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

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IN THE MATTER OF ADVICE LETTER NO. 1857-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 8-ELECTRIC TARIFF TO REVISE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL ELECTRIC RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE AUGUST 2, 2021	**) PROCEEDING NO. 21AL-______E**

DIRECT TESTIMONY AND ATTACHMENTS OF CHAD S. NICKELL

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

July 2, 2021

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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Attachment CSN-4	Distribution AGIS O&M Expenses by FERC Account for 2020-2022

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
2019 Electric Phase I	Proceeding No. 19AL-0268E
ADMS	Advanced Distribution Management System
AGIS	Advanced Grid Intelligence and Security
AGIS CPCN Proceeding	Proceeding No. 16A-0588E
AGIS CPCN Settlement	AGIS CPCN Settlement between the parties in the CPCN Proceeding
AGR	Advanced Grid Rider
Amended CPCN	Company-requested amendment to the AGIS CPCN
AMI	Advanced Metering Infrastructure
APT	Advanced Planning Tool
C&I	Commercial and Industrial
Commission	Colorado Public Utilities Commission
CPCN	Certificate of Public Convenience and Necessity
CPCN Projects	AMI, IVVO, and the associated mesh network portion of the FAN
DERs	Distributed Energy Resources
DI	Distributed Intelligence
DSM	Demand-Side Management
ENGO	Varentec’s Edge of Network Grid Optimization
EV	Electric Vehicle
FAN	Field Area Network
FCC	Federal Communications Commission
FERC	Federal Energy Regulatory Commission

Acronym/Defined Term	**Meaning**
FLISR	Fault Location Isolation and Service Restoration
FLP	Fault Location Prediction
FTY	Future Test Year
GEMS	Grid Edge Management System
GIS	Geospatial Information System
HAN	Home Area Network
HAN Proceeding	Proceeding No. 18A-0194E
IC	Integration Council
Itron	Itron, Inc
IVVO	Integrated Volt-VAR Optimization
LBNL	Lawrence Berkeley National Laboratory
LTCs	Load Tap Changers
Meter Contract	Xcel Energy selected Itron as its meter vendor to serve all jurisdictions
NICs	Network Interface Cards
O&M	Operations & Maintenance
PMO	Project Management Office
Public Service or Company	Public Service Company of Colorado
RF	Radio Frequency
RFP	Request for Proposal
RTUs	Remote Terminal Units
SAIDI	System Average Interruption Duration Index
SCADA	Supervisory Control And Data Acquisition
SMS	Sensor Management Software
WAN	Wide Area Network

Acronym/Defined Term	**Meaning**
WiMAX	Worldwide Interoperability for Microwave Access
WiSUN	Wireless Smart Utility Network
XES	Xcel Energy Services Inc.
Xcel Energy	Xcel Energy Inc.

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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 Advanced Grid Intelligence and Security ("AGIS") Delivery Lead for Distribution. 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 AGIS Delivery Lead for Distribution, I am responsible for managing the delivery of the AGIS projects for Distribution which includes management of costs, schedule, and scope in partnership with Business Systems. This also includes supporting the AGIS governance structure for Project Management, Resource Management, and Financial Management. A description of my qualifications, duties, and responsibilities is set forth after the conclusion of my Direct Testimony in my Statement of Qualifications.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to support the Company's request for Distribution capital additions and operations and maintenance ("O&M") costs related to the AGIS initiative. I provide support for capital additions placed into service since the Company's 2019 Electric Rate Case in Proceeding No. 19AL-0268E ("2019 Electric Phase I"), from September 1, 2019 through the year-end 2021 forecast, as well as the planned capital additions and O&M costs forecasted for the 2022 Future Test Year ("FTY"). To support this request, I provide an overview of the AGIS initiative and the need for this initiative. I also explain Distribution's role in AGIS implementation and describe the specific work undertaken by the Distribution area for each component of the AGIS initiative.

Several other Company witnesses provide Direct Testimony related to AGIS: Mr. Michael O. Remington provides an overview of Public Service's AGIS initiative with respect to the Business Systems organization; Mr. Emmett R. Romine provides Direct Testimony on how AGIS implementation supports the Company's overall efforts to improve the customer experience; Mr. Steven P. Berman supports the Company's request for deferred accounting treatment for certain AGIS costs beyond the FTY; and Ms. Deborah A. Blair supports the Company's cost of service and revenue requirement associated with AGIS.

Q. PLEASE DESCRIBE THE AGIS INITIATIVE.

A. 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 Public Service to safely integrate more distributed energy resources ("DERs"), and improve customer products and services. AGIS seeks to take advantage of existing advanced technology to increase grid reliability, transparency, efficiency, and access. Overall, the AGIS platform consists of multiple projects that will ultimately work together to support improved distribution technology, empowered customer choice, and improved energy management and savings. The AGIS initiative involves the following foundational projects: Advanced Distribution Management System ("ADMS"), including the Geospatial Information System ("GIS"); Advanced Metering Infrastructure ("AMI"); the Field Area Network ("FAN"); Intelligent Field Devices that include Integrated Volt-VAR Optimization ("IVVO") and Fault Location Isolation and Service Restoration ("FLISR") (including Fault Location Prediction ("FLP"); and the Advanced Planning Tool ("APT"). Each of these projects involves a coordinated approach – i.e., planning, design, build, deployment, and ongoing support – from the Distribution and Business Systems Business Areas.

Q. HAS THE COMPANY PREVIOUSLY PROVIDED INFORMATION ON THE AGIS INITIATIVE?

A. Yes. On August 2, 2016, Public Service filed an Application and Direct Testimony in Proceeding No. 16A-0588E (the "AGIS CPCN Proceeding"), requesting that the Colorado Public Utilities Commission ("Commission") grant a Certificate of Public Convenience and Necessity ("CPCN") to implement AMI, IVVO, and the associated mesh network portion of the FAN (collectively, the "CPCN Projects"). The Commission approved the Company's request for a CPCN pursuant to its Application as part of an AGIS CPCN Settlement between the parties in the CPCN Proceeding (the "AGIS CPCN Settlement").[1] Company witness Mr. Berman discusses the AGIS CPCN Settlement in greater detail. Company witness Ms. Brooke A. Trammell discusses the Company's subsequent application and the Commission's approval of Public Service's plan to activate the Home Area Network ("HAN") capability within the AMI meters in Proceeding No. 18A-0194E (the "HAN Proceeding").

In addition, the Company further discussed other AGIS components in the Company's 2019 Electric Phase I. As a result of the 2019 Electric Phase I, portions of AGIS costs have already been approved for recovery though base rates, as I will discuss in my Direct Testimony. The Company also provided extensive information on AGIS in Proceeding No. 20AL-0301E requesting approval to

[1] Unopposed Comprehensive AGIS CPCN Settlement in Proceeding No. 16A-0588E.

recover costs AGIS costs through a new Advanced Grid Rider ("AGR"). The Company's request to establish an AGR was dismissed; thus the applicable AGIS costs are included in the Company's rate request in this case.

I also note that on June 15, 2021, in compliance with Commission Decisions,[2] the Company requested an amendment to the AGIS CPCN ("Amended CPCN") in Proceeding No. 21A-0279E. Specifically, the Company requested that the AGIS CPCN be amended to allow for the deployment and utilization of the DI capabilities that are embedded within the AMI meters that are being installed pursuant to the initial AGIS CPCN. The Company also requested that the Commission recognize the new industry standard communication protocol between an advanced meter and a customer's HAN and that providing customers usage information over the Wi-Fi radio included in the advanced meters is beneficial to customers. Further, the HAN implementation plans discussed in my Direct Testimony reflect the Company's plans based on prior Commission decisions; however, during development of this rate case application, the Commission issued a decision precluding the Company from activating HAN capabilities prior to the completion of the Amended CPCN proceeding. To the extent the schedule or Commission decisions in the Amended CPCN proceeding alter the implementation of HAN capabilities described in my Direct Testimony, the Company will make any necessary adjustments to the rate case revenue requirements.

[2] Decision Nos. C21-0176 and C21-0177, both mailed March 19, 2021.

Q. CAN YOU SPECIFY HOW THE SUPPORT FOR AGIS PROJECTS IS DIVIDED BETWEEN YOUR DISTRIBUTION TESTIMONY AND MR. REMINGTON'S BUSINESS SYSTEMS TESTIMONY?

A. Yes. Support for the AGIS components is divided as shown in Table CSN-D-1 below.

TABLE CSN-D-1: AGIS Program Witness Support

AGIS Project	Component	Witness
ADMS	ADMS system and integration	Remington Direct, Section VI(B)
	GIS	Nickell Direct, Section III
AMI	IT Integration and AMI head-end application	Remington Direct, Section VI(C)
	Meters and deployment	Nickell Direct, Section IV
FAN	IT Integration and deployment	Remington Direct, Section VI(D)
	Installation of pole-mounted devices	Nickell Direct, Section V
IVVO	System development	Remington Direct, Section VI(E)
	Advanced application and field devices	Nickell Direct, Section VI
FLISR	Advanced application and field devices	Nickell Direct, Section VII
APT	System development	Remington Direct, Section VI(F)
	Advanced application	Nickell Direct, Section VIII

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

A. Yes, Attachments CSN-1 through CSN-4 are related to AGIS and were prepared by me or under my direct supervision. The attachments are as follows:

- Attachment CSN-1: Distribution AGIS Plant-Related Roll-Forwards for the Period September 1, 2019 through December 31, 2020;
- Attachment CSN-2: Distribution AGIS Plant-Related Roll-Forwards for the January 1, 2021 through December 31, 2022;
- Attachment CSN-3: Distribution AGIS Operations and Maintenance ("O&M") Expenses by Cost Element for 2020-2022; and

- Attachment CSN-4: Distribution AGIS O&M Expenses by Federal Energy Regulatory Commission ("FERC") Account for 2020-2022.

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

A. As part of approving the FTY cost of service developed by Ms. Blair, I recommend that the Commission approve Distribution's AGIS capital additions for September 1, 2019 through the 2022 FTY, and Distribution's forecasted AGIS O&M expenses for the 2022 FTY as set forth below.

II. OVERVIEW OF DISTRIBUTION AGIS TESTIMONY

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

A. In this section of my Direct Testimony, I provide an overview of the AGIS initiative and prior Commission proceedings and approvals related to the AGIS projects. I also review the drivers and benefits of AGIS implementation and discuss the work that Distribution has completed to date related to the AGIS projects. Finally, I provide an overview of Distribution's AGIS capital additions and O&M costs.

A. AGIS Overview

Q. PLEASE DESCRIBE THE AGIS INITIATIVE AND DISTRIBUTION'S ROLE IN PROVIDING SUPPORT FOR AGIS IN THIS PROCEEDING.

A. The Company's AGIS initiative involves the following foundational projects: ADMS (including the GIS), AMI, the FAN, IVVO, FLISR (including FLP), and APT. Each of these projects involves a coordinated approach – i.e., planning, design, build, deployment, and ongoing support from Business Systems and Distribution. Distribution is responsible for the Company's overall technical strategy for AGIS and the Distribution Business Area's AGIS implementation. Mr. Remington provides for the IT integration necessary to carry out the AGIS initiative.

Q. WHAT WERE KEY DRIVERS BEHIND THE NEED FOR AGIS IMPLEMENTATION, AND WHAT BENEFITS DOES AGIS IMPLEMENTATION PROVIDE?

A. Since Public Service discussed the need for and benefits of the AGIS initiative in depth in the approved CPCN Proceeding and has provided additional information on AGIS as discussed above, I provide here a review of the key drivers and benefits of the AGIS initiative. Based on the technologies available at the time, Public Service's distribution system was originally designed to accommodate primarily a one-way flow of electricity and information from the utility to the customer, limiting the visibility into the grid operations beyond the distribution substation level. The system was also designed to rely heavily on manual and local control configurations to operate, and it lacks connectivity to easily share information between different portions and components of the system.

With new technologies available, AGIS implementation will transform grid operations and monitoring capabilities, significantly enhance the customer experience relative to outages, voltage, and communications, and enable the design of new and enhanced programs and rates for our customers. AGIS applications promote energy efficiency and demand reductions, and enable new rate designs like time-of use rates. AGIS also enhances the Company's system planning capabilities allowing for increased distributed energy resources on the system. Specific benefits of individual AGIS components are discussed further in the separate sections that follow.

Q. WHAT IS THE DISTRIBUTION BUSINESS AREA'S ROLE IN IMPLEMENTING THE AGIS FOUNDATIONAL PROJECTS?

A. At a high level, the AGIS work that the Distribution Business Area is responsible for falls into six primary categories: (1) installing field devices (AMI meters, and field devices to implement IVVO, FLISR, FLP); (2) data collection for ADMS and GIS; (3) supporting the business requirements and the required testing in support of the software deployments; (4) managing and supporting the governance structure; (5) determining appropriate business processes to manage the systems; and (6) determining employees' roles and responsibilities to implement and operate the new projects that are part of the AGIS initiative.

Q. WHAT WORK HAS DISTRIBUTION ALREADY UNDERTAKEN OR COMPLETED WITH RESPECT TO THE AGIS INITIATIVE?

A. As previously noted, the Company previously obtained a CPCN for the AGIS CPCN Projects in 2017. Before and after the CPCN was obtained, Distribution has been working on the planning and implementation of the various components of the AGIS initiative. Public Service has undertaken scoping, planning, design, requests for proposal ("RFP"), and contracting with respect to a number of the components.

Further, Public Service is already deploying and operating some components and facets of the AGIS initiative. For example, the first deployment phase of ADMS was placed in service in April 2019 with the second and final deployment placed in service in the fourth quarter of 2020. Public Service has also deployed IVVO field devices and 13,000 AMI meters and is utilizing the FAN to support AMI and IVVO. Public Service is utilizing the AMI interfaces to provide customers who have AMI meters with valuable information on their energy use. In the coming years, the Company will continue to deploy the FAN and AMI, continue to add capabilities and functionality to AMI thru interfaces and customer systems to deliver more value to customers. Public Service has also started to deploy FLISR and FLP devices on some of the lower performing feeders within the service territory and those devices have begun to be used to generate reliability benefits for customers.

B. Introduction to Distribution's AGIS Costs

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

A. The capital costs for Distribution to implement each of the AGIS projects (AMI, GIS data collection in support of ADMS, FAN, FLISR, IVVO, and substation communications) generally include material and equipment, labor, and vendor services.

Q. WHAT ARE THE CAPITAL ADDITIONS FOR THE AGIS INITIATIVE THAT YOU ARE SUPPORTING IN THIS CASE?

A. Distribution's AGIS capital additions that I am supporting for inclusion in base rates are shown in Table CSN-D-2 below. AGIS capital additions through August 31, 2019 have already been included in base rates through the 2019 Electric Phase I. The capital additions "Other" category reflect capital additions for an AGIS testing lab in 2019.

TABLE CSN-D-2
Distribution AGIS Capital Additions
Public Service – Total Company

AGIS Program *($ in millions)*	**9/1/2019 through 12/31/2019 Actual**	**2020 Actual**	**2021 Forecast[3]**	**2022 Forecast**	**Total**
ADMS	$ 2.6	$ 1.5	$ 5.9	$ –	$ 9.9
AMI	7.5	1.4	67.4	73.7	150.1
FAN	7.9	5.2	6.9	4.1	24.1
IVVO	7.0	23.6	34.9	25.7	91.2
FLISR	2.2	4.8	7.1	5.9	19.9
Other	0.3	–	–	–	0.3
Total	**$ 27.6**	**$ 36.4**	**$ 122.1**	**$ 109.4**	**$ 295.5**
Any differences between sum of individual category amounts and Total are due to rounding.					

Total AGIS Distribution capital additions are also set forth in Attachments CSN-1 and CSN 2 to my Direct Testimony.

Q. WHAT TYPES OF O&M COSTS IS DISTRIBUTION INCURRING TO IMPLEMENT THE AGIS INITIATIVE?

A. Distribution's AGIS-related O&M costs include internal labor, external labor, vendor services, and materials.

Q. WHAT ARE THE DISTRIBUTION O&M COSTS FOR AGIS IMPLEMENTATION THAT THE COMPANY SEEKS TO UTILIZE IN ITS FTY COST OF SERVICE IN THIS RATE CASE?

A. Distribution's AGIS O&M costs for 2020 and 2021, as well as the forecasted costs for the 2022 FTY are shown below in Table CSN-D-3.[4] The O&M costs in the "Other" category relate to costs associated with program management, change

[3] Throughout my testimony, the 2021 forecasts for both capital additions and O&M include actuals from January and forecasts for February through December.

[4] Note the O&M costs presented in this testimony reflect both internal and external labor. The AGIS O&M adjustment for the 2022 FTY presented by Ms. Blair includes only incremental external labor. The internal AGIS labor is accounted for in the 2022 FTY along with all other internal Company labor.

management, delivery and execution leadership, and corporate communications which I discuss in Section IX.

TABLE CSN-D-3
Distribution AGIS O&M
Public Service – Electric

AGIS Program *($ in millions)*	**2020 Actual**	**2021 Forecast**	**2022 Forecast**
ADMS	$ 0.6	$ 0.3	$ 0.3
AMI	0.7	3.1	1.5
FAN	0.5	0.2	0.2
IVVO	0.30	1.0	1.6
FLISR	0.1	0.2	0.3
Other	4.6	2.6	1.9
Total	**$ 6.8**	**$ 7.4**	**$ 5.7**
Any differences between sum of individual category amounts and Total are due to rounding.			

Total AGIS O&M costs are provided in Attachment CSN-3 to my Direct Testimony by cost element and in Attachment CSN-4 by FERC account.

Q. ARE THE DISTRIBUTION AGIS CAPITAL ADDITIONS AND O&M EXPENSES PRESENTED ABOVE CONSISTENT WITH THE INFORMATION PROVIDED IN PUBLIC SERVICE'S AGIS COMPLIANCE FILINGS IN PROCEEDING NO. 16A-0588E?

A. Yes. The actual costs for 2019 and 2020 are consistent with the cost information filed by the Company its Annual Actuals Report in Proceeding No. 16A-0588E, filed in May 2020 and May 2021, respectively.[5] The Distribution forecast for 2021 is consistent with what was reported by Public Service in the Grid CPCN 2021 Forecast Report filed in October 2020 in Proceeding No. 16A-0588E, but has been

[5] The compliance reports submitted by the Company in Proceeding No. 16A-0588E relate only to the AGIS programs (of portions thereof) that were the subject of the CPCN and the AGIS CPCN Settlement in that proceeding. In addition, the compliance reports show expenditures, not capital additions. Accordingly, the cost information filed by the Company in its compliance reports in Proceeding No. 16A-0588E does not match Tables CSN-D-2 and CSN-D-3 above.

updated to reflect actuals through January 2021.

Q. HOW IS THE COMPANY ADDRESSING COSTS BEYOND 2022 FOR AGIS, RELEVANT TO THE DEFERRAL REQUEST YOU REFERENCED EARLIER?

A. The Company is not proposing specific costs for recovery beyond 2022, but rather a continuation of the deferral previously included in the AGIS CPCN Settlement and approved by the Commission. The Company will continue to provide ongoing reporting on the AGIS CPCN work through its annual filings, including available cost data for years beyond 2022 as relevant. While my Direct Testimony does not address the specific costs for deferral, I discuss the work that will continue beyond the 2022 test year. Mr. Berman provides the Company's request for deferral in his Direct Testimony.

III. ADVANCED DISTRIBUTION MANAGEMENT SYSTEM

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

A. In this section of my Direct Testimony, I review the purpose of the Advanced Distribution Management System or ADMS and provide updates on the deployment of ADMS and the associated GIS data collection effort. I also discuss Distribution's work to implement ADMS and identify Distribution's capital additions and O&M costs related to ADMS.

A. Overview of ADMS

Q. WHAT IS THE ADMS?

A. 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. The multiple applications within ADMS constitute a single system that enables the optimization of each application by using one operating model and the same power flow measurements and calculations. It will help control room, field operating personnel, and engineers manage the complex interaction of distributed energy resources, outage events, feeder switching operations, and real-time and near real-time data to provide all information on operator console(s) at the control center in an integrated manner.

Q. WHAT ARE THE PHYSICAL COMPONENTS OF ADMS?

A. ADMS is composed of hardware, software, distribution supervisory control and data acquisition ("SCADA"), and an impedance model, which is an accurate electrical representation of the distribution grid, including substations, core, and advanced applications.

Q. WHAT IS GIS?

A. GIS is a geospatial program that captures and stores the Company's electric grid asset information that is installed in the field. 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 DOES ADMS PROVIDE IMPROVEMENTS OVER THE FUNCTIONALITY OF THE COMPANY'S PRIOR SYSTEMS?

A. ADMS utilizes an enhanced distribution grid model in one user interface to more accurately represent the entire distribution grid. This model provides the Company with greater visibility into the distribution system, provides information about the system at a more granular level, and enables the optimization of each grid application by using one operating model and the same power flow measurements and calculations. In addition, when DER and sensor measurements are available, ADMS uses the measurements to improve power flow calculation accuracy and display the measurements and results with geospatial accuracy. This functionality enables optimization of both manual and automated switching sequences, advanced application functionality (e.g. for IVVO and FLISR), improved reaction time to outage events, increased awareness of voltage levels throughout the grid, awareness of the DER impact to power flow on the grid, and validation of grid operations prior to switching.

Q. WHAT DO YOU MEAN WHEN YOU REFER TO "GRID APPLICATIONS?"

A. ADMS has core applications, which make up the foundation of ADMS allowing it to function as designed, as well as advanced applications. The core 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 utilize the core applications and provide additional capability. Public Service plans to utilize two such advanced applications at this time: IVVO and FLISR. 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.

Q. DOES ADMS PROVIDE THE CAPABILITY TO ENABLE MULTIPLE APPLICATIONS AND OBJECTIVES?

A. Yes. As an example, when the IVVO and FLISR functions (which are discussed in more detail below) are 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 can be implemented independently, but the lack of awareness of the performance of the separate standalone systems would reduce the overall effectiveness of each system. By implementing IVVO and FLISR in ADMS, the applications are integrated and coordinated together to realize the full benefits of each application.

Q. ARE THERE OTHER POTENTIAL FUTURE USES FOR ADMS?

A. Yes. ADMS will provide a dynamic model and real-time power flow information that can facilitate increased penetration and integration of DERs, energy storage, integration of micro-grids, and future customer choice. As DERs, including renewable resources, increase 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 and maintain reliability. As another example, ADMS would allow for the integration of any protective devices installed in the field through adaptive protective settings within ADMS to reduce the risk of starting a wildfire during days with high fire risks.

B. ADMS Deployment Timeline

Q. WHAT WORK HAS DISTRIBUTION UNDERTAKEN TO IMPLEMENT THE ADMS AND GIS PROJECT?

A. Distribution is the business area that utilizes ADMS and has worked in partnership with Business Systems to implement ADMS. Distribution was responsible for four components of the ADMS implementation. First, Distribution's partnership with Business Systems included the design, implementation, and testing of ADMS as discussed in further detail by Mr. Remington. Second, Distribution was responsible for the GIS data collection effort, for which the Company is collecting and validating data for our Colorado distribution system that is needed to ensure proper ADMS functionality. Third, Distribution was responsible for the implementation of intelligent field devices to test ADMS and ensure it has the necessary operating information. Finally, Distribution has partnered with Business Systems to build out the system, interfaces, and network to support the deployment of ADMS and the advanced functionality for IVVO and FLISR.

Q. PLEASE DESCRIBE THE WORK THAT DISTRIBUTION HAS COMPLETED TO IMPLEMENT ADMS.

A. The Company deployed the ADMS software by executing the following phases of the project: requirements, design, build, test, and deploy. The requirements and detailed design for the implementation of ADMS which began in 2016 included definition of the business requirements and functionality of the ADMS software, high-level architecture diagrams, and detailed project design necessary to build and configure the ADMS software.

The implementation or build phase of ADMS began in 2017 which as described above is comprised of hardware, software, distribution SCADA, and an impedance model. Initial testing and development of the ADMS software began in 2018 and was deployed in two phases. All testing was competed as of May 2020.

The first ADMS deployment in April 2019 implemented the core functions and enabled operation of the IVVO function. The Company's Grid Management team has been using ADMS since April 2019 and has expanded IVVO and FLISR functionality and benefits to additional areas of the system as describe in more detail in Sections VI and VII. The second deployment of ADMS was completed in November 2020 resulting in additional functionality and an expanded network model to enable control center operators to use ADMS to manage the distribution system. The Company completed all of the activities necessary for the control center operators to begin using ADMS to manage the distribution system as of May 2020. However, the control center go-live date was pushed back to the fourth quarter of 2020 due to precautions the Company had taken to isolate the control center operators from risks related to COVID-19. In preparation for the control center go-live, the Company conducted final training with operators prior to going live in November 2020.

Q. WITH ADMS FULLY IMPLEMENTED IN 2020, WAS THERE ADDITIONAL WORK DISTRIBUTION IS ENGAGED IN WITH RESPECT TO ADMS?

A. Yes. The Company completed the ADMS integrations with AMI, Grid Edge Management System ("GEMS"), and Sensor Management Software ("SMS") software components that are part of the IVVO and FLISR deployments as described in more detail by Mr. Remington. The Company will continue to expand ADMS functionality by enabling the FLISR and IVVO functions to additional substations and feeders and will include the expansion of other potential future uses as described above.

C. Distribution's Capital Costs for ADMS and GIS

Q. WHAT ARE THE ADMS CAPITAL ADDITIONS FOR DISTRIBUTION RELEVANT TO THIS RATE CASE?

A. Table CSN-D-4 below provides Distribution' capital additions for ADMS and GIS for September 1, 2019 through the 2022 FTY.

TABLE CSN-D-4
ADMS and GIS Distribution – Capital Additions
(Public Service – Total Company)

AGIS Program *($ in millions)*	**9/1/2019 through 12/31/2019 Actual**	**2020 Actual**	**2021 Forecast**	**2022 Forecast**
ADMS and GIS	$ 2.6	$ 1.5	$ 5.9	$ –

Q. WHAT ARE THE PRIMARY COMPONENTS OF DISTRIBUTION'S ADMS AND GIS CAPITAL COSTS?

A. The primary components of the Distribution Business Area's ADMS and GIS capital costs are: (1) data collection of distribution field assets and (2) substation data collection to gather additional information needed in the Company's GIS data model for the ADMS capabilities to run successfully.

Q. PLEASE PROVIDE AN OVERVIEW OF THE PROCESS FOR DEVELOPING THE DISTRIBUTION ADMS CAPITAL BUDGET.

A. The ADMS costs are based on the contracts and pricing the Company has with its vendors that support the data collection process and the internal labor for the employees that support this effort.

In addition, to create a 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 SOME HISTORY ON HOW THE COMPANY DEVELOPED THE ADMS SCOPE AND COSTS?

A. Yes. The Company issued an RFP in 2014 to determine the most appropriate distribution management system for the Company, selecting Schneider Electric. After the ADMS vendor was selected, a detailed project cost estimate was created from the pricing and contract information as well as labor and hardware to support the overall ADMS project. This effort was benchmarked and reviewed with other utilities and industry research organizations such as EPRI. Upon completion of the detailed design, a detailed implementation plan was developed and the ADMS project cost estimates were updated. 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.

D. <u>Distribution’s O&M Costs for ADMS and GIS</u>

Q. WHAT ARE THE ADMS O&M COSTS FOR DISTRIBUTION RELEVANT TO THIS RATE CASE?

A. Table CSN-D-5 able below provides Distribution’s O&M expense for ADMS and GIS for 2020 through the 2022 FTY.

TABLE CSN-D-5
ADMS and GIS Distribution – O&M Expenses
(Public Service – Electric)

AGIS Program *($ in millions)*	**2020 Actual**	**2021 Forecast**	**2022 Forecast**
ADMS	$ 0.6	$ 0.3	$ 0.3

Q. HOW WAS THE O&M BUDGET FOR ADMS AND GIS DEVELOPED?

A. The Distribution O&M costs for ADMS in 2020-2022 primarily incurred by the Grid Management Team (Grid Analysts, Grid Engineers, Grid Analysts Supervisor, and Manager of Grid Management) to provide on-going support of the ADMS applications and system models within ADMS. There were additional O&M costs in 2020 related to the labor costs to build out the data in the ADMS model. These costs decreased in 2021 once ADMS was fully in service in the fourth quarter of 2020 and the initial data collection and model instantiation in Public Service was complete.

Q. WHY ARE DISTRIBUTION'S ADMS AND GIS DATA COLLECTION COSTS REASONABLE FOR CUSTOMERS TO SUPPORT?

A. ADMS is not only a foundational tool, it is a critical part or the "brain" 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. 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 had to be enhanced. These calculations will drive the operation of IVVO and FLISR, and the core capabilities within ADMS. These are reasonable and necessary expenses to enable the

ADMS capabilities, which in turn provide the customer benefits. Further, the Company underwent 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. Finally, the initial budget was 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.

IV. ADVANCED METERING INFRASTRUCTURE

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

A. In this section of my Direct Testimony, I provide an overview of AMI and discuss the progress that Public Service has made in the development and implementation of AMI since the Company's 2019 Electric Phase I. I then provide an overview of the AMI deployment timeline, discuss Distribution's work in AMI implementation, and identify Distribution's capital additions and O&M costs related to AMI.

A. Overview of AMI

Q. WHAT IS THE AMI PROJECT?

A. AMI is an integrated system of AMI meters, communications networks, and data management systems that enables secure two-way communication between customer meters and utilities' business and operational systems that enable benefits for both the customer and the utility. AMI meters are able to measure and transmit voltage, current, and power quality data and can act as a sensor, providing timely monitoring at the customer's point of service which has a variety of uses for customers and business operations. AMI is a key element of the AGIS initiative because it provides a central source of information that interacts with many of the other components of the AGIS initiative.

Q. HOW DOES THE AMI PROJECT BENEFIT CUSTOMERS?

A. AMI meters provide substantial near real-time data that can be used to improve the Company's ability to monitor, operate, and maintain the distribution grid. AMI meters are used to verify power outages and service restoration. Improved reliability monitoring leads to improved outage response, proper protection system analysis and ultimately reduces or eliminates outages. AMI meters also provide improved voltage monitoring and management, support better load studies and analysis resulting in improved planning and design, and are used to support additional systems such as ItronADMS with applications like IVVO that promote energy efficiency and demand reduction. AMI meters are also able to support new rate designs that cannot be supported by the Company's legacy meters, such as the rates resulting from the Company's Residential Energy Time-of-Use filing, Proceeding No. 19AL-0687E, in which the Company and intervenors reached a settlement agreement filed on June 11, 2020. As further discussed in Mr. Romine's Direct Testimony, AMI enhance the customer experience by providing timely, accurate, consistent, and granular energy usage data and there is potential for the new distributed intelligence ("DI") capability of these meters to further enhance the distribution grid capabilities as well as the customer experience.

B. AMI Meter Specifications

Q. WHAT METERS WILL THE COMPANY BE INSTALLING UNDER THE AMI PROGRAM?

A. The Company selected Itron, Inc. ("Itron") as the meter vendor and selected Itron's Riva Generation 4.2 AMI meter. The RFP process that was used to select this meter and vendor are described in greater detail below. I note that a different AMI meter, a Landis+Gyr Focus meters equipped with Itron Gen 5 network interface cards ("NICs"), were installed in support of IVVO in 2019 because the Riva Generation 4.2 AMI meter would not be ready for installation until 2021. These

13,000 meters installed to support IVVO will be replaced by Itron with the Riva Generation 4.2 during the mass deployment at no cost to Public Service.

Q. WHAT ARE THE COMPONENTS OF AMI METERS?

A. The components of the AMI meter include: (1) the meter itself (responsible for measurements and storage of interval energy consumption and demand data); (2) an embedded two-way radio frequency communication module (responsible for transmitting measured data and event data available to backend applications); (3) embedded DI capabilities (described below); and (4) an internal service switch (to support remote connection and disconnection).

Q. WHAT ARE THE FUNCTIONS OF THE AMI METER ITSELF?

A. The primary purpose of the AMI meter is the same as the Company's legacy meters – to measure the amount of electricity used by our customers for billing purposes. However, the AMI meters have additional capabilities and can be remotely configured to measure bi-directional and/or time-of-use energy consumption in kilowatt hours (kWh) and demand in kilowatts (kW). An AMI meter that is configured for bi-directional energy measurement measures energy provided by the Company to the customer and also measures net energy provided from customers (i.e., customers with solar panels) to the Company. Energy consumption data for billing purposes can be recorded by AMI meters in intervals as short as five minutes, or longer intervals if desired. The AMI meters also provide granular data regarding voltage and outages as explained further below.

Q. HOW OFTEN WILL AMI METERS COLLECT AND TRANSMIT DATA TO THE COMPANY?

A. The AMI meters will collect and transmit data to the Company a minimum of six times per day, or every four hours. However, there are several instances when the meters will communicate more often than every four hours. Some examples of this more frequent communication include:

- Individual meters can be read on an on-request basis. For example, a Customer Care employee may request and collect the meter data while on the phone assisting a customer.
- Through the customer portal or smartphone application, as described by Mr. Remington, a customer could request an on-demand meter reading. This request will provide a customer with near real-time energy information.[6]
- AMI meters will transmit data when an event occurs such as a power outage, power restoration, power quality event, or a diagnostic event. The length of time between the data transmission and the event depends on the type of the event.
- AMI meters selected along the distribution feeders to provide data to ADMS will be configured for five-minute interval data and will transmit data to the head-end application every five minutes to make that information available to ADMS. The interrelation between AMI and ADMS is discussed further below.

Q. WHAT ARE THE OTHER CAPABILITIES OF THE AMI METERS?

A. In addition to the ability to measure, store, and transmit interval meter data, AMI meters also have the capability to:

- Measure and transmit voltage, current, and power quality data;
- Detect and transmit meter power outage and restoration events;
- Detect and report meter tampering events;

[6] The term "near real-time" refer to the fact that there is a slight delay (under 10 seconds) between the time the data is pulled and when it is received by the customer.

- Perform and transmit meter diagnostics pertaining to the correct functioning of the meter and communications module;

- Support electric vehicle interconnections;

- Support customer-facing energy conservation technologies (i.e., smart thermostats);

- Support DI; and

- Support remote connect and disconnect functions[7] for customers taking single-phase service (generally, residential and some small business customers).[8]

Q. BEYOND SUPPORTING IVVO, HAS THE COMPANY REALIZED BENEFITS FROM THE INITIAL 13,000 AMI METERS THAT HAVE BEEN DEPLOYED TO DATE?

A. Yes, examples of benefits include:

- Safety Enhancement and Damage Notification: In January 2020, the Company's Metering group received a high temperature alarm from AMI meters in an apartment complex that was the result of a fire started by an individual. While the proper authorities were already aware and responding to the fire, the Company was able to perform timely repairs and replacements of the damaged AMI meters when it was safe to do so. Under the current AMR technology, the Company would not have known about this issue until notified by a customer or until the Company identified the issue when reviewing the billing cycle information.

- Safety Enhancement: The AMI meters send a notification when power is flowing from the customer onto the distribution system (that can be the result of on-site solar for instance). The Company has been able to identify several on-site solar installations that had been connected at customer premises but have not been approved through the interconnection process.

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[7] Public Service will continue to abide by the Commission's rules as well as the Company's tariff regarding the steps that will be taken by the Company prior to disconnection. Public Service's procedures for discontinuation of service for Residential and Small Commercial customers are outlined on Tariff Sheet Nos. R56-R59 of the Company's PUC No. 8 - Electric Tariff. Public Service also recognizes that the Settlement Agreement sets forth certain requirements related to remote connection/disconnection.

[8] The only AMI meters available in the marketplace with remote connection/disconnection switches are single-phase meters.

In instances like these, the Company will contact the customer and guide customers through the interconnection process and ensure proper, safe installation of solar facilities.

- Tampering and Theft: The fact that power is flowing from a customer premise unto the distribution system can also be a sign of meter tampering. Since the AMI meters send a notification when power is flowing from the customer onto the distribution system, the Company has been able to identify a few instances of meter tampering based on these notifications.

Q. WHAT ARE THE CAPABILITIES OF THE AMI METER'S TWO-WAY RADIO FREQUENCY ("RF") COMMUNICATION MODULE?

A. The RF communication module will utilize the Company's communication network (i.e., the FAN) to provide two-way communication between the meter and the AMI head-end application. The AMI head-end application is the operating system that is used to send data requests and commands to an AMI meter and receive data from the meter. These communications include:

- Transmitting the measurements, alarms, and events performed by the meter to the head-end application;
- Receiving commands from the head-end application to send specific meter measurements, alarms, and events, configure the meter to measure specific sets of energy parameters or time-of-use intervals and data recording intervals;
- Remotely perform meter firmware upgrades; and
- Receiving commands from the head-end application to open or close the internal service switch and communicate its status.

Q. WILL THE TWO-WAY RADIO MODULE WITHIN THE AMI METERS HAVE THE ABILITY TO COMMUNICATE WITH OTHER DEVICES?

A. Yes. While the primary purpose of the two-way radio is to capture and transmit customer billing data and service quality data from the AMI meter to the Company, there is also a second radio within the meter that is Wi-Fi compatible and can be configured to communicate with a customer's HAN and HAN devices.

Q. WHAT IS A HAN?

A. The HAN is a network contained within a customer's home or business that connects a customer's HAN devices together as well as to the customer's AMI meter. HAN devices can include thermostats, home security systems, energy display devices, and smart appliances. When connected through the HAN, these devices can communicate with each other to support energy management functions. As noted above, details about HAN capabilities and the Company's plans were discussed in the HAN Proceeding. Below, I review the basic HAN capabilities enabled by AMI meters. Mr. Remington discusses the integration necessary to enable basic HAN functionality, and Mr. Romine discusses the Company's plans to implement HAN offerings and programs for customers.[9]

Q. HOW WILL CUSTOMERS BE ABLE TO CONNECT THEIR HAN DEVICES TO THE AMI METERS?

A. The current AMI meter communication protocol allows HAN devices that are IEEE 2030.5 compliant (which includes Smart Energy Profile 2.0) to connect to the meter and the Company is in the process of reviewing other options with Itron for connecting HAN devices to the AMI meters. For devices that are compliant with the meter communication protocol there is a two-step process will involve customers submitting an activation request for their HAN devices and the

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[9] As discussed on page 10 of my Direct Testimony, HAN implementation will be consistent with any forthcoming Commission decision(s) in Proceeding No. 21A-0279E, and the Company will make any corresponding adjustments to the revenue requirements in this case as necessary.

Company processing that request and activating the appropriate components within the AMI meter to communicate with the customer's HAN device.

Q. WHAT IS DISTRIBUTED INTELLIGENCE?

A. Distributed intelligence or "grid edge computing" refers to the distribution of computing power, analytics, decisions, and action away from a central control point and closer to localized devices or platforms where it is actually needed, such as AMI meters or other "smart" devices on the grid. Since data does not need to be continually transmitted over the Company's FAN it reduces the strain on the network (for other uses of AMI, FLISR, and IVVO for example) and improves the computational speed, efficiency, and capabilities derived from these platforms.

Q. DOES THE AMI METER SELECTED BY THE COMPANY INCLUDE EMBEDDED DISTRIBUTED INTELLIGENCE CAPABILITIES?

A. Yes. The Company's AMI meters include an embedded distributed intelligence platform that can be used to enable new tools and products to help customers manage their energy usage and provide Public Service with new tools to manage the grid more efficiently. Company witness Mr. Romine provides discussion of the DI capabilities and the Company's plans for specific programs in his Direct Testimony.

C. AMI Deployment Timeline

Q. PLEASE DESCRIBE THE WORK THAT DISTRIBUTION WILL UNDERTAKE TO IMPLEMENT AMI.

A. Public Service plans to install 1.6 million AMI meters between 2021 and 2024. The deployment of AMI has two components: (1) meter deployment and (2) software deployment. The software deployment is discussed in the Direct Testimony of Mr. Remington. The Distribution Business Area is primarily responsible for the purchase, testing, and installation of these meters. Distribution will support the installation of the new AMI meters as well as removal, retirement, and disposal of the existing AMR meters, but the installation and removal work will primarily be done by the meter vendor. Distribution will also test and configure all AMI hardware to ensure that it is working properly and is able to integrate with other products and applications.

Q. PLEASE DISCUSS THE WORK THAT DISTRIBUTION HAS COMPLETED IN SUPPORT OF THE METER DEPLOYMENT.

A. The Company completed the installation of the 13,000 AMI meters in 2019. Prior to the installation of the meters the Company performed First Article Testing of the meter accuracy and functional operation, and evaluation of data from the meter through the meter reading and billing systems. First Article Testing is performed on meters containing the Company's requested functionality and configurations, to ensure they meet all specifications as required by the Company. In addition, the Company performed Integration Testing to examine business requirements and functionality across all products, applications, and platforms involved with the AMI meters.

Q. WHEN WILL THE COMPANY COMMENCE DEPLOYMENT OF THE REMAINDER OF THE AMI METERS?

A. While the AGIS CPCN Settlement contemplated that full deployment of AMI would begin in 2020, the Company plans for the full deployment to begin on June 28,

2021. The updated meter deployment schedule is discussed in detail in the Company's June 15, 2021 filing in the Amended CPCN proceeding.

Q. WHY WAS THE START OF THE METER ROLL-OUT DELAYED FROM THE ORIGINALLY PROJECTED START DATE?

A. The Company made the decision to delay deployment of the AMI meters in 2019 as Public Service learned that the meter vendor that was initially selected would not be able to integrate the selected NIC and provide distributed intelligence capabilities while also meeting the Company's deployment schedule.[10] I summarize the meter vendor selection process below, and a detailed discussion of the Company's process to select the AMI meter vendor is provided in the Amended CPCN proceeding. The current deployment schedule moves the start of the mass deployment of AMI meters from 2020 to 2021 and is based on the availability of the RIVA 4.2 meters and the timeline to complete First Article Testing meter testing and the integration testing. The Company still anticipates completing full deployment of all AMI meters in its electric service territory by the end of 2024, as contemplated by the AGIS CPCN Settlement.

Q. CAN YOU PROVIDE AN OVERVIEW OF THE CURRENT AMI DEPLOYMENT TIMELINE?

A. Public Service plans to install approximately 1.6 million AMI meters throughout our Colorado service territory as part of the AGIS initiative starting at the end of the second quarter of 2021. This deployment builds off the limited installation of

[10] Public Service discussed these changes to the AMI meter deployment as part of the Company's Annual Forecast Report for 2020 filed on October 31, 2019 in Proceeding No. 16A-0588E.

13,000 AMI meters that were installed in the southern Denver metro region in 2019 to support IVVO. By the end of 2023, the Company anticipates that close to 90 percent of the meter installations will be complete, with the remaining meters to be installed in 2024. Table CSN-D-6 below provides a summary of the number of meters the Company anticipates installing per year from 2021 through 2024.

TABLE CSN-D-6
AMI Meter Installations by Year

Year	**2021**	**2022**	**2023**	**2024**
Approximate Number of AMI Meters Installed	395,000	534,000	504,000	Remainder

Q. WITH RESPECT TO AMI, WHAT WORK HAS DISTRIBUTION COMPLETED SINCE THE COMPANY'S 2019 ELECTRIC PHASE I?

A. In 2020, the Company began testing the Itron Riva Generation 4.2 AMI meter focusing on the electric distribution and customer operational requirements. This meter testing included First Article Testing of the meter accuracy, and evaluation of the data sets from the meter through the meter reading and billing systems. First Article Testing is performed on meters containing the Company's requested requirements and configurations, to ensure they meet all specifications as required by the Company. The Company has completed Integration Testing that examines business requirements and functionality across the products, applications, and platforms involved in the implementation of AMI, from meter to bill. The purpose of Integration Testing is to confirm that changes made within individual applications work correctly when tested together with changes made within individual applications, ensuring data quality and accuracy across all systems in scope for AMI.

Q. WHAT ADDITIONAL WORK WILL DISTRIBUTION UNDERTAKE THROUGH THE 2022 FTY TO SUPPORT THE AMI METER DEPLOYMENT SCHEDULE?

A. In 2021, Distribution began Production Sample Testing which involves testing a random sample of meters for accuracy, proper operation of the NIC, and the internal switch. Table CSN-D-7 below provides a summary of the testing timelines in support of the first part of the mass deployment of AMI meters in 2021 and 2022.

TABLE CSN-D-7
AMI Testing Timeline

Scheduled Milestone	Timeframe
Preliminary Testing Single Phase	1st Quarter 2020 to 2nd Quarter 2020
First Article Testing Single Phase	4th Quarter 2020 to 1st Quarter 2021
Integration Testing Single Phase	1st Quarter to 2nd Quarter 2021
Production Sample Test Single Phase	2nd Quarter 2021
Field Deployment to Start Mass Deployment Single Phase	End of 2nd Quarter to 4th Quarter 2021
First Article Testing Poly Phase	3rd Quarter to 4th Quarter 2021
Integration Testing Poly Phase	4th Quarter 2021 to 1st Quarter 2022
Production Sample Test Poly Phase	1st Quarter 2022
Production Sample Test Poly Phase	1st Quarter 2022
Field Deployment to Start Mass Deployment Poly Phase	3rd Quarter 2022

Public Service will follow a similar testing schedule for each set of AMI meters in advance of their scheduled deployment through 2024.

D. <u>Distribution's Capital Costs for AMI</u>

Q. WAS DISTRIBUTION PRIMARILY RESPONSIBLE FOR DEVELOPING THE FORECAST FOR AMI?

A. Distribution is responsible for the costs associated with acquiring and installing the AMI meters. I describe how we developed our forecast for these costs in more detail below. Business Systems is responsible for developing the forecasts for the head-end application, other software and hardware to support AMI data processing, and integrations required by those technologies, and Mr. Remington will address the development of those costs.

Q. WHAT ARE THE AMI CAPITAL ADDITIONS FOR DISTRIBUTION RELEVANT TO THIS RATE CASE?

A. Table CSN-D-8 below provides Distribution's capital additions for AMI for September 1, 2019 through the 2022 FTY.

TABLE CSN-D-8
AMI Distribution – Capital Additions
(Public Service – Total Company)

AGIS Program *($ in millions)*	**9/1/2019 through 12/31/2019 Actual**	**2020 Actual**	**2021 Forecast**	**2022 Forecast**
AMI	7.5	1.4	67.4	73.7

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

A. Distribution's AMI capital forecast has five key components: (1) AMI meter purchase; (2) AMI meter installation; (3) vendor project management; (4) AMI operations (external and internal); and (5) testing equipment.

Q. HOW DID DISTRIBUTION DEVELOP ITS CAPITAL FORECAST FOR THE AMI METER AND INSTALLATION COSTS?

A. The costs for the AMI meters and installation are based on the meter contract with our AMI meter vendor, Itron. Additional overheads such as taxes are also included in these estimates.

Q. PLEASE SUMMARIZE THE PROCESS USED TO SELECT THE AMI METER VENDOR.

A. The Company issued its initial RFP in March 2018 to select an electric AMI meter vendor that could provide an AMI meter, project management, and installation services. The Company received and evaluated responses from four meter vendors. In addition to core evaluations around costs, schedule, technical requirements, capabilities, and customer benefits, the Company was also interested in making sure that the selected AMI meter could support distributed intelligence capabilities. As a result of the RFP process, the Company selected a meter vendor in December 2018 and proceeded with negotiations. However, in late March 2019, the AGIS team learned that the meter vendor that was initially selected would not be able to integrate the selected NIC and provide distributed intelligence capabilities while also meeting the Company's meter deployment schedule. The Company requested that the initially selected vendor provide a schedule for deployment for AMI meters that incorporated the vendor's own NIC and network, but the initial meter vendor was not able to integrate the required changes without a significant increase in cost and a risk of further schedule delays.

In April 2019, the Company solicited and received a comprehensive proposal from another meter vendor that had responded to the initial RFP. This meter vendor was able to meet the Company's requested deployment schedule with the necessary NIC integration, offered the necessary meter capabilities, including distributed intelligence, and offered favorable price and contractual terms. As a result, in May 2019, Xcel Energy selected Itron as its meter vendor to serve all jurisdictions, including Public Service, and a contract was executed on September 1, 2019 (the "Meter Contract"). As noted above, a detailed discussion of the Company's RFP process to select the AMI meter vendor and the Meter Contract are provided in the Amended CPCN proceeding.

Q. HOW DID DISTRIBUTION DEVELOP ITS CAPITAL FORECAST FOR THE AMI VENDOR PROJECT MANAGEMENT COSTS?

A. The forecast for AMI vendor project management is set forth in the Meter Contract. The Company's estimates also include internal overheads.

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

A. Cost estimates for internal and external personnel were developed based on the role and number of required personnel required to perform necessary tasks to enable installation and deployment of the AMI meters. The necessary positions include analysts, projects and project managers, engineers, and electricians. The cost estimates were determined using average pay scales for the needed positions combined with an estimate the amount of work required by each of these roles during the AMI installation and deployment. The Company then determined the appropriate allocation between capital and O&M for these costs based on the type of work being performed.

Q. HOW DID DISTRIBUTION DEVELOP ITS CAPITAL FORECAST FOR TESTING EQUIPMENT?

A. These cost estimates were based on quotes obtained and purchases that were made from vendors for this testing equipment. This testing equipment is standard off-the-shelf equipment and we leveraged our relationships with existing vendors to obtain the best cost for this equipment.

Q. DO DISTRIBUTION'S AMI CAPITAL ADDITIONS SHOWN ABOVE INCLUDE CONTINGENCY AMOUNTS?

A. No. There are no contingency amounts included through the 2022 FTY.

E. Distribution's O&M Costs for AMI

Q. WHAT ARE THE AMI O&M COSTS FOR DISTRIBUTION RELEVANT TO THIS RATE CASE?

A. Table CSN-D-9 below provides Distribution's O&M expense for AMI for 2020 through the 2022 FTY.

TABLE CSN-D-9
AMI Distribution – O&M Expenses
(Public Service – Electric)

AGIS Program *($ in millions)*	**2020 Actual**	**2021 Forecast**	**2022 Forecast**
AMI	0.7	3.1	1.5

Q. WHAT ARE THE COMPONENTS OF DISTRIBUTION'S O&M COSTS ASSOCIATED WITH AMI?

A. The primary components of Distribution's AMI O&M expense relate to: (1) support of the capital deployment, (2) business readiness, and (3) change management. As noted above, all internal labor costs have been excluded as these costs are already reflected in base rates.

Q. WHAT IS INCLUDED IN THE O&M IN SUPPORT OF THE CAPITAL DEPLOYMENT COST CATEGORY?

A. This category includes expenses related to equipment installations that are appropriately deemed O&M. For instance, any repair activities that are necessary to perform the meter exchange from an AMR meter to the AMI meter would be deemed an O&M expense.

Q. WHAT IS INCLUDED IN THE BUSINESS READINESS COST CATEGORY?

A. This category includes the costs to support the business readiness activities that are necessary to ensure the business is prepared and processes are in place to support the AMI meter and applications.

Q. WHAT IS INCLUDED IN THE CHANGE MANAGEMENT COST CATEGORY?

A. The change management costs consist of general change management activities such as training and communications which I discuss in more detail in Section X of my Direct Testimony. This includes the O&M portion of costs for development and delivery of training needed to prepare the Company's employees and contractors for the AMI meters and data management systems being deployed to support AMI. It also includes costs in 2020 and 2021 for the development and delivery of internal communications in support of the change management plan necessary to engage and prepare the business for upcoming changes due to AMI. These activities will primarily take place prior to the Company starting the mass deployment of AMI meters in order to prepare the Company's employees and contractors for the changes associated with the AMI project.

Q. IN SUMMARY, WHY ARE THE DISTRIBUTION BUSINESS AREA'S AMI COSTS REASONABLE FOR CUSTOMERS TO SUPPORT?

A. AMI is a fundamental element of the AGIS initiative because it provides a central source of information that interacts with many of the other components of the AGIS initiative. The system visibility and data delivered by AMI provides customer benefits in reliability and ability for remote connection, enables greater customer offerings for rates, projects, and services. AMI also enhances utility planning and operational capabilities. Access to timely, accurate and consistent data from the AMI system will provide insights for customers to make informed decisions about their energy sources and usage of reliable and sustainable energy. Distribution's capital investments described above that include the AMI meters are necessary to implement AMI and Distribution's capital and O&M forecast is reasonable.

V. FIELD AREA NETWORK

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

A. In this section of my Direct Testimony, I provide an overview of FAN and discuss the progress that Public Service has made in the development and implementation of FAN since the Company's 2019 Electric Phase I. The implementation of FAN is a joint effort with Business Systems with Business Systems leading this effort. As a result, Mr. Remington provides a more detailed discussion of FAN and its components and implementation. I discuss the implementation plan for Distribution's portion of FAN. Finally, I provide Distribution's capital additions and O&M cost forecasts for FAN.

A. Overview of FAN

Q. WHAT IS THE FAN?

A. The FAN is the wireless communications network that enables connectivity and two-way communications between the existing communication infrastructure that already exists at the Company, the ADMS and AMI software systems, the new AMI meters, and the intelligent field devices associated with advanced applications. The FAN applies to all aspects of AGIS but is designed and built according to the needs of various components, and each has different communication network requirements.

Q. WHAT ARE THE 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 wireless network to connect the WiSUN mesh network to the Company's pre-existing Wide Area Network ("WAN").

Q. HAVE THERE BEEN ANY CHANGES TO THE COMPONENTS OF THE FAN SINCE THE AGIS CPCN WAS GRANTED?

A. Yes. Initially, the Company proposed in the AGIS CPCN Proceeding to accomplish connectivity between the WiSUN mesh network and the WAN by the deployment of the Worldwide Interoperability for Microwave Access ("WiMAX") network. However, Federal Communications Commission ("FCC") rule changes effective in 2020 necessitated a change in network technology. In his Direct Testimony, Mr. Remington explains the changes in FCC regulations and the impact on WiMAX, the current technology replacing WiMAX, and the potential long-term options. The WiSUN mesh network is being deployed the same as it was always planned.

Q. WHAT ARE THE COMPONENTS OF THE WISUN NETWORK?

A. The WiSUN (mesh) network will communicate directly with the AMI infrastructure (including the AMI meters) and the field devices used for IVVO and FLISR. The core infrastructure for the WiSUN mesh network will consist of two 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 communication network. The access points will wirelessly connect directly to backhaul (which is an intermediate link in the communications network) to pass data between the mesh network and the WAN. The access points will be located primarily on distribution poles and other similar structures.

- *Repeaters*: are range extenders that are used to fill in coverage gaps where devices would be otherwise unable to communicate. The mesh network design of WiSUN means that additional nodes on the network provide devices more options to communicate with their access point. Repeaters will be located primarily on distribution poles.

Other devices that will participate in the mesh include AMI meters and DA 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. WHAT TECHNOLOGY IS REPLACING WIMAX TO TRANSMIT DATA BETWEEN THE WISUN MESH AND WAN?

A. In 2020, Xcel Energy moved to public cellular data technology to support continued connectivity to the WiSUN network. In his Direct Testimony, Mr. Remington discusses this technology as well as the options for the long-term solution for mesh to WAN communication.

B. FAN Deployment Timeline

Q. WHAT WORK IS DISTRIBUTION UNDERTAKING TO SUPPORT THE INSTALLATION OF THE FAN?

A. The implementation of FAN is a joint effort between Business Systems and Distribution. Distribution is responsible for the installation of the FAN devices (primarily access points and repeaters for the WiSUN mesh network) that will be located on distribution poles. Business Systems is responsible for the FAN implementation strategy, the design and security of the network systems, and configuring the software and hardware components of FAN.

Q. HOW WILL THESE FAN DEVICES BE INSTALLED BY DISTRIBUTION?

A. The access points and repeaters will be mounted primarily on distribution poles to provide adequate height for the radio signal to propagate. In certain instances, the distribution pole will need to be modified or replaced to support a particular device and Distribution will be responsible for completing this modification or replacement. In areas where Public Service has underground service, arrangements will be made to mount the devices on street lights or other structures with appropriate height.

Q. PLEASE DESCRIBE THE WORK THAT DISTRIBUTION HAS ALREADY COMPLETED IN SUPPORT OF FAN.

A. As discussed by Mr. Remington, the WiSUN portion of the FAN is being implemented in a three-phased approach. The Company engaged in comprehensive planning for implementation of the FAN beginning in 2016.

The first phase of the implementation of the WiSUN portion of the FAN was the design phase to select the WiSUN device vendor and to site potential locations for the WiSUN device. This phase was completed in 2018.

Phase II of the WiSUN FAN implementation involves site surveys to inspect each location identified in the design phase to evaluate its suitability for a WiSUN device. These inspections confirm that the Company can receive the appropriate signal anticipated in the design phase at the height and location on the pole where the device will be located. In 2019, the Company completed 119 site surveys and in 2020, the Company completed 333 site surveys.

Also, in 2019, Public Service commenced installation of WiSUN devices as part of Phase III. Due to the fact that the Company shifted out the start of the mass meter deployment from 2020 to 2021, the Company installed fewer WiSUN devices in 2019 than originally planned. Installation of WiSUN devices continued in 2020 to support further AMI deployments. The Company installed an additional 130 WiSUN devices in 2020. This schedule was slightly advanced to support IVVO and FLISR requirements as well. Further details regarding the implementation of WiSUN are discussed by Company witness Mr. Remington. Installation of WiSUN devices will continue through 2024 to support AMI deployments. The Company expects to install 480 WiSUN devices by the end of 2021.

Q. GOING FORWARD, WHAT WORK WILL DISTRIBUTION COMPLETE THROUGH THE 2022 FTY TO IMPLEMENT FAN?

A. In the third quarter of 2021, the Company will perform the first Network Optimization (a process where the network is tested and tuned to ensure optimal performance) for the WiSUN network supporting IVVO. Network Optimization will occur throughout the project as AMI deployments complete. The Company will continue to perform site surveys at a rate of 300 per year through 2024. The Company expects to install 400 WiSUN devices by the end of 2022.

C. <u>Distribution's Capital Costs for FAN</u>

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

A. As discussed above, the work that Distribution will be performing to support the implementation of FAN is limited to the procurement and installation of pole-mounted FAN devices. Mr. Remington discusses Business Systems' FAN costs.

Q. WHAT ARE THE FAN CAPITAL ADDITIONS FOR DISTRIBUTION RELEVANT TO THIS RATE CASE?

A. Table CSN-D-10 below provides Distribution's capital additions for FAN for September 1, 2019 through the 2022 FTY.

TABLE CSN-D-10
FAN Distribution – Capital Additions
(Public Service – Total Company)

AGIS Program *($ in millions)*	**9/1/2019 through 12/31/2019 Actual**	**2020 Actual**	**2021 Forecast**	**2022 Forecast**
FAN	7.9	5.2	6.9	4.1

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 for the FAN are (1) make ready work (labor and hardware) and (2) FAN device hardware and installation (labor and hardware).

Q. HOW DID DISTRIBUTION DEVELOP THESE CAPITAL COST ESTIMATES FOR FAN?

A. To estimate the device costs and installation costs for FAN, engineering performed a preliminary Radio Frequency Network Study. The purpose of this study was to determine the location and number of access points and repeaters that would be required to facilitate a reliable FAN communication network for the AMI meter and the distribution automation devices.

Q. WHAT WAS THE NEXT STEP IN DEVELOPING THE CAPITAL COST ESTIMATES?

A. After determining the number of devices, the price for each device was derived from prices included in contracts that resulted from several RFP processes as described by Mr. Remington. The labor costs to install each device are based on a combination of materials, contractor and internal labor.

Q. HOW DID DISTRIBUTION DETERMINE THE LABOR COSTS FOR THE INSTALLATION OF THE FAN DEVICES?

A. The Company's labor estimates are based on our prior experience with installing FAN devices.

Q. DOES DISTRIBUTION'S CAPITAL FORECAST FOR FAN INCLUDE CONTINGENCY?

A. Distribution's capital forecast for FAN does not include any contingency amounts through the 2022 FTY.

D. Distribution's O&M Cost for FAN

Q. WHAT ARE THE FAN O&M COSTS FOR DISTRIBUTION RELEVANT TO THIS RATE CASE?

A. Table CSN-D-11 below provides Distribution's O&M costs for FAN for 2020 through the 2022 FTY.

TABLE CSN-D-11
FAN Distribution – O&M Expenses
(Public Service – Total Company)

AGIS Program	2020 Actual	2021 Forecast	2022 Forecast
FAN *($ in millions)*	0.5	0.2	0.2

Q. WHAT ARE THE PRIMARY COMPONENTS OF DISTRIBUTION'S O&M COSTS FOR FAN?

A. FAN O&M costs will include costs for infrastructure and hardware, operations (including equipment and personnel), and preparation costs. These costs include the field level support for fixing broken and damaged equipment, additional personnel to monitor and manage the FAN, other preparation work that is designated as O&M, hardware and software maintenance, and training. Personnel will include both Company employees and contractors, which will be used based on workload, location, and timing. Most incremental work will be performed by contractors.

Q. HOW DID DISTRIBUTION DETERMINE THE O&M COSTS FOR FAN?

A. The projected costs associated with project employees are based on typical Company wages, and contractor costs are costs of contractors at estimated wage scales. The costs to fix and replace broken and damaged equipment are based on expected failure and damage rates for these devices.

Q. IN SUMMARY, WHY ARE THE DISTRIBUTION BUSINESS AREA'S FAN COSTS REASONABLE FOR CUSTOMERS TO SUPPORT?

A. The FAN provides the ability for all of the AGIS devices and components to communicate with each other in a safe, secure, and reliable way. This communication is essential to harnessing the benefits of the AGIS initiative in that it allows greater visibility into the customer experience at the edge of the grid. The Distribution components and their installation, as described above, are necessary to implement FAN and the Distribution forecast is reasonable.

VI. INTEGRATED VOLT-VAR OPTIMIZATION

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

A. In this section of my Direct Testimony, I provide an overview of IVVO, discuss the progress that Public Service has made in the development and implementation of IVVO since the Company's 2019 Electric Phase I, and provide information regarding IVVO benefits as required by the AGIS CPCN Settlement. I then discuss work that has already been completed and the work that is remaining to implement IVVO. Finally, I discuss Distribution's capital and O&M forecasts for IVVO.

A. Overview of IVVO

Q. CAN YOU PROVIDE AN OVERVIEW OF THE IVVO PROJECT AND THE BENEFITS OF IMPLEMENTATION?

A. Yes. The Company is approximately halfway through IVVO implementation, and the IVVO program was discussed in detail in the Company's 2019 Electric Phase I. As such, I provide a review of the program and benefits here. IVVO an integrated system that includes the advanced application within ADMS, a communication network, the AMI meters and head-end system and the deployment of automated field devices. Through IVVO, Public Service can more efficiently and accurately maintain proper voltage levels throughout the electric distribution system, thereby reducing energy usage without requiring customer usage changes. IVVO automates and optimizes the operation of the distribution voltage regulating devices located on distribution feeders.

IVVO capabilities improve the distribution grid by allowing voltage to be monitored along the entire length of the feeder and at selected end points (rather than only at the substation). This insight enables Public Service to operate its feeders at the lower end of acceptable voltage ranges to achieve a variety of operational benefits including:

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

Q. WHERE IS PUBLIC SERVICE DEPLOYING IVVO?

A. The Company is deploying IVVO in the Denver metropolitan area across approximately 60 percent of the Company's feeders which serve approximately 67 percent of Public Service's electric customers.

Q. WHAT FIELD DEVICES ARE INSTALLED ON THE DISTRIBUTION SYSTEM TO SUPPORT IVVO?

A. There are four principal utility equipment components of IVVO:

- *Capacitors* – Electric loads like motors require two types of power to operate: active and reactive power. Distribution line capacitors provide local VAr support or reactive power. By doing so, they help to limit both voltage drop and line losses across the distribution system.

- *Secondary static VAr compensators ("SVCs")* – SVCs are electronic secondary capacitors that provide fast, variable voltage support to help stabilize and regulate the voltage. The devices' capabilities also enhance the system's ability to respond to the variability of renewable DERs such as solar facilities and other intermittent distributed resources.

- *Voltage sensing devices* – The Company is using the 13,000 AMI meters installed in 2019 and intends to use newly installed AMI meters as "bellwether" sensing devices to provide near real-time voltage sensing. IVVO requires this end-of-line voltage sensing to monitor the voltage and ensure it is compliant with ANSI Standard C84.1.[11] The plan is to utilize approximately 10 meters per feeder to provide this data. Public Service will be able to reassign meters as bellwether meters as necessary should load or feeder topology change.

- *Load Tap Changers ("LTCs")* – This is equipment that is installed on the substation transformer to enable voltage regulation. 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. The LTCs themselves will be used, but the controls for some of the legacy units will be upgraded to allow ADMS to control the setpoints.

- *Remote Terminal Units ("RTUs")* – This is equipment that is installed at the substation and provides the communications and control interface between substation equipment such as the LTCs and ADMS.

Q. CAN YOU GENERALLY DESCRIBE HOW THE IMPLEMENTATION OF IVVO WILL RESULT IN ENERGY SAVINGS?

A. Yes. 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 in the future provide quantifiable benefits to our customers and the Company. 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

[11] ANSI C84.1 establishes the nominal voltage ratings and operating tolerances for the 60 Hertz electric power systems.

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. HAS THE COMPANY ESTIMATED THE REDUCTION IN ENERGY CONSUMPTION, DEMAND, AND ELECTRIC LOSSES THAT WILL BE ACHIEVED FROM IVVO?

A. The full scope of the deployment provides for energy savings through IVVO operations on 450 feeders, enabled through work performed from the end of 2017 through 2023. During this period, the Company plans to deploy 884 overhead and 90 pad-mounted capacitor banks, 4350 SVCs, replace LTC controllers on 121 power transformers, and update RTUs at 42 substations. As this IVVO hardware is deployed, the Company is able to begin lowering the LTC setpoint to achieve initial energy savings. Through IVVO, the benefit of energy savings through voltage reduction is planned to ramp up to 335,884 MWh annually in 2023. Concurrently, the Company estimates an additional 9,167 MWh/year in loss reduction through power factor improvement. As a result of energy savings and line loss reductions, the Company also estimates 43.9 MW in demand reduction for 2023. Table CSN-D-12 below provides a breakdown of the projected IVVO benefits by year and includes 2019 and 2020 actual benefits.

TABLE CSN-D-12
Projected IVVO Benefits[12]

Benefits	2019	2020	2021	2022	2023
Energy Savings (MWh)	18,100	61,577	172,000	255,000	336,000
Loss Reduction[13] (MWh)	550	2,170	4,583	6,875	9,167
Demand Reduction[14] (MW)	5.97	11.3	18.0	26.7	35.1

Q. WHAT ENERGY SAVINGS HAS THE COMPANY ACHIEVED IN THE AREAS WHERE IVVO HAS BEEN ENABLED?

A. The Company began to enable substations with IVVO functionality within the ADMS in April 2019. Two substations, comprising of six transformer areas serving approximately 53,000 customers, were enabled with IVVO functionality throughout 2019 and the Company saw positive results with the transformers areas consistently achieving over two percent energy saving.[15] Also during 2019, energy savings of 18,100 MWh were achieved resulting in approximately $973,000 in

[12] Per Section D.1.a.iii of the AGIS CPCN Settlement, IVVO energy savings are recovered annually through the Electric Commodity Adjustment (“ECA”) rider
[13] The Company has no accurate way of collecting metrics for line loss reduction. The 2019 and 2020 values are estimates based on the level of deployment of capacitive devices.
[14] Projected demand reduction savings are based on IVVO deployment schedule updates beginning in June 2020.
[15] The estimated savings as part of the CPCN filing were estimated to be 1.9 percent in 2020.

savings for customers on IVVO enabled feeders. In addition, 5.97 MW of demand reduction was achieved on feeders with IVVO enabled resulting in estimated savings of $585,000. In 2020, the Company achieved energy savings of 61,577 MWh. The rate of energy savings accrual is expected to increase dramatically as more areas are enabled with IVVO. Nine transformer areas at four substations were enabled in with model based IVVO in 2020 in addition to the six areas enabled in 2019. Line-loss reduction is difficult to calculate without a historical power-flow model. There is a calculation in the IVVO ADMS application, but this does not compare line losses to historical values which wouldn't account for the deployment of capacitive devices. The loss reduction primarily comes from deployment of capacitive devices and the associated power factor correction, the line loss estimates are constructed based on how many capacitive devices have been deployed and the expected loss reduction from each device. IVVO achieved an estimated loss reduction of 550 MWh in 2019 and 2,170 MWh in 2020.

Q. HOW DO THE ACTUAL ENERGY SAVINGS BENEFITS COMPARE TO THE COMPANY'S ESTIMATES?

A. For 2019 and 2020, customer energy savings were lower than expected. This does not indicate that IVVO is less effective than expected but is reflective of the complexity and the number the steps required to enable IVVO operation which I discuss further later. On average, areas running IVVO saw increased energy reduction when compared to initial estimates; however, the application was not enabled at a large enough area to achieve the forecasted benefits. Public Service anticipates that as IVVO is enabled across a larger area, that the energy savings achieved from IVVO will be in line with the Company's estimates. In addition, as the Company enhances it processes and expertise with enabling IVVO, the Company expects improvements with the timing to complete all of the steps required to enable IVVO.

B. IVVO Deployment Timeline

Q. WHAT WORK HAS BEEN COMPLETED TO DATE TO IMPLEMENT IVVO?

A. Implementation of IVVO is on a five-year deployment schedule from 2018 through 2022, with the potential for some installations to carry over into 2023. Table CSN-D-13 provides a breakdown of the IVVO field installations by year with 2018-2020 representing actual installations and 2021-2022 representing forecasted installations.

TABLE CSN-D-13
IVVO Device Installations

IVVO	2018	2019	2020	2021	2022	2023
Capacitors	142	74	244	215	193	106
SVCs	453	947	1,322	1,100	528	–
LTCs	6	20	27	38	29	–
RTUs	2	9	6	15	10	–

The Company has also been working to enable substations with IVVO functionality. IVVO is enabled one transformer area at a time, with each transformer generally consisting of three or four feeders. The Company began continuous IVVO operation on the Englewood Substation Transformer #1 in April 2019, with five more transformer areas (Englewood and Greenwood substations) subsequently enabled through October 2019. In addition, the Company lowers the LTC setpoint or voltage at each substation transformer in areas when the LTC upgrades are complete and capacitors are fully deployed, and where there is confidence in the local voltage support. This also results in a lower voltage and energy savings for customers prior to the IVVO functionality being deployed for each substation transformer area.

Q. PLEASE DETAIL THE STEPS REQUIRED TO ENABLE IVVO FOR EACH SUBSTATION TRANSFORMER AREA.

A. Enabling IVVO in ADMS requires several steps. This includes:

- *Field device installation:* Installation of capacitors and SVCS on the distribution feeders which can be installed on overhead poles or on pad-mounts for underground portions of our system. LTC upgrades at substations which may also require substation RTU upgrades due to the increased SCADA requirements.
- *Enabling Communication Through FAN:* Installation of the network interface card within each of the field devices and the necessary FAN devices to enable communication from the field devices to the Company's data servers.
- *Integrating the devices with ADMS:* Once the field devices are communicating to our data servers, the devices can be integrated with ADMS by configuring the communication and device settings within ADMS.
- *Point-to-Point testing:* Once the device is integrated with ADMS, point-to-point testing is performed to verify the device is functioning correctly and it configured correctly in the field and within ADMS.
- *Testing within ADMS:* Finally, before enabling IVVO functionality, final testing is performed in ADMS to verify all of the devices are configured correctly and respond correctly to ADMS commands such as the opening and closing of capacitors.

Q. WHAT WORK WILL BE COMPLETED BY DISTRIBUTION IN 2021 IN SUPPORT OF IVVO?

A. In 2021, Public Service intends to continue incorporating reporting from the bellwether AMI meters that were installed in 2019 into ADMS and from new meters installed in 2021. This reporting will help manage voltage along distribution feeders. In addition, the Company plans to enable 192 feeders in ADMS, lower 38 LTC setpoints, and enable IVVO operation on 51 transformer areas before the end of 2021. Through the end of April 2021, the Company has enabled IVVO on nine substation transformers areas in addition to the 15 areas enabled in previous years.

Q. PLEASE DESCRIBE THE WORK THAT DISTRIBUTION EXPECTS TO COMPLETE DURING THE 2022 FTY.

A. The IVVO deployment and implementation will continue in 2022 as shown in Table CSN-D-13 above, with as the additional devices are installed and the application is enabled at all planned areas. The integration of additional AMI meters will be enabled over time as full deployment of AMI continues as well.

C. Distribution's Capital Costs for IVVO

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 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. The Company has refined its forecast based on actual costs of field device installations and the associated costs to enable IVVO functionality. Some aspects of IVVO implementation, including a software application and ADMS integration, are discussed and supported by Company witness Mr. Remington.

Q. WHAT ARE THE IVVO CAPITAL ADDITIONS FOR DISTRIBUTION RELEVANT TO THIS RATE CASE?

A. Table CSN-D-14 below provides Distribution's capital additions IVVO for September 1, 2019 through the 2022 FTY.

TABLE CSN-D-14
IVVO Distribution – Capital Additions
(Public Service – Total Company)

AGIS Program *($ in millions)*	**9/1/2019 through 12/31/2019 Actual**	**2020 Actual**	**2021 Forecast**	**2022 Forecast**
IVVO	7.0	23.6	34.9	25.7

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

A. The primary components of the IVVO capital investments, shown in the tables above, 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 has continually refined its forecast based on actual costs of field device installation. 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. The Company had also piloted a project testing SVC device from Varentec, Inc. beginning in 2013. Cost estimates provided from Varentec and actual costs during that pilot were used to initially estimate costs for that component.

Q. HOW DID THE COMPANY GO ABOUT SELECTING VARENTEC AS THE VENDOR FOR SVCS?

A. The Company completed an RFP process and selected Varentec as its supplier of SVCs in 2018. The Company 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.

Q. HOW DID THE COMPANY SELECT THE VENDORS FOR THE OTHER IVVO DEVICES?

A. Primary capacitors and LTC controllers are a part of the Company's standard equipment, and the Company was able to use its existing equipment standards to support this deployment. The equipment selected for our standards undergoes periodic review, using the RFP process when appropriate.

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 had 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 primarily using contract labor for the installation of IVVO devices. The forecast for labor costs for device installation were developed using contractor wage scales.

Q. DOES DISTRIBUTION'S IVVO FORECASTS INCLUDE ANY REMAINING CAPITAL CONTINGENCY?

A. Distribution's capital forecast for IVVO does not include any contingency amounts through the 2022 FTY; however, beyond 2022, there are certain contingency amounts include in the IVVO budget.

D. Distribution's O&M Costs for IVVO

Q. WHAT ARE THE IVVO O&M COSTS FOR DISTRIBUTION RELEVANT TO THIS RATE CASE?

A. Table CSN-D-15 below provides Distribution's O&M costs for IVVO for 2020 through the 2022 FTY.

TABLE CSN-D-15
IVVO Distribution – O&M Expenses
(Public Service – Electric)

AGIS Program *($ in millions)*	**2020 Actual**	**2021 Forecast**	**2022 Forecast**
IVVO	0.3	1.0	1.6

Q. WHAT TYPES OF COSTS ARE INCLUDED IN THE IVVO BUDGET FOR DISTRIBUTION?

A. The O&M costs include: (1) support of capital deployment; (2) asset and device support; (3) minor device replacement; (4) communications network; and (5) training.

Q. WHAT IS INCLUDED IN THE O&M IN SUPPORT OF THE CAPITAL DEPLOYMENT COST CATEGORY AND HOW WERE THESE COSTS DETERMINED?

A. This category includes expenses related to equipment installations that are appropriately deemed O&M. One example is certain switching activities (operations) are necessary to safely install new equipment. The Company used actual, average installation costs to forecast these costs.

Q. WHAT IS INCLUDED IN THE ONGOING ASSET AND DEVICE SUPPORT COST CATEGORY AND HOW WERE THESE COSTS DETERMINED?

A. This category includes labor and repairs to maintain assets in good working order. The Company estimated these costs as a percentage of the number of installed IVVO assets.

Q. WHAT IS INCLUDED IN THE DEVICE REPLACEMENT COST CATEGORY AND HOW WERE THESE COSTS DETERMINED?

A. This category includes material and labor to replace assets (components which are not property units) in good working order. The Company estimated these costs as a percentage of installed IVVO assets.

Q. WHAT IS INCLUDED IN THE ON-GOING COMMUNICATIONS NETWORK COST CATEGORY AND HOW WERE THESE COSTS DETERMINED?

A. This category labor and incidental material to maintain IVVO assets communication. The Company estimated these costs as a percentage of the installed IVVO assets.

Q. WHAT IS INCLUDED IN THE TRAINING COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes training costs for the IVVO project. The Company estimated these costs based on number of employees, the time to train them, and wage scales.

Q. IN SUMMARY, WHY ARE THE DISTRIBUTION BUSINESS AREA'S IVVO COSTS REASONABLE FOR CUSTOMERS TO SUPPORT?

A. Fundamentally, IVVO is a demand-side management ("DSM") tool that reduces energy consumption without requiring behavioral changes from customers. IVVO allows voltage to be monitored along the entire length of the distribution feeder and at selected endpoints (rather than just at the substation). This insight into the voltage levels allows the Company to utilize lower voltages across the entire feeder most of the time. This results in a reduction in electrical losses, reduction in electrical demand, reduction in energy consumption, and an increase in the capacity to host DER. Reductions in energy consumption reduce carbon emissions (caused by certain types of generation) and supports of the Company's strategic vision for serving customers with 100 percent carbon-free electricity by 2050 and 80 percent carbon-free electricity by 2030 reasonable.

VII. FAULT LOCATION ISOLATION SYSTEM RESTORATION

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

A. In this section of my Direct Testimony, I provide an overview of FLISR and FLP and the benefits associated with these applications. I then discuss the implementation plan for FLISR and the work that has been completed to date. Finally, I discuss Distribution's capital and O&M forecasts for FLISR.

A. FLISR Overview

Q. WHAT ARE FLISR AND FLP?

A. FLISR is an integrated system that includes the advanced application within ADMS, a communication network, and automated field devices that enable automated switching devices to decrease the duration and number of customers affected by any individual outage. These automated switching devices detect feeder mainline faults, isolate the fault by opening section switches, and restore power to un-faulted sections by closing switches to adjacent feeders as necessary. FLISR reduces the frequency and duration of customer outages and improves utility performance metrics such as system average interruption duration index ("SAIDI") and the system average interruption frequency index ("SAIFI").

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 a failure on the system.

FLISR and FLP were introduced and discussed in the AGIS CPCN filing but has been implemented by the Company in the normal course of business. FLISR and FLP were further discussed in Public Service's 2019 Electric Phase I.

Q. WHERE IS PUBLIC SERVICE DEPLOYING FLISR?

A. The Company plans to install automated equipment on approximately 205 feeders or approximately 25 percent of the feeders on the Company's distribution system. The Company developed the overall deployment plan based on analysis of the highest level of benefits provided by deploying FLISR on feeders with the greatest number of outages and customers.

Q. WHAT ARE THE COMPONENTS OF FLISR?

A. There are four principal components of FLISR: reclosers; automated overhead switches; automated switch cabinets; and substation relays. FLP consists of two main components: powerline sensors and the substation relays.

- *Reclosers* – Reclosers are pole-mounted reclosing and switching devices with enhanced monitoring, communications, and control capabilities. The devices are able to identify and interrupt a fault event and report the fault to ADMS. ADMS can then use that information to execute FLP to determine the location of the fault. Reclosers will either reclose and restore service or will determine there is a permanent fault after multiple attempts to reclose. The device will communicate permanent 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

- *Automated overhead switches* – These switches are overhead remote supervisory sectionalizing and motor operated switching devices. When a fault occurs, a feeder breaker senses the fault and opens to isolate the fault. Although automated overhead switches lack the reclosing functionality, they are more compact and less expensive than reclosers, making them the preferred choice for space-constrained locations or where localized reclosing capability is not required.

- *Automated switch cabinets* – Automated switch cabinets are pad-mounted sectionalizing and switching devices. Each cabinet has motor-operated, remote-controlled devices that the Company will use for switching underground feeders. They will perform functions similar to the automated overhead switches for our underground feeders.

- *Powerline sensors* – Powerline sensors are equipment placed on distribution lines to continuously monitor the grid and send information back to the utility for analysis and response. Sensors are available to measure such attributes as current, voltage, power factor, and faults. For FLISR specifically, this technology will allow Public Service the ability to detect disturbances on the grid and use this information to identify fault locations, isolate faults, and analyze the unique patterns of these events to predict the likelihood of future outages.

- *Substation relays* – Substation-based relays provide the logic for when and why a breaker opens. The purpose of these relays is to monitor and, if warranted, to initiate commands to the feeder breaker to de-energize systems which have been compromised to protect the public and utility personnel, and to minimize damage to public or private property or utility equipment. These relays can also capture important fault information which will be sent to ADMS for the fault location application.

Q. CAN YOU DESCRIBE IN MORE DETAIL HOW FLISR BENEFITS CUSTOMERS?

A. Yes. Electric power outages and blackouts cost the United States about $44 billion annually, according to a 2018 study by Lawrence Berkeley National Laboratory ("LBNL").[16] The 2018 study by LBNL provides economic impact data per event based on the customer class (i.e., medium and large Commercial & Industrial ("C&I"), Small C&I, Residential) and the length of the outage.[17]

In addition, customer reliance on electricity has increased due to the rise of electrification, increasing customer service expectations imposed on the businesses and employees that use our electric service, and increasing overall expectations regarding power quality, number of outages, and outage length.

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[16] *Improving the Estimated Cost of Sustained Power Interruptions to Electricity Customers* (June 2018), available at: http://eta-publications.lbl.gov/sites/default/files/copi_26sept2018.pdf.

[17] *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*, available at https://emp.lbl.gov/sites/all/files/value-of-service-reliability-final.pdf.pdf. For instance, a one-hour outage would have an economic impact of $17,804 on a medium or large C&I customer, $647 on a small C&I customer, and $5.10 on a residential customer.

Whether or not customers understand metrics like SAIDI, they expect reliable electric service from their electric utility.

For commercial and industrial customers, the impacts from reliability tend to more readily apparent as outages result in loss of production and loss of revenue. For example, for many of the larger energy requests, such as data centers, electric reliability is typically one of the main considerations emphasized when determining a location as high reliability is essential to their operations. Being able to demonstrate a history and commitment to reliability make it easier to attract these types of customers which in turn can bring jobs and economic benefits to local communities.

B. <u>FLISR Deployment Timeline</u>

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 the worst performing feeders within the FAN and IVVO footprint area, which is mainly covering the Denver metropolitan area where the highest density of customers exists. Deployment of devices and enablement of feeders will be grouped in geographic areas to gain operational and reliability benefits. 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 field 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 device to be placed on that pole or reconfiguring an underground cable so that a pad-mounted piece of equipment can interconnect with it.

Q. WHAT WORK HAS DISTRIBUTION ALREADY COMPLETED TO IMPLEMENT THIS PROJECT?

A. Public Service is taking a multi-step approach to FLISR in Colorado. The first step involves deployment of protective equipment that can be leveraged with local programming to reduce outage exposure for customers. Secondly, this equipment will be enabled with FAN communications and those devices will report information about faults to the ADMS. That information will be leveraged to dispatch outage response teams closer to faults after they occur, thereby reducing outage durations for affected customers. Finally, Control Center staff will take an active role in managing FLISR devices, either remotely operating devices or allowing the ADMS to automatically operate devices so that customer sections can be brought back online within minutes of a fault occurring.

Today, Public Service has deployed approximately 317 new devices in the first stage and those devices have begun to generate benefits for customers. Company is in the final stages of device point to point testing and ADMS enablement with the goal of bringing seven FLISR feeders into the second stage. As the Control Center transitions to utilizing the ADMS later in 2020, feeders will be moved from the second stage to the third stage, with operators first manually operating devices as faults occur on the system (also known as 'Open Loop' FLISR), and ultimately allowing the ADMS to automatically operate devices (also known as 'Closed Loop' FLISR).

Q. WHAT WORK DOES PUBLIC SERVICE EXPECT TO COMPLETE IN 2021 AND 2022 TO IMPLEMENT FLISR?

A. Public Service is continuing to deploy FLISR field devices (reclosers, switches, and substation relays) at a relatively steady rate. Actual device installations since 2016 and the project installations for 2021 and 2022 are shown in Table CSN-D-16 below. Installations are expected to continue through 2025 with the possibility of rolling deployments into 2026 if necessary.

TABLE CSN-D-16
FLISR Field Device Installation

FLISR	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Field Devices	35	43	76	68	55	68	50	69	73	77
No. of Feeders	10	13	22	20	16	20	15	20	21	23

C. <u>Distribution's Capital Costs for FLISR</u>

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

A. Yes. 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. The IT integration necessary for

FLISR and FLP implementation has been implemented by Business Systems, as noted by Mr. Remington in his Direct Testimony.

Q. WHAT ARE THE FLISR CAPITAL ADDITIONS FOR DISTRIBUTION RELEVANT TO THIS RATE CASE?

A. Table CSN-D-17 below provides Distribution's capital additions for FLISR and FLP for September 1, 2019 through the 2022 FTY.

TABLE CSN-D-17
FLISR and FLP Distribution – Capital Additions
(Public Service – Total Company)

AGIS Program *($ in millions)*	**9/1/2019 through 12/31/2019 Actual**	**2020 Actual**	**2021 Forecast**	**2022 Forecast**
FLISR	2.2	4.8	7.1	5.9

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

A. The primary components of the FLISR and FLP capital forecast 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 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. The Company 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, Distribution 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. HOW DID THE COMPANY ESTIMATE THE INSTALLATION COSTS FOR FLISR AND FLP?

A. The installation costs for FLISR include the capitalized costs for installing and commissioning FLISR devices (switches, reclosers, sensors, and relays). The Company started to install FLISR and FLP devices in 2016 and was able to use historical installation and labor costs to develop the capital cost estimates.

Q. DOES DISTRIBUTION'S CAPITAL FORECAST FOR FLISR INCLUDE CONTINGENCY?

A. Distribution's capital forecast for FLISR does not include any contingency amounts; however, beyond 2022, there are certain contingency amounts include in the FLISR budget.

D. Distribution's O&M Costs for FLISR

Q. WHAT ARE THE FLISR O&M COSTS FOR DISTRIBUTION RELEVANT TO THIS RATE CASE?

A. Table CSN-D-18 below provides Distribution's O&M costs for FLISR for 2020 through the 2022 FTY.

TABLE CSN-D-18
FLISR and FLP Distribution – O&M Expenses
(Public Service – Electric)

AGIS Program *($ in millions)*	**2020 Actual**	**2021 Forecast**	**2022 Forecast**
FLISR	0.2	0.2	0.3

Q. WHAT ARE DISTRIBUTION'S O&M COSTS ASSOCIATED WITH THE IMPLEMENTATION OF FLISR?

A. Distribution's O&M costs for FLISR will include costs in the following categories: (1) capital support; (2) on-going asset/device support; (3) device replacement; (4) on-going communications network; and (5) training.

Q. WHAT IS INCLUDED IN THE CAPITAL SUPPORT COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes expenses related to equipment installations that are appropriately deemed O&M. One example is certain switching operations necessary to safely install new equipment. The Company used actual, average installation times to develop these cost estimates.

Q. WHAT IS INCLUDED IN THE ON-GOING ASSET/DEVICE SUPPORT COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes labor and repairs to maintain assets in good working order. The Company estimated the annual support costs by multiplying per-unit support cost estimates by the quantity of devices in service each year.

Q. WHAT IS INCLUDED IN THE COMPONENT REPLACEMENT COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes material and labor to replace batteries for certain devices on a five-year schedule. The Company estimated these costs by multiplying per-unit replacement cost by the quantity of devices expected to need battery replacement each year.

Q. WHAT IS INCLUDED IN THE ON-GOING COMMUNICATIONS NETWORK COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes costs to maintain the field devices communications. The Company estimated these costs based on historical time to troubleshoot device communication issues and an estimate of the quantity of devices which typically have required such maintenance.

Q. WHAT IS INCLUDED IN THE TRAINING COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes training costs for the FLISR project. The Company estimated these costs based on the labor costs of the employees requiring FLISR training (control center, engineering, line crews, etc.) and the time required to train them.

Q. IN SUMMARY, WHY ARE THE DISTRIBUTION BUSINESS AREA'S FLISR COSTS REASONABLE FOR CUSTOMERS TO SUPPORT?

A. Customers expect reliable power from their utility and the need for higher reliability has never been greater. The current pandemic has emphasized our increased dependency on high reliability throughout the service territory – even in remote areas as more people are working from home. Commercial and Industrial customers are more reliant on processes, equipment and cloud computing that require higher degree of electric reliability as well. The implementation of FLISR will enhance the reliability of our system and target areas that historically have experienced a higher number of outages. Enhancing the reliability of our system will not only improve reliability of our existing customers but can be important for attracting industries that require higher reliability (such as data centers) to Colorado which in turn can bring jobs and economic development to Colorado.

VIII. ADVANCED PLANNING TOOL

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

A. In this section of my Direct Testimony, I describe Distribution's need for the APT which is software that was implemented in 2020 by Business Systems for use by Distribution.

A. APT

Q. WHAT IS THE DISTRIBUTION APT?

A. The Distribution APT is a forecasting and planning tool that will enable Public Service to efficiently expand its distribution planning capabilities to incorporate distributed energy resources, enhance its load forecasting capabilities, and better integrate and align with the Company's other planning tools and processes. The Company's distribution planning team will utilize this new capability to study various forecasts and DER adoption scenarios resulting in improved distribution plans. The advanced planning tool is provided by Integral Analytics and is called LoadSeer.

Q. WHAT EVALUATION PROCESS WAS USED TO SELECT THE LOADSEER PRODUCT?

A. The Company took a multi-step approach to evaluating potential future tools. This included information gathering and prescreening, applying evaluation criteria to potential vendors' subsequent bid proposals, inviting the top vendors to provide product demonstrations, and external vetting. In order to further validate the LoadSeer selection determination, the Company also reached out to industry experts and existing LoadSeer utility industry customers to gauge tool experience, understand their use cases and tool and vendor services satisfaction. Based on the aforementioned evaluations, the Company determined LoadSeer is the appropriate tool for the next phase of the Company's distribution forecasting.

Q. WHY IS THE APT NEEDED?

A. Distribution planning involves analyzing the electric distribution system's ability to serve existing and future electricity loads by evaluating the historical and forecasted load levels, and utilization rates of major system components such as substations and feeders. Traditionally, load growth rates were developed by feeder, derived from historical data and known inputs. Planners then identified system constraints such as substation or feeder capacity or low voltage. However Public Service's customers are increasingly exercising more choice around their use of energy. Some of these choices, including DER and beneficial electrification such as electric vehicles ("EV") make granular load forecasting a much more complex and important undertaking than it was only a few years ago. Utilities, instead of planning just for load, need to analyze the system for future connections that may be load or generation. The Company also needs to view operations and customer tools from our customers' perspectives. An APT will allow Public Service to plan for its systems differently than before, allowing for improved processes and methodologies utilizing new tools and capabilities. The principal improvements APT will provide to the planning process will be 1) to more accurately forecasts feeder loads and generations, which will enable the electrical modeling tools to more accurately identify performance and system constraints, and 2) to enable our planners to more efficiently study various scenarios for load growth or DER adoption.

Q. WILL APT BENEFIT CUSTOMERS?

A. Given the capabilities and benefits the APT will enable for our distribution planning processes, this investment is in the interest of both customers and the Company and will help the Company meet our regulatory requirements. The customer benefits include quantifiable benefits and other benefits that are more difficult to specifically quantify. Deployment of APT will include the retirement of the Company's current distribution forecasting tool which has nearly $90,000 in annual O&M costs. Additional benefits that the Company expects when compared to our existing tools and processes include:

- Annual deferral of distribution capital investments as a result of the tool's enhanced capabilities to forecast both load and generation;
- Hourly analysis for all measured points on the grid that examines the minimum and peak loading differentials, load shapes and more clearly shows the impact of DER;
- Improved load forecasting precision that can account for two-way power flows;
- Enables easier identification of opportunities for non-wires alternatives investments for projected overloads and contingencies;
- Processes forecasting scenarios within the tool, rather than requiring an outside, manual process;
- Enables analysis closer to the customer than the traditional feeder and substation analysis, to examine impacts of DER at a more granular level;
- Better integrates customer data, including from future AMI deployment; and
- Aggregates forecasts to ensure better consistency with corporate-level forecasts, and better integration into other company planning processes.

Q. WHAT IS DISTRIBUTION'S ROLE IN IMPLEMENTING THE APT?

A. As APT is a software tool, Business Systems is responsible for its for budget and implementation and Distribution is responsible for defining the business requirements and supporting the implementation and testing of the software tool. Mr. Remington discusses both the deployment of APT and the costs forecast for APT.

IX. AGIS GOVERNANCE

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

A. Yes. The AGIS program has established distribution 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.

Q. WHAT IS THE COMPANY'S GOVERNANCE STRUCTURE FOR THE AGIS INITIATIVE?

A. A robust governance structure is necessary for any program of this size and scope, especially considering the technical and integrated nature of AGIS, the various operating and customer service areas of our business that support the initiative, and the coordination necessary to deliver value for our customers as Public Service implements AGIS. The Company has established a tiered governance structure for the AGIS initiative to provide the necessary controls and oversight that will enable us to achieve the desired customer and business outcomes. The program sponsors are responsible for approval of the overall strategy and funding as well as the overall program results. The program sponsors have instituted an executive-level Integration Council ("IC") to ensure alignment of the enterprise vision and drive cross-workstream integration of the AGIS initiative. This council resolves execution issues and risks, and provides enterprise visibility to the design, program management, change management, and benefits realization anticipated from AGIS implementation. Any proposed changes are individually documented and brought to a change control meeting composed of program management and senior AGIS leadership. The program management leaders can approve administrative and low impact changes to the initiative. Any significant changes to costs, benefits, scope, schedule, or resources are elevated to the IC for review and approval to provide a consistent approach across the initiative.

Q. HOW WILL THIS STRUCTURE ENSURE APPROPRIATE OVERSIGHT OF AGIS IMPLEMENTATION?

A. Any significant changes to costs, benefits, scope, schedule, and resources are escalated to the Integration Council from the program management leadership team to provide a consistent approach across the initiative. Program leaders ensure that when risks and issues are identified that could affect costs, benefits, scope, schedule, or resources, they are documented, and a mitigation strategy developed. Any risks, issues or changes that meet predetermined thresholds are then escalated to the IC and, if necessary, to the Executive Sponsors for appropriate resolution. This hierarchy of approvals ensures that scope, schedule, and costs are documented and controlled in order to align with customer and Company check as the initiative proceeds.

A. Program Management

Q. WHAT IS PROGRAM MANAGEMENT?

A. Program management is an organizational effort designed to coordinate all projects necessary to incorporate the AGIS initiative into the current distribution system. Large, complex initiatives like AGIS must have established program management controls in order to ensure the effective use of resources, and thus optimal costs for the scope and benefits intended. There are various aspects of program management, some that are specific to a particular business area, and other applicable across all functional areas involved in implementation.

Coordination of projects through program management is driven through standardized project planning, governance, budgeting, and execution metrics methodology. Program management 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, significant program management oversight is needed on a frequent and ongoing basis due to the highly interrelated and interdependent nature of the many components of the AGIS initiative at the individual project level. The project planning life cycle in broken into phases; Strategy, Planning, Initiation, Blueprinting, Design, Build, Test, Deploy, Warranty. Once a project has been initiated, each phase of the project's health is peer reviewed on a weekly basis. The weekly review includes schedule, milestone, issues, risk, and budget. The Project Management office conducts a peer review of the overall AGIS budget on a monthly basis and provides the results to the Integration Council.

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

A. Each of the budgets for the AGIS projects includes capital costs for program management for 2020 through 2025, when the AGIS projects will be substantially completed. In addition, O&M costs associated with program management are included in the "Other" cost category for Distribution. The program management costs are discussed together below.

Q. WHAT ASPECTS OF PROGRAM MANAGEMENT ARE INCLUDED IN THE AGIS BUDGET?

A. Program management costs include:

- Change Management;
- Environment/Release Management;
- Finance;
- Project Management Organization;
- Security;
- Supply Chain;
- Talent Strategy;
- Business Readiness;
- End to End Testing; and
- Delivery and Execution Leadership.

Change management makes up the largest portion of the program management costs in the AGIS budget.

B. Change Management

Q. WHAT IS CHANGE MANAGEMENT?

A. Change management is a systematic approach to effectively executing and managing fundamental organization and process changes, such as when an electric utility implements a significant change to the distribution grid. 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. In the context of change management, stakeholders include any person, process, or entity that is affected by the implementation of the AGIS initiative. The three main elements of change management – prepare, manage, and sustain – each involve significant detailed analysis, action and documentation. The AGIS initiative has a dedicated team ensuring that there is an appropriate overall change management plan in place, and that the plan is resourced and thoughtfully executed.

Q. WHAT TYPES OF COSTS ARE ASSOCIATED WITH AGIS CHANGE MANAGEMENT?

A. The change management capital costs are needed to complete work throughout the development, deployment, and conclusion of on implementing the AGIS components. 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. Change management also includes O&M costs related to strategic program oversight, communications and customer training, as well as incremental corporate services obtained in direct support of the AGIS initiative.

Q. PLEASE DESCRIBE THE OTHER TYPES COSTS RELATED TO AGIS PROGRAM MANAGEMENT AND HOW THOSE COSTS WERE DEVELOPED.

A. The other program management costs associated with AGIS implementation are described in below. As a general note, these functions will be performed using a combination of internal employees and external consultants, and the costs forecasts related to work performed by internal employees is incremental to the general corporate budget forecasts. I also note below where additional considerations were used in developing the specific cost forecasts.

- *Environment/Release Management*: These costs are related to performance and operating tests on the AGIS technology prior to deployment. This includes identification and remediation of issues in the software/hardware deployment and performance testing on the scalability requirements of certain AGIS technology.

- *Finance*: These costs include providing forecasting, budgeting, and reporting on the financial performance of the projects and the AGIS initiative. This includes internal reporting on monthly metrics and providing support in regulatory filings.

- *Project Management Organization*: These costs are related to governance activities for the projects and the overall AGIS initiative. This includes reporting on current project status, requirements for project change requests, and control of policies and guidelines designed to effectively govern the projects and AGIS initiative.

- *Security*: These costs are for work related to identifying security threats and issues on the AGIS technology prior to deployment. This includes identification and remediation of security threats in the software/hardware deployment and continuing requirements for effective cyber security programs. Security requirements for the AGIS initiative follow the corporate strategy and process as outlined in Mr. Remington's Direct Testimony.

- *Supply Chain*: These costs include providing centralized supply chain support, including negotiation of large strategic contracts.

- *Talent Strategy*: These costs include providing support in staffing and alignment of the project and initiative teams. This includes alignment with long term strategic priorities and staffing levels designed around the implementation of the AGIS technology.

- *Business Readiness*: These costs relate to ensuring the business is ready to operate and sustain the new technology. The Business Readiness function ensures that the technology meets the expectations of the business, and that the business is appropriately prepared for the deployment of that technology. The overall goal of the Business Readiness function is to protect the value of the investments by ensuring the new technology is integrated seamlessly into the Company's day to day business.

- *End to End Testing*: These costs are related to testing full business process, including software, system interfaces and other technologies that support or enable the business process from start to finish using real-world scenarios to simulate and test performance after deployment. For the ADMS these costs include full validation of 2-way data transfer between ADMS and field devices. The E2E test also confirms that the field data is displayed accurately on the ADMS User Interface (UI). This testing phase is a normally expected and desired part of testing to determine the business' ability to utilize the business process in normal daily activities.

- *Delivery and Execution Management*: These costs include project and initiative leadership through the design, build, and deployment phases of the AGIS initiative. Delivery and Execution Leadership will provide the oversight and alignment of the project and initiative objectives to the strategic priorities of the Company and the Commission.

Q. ARE PROGRAM MANAGEMENT COSTS REASONABLE?

A. Yes. The Company determined the costs based on the need to build a program management team that will consist of internal employees, as well as the engagement of consultants. This approach is based on the Company's experience with program management and is consistent with its recent experience implementing the new general ledger and work and asset management systems.

Q. DID THE COMPANY DEVELOP CONTINGENCIES FOR PROGRAM MANAGEMENT?

A. Yes. The contingencies for program management are consistent with the contingencies proposed for the overall AGIS initiative but are less than the overall contingencies estimated for design, deployment, and operations of the other components of the initiative. They reflect the uncertainty around the costs that will be necessary for program management, which may not be fully understood until the final requirements for implementation in Colorado are known. Until design and engineering are complete, contingencies are necessary to account for the unknowns that are likely to develop during the processes and through the installation and operations phase.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COSTS IN THE "OTHER" CATEGORY THAT INCLUDES COSTS FOR PROGRAM MANAGEMENT THAT SUPPORT THE AGIS INITIATIVE?

A. Table CSN-D-19 below provides Distribution's O&M expense forecast for the "Other" category for 2020 through the 2022 FTY, which includes costs associated with strategic program oversight, finance, program management, change management, talent strategy, business readiness, and delivery and execution management as described in this section. The O&M expenses in 2021 and 2022 are lower than 2020 primarily for two reasons: (1) governance and oversight costs associated with leadership, business readiness, change management, and testing are lower based on completion of AGIS activities (ADMS) for Public Service, shifting to support other operating companies that are in the earlier stages of deployment; and (2) efficiencies gains by utilizing lower cost resources to perform similar job duties.

TABLE CSN-D-19
AMI Distribution – O&M Expenses
(Public Service – Electric)

AGIS Program *($ in millions)*	**2020 Actual**	**2021 Forecast**	**2022 Forecast**
Other	4.6	2.6	1.9

Q. IN SUMMARY, WHY ARE THESE COSTS REASONABLE FOR CUSTOMERS TO SUPPORT?

A. AGIS is a transformational initiative for how the Company manages its distribution system and interacts with its customers, having a the robust program structure in place not only ensures that Public Service delivers each project but also ensures that Public Service prepares its employees and customers for the upcoming changes to maximize the benefits and value for customers.

X. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. As part of approving the cost of service developed by Ms. Blair, I recommend that the Commission approve Distribution's AGIS capital additions for September 1, 2019 through the 2022 FTY, and Distribution's forecasted AGIS O&M expenses for the 2022 FTY as set forth in my Direct Testimony.

Q. DOES THIS CONCLUDE YOU DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Chad S. Nickell

I am the AGIS Delivery Lead for Distribution for Xcel Energy. In my role I am responsible for managing the delivery of the AGIS projects for Distribution which includes management of costs, schedule, and scope in partnership with Business Systems. This also includes supporting the AGIS governance structure for Project Management, Resource Management, and Financial Management.

I joined Public Service Company of Colorado in 2008 and have over 13 years' experience in the utility industry and have held previous positions as a Distribution System Planning Engineer and the Manager of Distribution System Planning and Strategy—South. 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

* * * * *

IN THE MATTER OF ADVICE LETTER NO. 1857-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 8-ELECTRIC TARIFF TO REVISE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL ELECTRIC RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE AUGUST 2, 2021	**) PROCEEDING NO. 21AL-_____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 1 day of July 2021.

Chad S. Nickell
Chad S. Nickell
AGIS Delivery Lead for Distribution

Subscribed and sworn to before me this 1st day of July 2021.

Dawn Moffit
Notary Public

My Commission expires 4-22-2024

DAWN MOFFIT
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20084013859
MY COMMISSION EXPIRES APRIL 22, 2024