continue to use its existing capacitor banks and will install new capacitors as part of this project. There will typically be three to six capacitors installed per feeder.

Q. PLEASE DESCRIBE THE SVCS.

A. The SVCs are electronic secondary capacitors that will provide fast, variable voltage support to help stabilize and regulate the voltage. Aside from an earlier pilot program involving SVC devices that was implemented on feeders interconnected to two substations, these devices will be a new technology introduced to Public Service's distribution system. Each SVC device will be able to act in less than a cycle (a cycle is defined as 1/60 of a second since the United States AC frequency is 60 Hz), as opposed to a traditional utility capacitor device that operates on a 60-90 second time delay. These devices will provide dynamic voltage response for load, and will be located closer to customers or nearer the edge of the grid than the Company's existing capacitors. The devices' capabilities will enhance the system's ability to respond to the variability of renewable DERs such as solar facilities and intermittent distributed resources. The Company will strategically place approximately 4,350 SVC devices along feeders that need additional voltage support.

Q. PLEASE DESCRIBE THE VOLTAGE SENSING DEVICES.

A. IVVO requires end-of-line voltage sensing to monitor the voltage and ensure it is compliant with American National Standards Institute ("ANSI") Standard C84.1. The Company intends to use AMI meters as sensors to provide near real-time voltage sensing.

Q. PLEASE DESCRIBE THE LTCS.

A. Substation transformers equipped with LTCs will enable voltage regulation by varying the transformer ratio or tap. LTCs typically have 16 taps above and below neutral (33 taps total) and each tap adjusts the transformer turns ratio by 0.375 percent. LTCs are currently monitored and locally controlled based on the local bus voltage. LTCs raise or lower the voltage by tapping up or down based on the settings of the local controller and the demand of the substation transformer.

Q. HOW WILL IVVO INTERACT WITH THE OTHER COMPONENTS OF THE AGIS INITIATIVE?

A. As mentioned above, advanced meters will act as the voltage sensing device and collect voltage information at each service point, which will be transmitted back to the ADMS through the FAN. ADMS will take the inputs from these devices and compute the most efficient way for the system to operate and respond to changes. IVVO, through ADMS, will implement automated activities such as opening and closing of capacitors, and sending new settings to LTCs and SVCs. The LTC control devices will take direction from ADMS, which will make decisions based on knowledge about the entire system, rather than only about voltage at a single point. As a centralized system, ADMS will be able to control the distribution devices to work in unison and dynamically react to customer energy usage that is being increasingly complex.

2. IVVO Implementation and Costs

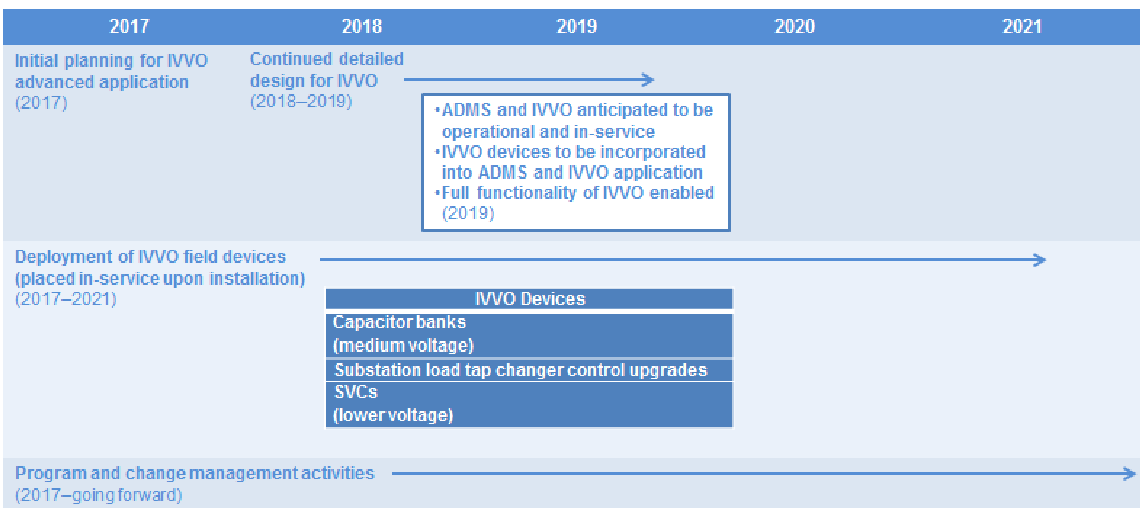
Q. WHAT WORK IS DISTRIBUTION UNDERTAKING TO IMPLEMENT IVVO?

A. Implementation of IVVO is on a five-year deployment schedule that began in 2017. In that year, Distribution engaged in initial planning for the IVVO advanced application and performed an initial deployment of medium voltage capacitor banks and substation load tap changer control upgrades. These devices were placed in-service upon installation. The deployment priority of the intelligent field devices has been determined based on considerations of demand and energy on the feeder, whether feeder lines and associated facilities are underground or overhead, and the location of existing capacitors. Deployment of devices on feeders is grouped by substation to gain efficiency benefits in localized areas. Distribution is responsible for the acquisition and installation of the physical devices that will enable the IVVO advanced application.

In the second quarter of 2018, the Company completed its RFP process for a SVC vendor, where it evaluated three different vendors based on a variety of factors including cost per unit, number of devices deployed across different utilities, support capabilities, and technical capabilities, ultimately selecting Varentec's Edge of Network Grid Optimization ("ENGO") unit as the best amongst these factors. Contract negotiations were completed in the third quarter of 2018, and we received our first shipment of SVC units late in the same quarter.

Distribution will also be responsible for the system analysis to determine the appropriate placement of the devices described above. There will also be make-ready work to complete before installing these devices, such as reconfiguring the location of a pole to allow an advanced application device to be placed on that pole or reconfiguring an underground cable so that a pad-mounted piece of equipment can interconnect with it. Figure CSN-D-4 shows a timeline of IVVO implementation activities, including device deployments.

Figure CSN-D-4



Q. WAS THE DISTRIBUTION BUSINESS AREA PRIMARILY RESPONSIBLE FOR DEVELOPING THE FORECAST FOR IVVO?

A. Yes. Therefore, I describe the forecast development process for IVVO in more detail. After the Company identified IVVO as an advanced application to be included in its AGIS initiative, the Distribution Business Area developed its IVVO forecast by using data from actual installations of comparable devices, as well as pricing details from vendor pricing and pilot projects. Some aspects of IVVO implementation, including a software application and ADMS integration, are discussed and supported by Company witness Mr. Harkness.

Q. WHAT ARE THE PRIMARY COMPONENTS OF THE IVVO CAPITAL FORECAST FOR ADVANCED APPLICATIONS?

A. The primary components of the IVVO capital forecast, shown in Table CSN-D-7 and Attachments CSN-1 and CSN-2, include: (1) device costs, and (2) installation costs, which include project management, labor, and device operations.

Q. HOW DID THE DISTRIBUTION BUSINESS AREA DERIVE THE CAPITAL FORECAST FOR THE IVVO DEVICE COSTS?

A. The Company was able to use actual costs to develop the capital forecast for the IVVO devices. Previous construction projects across Xcel Energy provided the basis for primary capacitor bank costs. The substation engineering group compiled estimate summaries for several different sites, and those were averaged to provide estimated substation costs. Finally, the Company had a pilot program testing SVC devices from Varentec, Inc. that began in 2013. Quotes provided from Varentec and actual costs during that pilot were used to estimate costs for that component.

Q. HOW DID THE DISTRIBUTION BUSINESS AREA DERIVE THE CAPITAL FORECAST FOR IVVO INSTALLATION COSTS?

A. Many of the devices involved in the IVVO deployment are not new to the Company. As such, the Company was able to use actual costs to develop the forecasts to implement the IVVO solution. With respect to the new SVC devices, Public Service has already engaged in a limited pilot installation of these devices on select distribution feeders, as discussed above; therefore, the Company was able to use actual costs for these devices as well. The Company is using primarily contract labor for the installation of IVVO devices. The forecast for labor costs for device installation were developed using contractor wage scales.

Q. DOES IVVO PROVIDE BENEFITS TO THE COMPANY AND ITS CUSTOMERS?

A. Yes. As described above, through the implementation of IVVO, the Company will be able to control the voltage on distribution feeders to a much tighter tolerance, permitting the Company to lower the voltage on that controlled feeder while still maintaining a high level of service quality. This lower voltage will result in a customer's devices operating more efficiently, and will effectuate energy and demand savings for customers and the system. The ability to avoid capacity, energy (fuel) costs, and defer capital investments will provide quantifiable benefits to our customers and the Company. Deployment of IVVO devices began in 2017; however we will not reach a critical mass of devices to realize these avoided energy and capacity benefits until 2019. IVVO will also provide benefits to customers that are not easily quantifiable. For example, the customers whose feeders are equipped with IVVO assets will experience higher efficiencies from their personal electrical devices and equipment because of the voltage management, which will enable their devices and equipment to consume less energy without having to take an action or change any use or behavior, or make any investment. This improved efficiency will result in lower bills for those customers. In addition, lower-income customers will have access to energy efficiency savings without having to participate in a specific low-income or efficiency-related program. Furthermore, there will be environmental benefits resulting from increased energy efficiency. The improved energy efficiency can result in reduced demand for electric generation, and thus a reduction in carbon emissions caused by certain types of generation resources. The reduction in greenhouse gas emissions, in turn, will provide environmental and societal benefits. The enhanced voltage management capabilities will also enable our system to have increased capacity to host DERs.

Q. WHY ARE THE IVVO COSTS REASONABLE FOR CUSTOMERS TO SUPPORT?

A. The service area for IVVO encompasses the majority of the Company's system load and its customers, while also including system infrastructure that inherently reacts positively to IVVO. For example, the IVVO service area generally includes feeders that are shorter and have stronger interconnections to surrounding feeders and substations.

The deployment of IVVO was also crafted to minimize cost impacts. Substation LTC control upgrades are being designed such that their replacement impacts as few other substation components as possible. The majority of Distribution device costs are associated with medium voltage capacitor banks, which have a low cost per Kilovolt-Amperes Reactive ("kVAr"). Existing capacitor banks also will be utilized as much as possible where they meet the technical requirements of IVVO. The addition of the lower voltage SVCs provides an appreciable benefit increase as well, and previous pilot projects in the Company's service territory have shown very favorable results from these devices.

Q. IS THERE ANYTHING ELSE REGARDING IVVO YOU WOULD LIKE TO ADDRESS?

A. Yes. There is one aspect of the AGIS CPCN Settlement related to IVVO I would like to address. Specifically, page 11 of the Commission-approved AGIS CPCN Settlement, Section II(D)(1)(b) provides:

> In the event the Company completes a base rate case that includes any portion of the IWO usage reductions in the forecasted or actual billing determinants, the Company shall present those anticipated reductions in a transparent manner, and propose an adjustment to the annual IWO recovery calculation to account for changes to billing determinants in order to prevent and avoid double recovery. After all IWO usage reductions associated with the initial deployment are captured in a base rate case, the Company will discontinue the IWO recovery treatment provided for in this Settlement Agreement.

Q. DOES THIS PROVISION NEED TO BE ADDRESSED IN THIS PROCEEDING?

A. No. Because the Company did not experience any usage reductions attributable to IVVO during the 2018 HTY, the Company is not proposing an adjustment to the IVVO recovery reduction in this proceeding.

Q. WILL THIS PROVISION BE USED IN THE FUTURE?

A. Yes. The Company is expecting to achieve IVVO energy savings in 2019 and beyond. Estimates of IVVO energy savings will be calculated in the year after they occur.

E. Fault Location Isolation and Service Restoration (FLISR) and Fault Location Prediction (FLP)

1. FLISR and FLP Functions and Capabilities

Q. WHAT ARE FLISR AND FLP?

A. As mentioned above, FLISR stands for Fault Location Isolation and Service Restoration. FLISR involves deploying automated switching devices with the objective of decreasing the duration and number of customers affected by any individual outage. FLISR can noticeably reduce the amount of time customers will experience outages from faults, enable the Company to react to the event more quickly, and improve utility performance metrics such as system average interruption duration index ("SAIDI") and the system average interruption frequency index ("SAIFI").

Fault Location Prediction, or FLP, is a subset advanced application of FLISR that leverages sensor data from field devices to locate a faulted section of a feeder line and reduce patrol times needed to physically locate the fault.

Q. PLEASE DESCRIBE IN MORE DETAIL A FAULT AND FAULT CURRENT.

A. Faults are either temporary or permanent. A permanent fault is one where permanent damage is done to the system and a sustained outage (i.e., greater than five minutes) is experienced by the customer. Permanent faults may be the result of insulator failures, broken wires, equipment failure (e.g., cable failure, transformer failure), or public damage (e.g., an automobile accident impacting a utility pole). Temporary faults are those where customers experience a momentary interruption (i.e., less than five minutes). Causes of temporary faults include lightning, conductors slapping in the wind, or tree branches that fall across conductors and then fall or burn off.

When there is a fault—either temporary or permanent—the current or fault current is several to many times larger in magnitude than the current that normally flows due to load. The general profile for fault current is based on the distance from the substation (fault current is generally highest at the substation, decreasing as the location is further from the substation), type of fault (e.g., line-ground fault, three-phase fault), system voltage, and conductor type and size.

Q. DOES FLISR OPERATE FOR ALL OUTAGE EVENTS?

A. No, FLISR devices will operate for outages that occur on the distribution mainline. Outages that occur on laterals will benefit from FLP information and outages that occur on the secondary system will benefit from information that will be made available from the deployment of AMI meters. Although mainline outages only account for 3 percent of distribution outage events, today they account for over 30 percent of the distribution SAIDI.

Q. ARE THERE CURRENTLY DEVICES ON PUBLIC SERVICE'S DISTRIBUTION SYSTEM TO ASSIST IN FAULT ISOLATION AND SERVICE RESTORATION?

A. Yes. Public Service currently has small automation programs existing across its distribution system. In general, reclosers and sectionalizers are used to limit potential impacts of faults. Reclosers act as circuit breakers and are able to interrupt a fault event, meaning the recloser opens and the customers downstream of the recloser experience an outage. This is comparable to a household ground fault circuit interrupter ("GFCI") that opens when it detects a fault or issue, only affecting the devices downstream of the fault or issue, and not opening the breaker in a household breaker panel. Reclosers can also try to close a circuit (that has opened due to the fault) a certain number of times (to clear a temporary fault) before de-energizing all customers downstream. If successful, the process ensures that all customers on the impacted distribution feeder do not experience a sustained outage.

In addition, once ADMS is operational breakers and reclosers will measure current during faults (fault current) and report that data to ADMS. This will allow identification of line sections where the fault may have occurred so crews can be dispatched to the location of the failure rather than patrolling miles of line.

Q. WHAT WILL BE THE COMPONENTS OF FLISR AND FLP?

A. There will be four principal components of FLISR:

- Reclosers;

- Automated overhead switches;
- Automated switch cabinets; and
- Substation Relaying.

There will be two main components to FLP:

- Power sensors; and
- Substation Relaying.

Q. WHAT ARE RECLOSERS?

A. Reclosers will be pole-mounted remote supervisory reclosing and switching devices. The Company currently has reclosers on the distribution system. The new devices will perform the same functions as existing reclosers described above. The devices will also be able to interrupt a fault event and will be able to report fault current to ADMS, which can then use that information to execute FLP to determine the location of the fault. The reclosers will be able to "re-close" after a fault event to determine if a fault still exists. If the fault does not exist, the recloser will reclose and restore service. If the recloser determines that there is a permanent fault after multiple attempts to reclose, the device will communicate the fault information to ADMS, which will inform the Company of the need to dispatch a crew to the fault location. In addition, the reclosers will be controlled by ADMS when there is a permanent fault to automatically restore service.

Q. WHAT IS AN AUTOMATED OVERHEAD SWITCH?

A. Switches are overhead remote supervisory sectionalizing and switching devices. When a fault occurs, a feeder breaker senses the fault and opens. Although the overhead switches do not communicate directly with the feeder breaker, local controllers on switches on both sides of the fault would sense the loss of voltage and open, isolating the fault. However, unlike a recloser, the overhead switches will not have the capability of reclosing to determine whether there is a permanent fault. Instead, overhead switches rely on the feeder breakers for the reclosing functionality.

Although automated overhead switches lack the reclosing functionality, they utilize a compact form factor that makes them a better choice for space-constrained locations compared to reclosers.

Q. WHAT ARE AUTOMATED SWITCH CABINETS?

A. Automated switch cabinets are pad-mounted sectionalizing and switching devices. They are motor-operated, remote-controlled devices that are expected to be utilized for underground feeder installations. They will perform functions similar to the automated overhead switches for underground feeders.

Q. HOW WILL FLISR FUNCTIONALITY IMPROVE THE CURRENT SITUATION?

A. Public Service currently has an average of 1,745 customers on each feeder. Because of the Company's current lack of visibility into the conditions on the distribution system feeders, when a fault occurs Public Service generally relies on calls from customers to inform the Company of the problem. Once customers have reported an outage in a given area, Public Service operators dispatch crews to patrol the area where they believe the fault occurred, based on the information gathered from the calls. Crews then proceed to isolate the fault and manually close switches to restore service to customers affected by the fault. The average time to restore a feeder-level fault is 68.3 minutes. Such a fault affects all customers on that feeder (1,745 on average).

With FLISR, the components (described above) will divide the distribution feeders approximately into thirds, with intelligent switches in place to tie each section to another feeder when the section that is experiencing the fault is isolated. When a fault occurs, the system—in coordination with ADMS and FAN functionality—will automatically restore service to two-thirds of the customers on a feeder (or 1,163 customers on average) within minutes of the fault, and the other one-third of customers on the feeder (or 582 customers on average) may experience shorter service restoration times than the average of 68.3 minutes today due to the availability of more precise information regarding the location of the fault, rather than requiring the Company to patrol the length of the entire feeder with limited knowledge of the general location of the fault.

Existing reclosers and intelligent devices will be integrated into the FLISR scheme. If an existing device is in the correct location to employ FLISR functionality, this will obviate the need for a new device. Other existing devices will enhance FLISR's capabilities by enabling greater granularity in switching arrangements by having more precise voltage, current, and power information.

Q. CAN YOU DESCRIBE IN MORE DETAIL HOW FLISR OPERATES?

A. Yes, in the event of a fault, the FLISR protective devices will reclose or sectionalize the feeder as they currently do to isolate the fault. In addition, ADMS will provide for remote monitoring and control of FLISR and FLP devices. When a fault occurs on a FLISR- or FLP-enabled feeder, any of the intelligent field devices that are exposed to the fault will send a signal to ADMS notifying the system of the event. Devices that are capable will also send fault current during the event. ADMS will use both of sets of data, comparing fault current data against the impedance model (GIS data) to generate an expected fault location. If that feeder is FLISR-enabled, ADMS will generate a switching plan to isolate the faulted section based on system conditions, and will issue commands to field devices on the feeder and adjacent feeders so that non-faulted sections can be automatically restored, taking into account not only device and feeder loading, but surrounding substation loading as well. ADMS will then execute the proposed switching plan and notify the operator of the need to send a crew to the isolated section to manually investigate the fault event. This process is expected to take less than five minutes from the occurrence of an outage to operator notification. ADMS will also be able to run the FLP algorithm and predict which segment within a FLISR section the fault exists, which will reduce expected patrol times by crews.

Q. PLEASE DESCRIBE IN MORE DETAIL HOW FLP OPERATES AND HOW IT WILL IMPROVE DISTRIBUTION GRID PERFORMANCE.

A. Public Service is proposing to install up to two sets of three-phase advanced line power sensors along each feeder targeted for FLP deployment. One set will be installed on the feeder side of the substation, and another set could be installed down the line. Existing remote fault indicators and new intelligent device telemetry will be incorporated into the FLP deployment. If an existing device is in the correct location to employ FLP functionality, this will obviate the need for a new device. Other existing devices will enhance FLP's capabilities by providing additional data to improve FLP algorithm performance.

Feeders enabled only with FLP will operate in a slightly different manner from FLISR-enabled feeders. Should a fault occur, FLP devices upstream of the fault will capture an event occurring and will communicate relevant measurements during the fault (fault current) to ADMS. ADMS will compare these measurements to the impedance model and will generate expected fault locations. It will then notify the operator of these locations (with a level of certainty for each location), and the operator will dispatch a crew directly to the expected faulted section (as opposed to having the patrol the entire feeder line, as in the current situation) to isolate the faulted section. This process is expected to reduce the patrol time per fault by providing a specific location of the faulted section and reducing the area needed to be patrolled. However, where FLP is implemented on its own, the devices will not have the ability to automatically restore service to the sections of the feeder that are not experiencing the fault event.

Q. CAN YOU PROVIDE A COMPARISON TO A COMMON HOUSEHOLD SITUATION?

A. Yes, as a comparison, most strings of Christmas lights will not function at all if any one of the lights has a problem. Identifying the problematic light that causes the entire strand not to function requires testing each individual light. However, on a string of hypothetical "smart" Christmas lights, equipped with a centralized controller (comparable to ADMS) that communicates with each individual light, the centralized controller would use the data communicated to it by each of the lights to predict the location of the problematic light(s) to within a small set of lights. This is comparable to FLP. Once the lights' centralized controller isolated the small set of lights with the problem light, it would engage a switch that would allow the remaining lights to continue to work properly while the problem light is replaced. This is comparable to FLISR functionality.

2. FLISR and FLP Implementation and Costs

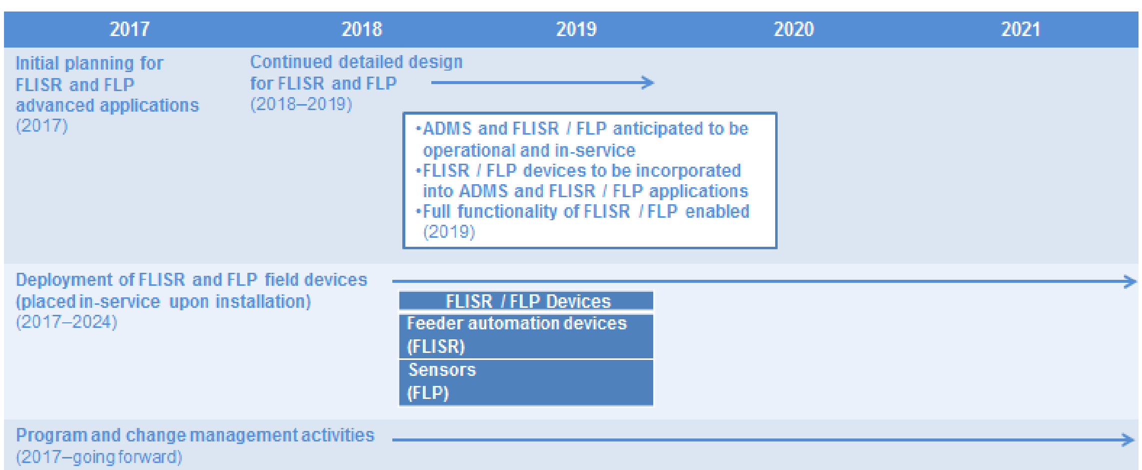
Q. WHAT WORK IS THE DISTRIBUTION BUSINESS AREA UNDERTAKING TO IMPLEMENT FLISR AND FLP?

A. The FLISR and FLP devices are on a nine-year deployment schedule that began in 2016. The deployment priority is based on the historical reliability performance of the feeders, starting with lower performing feeders. Deployment of devices will be in clusters of three-to-five feeders to gain the operational and reliability benefits in localized areas. Distribution will be responsible for managing the engineering, procurement and installation of the physical devices that will enable the FLISR and FLP advanced applications. This work will be done in combination with internal labor and third party contractors.

Distribution will also be responsible for the system analysis to determine the appropriate placement of the devices described above. There will also be make-ready work that is necessary to complete in order to install these devices, such as reconfiguring the location of a pole to allow an advanced application device to be placed on that pole or reconfiguring an underground cable so that a pad-mounted piece of equipment can interconnect with it.

Figure CSN-D-5 shows a timeline of FLISR and FLP implementation activities, including device deployments.

Figure CSN-D-5



Q. WAS DISTRIBUTION PRIMARILY RESPONSIBLE FOR DEVELOPING THE FORECAST FOR FLISR AND FLP?

A. Yes. Therefore, I describe the forecast development process for FLISR and FLP in more detail. After the Company identified FLISR and FLP as advanced applications to be included in the AGIS initiative, Distribution developed its forecast for FLISR and FLP by using data from actual installations of comparable devices, as well as pricing details from vendors and pilot projects. Some aspects of FLISR and FLP implementation, including the integration of the Sensor Management System ("SMS") for Aclara sensors into ADMS and ADMS IT integration are discussed and supported by Company witness Mr. Harkness.

Q. WHAT ARE THE PRIMARY COMPONENTS OF THE FLISR AND FLP CAPITAL FORECAST FOR ADVANCED APPLICATIONS?

A. The primary components of the FLISR and FLP capital forecast, shown in Table CSN-D-7 and Attachments CSN-1 and CSN-2, include: (1) device costs, which include device replacements, and (2) installation costs, which include project management, labor, and commissioning support.

Q. HOW DID DISTRIBUTION DERIVE THE CAPITAL FORECAST FOR THE FLISR AND FLP DEVICE COSTS?

A. The Company was able to use actual costs to develop the capital forecast for the FLISR and FLP devices, such as the costs for previous, completed projects utilizing the same equipment that will be deployed for FLISR. Xcel Energy had previously piloted FLP sensors from Aclara and actual costs from this work were used to develop forecasts for FLP.

With respect to device replacement costs, the Distribution Business Area experiences a roughly 0.6 percent equipment failure rate per year. This includes various factors such as product infancy failure rates and equipment failures due to public or environmental damage. This failure rate was applied to total equipment quantities to determine the number of devices that would need to be replaced and accurately reflect those costs in the FLISR and FLP deployments.

Q. WHY ARE THE FLISR AND FLP COSTS REASONABLE FOR CUSTOMERS TO SUPPORT?

A. Customer outages are an inevitable part of operating our system and, as discussed above, the deployment of FLISR and FLP devices will provide our customers with reliability benefits and reduce the frequency and duration of those outages by streamlining restoration efforts. Moreover, we are prioritizing areas that will result in the greatest benefit for our customers by targeting FLISR deployments to areas that have experienced a higher rate of outages that impact a greater number of customers across the Public Service system. For customers that are not located on FLISR-enabled feeders, FLP will provide the Company with more granular information about the location of a fault so that the Company can restore service more quickly, rather than having to rely on calls from customers and having to patrol miles of distribution lines when an outage is reported.

F. Program and Change Management Supporting AGIS

Q. WHAT OTHER COSTS ARE INCLUDED IN THE IMPLEMENTATION OF THE FOUNDATIONAL COMPONENTS OF AGIS?

A. Public Service's Distribution Business Area has primary responsibility for the Program and Change Management work that needs to be done for each foundational AGIS component to ensure a successful implementation of the AGIS initiative. The work that Distribution is undertaking for these activities is nearly identical for each foundational component of AGIS.

Q. WHAT IS PROGRAM MANAGEMENT?

A. Program Management is an organizational effort designed to coordinate project management tasks across individuals and business units that are necessary to support a transformational initiative such as AGIS. It also provides essential corporate resources to ensure that the various individual AGIS projects are completed successfully. The Program Management team will coordinate the work required for the individual projects that will build the assets that make up the overall AGIS initiative. The Program Management team is also responsible for financial analysis and control, accounting, contract management, resource management, initiative governance, communications and administrative assistance for each individual project and the overall AGIS initiative. The Program Management team will also track results, identify and determine if remedial action is necessary to keep the AGIS initiative on track, and monitor interdependencies between individual projects. Given the size of this initiative, Program Management is needed due to the highly interrelated and interdependent nature of the many components of the AGIS initiative at the individual project level.

Q. PLEASE DESCRIBE THE COSTS ASSOCIATED WITH PROGRAM MANAGEMENT FOR THE AGIS INITIATIVE.

A. Program Management will include capital costs and O&M expenses. The capital costs include engaging consultants and contractors throughout the development, deployment, and conclusion of the AGIS initiative. The Program Management costs are based on the need to build a Program Management team that will consist of both internal employees, as well as the engagement of consultants. This approach is based on the Company's experience with Program Management for other large-scale projects, and is consistent with its recent experience implementing the new general ledger and work and asset management systems.

Q. WHAT IS CHANGE MANAGEMENT?

A. Change Management is a formal discipline that dates back to the 1980's. It is a systematic approach to effectively execute and manage fundamental organization changes, related to people, process, technology and data. The Company's AGIS Change Management framework consists of three main elements or phases: preparation for the change, management of the change, and sustaining the change.

Q. WHY IS CHANGE MANAGEMENT NEEDED FOR THE AGIS INITIATIVE?

A. The implementation of the AGIS initiative will impact and transform the job functions for many of the Company's employees. In order to manage this transformation and properly engage employees and external stakeholders to ensure a successful transition, a comprehensive Change Management plan is necessary, particularly because AGIS will fundamentally change nearly all aspects of the Company's management of its distribution system and how it interacts with customers. For example, the Company will communicate with customers differently when it comes to an outage response or how meters are activated and read. AMI meter data will also provide information to customers about how they are using energy, rate structures, and energy options available to a customer. Through Change Management, the Company utilizes a mix of employees and consultants to support the Company and its employees through the three main phases of change identified above.

Q. PLEASE DESCRIBE THE COSTS ASSOCIATED WITH AGIS CHANGE MANAGEMENT.

A. Change Management will have capital costs and O&M expenses. The capital costs include engaging consultants and contractors throughout the development, deployment, and conclusion of the implementation of the AGIS initiative. Specific tasks that will be capitalized are those that relate directly to design and deployment of assets, such as, but not limited to, the development of key design decisions, training development, functional alignment, integration reviews, program architecture documentation, technical change management, managing quality, and performing independent deliverable reviews. The cost estimates for Change Management were developed independently for each AGIS program. For example, the AMI Change Management costs were benchmarked against and consistent with those of Ameren Illinois and First Energy Corporation, which installed AMI projects of a similar size. The Company's Change Management costs for IVVO and the FAN are consistent with the Company's own experience in Change Management during its recent experience implementing an enterprise-wide initiative involving the Company's new general ledger and work asset management systems (Productivity Through Technology ("PTT") is discussed by Company witness Daniel C. Brown).

IX. AGIS O&M

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

A. In this section of my Direct Testimony I support Distribution's O&M expenses for which the Company seeks recovery in this rate review with respect to the AGIS initiative, which include the Distribution Business Area's actual 2018 AGIS-related O&M expenses as well as an adjustment to account for the known and measurable O&M that the Company anticipates for its AGIS-related Distribution O&M in 2019, which the Company proposes to utilize as the primary basis for establishing Distribution's AGIS-related O&M expenses included in the Company's cost of service, which is supported by Company witness Ms. Blair.

Q. WHAT TYPES OF EXPENDITURES FOR AGIS ARE CLASSIFIED AS O&M EXPENSE?

A. O&M expenses includes those typically associated with construction and the operating and maintaining of the system, such as contracted labor, materials, transportation, permitting, restoration, and other services that are carried out in the normal course of business. During the construction and deployment of the AGIS field devices, the Company will incur O&M expense because some aspects of the work will be on existing facilities that must be rebuilt or otherwise modified. Once the devices are deployed, expenses will be incurred to operate and maintain the installed devices in the normal course of business.

Q. WHAT ARE DISTRIBUTION'S O&M EXPENSES RELATED TO AGIS IMPLEMENTATION THAT THE COMPANY HAS UTILIZED IN ITS COST OF SERVICE IN THIS RATE REVIEW?

A. Distribution's AGIS O&M expenses are shown below in Table CSN-D-8.

Table CSN-D-8
Public Service Electric

AGIS Distribution O&M (Dollars in Millions)		
AGIS Program	**2018**	**2019**
ADMS	0.8	1.1
AMI	0.5	1.7
FAN	0.2	2.0
FLISR	0.3	0.4
IVVO	0.4	1.7
Total*	**2.3**	**6.8**
*There may be differences between the sum of the individual AGIS program amounts and Total amounts due to rounding.		

Q. WHAT ARE THE PRIMARY COMPONENTS OF DISTRIBUTION'S O&M EXPENSES?

A. The primary components of Distribution's O&M expenses relate to contract labor costs and training activities. Although AGIS programs will have other types of O&M expenses, because the implementation and deployment of these programs and their respective devices are in early stages, costs related to device replacement or maintenance—such as for the FAN, IVVO, and FLISR—are expected to be minimal.

Q. PLEASE EXPLAIN THESE EXPENSES AND THE FORECASTED INCREASE IN DISTRIBUTION'S O&M EXPENSES FROM 2018 TO 2019.

A. The forecasted increase in O&M expenses is due to the anticipated increase in contract labor costs as the AGIS programs are implemented, particularly starting in 2019. This known and measurable increase in labor costs is the reason the Company is seeking to adjust its 2018 actual O&M expenses.

For example, with ADMS anticipated to go live in 2019, the Company will need additional resource support for managing the data and testing process, begin supporting the management of ADMS upon go live, and training individuals that will be impacted by the ADMS deployment, both continuing through the end of the ADMS project.

For AMI, the primary components of the AMI O&M expenses relate to AMI operations, and the removal, retirement, and disposal of the AMR meters by the meter installation vendor. The forecast for AMI Operations is based on costs associated with external project personnel using known and estimated contractor costs for the specified personnel. Similarly, the Company plans to have meter removal, retirement, and disposal of the AMR meters performed by the meter installation vendor, and the Company is in contract negotiations with the meter installation vendor to perform these activities.

The types of O&M expenses that Distribution will incur for IVVO and FLISR implementation in 2018 and 2019 are similar to each other and will initially involve O&M activities that are required such as modifying existing equipment that is in support of the installation of a new device, and device support, which consists largely of contract labor costs. As more devices are installed, more resources will be needed to provide support. In future years, programs like the FAN, IVVO, and FLISR will have greater amounts of costs related to device replacement, on-going communications network costs, and training activities.

Finally, all programs will have O&M expenses related to change management activities, which involves contractor labor, as discussed above.

For these reasons, the Company is making an adjustment to account for known and measurable AGIS O&M expenses that the Company anticipates for 2019 in the Company's 2018 HTY cost of service, as further explained by Ms. Blair.

X. RELIABILITY

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

A. In this section of my Direct Testimony I discuss the Company's historical reliability and service quality performance and how that performance has generally improved in recent years, and compare our performance to peers in the electric utility industry based on industry standard benchmark results. Further, I discuss the Company's expectations regarding future trends in electric utility reliability performance and how the AGIS programs will help continue to maintain the Company's reliability performance at levels that provide strong results for customers as compared to industry averages. These reliability goals reflect just one value stream of the AGIS initiative.

Q. PLEASE PROVIDE A HIGH-LEVEL OVERVIEW ON HOW PUBLIC SERVICE PROVIDES RELIABLE ELECTRIC SERVICE?

A. Public Service provides reliable service by designing the system to limit the number of outages and the number of customers impacted by an outage. When there is an outage or when a major storm hits, we respond swiftly and effectively to restore power. Public Service continues to be a leader in terms of reliability performance. The Company is consistently in the top performance quartile and, on average, customers have electric service more than 99.9 percent of the time.

Q. HOW DOES THE COMPANY ENSURE THAT IT IS PROVIDING RELIABLE SERVICE TO ITS CUSTOMERS?

A. Distribution commits capital and O&M investments to maintain reliable electric service. These generally either mitigate future outages, or improve our ability to limit any outages to the smallest number of customers for the shortest possible duration. The Company tracks reliability metrics and measures performance through benchmarking with other utilities. The Company also has a Quality of Service Plan ("QSP") in place with the Commission.

Q. WHAT ARE THE QSP'S RELIABILITY MEASUREMENTS?

A. The QSP has two types of measurements: system level and customer level. For the system level measurement, the QSP utilizes SAIDI for a selected set of data. SAIDI is the average duration of interruptions customers experience during a year quantified in minutes. It is normalized data that focuses on performance of distribution lines only, and specifically excludes impacts due to public damage, properly planned outages, and outages deliberately caused in the interest of public safety. Annual performance targets are defined based on historical performance within each region separately. Public Service pays its customers performance penalties if the Company does not meet its target for any region for two years or more in a row. For the customer based measurements the QSP has monitoring and penalty structures so that customers receive compensation if they experience multiple outage events within a given time frame, or if they experience outage events that last longer than 24 hours. Company witness Ms.

Applegate supports the Company's request for a three-year extension of the QSP.

Q. PLEASE DESCRIBE THE COMPANY'S QSP PERFORMANCE IN 2018.

A. The Company has performed well in 2018 relative to the QSP. For each the nine QSP reporting regions, SAIDI penalties are paid if the region's Reliability Warning Threshold ("RWT") is exceeded two years in a row. In 2018, only one of the nine regions, San Luis Valley, exceeded the Reliability Warning Threshold ("RWT") and this was mainly attributable to uncontrollable weather events on February 19, May 20, and May 21. These three days resulted in approximately 27 percent of the SAIDI impact in 2018 for this region. San Luis Valley also exceeded the target in 2017 resulting in a penalty of $121,081. The Company outlines the details of these events in the Annual QSP report for 2018 filed with the Commission on April 1, 2019 along with Company's plans to continue to enhance the reliability for this region.

For the customer based metric for customers experiencing multiple interruptions, penalties were paid in 2018 to some of Public Service's approximately 1.4 million customers. The maximum penalty for Public Service is $1 million/year for this metric, with a $50 maximum paid to any customer. In 2018, Public Service paid $266,450 as $50 bill credits to 5,329 customers who exceeded the Electric Continuity Threshold ("ECT") of no more than five sustained electric service interruptions in the performance year. The penalties paid, and thus, the number of customers who exceeded the ECT, was lower than in 2015, 2016, and 2017.

For customers experiencing long interruptions, a $50 bill credit is paid anytime the Electric Restoration Threshold ("ERT") of 24 hours is exceeded. In 2018, 198 customers received penalty payment for a total of $9,900 in bill credits.

Q. HOW DOES THIS COMPARE TO PREVIOUS QSP DATA?

A. The Company has continuously improved and reduced the number of customers experiencing multiple interruptions from 2012 to 2018 as shown in the figure below.

Figure CSN-D-6

The number of customers experiencing long duration outages tends to be lumpy year over year as there are very few events that can cause customers to experience long duration outages that exceed the 24-hour threshold. The 2018 result—198 customers exceeding the threshold—was an average year when compared to other years that include a high of 486 customers in 2012 and a low of 6 customers in 2014.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE QSP?

A. Yes, but such changes are limited to the addition of new Adequate Service metrics that will focus on providing adequate service in conjunction with improvements to Public Service's new Electric Distribution Extension Policy proposed in Consolidated Proceeding 18AL-0852E, which is pending before the Commission. Tracking mechanisms for these metrics are under development, and the Company proposes to meet with Staff and OCC quarterly throughout 2019 to share what has been learned, captured and resolved. Company witness Ms. Applegate discusses these new metrics in her Direct Testimony.

Q. IS THE COMPANY PROPOSING TO EXTEND THE QSP?

A. Yes. Ms. Applegate provides the details and reasons for the Company's recommendation to extend the QSP through 2021.

Q. HOW DOES THE COMPANY COMPARE TO ITS PEERS WITH RESPECT TO SAIDI PERFORMANCE?

A. The Company utilizes the Institute of Electrical and Electronics Engineers ("IEEE") Distribution Reliability Working Group large utility group benchmarking to compare its performance against similar sized electric utilities. The Company compares itself to other large utilities—that is, utilities with over one million customers. The IEEE survey is voluntary; in 2018, 93 entries were received (reporting 2017 data), of which 31 were included in the large utilities group.

The Company has consistently ranked in the 1st quartile or the top of the 2nd quartile even as overall industry reliability has continued to improve each year. For the most recent survey year available (2018 survey for 2017 data), Public Service ranked in the first quartile for 2017 with a SAIDI value of 84.5 minutes. The following table details the Company's rankings for the past eight years:

Table CSN-D-9
IEEE DRWG Benchmarking (Large Utility Group) – SAIDI

Year	Quartile	Minutes
2017	1st	84.5
2016	1st	86.5
2015	1st	88.3
2014	1st	84.8
2013	2nd	93.9
2012	1st	93.2
2011	1st	95.1
2010	2nd	94.7

Q. DID THE COMPANY EVER EXPRESS CONCERN REGARDING ITS ABILITY TO CONTINUE TO MAINTAIN ITS RELIABILITY?

A. Yes. In the Direct Testimony of Company witness Mr. John Lee in the AGIS CPCN Proceeding No. 16A-0588E, Mr. Lee stated that the Company ranked within the first quartile for SAIDI at that time, but that it was highly unlikely to maintain that position amongst the Company's peers by 2020 without advancing the distribution grid. This is because industry expectations are becoming more stringent as technology for advanced grids develops. It is expected that by 2020 utilities will need a SAIDI of 84 minutes to achieve first quartile SAIDI status, and that second quartile status will consist of rankings between 84 and 88 minutes.

Q. WITH THE IMPLEMENTATION OF THE AGIS INITIATIVE, DOES THE COMPANY EXPECT TO MAINTAIN ITS FIRST QUARTILE SAIDI RANKINGS?

A. Yes. ADMS, AMI, FLISR and FLP all contribute to improving reliability on the distribution grid. The Company expects to reduce SAIDI by more than 4.5 minutes by 2020 through the initial implementation of the FLISR initiative and more than 1 minute through FLP. The Company will work to install these devices first in the locations that will benefit the most. We continue to strive for improvement through other areas, including cable replacement, and overhead protection improvements.

While the industry is expected to continue to improve, the Company expects to continue to be a leader in reliability performance through the capabilities of the AGIS programs. Even as early as 2020, when these programs are in the early stages of deployment, they begin having significant impacts on reliability.

Q. HOW DOES THIS RELIABILITY DISCUSSION RELATE TO THE COMPANY'S OVERALL REQUEST FOR RECOVERY OF AGIS INVESTMENTS IN THIS RATE REVIEW?

A. While the Company has had strong reliability metrics for some time, the investment in distribution grid advancement is expected to continue to support and even improve the ability of Public Service to provide reliable electric service. These outcomes underscore the value and importance of AGIS investments for the benefit of customers.

XI. RECOMMENDATIONS AND CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. In sum, as part of approving the cost of service developed by Ms. Blair, I recommend that the Commission approve the 2014-2019 Distribution Business Area capital additions and 2018 Distribution Business Area O&M expenses, including the AGIS capital additions and O&M, and adjusted for Mutual Aid to Puerto Rico, as set forth above. I also recommend the Commission approve the Company's request related to recovery of Wildfire Mitigation Plan O&M expenses, which comprise an adjustment to the 2018 O&M expenses for known and measurable costs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Statement of Qualifications

Chad S. Nickell

I am the Manager of Distribution System Planning and Strategy—South for Xcel Energy. My role is to provide strategic direction for building a five-year distribution plan for ensuring a reliable and cost effective electric distribution system. My key responsibilities include developing and leading a system advancements and renewal strategy and managing the current year and five-year distribution capital budget for Public Service and Southwestern Public Service Company, one of the other Xcel Energy Operating Companies.

I joined Public Service Company of Colorado in 2008 as a Distribution System Planning Engineer and have over ten years of experience in the utility industry. I graduated from the University of Colorado, Boulder in May 2004 where I earned a Bachelor of Science degree in Electrical Engineering.

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

* * * *

RE: IN THE MATTER OF ADVICE NO. 1797-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8-ELECTRIC TARIFF TO IMPLEMENT RATE CHANGES EFFECTIVE ON THIRTY-DAYS' NOTICE.	**) PROCEEDING NO. 19AL-______E**

**AFFIDAVIT OF CHAD S. NICKELL
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO**

I, Chad S. Nickell, 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 15 day of May, 2019.

____
Chad S. Nickell
Manager, System Planning and Strategy - South

Subscribed and sworn to before me this 15th day of May, 2019.

ROBERT E. BLU, II
Notary Public
State of Colorado
Notary ID # 20104014057
My Commission Expires 04-22-2022

____
Notary Public

My Commission expires April 22, 2022