NOTICE OF CONFIDENTIALITY
A PORTION OF THIS TESTIMONY OR TESTIMONY AND ATTACHMENTS HAS/HAVE BEEN FILED UNDER SEAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF ADVICE LETTER NO. 1906-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 TARIFF PROPOSALS EFFECTIVE DECEMBER 31, 2022.	**) PROCEEDING NO. 22AL-XXXXE**

DIRECT TESTIMONY AND ATTACHMENTS OF DAVID C. MINO

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

NOTICE OF CONFIDENTIALITY

A PORTION OF THIS TESTIMONY OR TESTIMONY AND ATTACHMENTS HAS/HAVE BEEN FILED UNDER SEAL.

Confidential: Attachment DCM-2C

November 30, 2022

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF ADVICE LETTER NO. 1906-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 TARIFF PROPOSALS EFFECTIVE DECEMBER 31, 2022.	**) PROCEEDING NO. 22AL-XXXXE**

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Attachment DCM-2C	Confidential Community Resilience Initiative Project Costs
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Attachment DCM-3	July 1, 2021 through June 30, 2022 Operations and Maintenance by Cost Element
Attachment DCM-4	July 1, 2021 through June 30, 2022 Operations and Maintenance by FERC Account

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

* * * * *

IN THE MATTER OF ADVICE LETTER NO. 1906-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 TARIFF PROPOSALS EFFECTIVE DECEMBER 31, 2022.	**) PROCEEDING NO. 22AL-XXXXE**

DIRECT TESTIMONY AND ATTACHMENTS OF DAVID C. MINO

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David C. Mino. My business address is 1123 West 3rd Avenue, Denver, CO 80223.

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

A. I am employed by Xcel Energy Services Inc. ("XES") as Manager, Distribution System Planning and Strategy South. XES is a wholly owned subsidiary of Xcel Energy Inc. ("Xcel Energy"), which provides an array of support services to Public Service Company of Colorado ("Public Service" or the "Company") and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis.

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

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As the Manager, Distribution System Planning and Strategy South, I provide an array of support services to Public Service and other utility operating company subsidiaries of Xcel Energy. I lead a team of engineers responsible for tracking load additions and forecasting the demand growth to develop load forecasts for distribution feeders and substation transformers. Electric distribution system planning engineers are responsible for identifying system risks in the forecast and developing capital projects to mitigate these risks to ensure safe and reliable operation of the electric distribution system. I am also responsible for providing strategic direction for building a five-year distribution plan to ensure a reliable and cost-effective electric distribution system. A description of my qualifications, duties, and responsibilities is set forth in my Statement of Qualifications at the conclusion of my Direct Testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to support Distribution capital plant additions since the Company's last electric rate case in Proceeding No. 21AL-0317E (the "2021 Electric Phase I"), through December 31, 2023. I also support the Distribution operations and maintenance ("O&M") expense that the Company is seeking to recover through this rate case.[1]

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[1] Company witness Mr. Kristopher R. Farruggia addresses Distribution plant additions and O&M associated with the Company's Wildfire Mitigation Program ("WMP").

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

A. Yes, I am sponsoring the following Attachments DCM-1 through DCM-4:

- Attachment DCM-1: Capital Additions January 1, 2021 – December 31, 2023;
- Attachment DCM-2: Confidential and Public Versions of Community Resilience Initiative Project Costs;
- Attachment DCM-3: July 1, 2021, through June 30, 2022, Operations and Maintenance Expenses by Cost Element; and
- Attachment DCM-4: July 1, 2021, through June 30, 2022, Operations and Maintenance Expenses by FERC Account.

Q. HOW IS THE REMAINDER OF YOUR DIRECT TESTIMONY ORGANIZED?

A. I first provide background on the Distribution function and its activities. Thereafter, in Section III, I provide an overview of the Distribution Business Area's[2] capital budgeting process, project development, and budget management processes. In Section IV, I discuss the Distribution Business Area's capital additions included in the Test Year,[3] followed by Section V, which presents the Company's Distribution Business Area O&M expense.

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[2] In my Direct Testimony, "Distribution Business Area" is also referred to as "Distribution."

[3] As discussed by Company witness Mr. Steven P. Berman, the Company is proposing a test year (the "Test Year") that reflects rate base using a 13-month average convention for the period ending December 31, 2023. Plant balances are based on actual plant additions through June 31, 2022, plus forecasted additions through December 31, 2023. The Test Year also consists of forecasted sales revenue for 2023 and actual O&M expense for the twelve months ended June 30, 2022, with individual adjustments and inflationary increases to reflect a representative level of costs for the period the rates will be in effect.

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

A. I recommend the Colorado Public Utilities Commission ("Commission") approve the Company's 2022-2023 Distribution Business Area capital additions and Test Year O&M expenses, as set forth in my Direct Testimony and in the cost of service presented by Company witness Mr. Arthur P. Freitas.

II. ELECTRIC DISTRIBUTION BUSINESS AREA

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

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

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

A. To reliably and efficiently serve our approximately 1.5 million Colorado customers, Public Service owns and operates an extensive electric distribution system. Our electric distribution system has assets in 25 counties throughout Colorado and provides electric service to both rural and urban customers. The distribution system consists of approximately 152 distribution-level substations that support a network of 833 distribution feeders necessary to serve our customers. These distribution feeders include approximately 9,600 circuit miles of overhead distribution lines, 14,100 circuit miles of underground distribution lines, and over 518,000 Company-owned distribution poles.

Q. PLEASE PROVIDE AN OVERVIEW OF THE DISTRIBUTION BUSINESS AREA.

A. The Distribution Business Area is responsible for the construction and operation of Public Service's distribution system, which is the portion of its electric system that delivers electricity to the vast majority of our customers. There are a total of approximately 1,017 Public Service and XES Distribution employees assigned to provide services to the Public Service's electric distribution system. Of those employees, approximately 753 are Public Service employees.

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

A. The Distribution Business Area is responsible for engineering, constructing, operating, maintaining, and repairing the portion of the electric system that directly connects customers' homes and businesses to the distribution system. The key services provided by the Distribution Business Area include performing regular maintenance, repairs, and replacement of poles, wires, underground cables, metering, and transformers, extending service to new customers or increasing the capacity of the system to accommodate new or increased load, repairing facilities damaged during severe weather to quickly restore service to customers, and interconnecting new Distributed Energy Resources ("DER") to the distribution system. To deliver these services, the Distribution Business Area is structured around five key functions:

- *Operations:* Responsible for the design, construction, and maintenance of the distribution system, as well as monitoring and operating the distribution system from the Electric Control Center, responding to electric distribution trouble calls, and coordinating emergency response.

- *Engineering:* Provides technical support and system planning, including design, construction, and material standardization, reliability planning, and responsible for addressing distribution-related customer load, resource, and service issues.

- *Business Operations:* Responsible for vegetation management, outdoor lighting, facility attachments, and the builder's call line.

- *AGIS[4] and Metering.* Responsible for implementing the AGIS initiative and metering.
- *Planning and Performance:* Provides business planning, consulting, analytical services, and performance governance and management.

Q. HOW DOES THE DISTRIBUTION BUSINESS AREA SUPPORT THE FUNCTIONS DESCRIBED ABOVE?

A. Distribution makes capital investments and incurs O&M costs to maintain and improve the reliability of the system, modernize the distribution system, improve functionality, extend service to new customers, and relocate facilities in response to road construction or other governmental projects. I will discuss Distribution's capital investments and O&M trends in more detail below.

[4] "AGIS" refers to the Company's Advanced Grid Intelligence and Security initiative.

III. DISTRIBUTION CAPITAL BUDGET, PROJECT SELECTION, AND FUNDING

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

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

A. Overview of Distribution's Capital Investments

Q. HOW DOES DISTRIBUTION CATEGORIZE ITS CAPITAL ADDITIONS?

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

- *AGIS:* This category consists of projects included in the Company's AGIS initiative. The AGIS initiative involves the following foundational projects: Advanced Distribution Management System ("ADMS"), including 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); and the Advanced Planning Tool (also referred to as LoadSEER).

- *Asset Health and Reliability:* Projects classified as Asset Health and Reliability are related to infrastructure that is reaching the end of its useful life and is experiencing higher failure rates – and that, as a result, negatively impact reliability of service while increasing O&M expenses. Distribution assets are monitored to ensure that they provide reliable service throughout the year. When poor-performing assets are identified, projects that will improve asset performance are included in the budget. Examples of these types of projects include replacing underground tap and feeder cables, wood poles, overhead lines, substation equipment, transformers, and switchgear that have reached the end of their lives. This category also captures asset replacements due to storms and public damage.[5]

[5] Distribution WMP capital additions are part of the Asset Heath & Reliability category. As noted above, Mr. Farruggia addresses the Company's WMP capital additions and Distribution WMP capital additions are not reflected in this Direct Testimony.

- *Capacity:* This category includes capital investments associated with upgrading or increasing distribution system capacity to handle load growth on the system and to serve load when other elements of the distribution system are out of service. This category also allows the system to support the interconnection of additional DER, including rooftop solar, and greater electric vehicle adoption, both of which are key to achieving the Company's and Colorado's emissions reduction goals. This additional capacity is provided by constructing new substations and installing new or upgraded substation transformers and distribution feeders. Capacity projects generally span multiple years and are necessitated by increased load from either existing or new customers.

- *New Business:* This work includes new overhead and underground extensions and services associated with extending service to new customers. Capital projects required to provide service to new customers include the installation or expansion of feeders, primary and secondary extensions, service laterals that bring electrical service from an existing distribution line to a new home or business, installation of street lighting, and converting existing streetlights to light-emitting diode lights.

- *Mandates:* This category includes projects to relocate utility infrastructure in public rights-of-way ("ROW") when mandated to do so to accommodate public works projects such as a road widening or realignment project. These projects are normally identified during planning meetings with local communities. Examples of these projects include utility relocations for state and local governments such as the Central 70 project, which involves utility relocation in the I-70 corridor.

- *Tools and Equipment:* This category includes tools, ROW, communications equipment, and locate costs associated with modifications or additions to the distribution system or supporting assets.

Q. ARE FLEET CAPITAL INVESTMENTS INCLUDED IN THESE GROUPINGS?

A. No. Fleet capital, which is associated with the necessary replacement of vehicles and construction equipment that have reached their end of life, is addressed in the

Direct Testimony of Company witness Mr. Adam R. Dietenberger for all of the Company's business units.

B. Distribution's Budget Development and Management

Q. HOW DOES DISTRIBUTION ESTABLISH A REASONABLE CAPITAL BUDGET FOR A GIVEN YEAR?

A. The Distribution Business Area budgets identify the investments needed each year to maintain reliable service to existing customers and to extend service to new customers. Distribution identifies specific projects that are needed and also forecasts appropriate funding for our routine investments. Distribution utilizes a comprehensive capital forecasting system to budget for and track these costs.

Distribution's annual capital budget is dependent on the Company's overall finances and other business area needs. In his Direct Testimony, Mr. Dietenberger explains that generally, there are more projects and work to be done than there is the capacity to fund, resulting in assessment and prioritization across business areas and operating companies and ultimately a capital budget specific to the Company (and its Distribution Business Area).

Q. CAN YOU PROVIDE A SUMMARY OF HOW THE DISTRIBUTION BUSINESS AREA DEVELOPS ITS CAPITAL BUDGET?

A. Distribution prioritizes, funds, and undertakes those capital projects that are necessary to maintain Public Service's distribution system to enable Public Service to provide safe and reliable electric service to our existing customers. As noted above, Public Service's distribution system is extensive, and it is necessary to make regular investments that support the continued health and reliability of the system.

Distribution begins its load forecast and budgeting process in October by reviewing the peak loads from the previous year to identify new or increased risks on the distribution system. Unlike the electric resource planning process, which is conducted to meet system-wide energy and capacity needs, the distribution system load forecasting process is a "bottom-up", locationally specific process, that considers the impact of load growth on specific pieces of equipment, including substation transformers and distribution feeders. Distribution System Planners use detailed load flow modeling tools and historical Supervisory Control and Data Acquisition ("SCADA") information to determine the risk of assets being overloaded during both normal and contingency situations.[6] The annual distribution system load forecasting process is depicted below in Figure DCM-D-1 below.

FIGURE DCM-D-1
Overview of Load Forecasting Process

[6] Overloads during normal system configuration with all assets in operation supporting the capacity of the distribution system are considered N-0 Risks, whereas N-1 Risks are overloads under conditions where one asset is removed from operation.

The Distribution Business Area employs this "bottom-up" approach to budgeting and planning for the future needs of the distribution system. Distribution's capital budget is dependent on the state of the economy, which has a significant impact on the development of new and expanded business, conditions that drive new housing, large commercial load increases, and road work projects that affect distribution facilities. To obtain an accurate gauge of this work, the Company also utilizes a top-down approach with our budgeting process by utilizing economic forecasting and analysis of historical spending trends to assess likely new business needs and required replacement or upgrade of existing assets. This helps account for demand growth that has not yet been submitted to the Company in the form of a service application.

In addition, to accommodate road construction projects planned by state and local governments in our service territory, the Company also budgets for the necessary relocation of distribution facilities to accommodate these road construction projects. Distribution also assesses the impacts of system growth on our capacity needs, including the risk of overloads and the system's ability to handle single contingency events.

Q. HOW DOES THE BUDGETING PROCESS INCORPORATE RELIABILITY INTO ITS ANALYSIS?

A. Although economic factors drive part of our budget, Distribution also must ensure that the existing system remains reliable. This includes proactively replacing assets near the end of their useful lives as well as budgeting for replacement of facilities due to unanticipated failure or damage such as those facilities damaged during storms or by the public. To budget for proactive replacements, Distribution evaluates the age and condition of facilities and determines the amount of replacement or refurbishments that are needed in a particular year. To budget for unanticipated failures, Distribution forecasts the likely costs of replacing assets that will fail or become damaged based on historical trends. This analysis results in identification of capital projects that are needed for routine work necessary to maintain our existing system and the work required to support new customers or new construction.

Q. DO NON-WIRES ALTERNATIVES FACTOR INTO THIS PROCESS?

A. Yes. As part of our budget development process, the Company considers a variety of non-wires alternatives ("NWAs") to meet the system capacity needs identified by Distribution Planning. Further, on January 14, 2022, new distribution system planning rules, which include NWA components, became effective. As required, the Company filed its first Distribution System Plan in Proceeding No. 22A-0189E, which is currently pending before the Commission. In that case, Public Service had to develop a process for screening and identifying future major distribution grid capacity projects for which NWAs might be appropriate, present the results of that screening, develop and propose a cost-benefit analysis methodology to use in evaluating NWA proposals, and create and present form Request for Proposal

("RFP") and contract documents to use in the NWA technology neutral solicitation. Those matters continue to be developed in that case at the time of this filing.

Q. WHAT PROJECTS FALL WITHIN THE ROUTINE WORK CATEGORY?

A. Routine work consists of common capital additions that occur year-over-year to replace aging assets, support new business growth, and includes system reinforcements, or rebuilds. This routine work also can include material upgrades to the distribution system, such as reconductoring a line, upgrading a transformer, or replacing a substation regulator. The two largest categories of routine capital additions are cable replacements and transformer purchases under the Asset Health and Reliability category, which I discuss later in my Direct Testimony.

Q. HOW DOES DISTRIBUTION BUDGET FOR ROUTINE WORK THAT MUST BE PERFORMED EACH YEAR?

A. For routine work orders that address asset health issues or relocations, Distribution uses historical averages escalated by a corporate escalator to determine expected levels of spend. The escalation factors include, but are not limited to labor, non-labor, contractor, material, equipment, and bargaining labor increases. The budget for routine work orders for new service extensions is developed using a cost-per-meter methodology. This process relies on the forecast for the number of new meter sets for each local operating area. The total expected routine work order budget is then allocated to each service area using the average historical ratio for the past five years. The allocation is adjusted to ensure unique, one-time projects in a service area do not impact the calculation of the average five-year historical expenditures.

Q. DOES THE DISTRIBUTION BUSINESS AREA ESTABLISH BUDGETS FOR NON-ROUTINE PROJECTS?

A. Yes. In addition to routine work orders, the Distribution Business Area also budgets for and implements certain discrete projects that are identified to address a particular system need that does not reoccur each year. At a high level, the identification and assessment of problems or “risks” along with their related solutions or “mitigations” is integral to identifying larger projects Distribution must fund in addition to the routine work I described above.

System risks are issues that can result in negative consequences to the Company’s ability to provide safe and reliable service. Distribution Planning Engineers identify risks to the distribution system by using the distribution load forecast to identify two main types of risk to distribution feeders and banks: N-0s and N-1s. N-0 risks occur when a feeder or substation transformer bank overloads during normal system configuration in which all distribution feeder and substation transformers are in service and supporting the capacity of the distribution system. N-1 risks are overloads that occur during contingency situations if a feeder or bank is out of operation and the system, as a result, has one less asset supporting system capacity. Mitigations are solutions that address the risks. To help ensure that each risk is being addressed by the most efficient solution, Distribution assesses all mitigation alternatives and selects the one that provides the best value to our customers and our Company.

Q. DOES THE COMPANY RANK AND PRIORITIZE IDENTIFIED NON-ROUTINE, INDIVIDUAL PROJECTS?

A. Yes. Funding for capital projects is limited, and typically the cost for all identified individual projects exceeds available funding. In addition, the volume and diverse types of risks require utilization of a systematic process to perform specific risk assessment of the asset's overall future performance expectations. Therefore, it is important to rank or prioritize proposed individual projects before authorizing a project to move forward. This is accomplished by ranking the assessment of each project against each other. Highest priority is given to projects that Distribution must complete within a given budget year to ensure that we meet regulatory and environmental compliance obligations and to connect new customers.

Q. HOW DOES THE DISTRIBUTION BUSINESS AREA MANAGE AND CONTAIN ITS CAPITAL COSTS?

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

Q. DOES THIS PROCESS ACCOUNT FOR EVENTS THAT OCCUR DURING THE YEAR?

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

Q. ARE THE COMPANY'S INVESTMENTS IN DISTRIBUTION PROJECTS REASONABLE AND PRUDENT?

A. As discussed in my Direct Testimony, Distribution's 2022 and 2023 capital additions presented in Attachment DCM-1 are reasonable and necessary to provide safe and reliable service to Public Service's retail customers. The rigorous processes that are followed in evaluating, selecting, and monitoring the execution and implementation of capital projects ensure that the additions are reasonable and necessary and that the costs are prudently incurred to provide safe and reliable service to Public Service's customers.

IV. DISTRIBUTION 2022-2023 CAPITAL ADDITIONS

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

A. The purpose of this section of my Direct Testimony is to describe Distribution's 2022 and 2023 capital additions.[7] I begin with an overview and then provide details, organized by Distribution's six budget categories: (1) AGIS; (2) Asset Health and Reliability; (3) Capacity; (4) New Business; (5) Mandates; and (6) Tools and Equipment.

A. Overview of 2022-2023 Capital Additions

Q. CAN YOU SUMMARIZE DISTRIBUTION'S 2022-2023 CAPITAL ADDITIONS?

A. Yes. Table DCM-D-1 summarizes Distribution's capital additions for 2022-2023 included in this case. I have also provided 2021 actual capital additions for reference.

[7] Distribution's WMP capital additions are discussed by Mr. Farruggia in his Direct Testimony.

TABLE DCM-D-1
Distribution Capital Additions
Public Service Electric
(Dollars in Millions)

Budget Category	2021 (Actual)	2022			2023 (Forecast)
		1/1 – 6/30 (Actual)	7/1 – 12/31 (Forecast)	Total	
AGIS	$89.7	$49.2	$50.7	$99.9	$99.2
Asset Health and Reliability	$162.9	$68.3	109.7	$178.0	$151.7
Capacity	$23.9	$23.5	$23.1	$46.6	$102.1
New Business	$96.0	$31.5	$52.1	$83.6	$93.1
Mandates	$28.8	$19.5	$45.6	$65.2	$22.1
Tools and Equipment*	$9.8	$4.9	$3.9	$8.8	$21.3
Total**	**$411.1**	**$196.9**	**$285.1**	**$482.2**	**$489.5**

This table does not include Distribution's WMP capital additions, which are discussed separately by Company witness Mr. Farruggia. It also does not include capital additions recovered through the Company's Transportation Electrification Plan rider.
* Reflects the following amounts of common plant additions: approximately $1.6 million in 2021, approximately $0.6 million in 2022 and approximately $0.4 million in 2023.
** There may be differences between the sum of the individual category amounts and Total amounts due to rounding.

Q. WHAT ARE THE HIGH-LEVEL DRIVERS OF THE COMPANY'S DISTRIBUTION INVESTMENTS IN 2022 AND 2023?

A. Since the 2021 Electric Phase I, Distribution has been making increasing investments in its Asset Health and Reliability category, which is Distribution's largest capital budget category. Public Service's distribution system is aging: many components were constructed in the 1950s and 1960s and have a typical life expectancy of 50 years or longer (dependent upon equipment type). Further, unlike practically all of the transmission system, the distribution system is not fully redundant – so individual system component failures can directly impact a customer's reliability. As a result, Distribution needs to make continuous investments to replace its aging and worn infrastructure to ensure continued reliable service for Public Service's customers. In particular, Distribution has been making large investments in its cable replacement programs, which identify and replace underground cable that is aging and in poor condition. It is important to replace cables that are aging and in poor condition to help avoid outages for customers served by our underground cable system.

Q ARE ASSET HEALTH AND RELIABILITY INVESTMENTS ALSO IMPACTED BY HOW CUSTOMERS USE THE DISTRIBUTION SYSTEM?

A. Yes. In addition to the age and condition of our Distribution assets, Distribution's investments in Asset Health and Reliability also are being driven by changes in the way that Public Service's customers use the distribution system. The distribution system is moving from exclusively one-way power flows to two-way power flows as customers install DER (e.g., rooftop solar) on their homes and businesses and the number of community solar gardens that are interconnected continues to grow. Accommodating these distributed resources requires Public Service's distribution equipment be robust enough to maintain proper voltage levels when these new resources come online. In addition, these distributed resources will accelerate the wear on our already aging facilities and also can prompt the need for changes to protection schemes and equipment. At the same time, a distribution system that is able to accommodate increasing amounts of DER will contribute to Public Service meeting its emissions-reduction goals.

Q. HAS LOAD GROWTH IMPACTED DISTRIBUTION'S CAPITAL ADDITIONS?

A. Yes. Load growth on certain portions of the distribution system has been a key driver of capital additions in recent years. Over the past 10 years, Colorado has experienced tremendous population growth that has caused increased load on certain portions of Public Service's distribution system, outpacing the current capabilities in those areas. In addition, the anticipated increase in adoption of electric vehicles and building electrification are expected to further stretch, and in some cases, exceed the capacity of the existing system. As a result, Distribution has completed several Capacity projects in recent years to build new substations, install larger transformers, and to construct new feeders to serve this load growth. For instance, in 2022 Distribution completed the Timnath Substation Project for approximately $19 million. I provide additional details on this project later in my testimony.

Q. DOES LOAD GROWTH IMPACT OTHER DISTRIBUTION CAPITAL ADDITIONS?

A. Yes. Since the 2021 Electric Phase I, Distribution has also been making steady investments in New Business projects to accommodate new residential and commercial developments. Also, expanded economic activity like new data centers, and oil and gas development in Colorado, has resulted in New Business investments. These investments include new service extensions and new substation transformer purchases.

B. AGIS

Q. PLEASE DESCRIBE THE AGIS INITIATIVE.

A. AGIS is a multi-year strategic initiative that will transform the Company's electrical distribution system by enhancing security, efficiency, and reliability, which will enable Public Service to safely integrate more DERs and improve customer reliability, 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.

Q. WHAT PROJECTS ARE INVOLVED IN THE AGIS INITIATIVE?

A. The AGIS initiative involves the following foundational projects: ADMS, including the Geospatial Information System ("GIS"); AMI; the FAN; IVVO; and FLISR (including Fault Location Prediction and the Advanced Planning Tool). Each of these projects involves a coordinated approach – i.e., planning, design, build, deployment, and ongoing support – from the Distribution and Technology Services Business Areas.[8]

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

[8] Mr. Michael O. Remington is the Company's Technology Services Business Area witness.

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").[9] Under the AGIS CPCN Settlement, the Company was authorized to implement deferred account mechanisms for each project (AMI, IVVO, and associated FAN); one for deferred capital investment and one for O&M expenditures. Regular reporting regarding the AGIS Initiative continues to be made in the AGIS CPCN Proceeding, including an annual Actuals Report filed in May each year and an annual Forecast Report filed in October of each year.

In addition, the Company further discussed other AGIS components in the Company's 2019 Electric Phase I (Proceeding No. 19AL-0268E) and in the Company's 2021 Electric Phase I. As a result of the 2019 and 2021 Electric Phase I proceedings, many of the AGIS costs have already been approved for recovery through base rates.

I also note that on June 15, 2021, in compliance with Commission Decisions,[10] 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

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[9] Unopposed Comprehensive AGIS CPCN Settlement in Proceeding No. 16A-0588E.
[10] Decision Nos. C21-0176 and C21-0177, both mailed March 19, 2021.

utilization of the distributed intelligence capabilities that are embedded within the AMI meters that are being installed pursuant to the initial AGIS CPCN. Parties in that case reached a settlement agreement, which allows the Company to develop and deploy certain distributed intelligence ("DI") capabilities, as well as Home Area Network ("HAN") functionality (the "Amended AGIS CPCN Settlement").[11] The Commission approved the Amended AGIS CPCN Settlement as of March 28, 2022.[12] Company witness Mr. Remington addresses these DI and HAN capabilities in his Direct Testimony.

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

A. Yes. My testimony includes support for the Distribution AGIS projects related to meter deployment and field devices. Mr. Remington's Direct Testimony supports AGIS components related to IT Integration and System Development.

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 enhancement in support of ADMS, FAN, FLISR, and IVVO) generally include material and equipment, labor, and vendor services.

[11] Unanimous Comprehensive Settlement Agreement in Proceeding No. 21A-0279E (February 18, 2022).
[12] Decision R22-0131 (Mailed March 7, 2022).

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 DCM-D-2 below. AGIS capital additions through December 31, 2021, have already been included in base rates through the 2021 Electric Phase I.

TABLE DCM-D-2
Distribution AGIS Capital Additions
Public Service Electric
(Dollars in Millions)

AGIS Program	2021 (Actual)	2022			2023 (Forecast)
		1/1 – 6/30 (Actual)	7/1 – 12/31 (Forecast)	Total	
ADMS	$6.4	$0.0	$0.0	$0.0	$0.0
AMI	$46.2	$30.6	$35.5	$66.1	$70.0
FAN	$7.2	$2.9	$2.3	$5.2	$8.4
FLISR	$6.6	$2.0	$3.1	$5.1	$10.4
IVVO	$23.3	$13.6	$9.9	$23.5	$10.4
Total**	**$89.7**	**$49.2**	**$50.7**	**$99.9**	**$99.2**

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

Q. HOW DO THE TABLE DCM-D-2 DISTRIBUTION AGIS CPCN PROJECTS CAPITAL ADDITIONS FOR 2022 COMPARE TO THE INFORMATION PROVIDED BY THE COMPANY IN ITS AGIS FORECAST REPORT?

A. The Company's 2022 Forecast Report (filed November 1, 2021, in the AGIS CPCN Proceeding) identified approximately $106.8 million of expected 2022 AGIS capital additions for the CPCN Projects, of which approximately $101.1 million was for Distribution components of the CPCN Projects. The 2022 capital additions for

Distribution non-AMI components of the CPCN Projects shown in Table DCM-D-2 (i.e. IVVO and FAN) generally are consistent with the amounts shown in the 2022 Forecast Report. We anticipate 2022 AMI capital additions to be below the amount shown in the 2022 Forecast Report.

Q. WHY DOES THE COMPANY EXPECT 2022 AMI CAPITAL ADDITIONS TO BE BELOW THE AMOUNTS SHOWN IN THE 2022 AGIS FORECAST REPORT?

A. The 2022 Forecast Report was made November 1, 2021, and reflected then-current AMI deployment expectations. The Company subsequently revised its AMI roll-out target schedule due to ongoing supply chain issues, resulting in a reduction in anticipated 2022 deployments. As a result, we anticipate 2022 AMI capital additions to be below the amount shown in the 2022 Forecast Report.

Q. HOW DOES THE TABLE DCM-D-2 DISTRIBUTION AGIS CPCN PROJECTS CAPITAL ADDITIONS FOR 2023 COMPARE TO THE INFORMATION PROVIDED BY THE COMPANY IN ITS 2023 AGIS FORECAST REPORT?

A. The Company's 2023 Forecast Report (filed October 31, 2022, in the AGIS CPCN Proceeding) identified approximately $108.1 million of expected 2023 AGIS capital additions for the CPCN Projects, of which approximately $88.8 million was for Distribution components of the CPCN Projects. The 2023 capital additions shown for Distribution components of the CPCN Projects in Table DCM-D-2 (i.e. AMI, IVVO, and FAN) are consistent with the amounts shown in the 2023 Forecast Report.

Q. DOES THE COMPANY ANTICIPATE THAT THE IVVO PROJECT WILL BE COMPLETE IN 2023?

A. Yes. At this time, we expect the IVVO project that is part of the AGIS initiative will be complete in 2023.

Q. DOES THE COMPANY HAVE AN EXISTING OBLIGATION UNDER THE AGIS CPCN SETTLEMENT RELATED TO THE COMPLETION OF THE IVVO PROJECT?

A. Yes. Under the AGIS CPCN Settlement, the Company is entitled to a rebuttable presumption of prudence for the IVVO project costs. The estimated total capital cost of the IVVO project in the AGIS CPCN Proceeding was $131.8 million.[13] Currently, the Company estimates the total capital cost of the project (actual costs incurred plus remaining work to be completed) will be $132.2 million. With the IVVO project expected to be complete in 2023 and with the project being substantially complete, the Company is expecting the total project costs to be in alignment with the CPCN estimates.

Q. IS THE IVVO TECHNOLOGY PERFORMING BETTER THAN EXPECTED?

A. Yes. The areas that are running IVVO have seen average energy reduction greater than two percent, higher than the expected reduction of 1.83 percent. Therefore, in addition to the total project costs being aligned with the initial

[13] Table 1 in the AGIS CPCN Settlement identified the IVVO baseline amount of capital *and* O&M of $193.7 million.

estimates, the areas running IVVO are seeing higher than expected energy savings.

Q. HOW IS THE COMPANY ADDRESSING AGIS COSTS BEYOND 2023?

A. As discussed by Company witness Ms. Marci A. McKoane, the Company is requesting the continuation of the AGIS CPCN deferral. The Company will continue to provide required reporting on the AGIS CPCN work, including available cost data beyond 2023 as required.

C. Asset Health and Reliability

Q. WHAT ARE THE MAJOR CATEGORIES OF ASSET HEALTH AND RELIABILITY PROJECTS?

A. Asset Health and Reliability projects can be placed into the following categories: Cable Replacement, Overhead Rebuilds and Underground Conversions, Pole Replacements, Substation Renewals, and Restoration/Failure Reserves. Table DCM-D-3 provides a breakdown of our 2022-2023 Asset Health and Reliability capital additions by these subcategories.

TABLE DCM-D-3
Asset Health and Reliability Capital Additions
Public Service Electric
(Dollars in Millions)

Asset Health and Reliability	**2021** (Actual)	**2022**			**2023** (Forecast)
		1/1 – 6/30 (Actual)	7/1 – 12/31 (Forecast)	Total	
Cable Replacement	$41.6	$23.3	$31.9	$55.2	$49.5
Rebuilds and Conversions	$50.4	$31.4	$31.9	$63.3	$56.5
Pole Replacement	$35.5	$2.8	$28.5	$31.3	$24.9
Substation Renewal	$27.4	$7.4	$10.4	$17.8	$30.4
Restoration/Failure Reserves	$8.0	$3.4	$7.0	$10.4	$(9.6)
Total**	**$162.9**	**$68.3**	**$109.7**	**$178.0**	**$151.7**

* This table does not include Distribution's WMP capital additions, which are discussed separately by Company witness Mr. Farruggia.
** There may be differences between the sum of the individual category amounts and Total amounts due to rounding.

Q. HOW DOES THE COMPANY ASSESS ASSET HEALTH?

A. As discussed in Section III.A above, the Company's Asset Health and Reliability projects address the age and condition of our distribution facilities. To determine which facilities need replacement or repair each year, we track the age of our major distribution assets and use age as a proxy for asset health. We also analyze reliability data and work to address those components that have poor reliability performance.

Q. PLEASE DISTINGUISH BETWEEN ROUTINE AND NON-ROUTINE ASSET HEALTH AND RELIABILITY PROJECTS.

A. Distribution's investments in Asset Health and Reliability fall into two categories – routine projects and larger discrete projects. As I mentioned earlier, routine projects are those that are performed each year to replace various aging and worn distribution facilities based on the age profile and overall reliability performance of these facilities. This includes replacement of underground cable, poles, and substation equipment that has reached the end of life. This category also captures replacements due to storms and public damage.

In addition to these routine projects that we perform each year, Distribution also undertakes non-routine discrete Asset Health and Reliability projects that relate to asset renewal (addressing aging infrastructure with specific conversion or upgrade projects) or reliability (where the age of facilities impacts failures, reliability, and customer outages). Projects are identified based on system needs and are scored based on our standard budgeting processes and evaluated for funding based on risk score, need, and available funding.

Q. WHAT IS DRIVING 2022 AND 2023 ASSET HEALTH AND RELIABILITY CAPITAL ADDITIONS?

A. As shown in Table DCM-D-3, in 2022, Distribution is investing more in Public Service's cable replacement program and substation renewal program as compared to 2021. These investments are needed to address the condition of aging infrastructure that is key to maintaining the reliability and resiliency of the distribution system.

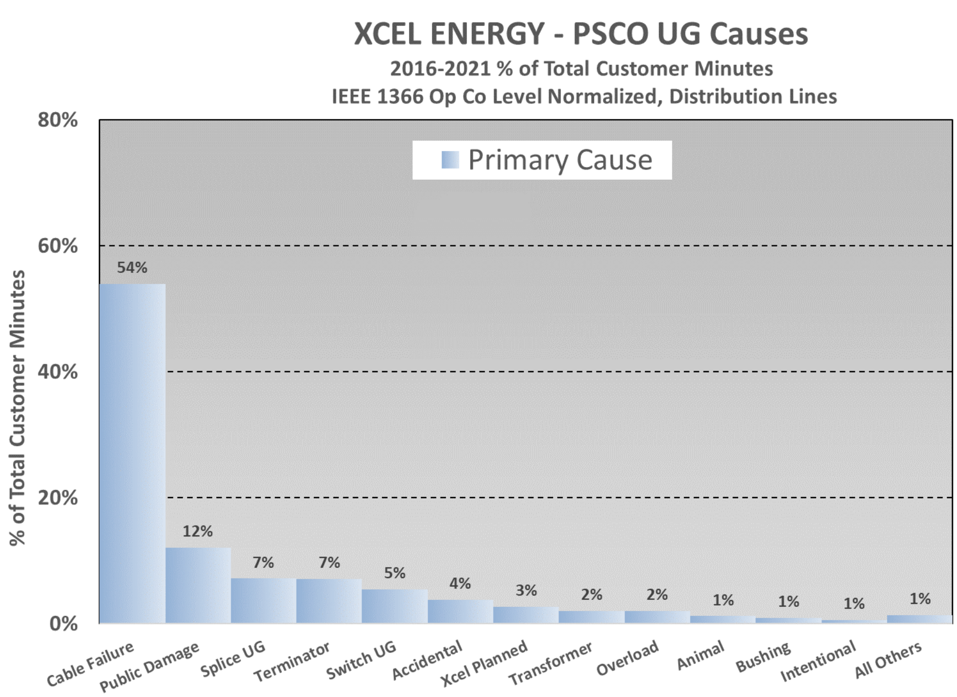
As discussed in greater detail below, Distribution's investments in its cable replacement program in 2022 and 2023 are needed to bring these investments in line with the level of historical spending that Public Service has determined is needed to maintain or lower the current number of annual cable failures. As I noted earlier, cable failures in older parts of the system are a primary cause of outages for customers served by these underground facilities, so it is important to address the aging and worn cables to maintain the reliability of the system. The increase in substation renewal investments in 2022 and 2023 are detailed in Section IV.C.4 below.

1. Cable Replacement Programs

Q. PLEASE FURTHER DESCRIBE PUBLIC SERVICE'S CABLE REPLACEMENT PROGRAM.

A. Public Service's distribution system has over 14,100 miles of total tap and mainline underground cable. As shown in the Figure below, cable failures are a main cause of outages for customers who are served by underground distribution facilities.

FIGURE DCM-D-2: Underground Outage Causes



To minimize these types of outages, the Company has two cable replacement programs: (1) underground residential distribution ("URD") cable or tap level cable replacement; and (2) mainline cable replacements. Within these two programs, Public Service performs both the proactive replacement of the tap level or mainline cable and the emergency replacement of tap level or mainline cable. Proactively replacing means that a cable is replaced prior to failure. The specific sections of cable selected for replacement are based on reliability data, failure history, and in some cases, by historical performance of similar types and vintages of cable. Proactively replacing cable allows Public Service to avoid a potential outage caused by a cable failure and utilize a systematic approach in the replacement of this asset.

Q. WHAT HAS BEEN THE FOCUS OF PUBLIC SERVICE'S CABLE REPLACEMENT PROGRAMS?

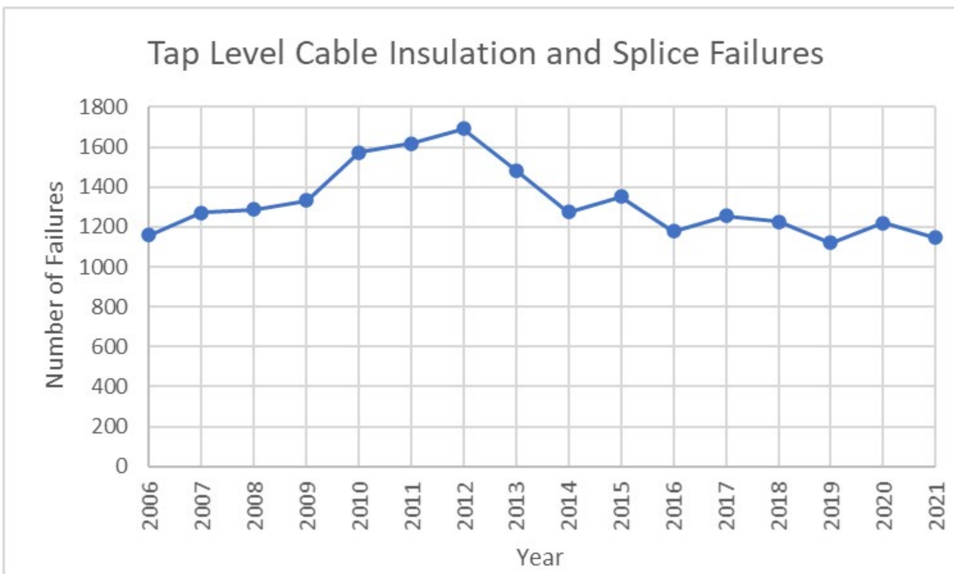
A. Public Service has been working on replacing all non-jacketed cross-linked polyethylene ("XLPE") cable on its system. This non-jacketed XLPE cable was installed prior to 1990 beginning in the early 1970s and is more prone to failures and has a shorter useful life (approximately 45 years) than newer jacketed cable types that Public Service currently installs. To address this issue, since 2000, Public Service has been replacing both URD and mainline non-jacketed XLPE cable that has failed or reached the end of its life with newer jacketed cable. Even with these investments, there is still approximately 240 miles of non-jacketed XLPE mainline cable in Colorado that needs to be replaced. Based on current replacement rates, it is anticipated that this non-jacketed XLPE cable replacement program will be in effect for approximately another 20 years.

Public Service has also been focusing on replacing non-jacketed XLPE cable in entire half loops as opposed to single cable segments. By way of background, an underground residential distribution system is comprised of an underground circuit, in a loop arrangement, segmented by distribution transformers. Once multiple failures occur on a segment, replacing the entire half loop is required to avoid future failures of other segments of that half loop, benefitting both impacted customers and system reliability. This is because the cables in these half loops are of similar vintage and type of cable (they were installed at the same time originally) and once repeated failures have occurred within that loop, it is only a matter of time before additional failures occur, affecting customer reliability, repair costs, and customer experience. Once a half loop has experienced a fault for a second time and that half loop is not replaced, the average number of days between failures decreases substantially with each subsequent fault resulting in more customer outages and more repairs.

Q. HOW WAS THE BUDGET FOR THE ROUTINE CABLE REPLACEMENT PROGRAM DEVELOPED?

A. The budget for routine cable replacements is developed based upon historical trends of failure/fault rates and reliability needs. The specific sections of cable selected for replacement based on reliability data, and in some cases, selections are influenced by historical performance of the types and vintages of cable. Given the disruptive impact that an underground cable failure can have, Public Service invests in our cable replacement programs with the aim of maintaining or lowering the number of cable failures from year to year. As shown in the Figure below, Public Service's investment strategy has resulted in relatively steady reductions in tap level cable failures from 2012 forward.

FIGURE DCM-D-3: Tap Level Cable and Splice Failures



Q. WHAT IS DRIVING THE INCREASE IN CABLE REPLACEMENT INVESTMENTS IN 2022 AND 2023?

A. In 2019 and 2020, Public Service had lower amounts of investment in cable replacements due to more pressing investment needs in other areas. For example, capital expenditures for cable replacements from 2015 to 2018 averaged $48.4 million per year, whereas the capital expenditures for 2019 and 2020 were $33.5 million and $32.9 million, respectively. This lower level of investment in 2019 and 2020 was not sustainable given reliability impacts and the large amount of aging cable on the system that needs to be replaced in the coming years. Public Service refocused investments into cable replacements in 2021 and continues to focus on cable in 2022 and 2023 to address the aging population of cable and maintain reliability on the system. A small portion of the increased investment in cable replacements is due to increased costs for cable materials.

Q. CAN YOU PROVIDE EXAMPLES OF CABLE REPLACEMENT PROJECTS INCLUDED IN THE TEST YEAR?

A. Yes. An example of one of these cable replacement projects is the Chatfield 1344 feeder replacement project, which was completed in 2022 with $0.75 million in capital additions. This project involved replacing aged 500 aluminum XLPE cable in Littleton, Colorado with new 1000 aluminum. The project was needed to address reliability issues as the 500 aluminum was reaching end of life and had failed multiple times.

Another example is the Allison 1148 feeder cable replacement, which is expected to be completed in 2023 resulting in $1.2 million of capital additions. This project is to replace aged 500 aluminum XLPE cable with new 1000 copper in Lakewood, Colorado. The project is needed to address reliability concerns in the area as the cable is reaching end of life and has failed multiple times.

2. Overhead Rebuilds and Underground Conversions

Q. WHAT TYPES OF PROJECTS ARE INCLUDED IN THE REBUILD AND UNDERGROUND CONVERSION CATEGORY?

A. The rebuild category refers to the replacement, rebuild, and refurbishment of feeder, tap, and secondary lines that have or are reaching their end of life, in order to improve service and reliability to our customers. This may include replacing a single pole or cross-arm, or completely rebuilding a section of line. The specific rebuild projects are determined by an engineering review of previous line performance and reliability measures, as well as visual inspection by qualified line personnel to evaluate the condition of the equipment. This category also includes rebuilds necessitated by severe weather events.

Underground conversion projects relate to undergrounding overhead lines. The need for underground conversions may be driven by customer request, redevelopment requirements, franchise requirements, or the condition of the equipment. This category also includes work to upgrade and replace underground equipment based on the age, performance, and condition.

Q. CAN YOU PROVIDE AN EXAMPLE OF AN OVERHEAD REBUILD PROJECT INCLUDED IN THE TEST YEAR?

A. An example of one of these rebuild projects is the Boulder Hydro overhead feeder rebuild with $1.6 million in capital additions in 2023. This project involved rebuilding approximately 3 miles of several small conductor types #4 copper, #2/0 aluminum conductor, steel reinforced (ACSR), and #6 copperweld copper (CWCP) to larger 336 ACSR conductor. These conductors were aging and reaching the end of their useful life. The rebuild brought the older pole line in the area up to current standards with 10-foot crossarms which will improve reliability and feeder resiliency.

Q. CAN YOU PROVIDE AN EXAMPLE OF OTHER TYPES OF PROJECTS THAT ARE INCLUDED IN THE REBUILD AND CONVERSION CATEGORY THAT ARE INCLUDED IN THE TEST YEAR?

A. Yes. One example is Public Service's replacement of aged network protectors and isolation boxes that have reached the end their useful life in our downtown Denver underground network system. Proactively replacing this equipment helps maintain safe working conditions for our employees, and also avoids reliability risk to network customers. Another program within this category is the replacement of switch cabinets. These cabinets typically serve customer load in residential areas, and failure may result in extended outages to many customers.

3. Pole Replacement Program

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

A. Yes. Public Service owns approximately 518,000 wood distribution poles in the State of Colorado. Pole longevity can vary widely based on the wood species, treatment, and the environment where it is placed, but poles have a useful life of approximately 60-70 years (on average). As part of the pole replacement program, Distribution assesses wood poles, remedially treats deteriorating poles, and replaces poles that have reached the end of their life. The goal is to replace poles prior to failure at or near the end of their useful life.

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

A. Distribution assesses its poles in order to determine which ones need to be replaced or rehabilitated based on National Electrical Safety Code standards. The assessment process includes a visual, sound and bore, and/or excavation assessment (i.e., hand digging around the base of pole). Depending on the results of this assessment, poles will either be treated with wood preservatives or replaced as appropriate. The determination of whether or not a pole needs to be treated or replaced depends on the remaining strength of the pole and existence of any above ground deterioration severe enough to put hardware at risk of failure (i.e., top split/rot, lightning damage).

If a pole has less than 70 percent of its original strength left or exhibits extensive above ground deterioration, the pole is replaced. If a pole needs to be replaced, we typically plan to replace the pole the following year unless the pole is in such poor condition that it requires immediate replacement. While we plan to replace poles within one year of a failed inspection, sometimes certain of the poles are replaced more than one year after a failed inspection. Distribution prioritizes pole replacement based on a pole's likelihood of failure using the percentage of original strength left in the pole as the guide. Based on this prioritization, Distribution replaces those poles with the lowest percentage of remaining strength before those poles with a higher percentage of remaining strength.

Q. HOW OFTEN DOES DISTRIBUTION INSPECT ITS POLES?

A. Public Service aims to assess its poles on a 12-year cycle, resulting in approximately 43,000 assessments of distribution poles each year. However, the actual number of poles assessed each year varies as budget pressures may result in the need to reduce funds allocated to pole assessments to fund higher priority needs within Distribution or other business areas.

Q. HOW DOES PUBLIC SERVICE DETERMINE THE BUDGET FOR POLE REPLACEMENTS?

A. Public Service budgets for pole replacements based on the number of poles that will be assessed each year and the rolling 3-year average of the pole rejection rate (i.e., the percentage of poles that failed assessment and needed to be replaced). The current rolling 3-year average of the pole rejection rate is 7.6 percent. Pole replacement costs are estimated on a per-pole basis, using historical data and any known changes in labor and material costs.

4. Substation Renewal Program

Q. PLEASE DESCRIBE THE COMPANY'S SUBSTATION RENEWAL INVESTMENTS.

A. The substation renewal category refers to the replacement of transformers, circuit breakers, switchgear, and other substation equipment that has either failed or has reached the end of its useful life. The specific equipment that is selected to be proactively replaced is managed by our Transmission System Performance group based on the age, condition, and by historical performance of similar types of equipment. Replacing substation equipment that has reached the end of its useful life can mitigate some of the greatest reliability risks to our customers. For instance, while the failure of a substation transformer is not a common occurrence, when it does fail, it can result in between 5,000 to 15,000 customers losing service.

Q. HOW DOES PUBLIC SERVICE DETERMINE WHICH SUBSTATION ASSETS REQUIRE REPLACEMENT?

A. To identify those substation assets in need of replacement, Public Service evaluates the age and condition of these assets. For instance, Public Service monitors the condition of its substation transformers by performing a dissolved gas analysis of the transformer fleet on a regular basis. All substation transformers are tested annually. Transformer readings that indicate the unit is at risk of imminent failure may cause the transformer to be proactively taken out of service and replaced.

Public Service also considers the average useful life and age of individual assets. The average useful life of a distribution substation transformer is approximately 40 years; beyond 40 years, the probability of failure begins to increase. Distribution has approximately 380 substation transformers and approximately 90 of these transformers are over 50 years old and approximately 51 transformers are between 40 to 50 years old.

Q. PLEASE EXPLAIN THE PATTERN OF SUBSTATION RENEWAL CAPITAL ADDITIONS BETWEEN 2021 AND 2023.

A. The pattern of substation renewal capital additions over the 2021 through 2023 period is primarily the result of the timing of placing larger substation projects into service.

The California Substation renewal project began in 2021 and involved the replacement of three metal clad switchgear units and one substation transformer over multiple years. The metal clad switchgear at the California Substation was amongst some of the oldest on Public Service's system and was constructed in such a way where there is a risk of cascading failure if one of the units were to fail. The new switchgear equipment will mitigate cascading failure risk. The then-existing transformer at the California Substation also required replacement, as routine transformer testing revealed that the unit was "gassing" – this is an indicator that the transformer had experienced an internal fault and increases the likelihood of unit failure. The Company spent approximately $13.7 million in 2021 on this project and anticipates spending approximately $9.6 million through 2022.

The next major driver for increased substation renewal spend is the Englewood renewal project. The Englewood Substation renewal project began in 2022 and involves the replacement of two metal clad switchgear units and two substation transformers over multiple years. All four assets have reached the end of their useful lives and need to be replaced. Transformer #2 was replaced and placed into service in 2022. The transformer #3 replacement is underway and is expected to be placed into service by the end of 2022. Both switchgear replacements are scheduled to occur in 2023. The Company is expecting to spend approximately $4.5 million through 2022 and another $9.5 million in 2023.

5. Restoration/Failure Reserves

Q. DESCRIBE THE RESTORATION/FAILURE RESERVE BUDGET CATEGORY.

A. This category includes investments required to repair facilities that are damaged during storm events. Public Service has a strong track record related to storm restoration and these investments are key to our ability to restore power quickly and safely after a severe weather event.

In terms of budgeting for storm restoration, due to its significant variability from year-to-year, we budget dollars in a working capital fund (i.e., emergent work). This storm restoration budget is not assigned to a specific project or program. When emergent circumstances, such as storm restoration arise, we reallocate budgeted dollars to address the circumstance while remaining in balance with our overall annual budget.

D. <u>Capacity</u>

Q. WHAT IS THE PRIMARY DRIVER OF CAPACITY-RELATED DISTRIBUTION CAPITAL ADDITIONS?

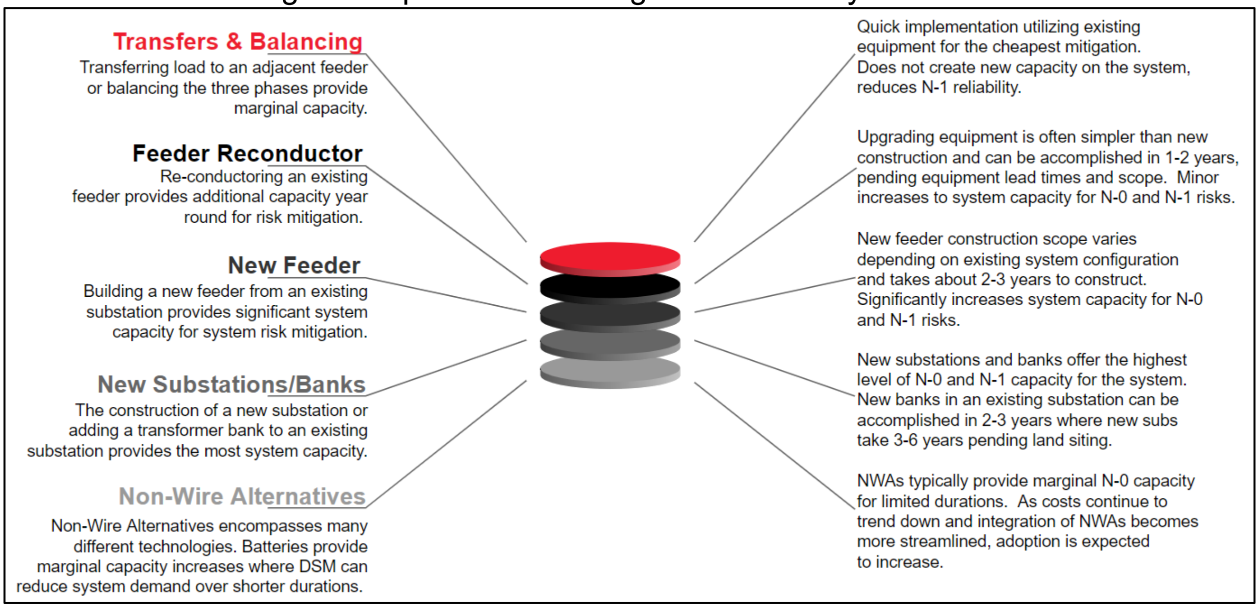
A. Capacity projects are needed to address growth on the system, which in turn, is primarily a result of population growth and economic expansion. Colorado has experienced tremendous population growth over the last decade, which has spurred new residential and commercial development in Public Service's service territory. In certain areas, these new developments have resulted in load growth that exceeds the current capacity and capabilities of the existing distribution system. To provide additional capacity on the distribution system to support these growing customer demands, Public Service has invested in new capacity projects.

Q. WHAT KINDS OF INVESTMENTS CONSTITUTE DISTRIBUTION CAPACITY PROJECTS?

A. Capacity projects include the construction of new substations, expanding existing substations, adding new feeders, and upgrading existing distribution equipment to mitigate specific risks on the distribution system. In broad terms, mitigations are potential solutions the Company can implement to resolve the N-0 and N-1 risks identified by our planners based on the distribution load forecasts and the system configuration. All mitigations must provide adequate capacity for normal and contingency operating conditions while maintaining system voltage and operational flexibility. The Figure below summarizes the types of mitigations available to planners.

FIGURE DCM-D-4

Mitigation Options for Solving Distribution System Risks



Q. HOW DO CAPACITY PROJECTS COMPARE TO OTHER DISTRIBUTION PROJECTS?

A. Capacity projects tend to be fewer in number each year, as compared to other budget categories, but each of these projects is typically more costly. As a result, there is variation year over year in the capital additions amount for capacity projects based on the cost and magnitude of projects that go in-service.

Q. DOES THAT VARIABILITY EXPLAIN THE PATTERN OF CAPACITY-RELATED CAPITAL ADDITIONS IN TABLE DCM-D-1, ABOVE?

A. Yes. As discussed below, several large projects were constructed in 2022 or are planned for 2023. Timnath (Avery) Substation Project was placed in service in 2022. Community Resiliency Initiative projects, High Point Substation Project, Powhaton Transformer #2 and Picadilly Transformer #3 are some of the major projects that will be placed into service in 2023. As a result, 2022 and 2023 capacity-related capital additions are significantly higher than 2021 actuals. A major driver for the increase in capacity needs for the distribution system is the expansion of data centers and large customers. I discuss these and other significant capital projects that have more than $3 million in capital additions below.

1. Community Resiliency Initiative

Q. PLEASE DESCRIBE THE COMMUNITY RESILIENCY INITIATIVE PROJECTS.

A. During extreme weather events such as severe storms, wildfires, or floods, it is vital that there is a secure, reliable power supply for critical infrastructure, such as evacuation centers. Installing onsite energy storage systems and generation allows these critical sites to operate independently from the electric grid in the event of an emergency resulting in grid outage, and they also provide grid benefits during normal operation.

Q. HAS THE GENERAL ASSEMBLY ENACTED ANY LAWS REGARDING COMMUNITY RESILIENCY INITIATIVE PROJECTS?

A. Yes. The Colorado legislature recognized the importance of these energy storage systems, and in 2018 enacted the Energy Storage Procurement Act ("HB 18-1270").[14] HB 18-1270 allowed investor-owned electric utilities to file applications for rate-based energy storage system projects up to 15 MW of capacity on or before May 1, 2019.

[14] Codified at §40-2-201, et seq., C.R.S.

Q. DID THE COMPANY SEEK APPROVAL OF ANY COMMUNITY RESILIENCY INITIATIVE PROJECTS?

A. Yes. On May 1, 2019, Public Service requested approval of its proposed Community Resiliency Initiative in Proceeding No. 19A-0225E. The Community Resiliency Initiative sought to fulfill the intent of HB 18-1270 through seven targeted battery-based microgrid projects designed to enhance the Company's resource diversity as well as the safety, reliability, and resiliency of the electric grid.

Q. DID THE COMMISSION APPROVE THE COMPANY'S APPLICATION?

A. Yes. On October 15, 2019, the Commission approved the Unopposed and Unanimous Comprehensive Settlement Agreement ("Community Resiliency Settlement Agreement") signed by the parties to the case that granted the Company's Verified Application.[15] Following the Commission's approval, Public Service has moved forward with six of the seven microgrid projects at the following locations: (1) the Denver International Airport; (2) the National Western Center; (3) the Denver Rescue Mission Lawrence Street Community Center; (4) the City of Arvada Center for the Arts and Humanities; (5) the Town of Nederland Community Center; and (6) Alamosa Family Recreation Center.[16]

[15] Decision No. R20-0732.
[16] Public Service informed the Commission and stakeholders in its initial Compliance Report filed on December 15, 2020, that local administrators of the Summit Middle School project in Frisco, Colorado decided not to move forward with the seventh approved project.

Q. HAS THE COMPANY FILED UPDATES REGARDING THE STATUS OF THE COMMUNITY RESILIENCY INITIATIVE PROJECTS?

A. Yes. The Community Resiliency Settlement Agreement requires Public Service to file semi-annual reports that update the status of the projects. The most recent semi-annual report was filed by Public Service on June 15, 2022, in Proceeding No. 19A-0225E.

Q. IS THE COMPANY SEEKING TO RECOVER THE COSTS OF THE COMMUNITY RESILIENCY INITIATIVE PROJECTS IN BASE RATES AS PART OF THIS PROCEEDING?

A. Yes. All six Community Resiliency Initiative Projects are projected to be in-service by the end of 2023 and therefore are part of the proposed Test Year.

Q. DOES THE COMMUNITY RESILIENCY SETTLEMENT AGREEMENT REQUIRE CERTAIN INFORMATION IN CONNECTION WITH THE INCLUSION OF THE COMMUNITY RESILIENCY INITIATIVE PROJECTS IN BASE RATES?

A. Yes. While the Community Resiliency Settlement Agreement provides the Community Resiliency Initiative Projects costs are entitled to a rebuttable presumption of prudence, the Company is required to provide evidence comparing the final capital costs to those presented in Proceeding No. 19A-0225E.[17]

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[17] Community Resiliency Settlement Agreement at II ("The project capital costs incurred for the seven CRI projects shall be entitled to a rebuttable presumption of prudence when these projects are brought forward for recovery . . . When Public Service proposes to recover these project costs through base rates or an appropriate cost recovery mechanism, the Company bears the burden of going forward and shall present robust testimony with appropriate accompanying exhibits to justify the expenditures: (1) at or below the amounts set forth in Updated Table CAG-SD-3; and (2) if applicable, amounts in excess of the amounts set forth in Updated Table CAG-SD-3"). As discussed above, the Test Year reflects O&M for the 12-month period ended June 30, 2022. As a result, the Test Year does not include O&M associated with the Community Resiliency Initiative Projects.

Q. PLEASE COMPARE THE COMMUNITY RESILIENCY INITIATIVE PROJECTS COSTS INCLUDED IN THIS RATE CASE WITH THE AMOUNTS PRESENTED IN PROCEEDING NO. 19A-0225E.

A. As shown in the Table below, the costs included in this rate case generally are comparable with the estimates provided in Proceeding No. 19A-0225E.

TABLE DCM-D-4
Comparison of Community Resiliency Initiated Projects Capital Costs[18]
Public Service Electric
(Dollars in Millions)

Cost Category	Proceeding No. 19A-0225E	Current Case
Medium Voltage Work, Site Prep, etc.	$6.2	$7.4
BESS (Battery Energy Storage System) *	$9.8	$13.5
Systems Integration	$3.1	$0.2
Contingency	$1.9	N/A
Total Capital Cost	**$21.0**	**$21.1**
* BESS costs included for comparison to Proceeding No. 19A-0225E. Battery costs are part of Distribution's Tools and Equipment budget category.		

Confidential Attachment DCM-2 provides additional detail on a project-by-project basis.

Q. PLEASE DESCRIBE THE DIFFERENCE IN CAPITAL COSTS BETWEEN PROCEEDING NO. 19A-0225E AND THIS CASE.

A. As shown in the Table above, the total estimated capital expenditures to complete these Community Resiliency Initiative Projects is in line with the amount included in the Community Resiliency Settlement Agreement. While the total of the

[18] Table DCM-D-4 reflects capital expenditures, not capital additions, to provide for direct comparison to Updated Table SGS-SD-3 from the Community Resiliency Settlement Agreement.

currently forecasted capital expenditures are the same as what was presented in the Community Resiliency Settlement Agreement, there have been some updates to these cost estimates for each category detailed in Table DCM-D-4. These updates include:

- The cost of medium voltage and site work has increased by approximately 19 percent, or approximately $1.2 million. This is largely due to inflation and supply chain challenges creating upwards pressure.
- The BESS costs are expected to be approximately 38 percent higher, or by approximately $3.7 million. This is largely due to inflation and supply chain challenges creating upwards pressure.
- The system integration costs were not as significant as anticipated, as detailed in Table DCM-D-4.

2. Timnath (Avery) Substation

Q. PLEASE DESCRIBE THE TIMNATH (AVERY) SUBSTATION PROJECT.

A. This project involves the construction of the new 230/13.8 kV Avery Substation in the Town of Windsor in northern Colorado. The substation includes a three-breaker ring design and a single 230/13.8 kV, 28 MVA transformer, with the ability to accommodate a total of two 230/13.8kV, 28 MVA transformers for future load growth. This project also involves the construction of new distribution feeders from the new Avery Substation and upgrades to existing distribution feeders near the towns of Windsor, Severance, and Timnath, Colorado. The transmission scope for this project includes the construction of a three-mile long double-circuit 230 kV transmission line to connect the new Avery Substation to the existing Ault –

Timberline 230 kV transmission line. Company witness Mr. Gilbert Y. Flores details the transmission scope of work in greater detail in his Direct Testimony.[19]

This project is needed to provide additional capacity to serve new load growth in this fast-growing area of northern Colorado and to provide back-up service to the Cobb Lake and Windsor substations. The distribution portion of this project started construction in January 2021 and was placed into service in June of 2022 with $19.0 million in capital additions for the Distribution components. A CPCN was granted for this project in Decision No. C15-0461 in Proceeding No. 15A-0159E.

3. High Point Substation

Q. PLEASE DESCRIBE THE HIGH POINT PROJECT.

A. The High Point Project has both distribution and transmission components for a new greenfield substation. The distribution portion of the High Point Project includes the construction of the new 230/13.8 kV, 50 MVA High Point Substation in the City of Aurora, and the construction of five new distribution feeders. The transmission portion of the project involves the construction of 3.5 miles of new 230 kV double-circuit transmission line to connect the new High Point Substation to the Company's existing 5277 Spruce – Green Valley 230 kV transmission line.

The High Point Project is needed to serve projected new load growth in the City of Aurora, south of the Denver International Airport. There are several large residential and commercial developments planned in the City of Aurora between

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[19] The costs of the transmission portion of the project are not included in Table DCM-D-1.

Pena Boulevard and Powhaton Road, which include the following: Pena Station, High Point, Painted Prairie, Harvest Mile, Porteos, Aurora Highlands, Data Centers, and several industrial customers. These developments will include approximately 24 million square feet of commercial space, 5,000 hotel rooms, and 22,000 residential dwelling units and will have a projected load of over 130 MVA. The Company filed a CPCN application for the High Point Project on March 2, 2020, in Proceeding No. 20A-0082E (the "High Point CPCN Proceeding") and the CPCN was granted on October 12, 2020, by Decision No. R20-0725 (exceptions denied in Decision No. C20-0886).

Q. HAS THE COMMISSION REQUESTED THE COMPANY PROVIDE SPECIFIC INFORMATION IN CONNECTION WITH COST RECOVERY OF THE HIGH POINT PROJECT?

A. Yes. In Decision No. R20-0725, Public Service was directed "to specifically identify the actual costs for the Project, individually and in total, in at least as much detail as provided in this proceeding."[20]

Q. IS THE COMPANY PROVIDING THAT INFORMATION IN THIS PROCEEDING?

A. Yes. Mr. Flores's Attachment GYF-5 provides detailed cost estimates for the High Point Project and compares those estimates to the estimates provided by Public Service in the High Point CPCN Proceeding. In total, Public Service is requesting

[20] Decision No. R20-0725, at 12.

recovery of $30.1 million in capital additions for the High Point Project in this rate case ($17.2 million for Distribution and $12.9 million for Transmission).[21]

Q. IS THE CURRENT PROJECTED IN-SERVICE DATE FOR THE HIGH POINT PROJECT THE SAME AS WHAT WAS PRESENTED IN THE HIGH POINT CPCN PROCEEDING?

A. In the CPCN Proceeding, Public Service anticipated that the High Point Project would be in service by June 2022. Public Service currently anticipates that the High Point Project will be in service in the first half of 2023 due to delays associated with local permitting for the project.

4. Powhaton Transformer #2

Q. PLEASE DESCRIBE THE POWHATON TRANSFORMER #2 PROJECT.

A. The Powhaton Transformer #2 Project has only distribution components at an existing distribution substation. The project includes the construction of the new 230/13.8 kV, 50 MVA in the City of Aurora and the construction of one new distribution feeder. This project is driven by a large data center customer and general growth in the area surrounding the substation. Since there were no available feeder breakers available on Powhaton Transformer #1, a new bank installation was required to extend a new distribution feeder. In total, Public Service is requesting recovery of $15.2 million in capital additions for the Powhaton Transformer #2 Project in this rate case, which is expected to be placed in service in 2023.

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[21] The Transmission portion of the project is discussed in greater detail by Mr. Flores in his Direct Testimony

5. Picadilly Transformer #3

Q. PLEASE DESCRIBE THE PICADILLY TRANSFORMER #3 PROJECT.

A. The Picadilly Transformer #3 Project has distribution and transmission components at an existing distribution substation. The distribution portion of the Picadilly Transformer #3 Project includes the construction of the new 230/13.8 kV, 50 MVA in the City of Aurora and the construction of three new distribution feeders. The transmission portion also required new 230kV line arresters and 230kV line relay panels with breaker failure capability in the Spruce and Chambers Substations. This project is driven primarily by several large data center customers in addition to other large development plans in the vicinity of this substation. Since there were no available feeder breakers available on Picadilly Transformer #1 or Transformer #2, a new bank installation was required to extend new distribution feeders. In 2022, the Company installed the second substation transformer at Picadilly Substation and highlights the significant demand growth the Company is experiencing in this area. In total, Public Service is requesting recovery of approximately $16.5 million in capital additions for this project in this rate case ($10.9 million for Distribution and $5.6 million for Transmission), which is expected to be in service in 2023.

6. Other Capacity Projects

Q. PLEASE DESCRIBE THE OTHER CAPACITY PROJECTS THAT ARE PLANNED TO GO IN SERVICE IN 2022.

A. The other Capacity projects that are planned for 2022 that have more than $3 million in capital additions include:

- *Rosedale 1924 Feeder Project:* This project involves the extension of a new distribution feeder from the Rosedale Substation. The new feeder is needed to offload part of Evans Substation, which is being decommissioned as the Company looks to retire the 44kV sub-transmission network in the Greeley area. The total capital addition for this project is $3.4 million in 2022.
- *Replace California MCSG#2, Phase 3*: This project is the final portion of replacing the metalclad switchgear at California Substation, which has reached the end of its useful life. The total capital addition for this project is $3.1 million in 2022.
- *Picadilly Feeder Extension Project from Transformer #2*: This project includes extending a new distribution feeder from transformer #2 at Picadilly Substation to supply a data center customer and other large development plans near the substation. The total capital addition for this project is approximately $4.8 million in 2022.

Q. PLEASE DESCRIBE THE OTHER CAPACITY PROJECTS THAT ARE PLANNED TO GO IN SERVICE IN 2023.

A. The other Capacity projects that are planned for 2023 that have more than $3 million in capital additions include:

- *Extension of Louisville Feeder:* This project involves the construction of a new feeder and the extension of an existing feeder from the Louisville Substation in the City of Louisville. This project is needed as existing feeders in this area are overloaded and are unable to accommodate future load growth. This project will be placed in service in 2023 with $4.2 million in capital additions.

- *Mayflower Bank #1 Replacement:* This project involves replacing a substation transformer at Mayflower Substation that has reached the end of its useful life. The new transformer will be larger than the original bank to allow for future load growth that has been identified in the forecast. This requires some of the substation bus and ancillary equipment to be upgraded to meet safety and operational standards. The capital additions for this project in 2023 are expected to be $6.1 million.

- *Reinforce Moffat Transformer #1*: The Company has seen an increase in customer applications for increased electrical demand at Moffit substation. The substation transformer being replaced was a combination of three 1 MVA transformers, one for each phase, for an equivalent capacity of approximately 3 MVA. This increased capacity is needed to serve new demands. The capital additions for this project in 2022 and 2023 are expected to be $4.5 million.

- *North 1434 Feeder Extension*: The Company has been experiencing high demand growth in the River North Art District (RiNo) area of Denver. Many single- and two-story buildings are being converted to high rise buildings, significantly increasing demand growth in the area. This feeder is needed to support this growth. The 2023 capital additions for this project are expected to be $3.9 million.

- *Picadilly Feeder Extension Project from Transformer #3*: This project includes extending a new distribution feeder from transformer #3 at Picadilly Substation to supply a data center customer. The total capital addition for this project is approximately $5.9 million.

E. New Business

Q. WHAT TYPES OF CAPITAL PROJECTS ARE INCLUDED IN THE NEW BUSINESS CATEGORY?

A. The projects in this category are related to extending electric service and distribution feeders to new customers or to support increased loads from existing customers.

Q. WHAT KIND OF WORK IS ASSOCIATED WITH SERVING NEW CUSTOMERS?

A. Generally, at a minimum, the Company extends its distribution system from the nearest practical point and installs a transformer, a service extension, and meter(s).

Q. HOW ARE NEW BUSINESS INVESTMENTS CATEGORIZED?

A. Our capital investments in this category fall into five main categories – extensions/ contribution in aid of construction ("CIAC"), new services, transformer purchases, meter purchases, and street lighting. Table DCM-D-5 provides a breakdown of the capital additions within the New Business category.

TABLE DCM-D-5:
New Business Capital Additions
Public Service Electric
(Dollars in Millions)

New Business	2021 (Actual)	2022			2023 (Forecast)
		1/1 – 6/30 (Actual)	7/1 – 12/31 (Forecast)	Total	
Extensions/CIAC	40.8	7.4	22.9	30.3	39.5
New Services	10.8	4.9	5.9	10.8	10.6
Meter Purchases	6.4	2.9	2.2	5.1	5.4
Transformer Purchases	27.6	11.4	15.9	27.3	32.8
Street Lighting	10.6	4.9	5.2	10.1	4.6
Total**	**96.2**	**31.5**	**52.1**	**83.6**	**92.9**

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

Q. WHAT IS DRIVING 2022 AND 2023 NEW BUSINESS CAPITAL ADDITIONS?

A. New Business needs are highly dependent on the state of the economy which, in turn, drives the number of requests for new service. Over the past several years, our New Business investments have remained steady despite the economic impacts from the COVID-19 pandemic. Through June of 2022, new customer service requests have remained relatively flat compared to 2021 and are expected to remain flat through 2023. Extensions/CIAC can vary from year to year, with the number of large projects having a significant impact.

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

A. The meters category includes the purchase and installation costs of distribution meters necessary to serve new or existing customers.[22] Meter purchases are primarily for new customers in order to measure demand and energy at the point of delivery. Meters in some instances require replacement due to increased customer demand, load, or in the event an existing meter fails or malfunctions.

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

A. The transformers category includes the purchase and installation costs of any distribution service transformer and voltage regulator necessary to serve new or existing customers. Transformer purchases are primarily needed to serve new customers. However, transformers purchases are also needed to serve increased customer load, or in the event an existing transformer fails, malfunctions, or reaches end of life. Voltage regulators are used on distribution feeders to maintain downstream voltage within acceptable ANSI bandwidths.

[22] This category does not include the installation of AMI meters as part of the AGIS initiative.

Q. ARE TRANSFORMERS PARTICULARLY IMPACTED BY THE CURRENT INFLATIONARY ENVIRONMENT?

A. Yes. The COVID-19 pandemic, along with other disruptions in overseas manufacturing and the impact of Hurricane Ian have caused significant delays in critical materials needed for our distribution and transmission infrastructure to support new customers. Recognizing these impacts, the Company is growing the inventory of transformers and other energy delivery equipment and is working with vendors to ensure that they are expanding their own inventories wherever possible. Due to these challenges, spending in this category is expected to increase in 2023.

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

A The street lighting category includes any new street or area lights placed into service, as well as the reconstruction or rebuilding of street or area lights. Streetlight reconstruction or rebuilds includes streetlights that require replacement due to adverse weather impacts, public damage, or failed equipment. This category also includes conversion of streetlights to light-emitting diode fixtures which are more energy efficient and have better lighting quality. The street lighting program funding remains steady through 2022 and is expected to drop in 2023 as the dual use street lighting program is expected to decrease.

F. Mandates

Q. WHAT ARE THE DRIVERS OF MANDATED CAPITAL ADDITIONS?

A. The primary drivers of the Company's capital additions related to mandated projects generally fall into two main categories: (1) relocating existing utility infrastructure to accommodate public projects (such as road widening or realignment); and (2) undergrounding facilities pursuant to franchise agreements with municipalities. The capital additions for mandates increased significantly in 2022, well beyond historical levels. The 2023 capital additions reflect a return to historical norms.

Q. PLEASE DESCRIBE RELOCATION PROJECTS IN GREATER DETAIL.

A. These projects include relocating facilities that are in direct conflict with street expansions within public right-of-way. Relocation projects tend to trend higher with a favorable economy as cities and counties have additional tax revenues for road improvement projects.

Q. ARE THERE ANY MAJOR RELOCATION PROJECTS PLANNED FOR 2022?

A. Yes. One major relocation project that is planned for 2022 is related to the expansion of I-70 east of I-25. This project has been ongoing and is expected to be completed in 2022. The project is expected to have $2.9 million of capital additions in 2022. Another major relocation project is the US85 OH Relocation Project. This project is related to the expansion of highway US85 near C-470 requiring electric facilities to be relocated and is expected to have $5.8 million of capital additions in 2023.

Q. WHAT ARE UNDERGROUNDING PROJECTS?

A. The Company will underground existing overhead lines at the request of the local jurisdiction pursuant to franchise agreements. Along with meeting our obligations under franchise requirements, these projects provide benefits to our customers in the form of a more reliable, resilient system, renewal of existing assets, and improved aesthetics. The majority of the capital additions for mandates comes from these franchise undergrounding projects.

Q. ARE THERE ANY MAJOR UNDERGROUNDING PROJECTS PLANNED FOR 2022?

A. Yes. One major project in this category is the undergrounding of overhead assets in Boulder, along Broadway and Violet Ave. This project is expected to result in approximately $3.6 million of 2022 capital additions. Another large undergrounding project for 2022 is between Simms and Kipling Streets in Arvada, Colorado. This project is expected to have approximately $3.1 million of 2022 capital additions.

G. <u>Tools and Equipment</u>

Q. PLEASE DISCUSS THE PRIMARY DRIVERS OF TOOLS AND EQUIPMENT CAPITAL ADDITIONS.

A. This category includes various expenditure types required to support Distribution’s overall operations. The main categories for tools and equipment capital additions are: (1) tools, (2) substation communication equipment, (3) electric locates, and (4) acquisition of right-of-way for distribution facilities. The primary driver for the cost increases in this budget category is related to the battery installations under the Community Resiliency Initiative projects.[23]

Q. CAN YOU PROVIDE AN EXAMPLE OF A RECENT INVESTMENT IN TOOLS AND EQUIPMENT?

A. An example of one of our Tools and Equipment investments is the installation of substation communication equipment in new substations such as the recently completed Cloverly Substation. In that substation, Distribution installed a Remote Terminal Unit ("RTU") and a Human Machine Interface ('HMI")/annunciator for SCADA as well as our Local Area Network suite of equipment featuring a firewall and ethernet switch. This is standard equipment that is typically installed with each new substation to allow the substations to communicate with our control center.

[23] Overall, these battery energy storage systems account for approximately $13.5 million of the total $21.1 million of tools and equipment 2023 capital additions.

V. DISTRIBUTION O&M

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

A. The purpose of this section of my Direct Testimony is to support the Company's non-WMP Distribution O&M expense through June 30, 2022, as adjusted for: (1) items discussed below; and (2) labor and non-labor costs as discussed and quantified by Company witnesses Mr. Michael P. Deselich and Mr. Freitas, as the appropriate level of non-WMP Distribution O&M expense in the Test Year.[24]

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

A. The Distribution Business Area performs a variety of O&M work in support of Distribution assets. Distribution's O&M expenses include labor costs associated with maintaining, inspecting, installing, and constructing distribution facilities. It also includes labor costs related to vegetation management, pole inspection, cable repairs and damage prevention programs. Finally, it includes transportation costs and miscellaneous materials and minor tools necessary to build out, operate and maintain our electric distribution system.

Q. WHAT COSTS ARE INCLUDED IN THE TRANSPORTATION CATEGORY?

A. Distribution's transportation costs include annual fuel costs plus the allocation of fleet support to O&M based on the proportion of the distribution fleet utilized for O&M activities as compared to capital projects.

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[24] Distribution's WMP O&M is discussed by Mr. Farruggia.

Q. ARE AGIS-RELATED O&M COSTS PART OF THE OVERALL O&M COSTS FOR THE DISTRIBUTION BUSINESS AREA?

A. Yes. My discussion of Distribution O&M includes O&M for the distribution portions of the AGIS initiative. Distribution AGIS O&M costs include internal labor, external labor, vendor services, and materials, along with costs for the teams that support the AGIS technology. Also, AGIS Distribution O&M consists of the costs to maintain the equipment installed as part of the AGIS initiative and the costs needed to support the initiative, including program management, change management and training, delivery and execution leadership, and corporate communications.

Q. CAN DISTRIBUTION'S O&M COSTS BE PLACED INTO SPECIFIC CATEGORIES?

A. Yes. Distribution's O&M expenses can be further broken down into the following six categories:

- *Internal Labor*: Internal labor costs are the employee costs associated with maintaining, inspecting, installing, and construction distribution facilities such as poles, wires, transformers, and underground electric facilities.

- *Contract Labor*: Contract labor costs are the costs associated with the use of contractors to support more specialized or seasonal tasks such as tree trimming, pole inspections, storm response, and underground facility location.

- *Materials*: Material costs are the costs for maintaining and operating the distribution system such as braces, insulators, cross-arms, and splices.

- *Transportation*: Transportation costs are the costs associated with the use and maintenance of our fleet vehicles that is necessary to operate and maintain our electric distribution system.

- *Other*: Other costs include costs associated with employee expenses and miscellaneous expenses.

- *First Set Credits*: First set credits are O&M labor, transportation, and miscellaneous material credits associated with the installation of meters and line transformers. Because of the way meters and transformers are accounted for (fully installed costs are capitalized upon purchase instead of installation), the actual labor, transportation and miscellaneous materials used to install this equipment are expensed to O&M, and an equal and opposite credit is then applied upon purchase to offset these actual installation costs that are expensed to O&M to avoid accounting for these expenses twice.

A. Overview of Distribution O&M

Q. PLEASE SUMMARIZE THE DISTRIBUTION BUSINESS AREA'S TEST YEAR O&M EXPENSE.

A. Table DCM-D-6 summarizes Distribution's Test Year O&M expense. Attachments DCM-3 and DCM-4 provide an accounting of these expenses by Cost Element and FERC account, respectively. I note that the O&M amounts presented in my testimony and attachments include Distribution O&M for the WMP. Mr. Farruggia provides details regarding the Distribution WMP O&M in his Direct Testimony.

TABLE DCM-D-6:
Distribution's Test Year O&M Expenses
Public Service Electric
(Dollars in Millions)

Category	Test Year Amount
12 Months Ended June 30, 2022	$123.0
Test Year Adjustments	$3.6
Total*	**$126.6**
*There may be differences between the sum of the individual category amounts and totals due to rounding.	

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

A. Yes. These O&M expenses, along with associated Distribution Business Area labor and non-labor costs discussed and quantified by Company witnesses Mr. Deselich and Mr. Freitas, are necessary to ensure that the Distribution Business Area can deliver safe and reliable electric service to our Colorado customers.

B. Historical O&M

Q. PLEASE DISCUSS THE CHANGE BETWEEN DISTRIBUTION O&M FOR THE 12 MONTHS ENDED DECEMBER 31, 2021, AND JUNE 30, 2022.

A. As shown in Table DCM-D-7, below, Distribution's actual O&M costs for the 12 months ended June 30, 2022, were approximately $5.1 million higher than those for the 12 months ended December 31, 2021. Table DCM-D-7 identifies the differences in O&M by cost category.

TABLE DCM-D-7:
Comparison of Historical Distribution O&M Expenses
Public Service Electric
(Dollars in Millions)

Driver	12 Months Ending December 31, 2021	12-Months Ending June 30, 2022	Difference
Internal Labor	$42.0	$43.5	$1.5
Contract Labor	$69.2	$70.8	$1.6
Materials	$7.9	$9.0	$1.1
Transportation	$6.8	$6.5	$(0.3)
First-Set Credits	$(13.6)	$(12.6)	$1.0
Other	$5.6	$5.8	$0.2
Total	**$117.9**	**$123.0**	**$5.1**

Q. WHAT ARE THE PRIMARY DRIVERS OF THE DIFFERENCES SHOWN IN TABLE DCM-D-7, ABOVE?

A. A summary of the differences between December 31, 2021, Distribution O&M and actuals for the 12-months ended June 30, 2022, are as follows:

- <u>Internal Labor:</u> The $1.5 million increase in Internal Labor is the result of: (1) internal labor wage increases (which historically have been approximately three percent); (2) restoration of pre-pandemic activity levels; and (3) weather events.
- <u>Contract Labor</u>: The $1.6 million increase in Contract Labor is the result of: (1) a $0.4 million increase in vegetation management; and (2) increases in administrative O&M costs.
- <u>Materials</u>: While material costs tend to fluctuate year over year depending on the type of O&M activities and associated materials for each year, inflation in the first part of 2022 put an upwards price pressure on materials and contributed to the $1.1 million increase.
- <u>First Set Credits:</u> First Set Credits decreased by $1.0 million due to the timing of transformer/meter purchases.

C. <u>Test Year Adjustments</u>

Q. IS THE COMPANY PROPOSING ANY DISTRIBUTION-RELATED ADJUSTMENTS TO ITS TEST YEAR COST OF SERVICE?

A. Yes, the Company is proposing two adjustments for Distribution O&M: (1) vegetation management; and (2) damage prevention. These adjustment amounts are shown in Table DCM-D-8 below.

TABLE DCM-D-8:
Test Year Adjustments to Distribution's O&M Expense
Public Service Electric
(Dollars in Millions)

O&M Expense	12-Months Ending June 30, 2022	Adjustment	Test Year Requested Amount
Vegetation Management*	$19.3	$2.9	$22.2
Damage Prevention	$14.4	$0.7	$15.1
* Distribution manages all vegetation management activities, including those for the Transmission function. Amounts shown are total vegetation management expenses.			

Q. PLEASE EXPLAIN THE COMPANY'S VEGETATION MANAGEMENT ACTIVITIES.

A. Vegetation management expenses are those costs associated with the pruning, removal, mowing, and application of herbicide to trees and tall-growing brush on land adjacent to Public Service's rights-of-way. The Company engages in vegetation management to limit preventable vegetation-related service interruptions.

Q. WHY IS THE COMPANY PROPOSING A TEST YEAR ADJUSTMENT FOR VEGETATION MANAGEMENT?

A. The Company is proposing an adjustment for vegetation management O&M expenses for both Distribution and Transmission to reflect the cost of necessary line clearance work during the period rates will be in effect.

Q. HOW DID PUBLIC SERVICE DEVELOP THE ADJUSTMENT FOR VEGETATION MANAGEMENT?

A. The adjustment began with the actual amount of vegetation management expense for the 12-month period ended June 30, 2022, adjusted for an increase in contract labor expenses, to be effective January 1, 2023.

Q. PLEASE EXPLAIN WHY AN ADJUSTMENT IS NEEDED FOR DAMAGE PREVENTION O&M EXPENSES.

A. The Company is proposing an adjustment of $0.7 million for damage prevention O&M to reflect increases in both the costs of contractors who perform this work and the number of locates. The Company relies on contractors for the Damage Prevention program, which helps excavators and customers locate underground electric infrastructure to avoid accidental damage and safety incidents. The adjustment also reflects an increase in the number of locates per year, a trend that has been continuing for several years. As shown in the table below, the number of electric locates performed each year increased by over 125,000 between 2016 and 2021. In addition, year-to-date electric locates through June 2022 are two percent higher than the same period in 2021, demonstrating the trend is continuing.

TABLE DCM-D-9:
Public Service Electric Locates

Year	Number of Electric Locates
2016	439,748
2017	462,717
2018	509,391
2019	520,220
2020	565,627
2021	567,840

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

David C. Mino

Mr. Mino earned a Bachelor of Science degree in Electrical Engineering from Temple University in 2013. After graduation, he was hired in June 2013 by PPL Corporation's Generation Department, where he was responsible for providing electrical engineering support for coal, combined cycle, and hydropower plants in Central Pennsylvania. In 2015, he joined the Distribution Planning group within PPL Electric Utilities, where he was responsible for capacity planning (capacity checks, risk evaluation, and mitigation), DER interconnection studies, reliability improvements, and smart grid deployment. Throughout his four and a half years within the Distribution Planning group at PPL EU, he was promoted twice from Engineer to Support, and then Senior Engineer. In 2019, he took on the role of Interconnection Engineer within the Distribution Planning group.

He left PPL Electric Utilities in September of 2019 to join the Distribution System Planning team as a Senior Engineer at Public Service Company of Colorado (PSCo) in Colorado. He was responsible for performing capacity planning for the Boulder, Front Range, and North Metro planning divisions, including reviewing capacity checks for new load additions as well as developing feeder and substation bank forecasts, risk profiles, and project mitigation development. He also oversaw the System Impact Study process for Public Service Company of Colorado, which included developing system models and study packages for consultants to study Community Solar Garden interconnections, and then reviewing their study reports to ensure accuracy.

He was promoted to Principal Engineer in August of 2021 at PSCo. As a Principal Engineer, his focus shifted to support regulatory efforts, managing the system impact study process, conducting special analyses, and developing pilots for emerging technologies. He recently supported the Distribution System Planning Notice of Proposed Rulemaking (Proceeding No. 20R-0516E), where he provided technical input on the proposed rules and data requirements. He is also responsible for developing analysis methodologies and scenario forecasting for all types of electric vehicles and beneficial electrification.

Mr. Mino was promoted to Manager of the Distribution System Planning and Strategy group for Xcel Energy Services in February of 2022, where he oversees the Distribution System Planning team and the development of the distribution capital budget.

OF THE STATE OF COLORADO

* * * *

IN THE MATTER OF ADVICE LETTER NO. 1906-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 TARIFF PROPOSALS EFFECTIVE DECEMBER 31, 2022.	) PROCEEDING NO. 22AL-XXXXE

AFFIDAVIT OF DAVID C. MINO
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO

I, David C. Mino, 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 23 day of November, 2022.

David C. Mino

David C. Mino
Manager, Distribution System Planning and Strategy South

Subscribed and sworn to before me this 23rd day of Nov., 2022.

Hannah Ahrendt
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID# 20224026062
MY COMMISSION EXPIRES JULY 5, 2026

Notary Public

My Commission expires July 5, 2026