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

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

DIRECT TESTIMONY AND ATTACHMENTS OF CONNIE L. PAOLETTI

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

July 2, 2021

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

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
2019 Electric Phase I	Proceeding No. 19AL-0268E
ACSS	Aluminum Conductor Steel Supported
ANSI	American National Standards Institute
BES	Bulk Electric System
CIP	Critical Infrastructure Protection
Commission	Colorado Public Utilities Commission
CPCN	Certificate of Public Convenience and Necessity
DCP	Distribution Capacity Planning
ECA	Electric Commodity Adjustment
EEE	Electrical Equipment Enclosure
EHS	Extra High Strength
ELR	End-of-Life Replacement
EMS	Energy Management System
FERC	Federal Energy Regulatory Commission
FTY	Future Test Year
HTY	Historical Test Year
IT	Information Technology
JF-USA	Joint Facilities USA Agreement
kV	Kilovolt
MVA	Megavolt-ampere
NCAR	National Center for Atmospheric Research
NERC	North American Electric Reliability Corporation

Acronym/Defined Term	**Meaning**
NREL	National Renewable Energy Laboratory
NWPP	Northwest Power Pool
NWTC	National Wind Technology Center
O&M	Operations and Maintenance
OATT	Open Access Transmission Tariff
OPGW	Optical Ground Wire
OT	Operational Technology
PTC	Production Tax Credit
PTP	Point-to-Point
Public Service or Company	Public Service Company of Colorado
QA/QC	Quality Assurance/Quality Control
ROW	Right of Way
RTAC	Real-time Automation Controller
S&E	Storms and Emergency
SB 07-100	Senate Bill 07-100
SCADA	Supervisory Control and Data Acquisition
SPCC	Spill Prevention, Control, and Containment
TCA	Transmission Cost Adjustment
Tri-State	Tri-State Generation and Transmission Association, Inc.
UAV	Unmanned Aerial Vehicle
WAPA	Western Area Power Administration
WMP	Wildfire Mitigation Plan
XES	Xcel Energy Services Inc.
Xcel Energy	Xcel Energy Inc.

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

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

<u>DIRECT TESTIMONY AND ATTACHMENTS OF CONNIE L. PAOLETTI</u>

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Connie L. Paoletti. My business address is 1800 Larimer Street, Denver, Colorado 80202.

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

A. I am employed by Xcel Energy Services Inc. ("XES") as the Manager of Transmission Panning for Public Service Company of Colorado ("Public Service" or the "Company"). XES is a wholly owned subsidiary of Xcel Energy Inc. ("Xcel Energy") and provides an array of support services to Public Service 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 Manager of Transmission Planning, I am responsible for overseeing the engineering group responsible for planning Public Service's transmission system and also responsible for the development of Transmission budgets, regulatory compliance, and portions of the Operations & Maintenance ("O&M") associated with Public Service's transmission system. I also oversee various aspects of transmission policy and manage participation in key regional Public Service transmission projects, as well as other regional projects on and adjacent to Public Service's transmission system. This includes conducting strategic analyses for potential transmission projects, evaluating and negotiating joint agreements, and engaging in stakeholder outreach. 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: (1) support the $523.5 million in Transmission plant additions and projected additions for September 1, 2019 to December 31, 2022 since the Company's last electric rate case in Proceeding No. 19AL-0268E ("2019 Electric Phase I"); and (2) support the $27.4 million in Transmission 2020 O&M, which serves as the basis for the 2022 Future Test Year ("FTY"). All of these are appropriately allocated to Public Service retail electric and included in the cost of service that is presented by Company witness Ms. Deborah A. Blair. These amounts do not include any plant additions or O&M associated with the Company's Wildfire Mitigation Plan ("WMP"), which Company witness Ms. Sandra L. Johnson supports.

I also describe Public Service's use of third-party wheeling service to transmit power to serve its customers as well as the costs for these services, and I support the FTY adjustments for Transmission Wheeling Services included in the 2022 FTY.

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

A. Yes, I am sponsoring Attachments CLP-1 through CLP-7, which were prepared by me or under my direct supervision. The attachments are as follows:

- Attachment CLP-1: Transmission Capital Additions for September 1, 2019 – December 31, 2020;
- Attachment CLP-2: Transmission Capital Additions for January 1, 2021 – December 31, 2022;
- Attachment CLP-3: Pawnee-Daniels Park Project Semi-Annual Status Report Dated January 23, 2020;
- Attachment CLP-4: Transmission 2020 O&M Expenses by Cost Element;
- Attachment CLP-5: Transmission 2020 O&M Expenses by FERC;
- Attachment CLP-6: Public Service Wheeling Transactions; and,
- Attachment CLP-7: WAPA 110 MW Reservation Costs.

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

A. As part of approving the cost of service developed by Ms. Blair, I recommend that the Colorado Public Utilities Commission ("Commission") authorize base rate recovery of the September 1, 2019 to December 31, 2022 capital additions and 2020 O&M expenses included in the 2022 FTY. Last, I recommend the Commission include the FTY adjustments for Transmission Wheeling Services in the Company's cost of service.

II. TRANSMISSION BUSINESS AREA OVERVIEW, FUNCTIONS, AND ACTIVITIES

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 Public Service's Transmission Business Area (or "Transmission") functions and activities.

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

A. Public Service is a vertically integrated electric utility that owns and operates electric transmission facilities in Colorado. The Company uses its transmission system to deliver energy from our generating resources (both owned and purchased) to our wholesale and large retail customers, and to the Company's distribution facilities, which are used to provide service to most of our retail customers. Public Service's transmission system comprises approximately 4,867 circuit-miles of transmission lines. The transmission lines are rated at voltages between 44 kilovolt ("kV") and 345 kV. Public Service's transmission system includes many lines that are jointly-owned with neighboring systems, such as Tri-State Generation and Transmission Association, Inc. ("Tri-State") and the Western Area Power Administration ("WAPA"). The Company's 236 transmission and distribution substations are also used to deliver electric energy to customers.

Q. PLEASE DESCRIBE THE TRANSMISSION BUSINESS AREA.

A. The Transmission Business Area plans, constructs, operates, and maintains the electric transmission infrastructure necessary to meet the current and future energy needs of our customers in a safe and reliable manner.

Q. PLEASE DESCRIBE THE DEPARTMENTS WITHIN THE COMPANY'S TRANSMISSION ORGANIZATION AND THEIR KEY FUNCTIONS.

A. There are six departments within the Company's Transmission organization. The key functions of these departments are as follows:

- *Asset management* is responsible for substation field engineering, which includes routine and emergency maintenance and operational activities for all Public Service substations. The organization also provides field implementation of certain North American Electric Reliability Corporation ("NERC") and Critical Infrastructure Protection ("CIP") compliance activities, and commissioning new substation facilities. Commissioning of substation facilities involves ensuring that our substation facilities meet Federal Energy Regulatory Commission ("FERC"), NERC, and Company operational and reliability requirements. The Quality Assurance/Quality Control ("QA/QC") process performed by Company engineers and technicians tests the equipment and control systems of our electric substations prior to energizing. This organization is also responsible for system sustainability. System sustainability provides, among other things, electric material and design standards for the design, construction, and maintenance of our transmission assets by interpreting industry standards such as American National Standards Institute ("ANSI") standards. System sustainability is also responsible for developing Public Service's reliability-centered maintenance programs that ensure the health and reliability of existing assets. These processes establish the baseline performance expected by our operations and maintenance organizations and confirm the performance for compliance standards.

- *Transmission strategy and planning* is responsible for: (1) life cycle planning, transmission system planning, and associated capital budgeting; (2) negotiating transmission-service-related contracts with generators, transmission owners, and distribution utilities; and (3) resolving wholesale customer transmissions service concerns. In addition, this organization manages Xcel Energy's participation in key regional projects throughout its service territories, as well as other regional projects on and adjacent to the Company's transmission systems, including the Public Service Transmission System. This group is also responsible for the Company's policies and procedures in the competitive transmission acquisition processes.

- *Field operations* provides field services for construction, maintenance, and emergency repairs for transmission assets.

- *Transmission portfolio delivery* is responsible for managing capital projects, programs, and portfolios, including designing and engineering transmission assets, managing third-party contractors, and securing and managing transmission land rights.

- *System operations* is primarily responsible for the NERC Balancing Authority and Transmission Operations function for all Company transmission systems.

- *Transmission business operations* directs the Transmission business area's efforts pertaining to compliance with NERC requirements and directs business performance achievement efforts.

III. TRANSMISSION 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 primary drivers of the Transmission Business Area's capital additions included in this rate case proceeding, and the Transmission Business Area's project development, project budgeting, and project management processes.

Q. WHAT ARE THE PRIMARY DRIVERS AFFECTING THE LEVEL OF PUBLIC SERVICE'S TRANSMISSION CAPITAL ADDITIONS INCLUDED IN THIS RATE CASE PROCEEDING?

A. Transmission capital additions generally fall into two major types. The first consists of large capital projects that are often multi-year projects. These projects are capital intensive and are aimed at improving the transmission system, upgrading existing facilities to meet NERC compliance requirements and to accommodate new generation, replacing aging facilities, and making improvements to communication infrastructure and physical security.

In addition to these larger, multi-year capital projects, the Transmission Business Area also completes many smaller capital projects each year. These smaller projects comprise a majority of the total number of projects that we complete each year, but make up only a minor part of our overall capital budget. Some examples of smaller projects include replacement of one to two structures or cross-arms due to age, condition, or storm damage.

Both of these types of capital projects require investments in transmission line components such as poles, conductors, gang-operated switches, and land rights for transmission line easements. They also include investments in substation components such as transformers, capacitor banks, circuit breakers, remote terminal units, and real property.

Figures CLP-D-1 and CLP-D-2 below depict this breakdown for Public Service's 2019-2022 capital additions that it is seeking to recover through base rates in this proceeding. As shown in these figures, capital projects that are greater than $6 million in capital additions make up approximately 80 percent of Public Service's total capital additions budget over the time period of this case, but comprise approximately 20 percent of the total number of projects undertaken or to be undertaken during this timeframe.

FIGURE CLP-D-1:
2019-2022 Total Number of Transmission Capital Projects
(Dollars in Millions)

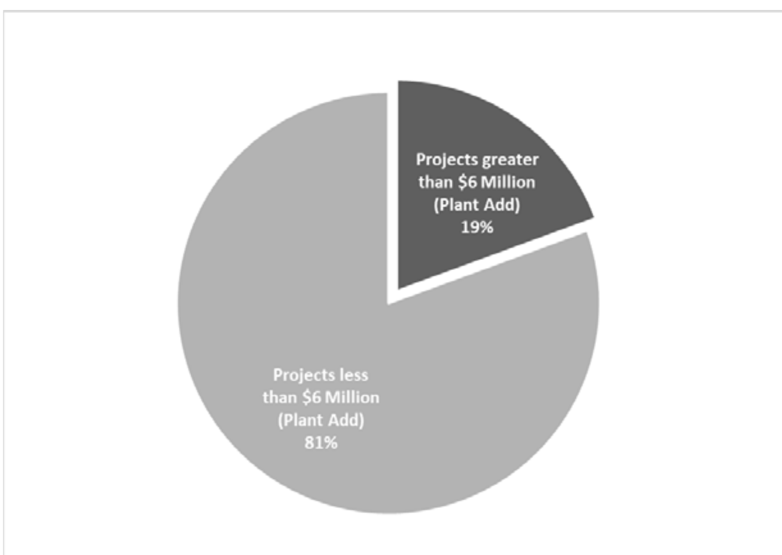
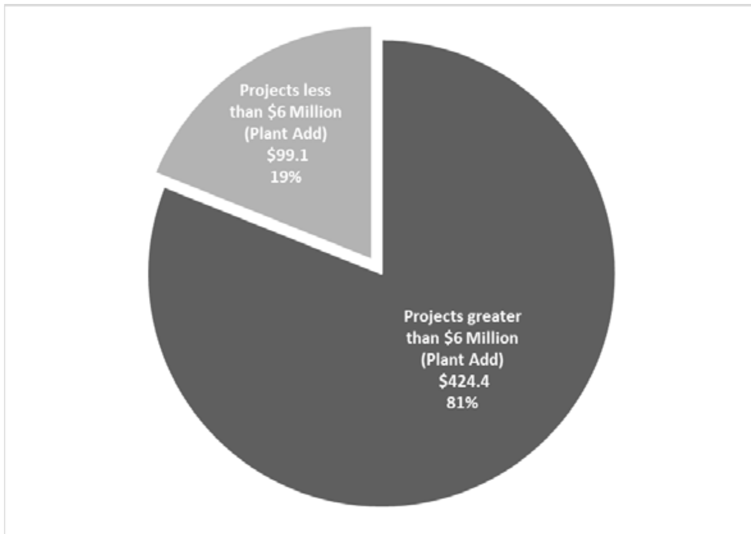


FIGURE CLP-D-2:
2019-2022 Total Transmission Capital Budget
(Dollars in Millions)



Q. WHAT ARE THE CORE CAPITAL BUDGET GROUPINGS THAT REFLECT THE GENERAL CATEGORIES OF SPEND WITHIN THE TRANSMISSION BUSINESS AREA?

A. Based on these drivers, Transmission's capital projects generally fall into six capital budget groupings depending on the main purpose of the project. These groupings are: (1) Asset Renewal; (2) Reliability Requirement; (3) Regional Expansion; (4) Interconnection; (5) Physical Security and Resiliency; and (6) Communication Infrastructure. I provide more detail on each of these categories below.

- *Asset Renewal:* This category is primarily for managing the health and performance of transmission assets. The main goal is to ensure that critical assets including transmission lines, substations, and other related assets meet reliability and capacity requirements, while minimizing life-cycle costs. This includes planned replacement of aging transmission lines and substation equipment, and unplanned replacement of lines or equipment damaged by storms. This category also includes additions to, or replacement of, aging fleet vehicles and tools that support capital additions and line relocations due to road projects.

- *Reliability Requirement:* Reliability projects are constructed to ensure that the transmission system is compliant with all NERC reliability standards. Compliance with NERC reliability standards is mandatory for all users, owners, and operators of the Bulk Electric System ("BES"). FERC, NERC, and regional reliability entities monitor and enforce compliance. The Transmission organization is continually studying the transmission system to assess compliance with NERC standards. These studies analyze the impacts of forecasted load growth, existing and anticipated generation needs, and new generation interconnections to determine whether transmission upgrades are necessary.

- *Regional Expansion:* This category includes major high voltage transmission line projects that are developed through the regional planning process and seek to serve multiple needs including regional and local reliability and renewable energy development. Generally, these are multi-year initiatives and the types of projects for which the Company seeks a Certificate of Public Convenience and Necessity ("CPCN") from the Commission.

- *Interconnection:* This category includes projects that the Company is required to construct under the FERC Open Access Transmission Tariff ("OATT") to accommodate interconnection requests from generators, other transmission providers for their transmission lines, and new load.

- *Physical Security and Resiliency:* There are two critical aspects to this grouping of projects: physical security and grid resiliency. Physical security addresses physical threats to utility infrastructure, such as transmission lines and substation equipment. Grid resiliency addresses the Company's ability to monitor and recover from incidents occurring on our system to limit disturbances that may leave our service territory exposed to prolonged outages, oftentimes by adding redundancy to our transmission system. This category also includes projects intended to address NERC standards related to security and grid resiliency.

- *Communication Infrastructure:* This category includes the fiber optic and communication network infrastructure build-out on the existing transmission system to improve communication connectivity for all business areas. This infrastructure allows the digital transfer of Supervisory Control and Data Acquisition ("SCADA") data and tele-protection services. As telecommunication service providers are retiring the existing obsolete analog connections, we will be continuing our efforts to privatize our communication network infrastructure across the Company's service territory. By reducing dependencies on third-party telecommunications providers and building our own, the transmission system communication infrastructure improves the transmission and distribution system reliability, performance, and cyber security.

Q. PLEASE OUTLINE HOW PUBLIC SERVICE DEVELOPS ITS CAPITAL BUDGET FOR ITS TRANSMISSION BUSINESS AREA.

A. The annual capital budget for Transmission is based on collaboration between corporate management of overall Company finances and the business needs that are identified by Transmission. Company witness Mr. Adam R. Dietenberger explains how the Company establishes overall business area capital spending guidelines and budgets based on financing availability, specific needs of business areas, and the overall needs of the Company.

Q. CAN YOU PROVIDE A SUMMARY OF TRANSMISSION'S CAPITAL BUDGETING PROCESS?

A. Transmission employs a "bottom-up" budgeting process to identify the capital projects that we need to complete within a specific year for our business area. All of our capital projects are executed under the Capital Project Governance Process. This governance process has policies and procedures in place that enable Transmission to prioritize and balance our budget such that we appropriately allocate funds. Our capital budgeting process includes four main steps:

1. Identification of potential projects;
2. Vetting of potential projects;
3. Prioritization of potential projects; and

4. Rebalancing and reprioritization of projects based on corporate budget requirements.

Q. PLEASE EXPLAIN HOW THE TRANSMISSION BUSINESS AREA RANKS AND FUNDS PROJECTS.

A. The Transmission Business Area uses a multi-step project lifecycle process that takes a project from the identification of a need, through mitigation development, alternative evaluation, preliminary scope development, and cost estimating, before concluding with final scope approval.

The project originator develops a proposed statement of work for each project—typically consisting of the proposed scope, project description, necessity description, alternatives and proposed option, desired completion date, consequences of not pursuing the project, and a basic electric circuit diagram.

Multi-disciplinary project teams are established with members who have functional skills such as financial management, project management and controls, design and engineering, system operations, construction, siting and land rights, scheduling, and planning. Each project team is assembled to review the proposed scope and evaluate alternatives, and then to identify additional details for the preliminary scope and schedule, along with supporting documentation. The project team may prepare multiple higher-level estimates to assess alternative system solutions, and weigh proposed solutions against other alternatives. This determines the most reasonable electrical and financial solution that meets transmission needs as part of the overall planning process. The estimates for each proposed project may be included in the latter years of the Transmission Business Area's five-year budget.

Once the conceptual electric solutions are identified, the Transmission Business Area reviews the capital projects to select those projects that best meet the system's reliability needs and contractual and regulatory obligations. The Transmission Business Area then assesses risks for the projects and captures project requirements, project scope, preliminary cost estimates, and required in-service date information.

All capital projects are then prioritized. Key drivers for risk prioritization strategy include reliability, regulatory compliance, contractual agreements, and economic, security, and other risk factors. The risk assessment process categorizes projects as "discretionary" or "non-discretionary." Discretionary projects are prioritized based on the risk and urgency. Non-discretionary projects include emergency related work, contractual agreements, regulatory compliance, and other mandates.

Q. WHAT PROCESS DOES THE TRANSMISSION BUSINESS AREA FOLLOW TO MANAGE AND CONTAIN ITS CAPITAL COSTS?

A. The Transmission Business Area reviews capital projects on a monthly basis after approval to compare the monthly budget to actual funds spent, and forecast at completion to total project budget. We perform a monthly project-forecasting exercise to ensure we have a steady and dependable flow of financial information regarding capital expenditures. Through this process, the entire Transmission Business Area project portfolio is reviewed and consolidated each month and any variances are addressed. All projects that indicate they may be outside of allowed variances are re-evaluated and assessed internally by the Transmission organization, and may be escalated for higher-level corporate review. For larger projects (*i.e.*, those greater than or equal to $10 million), we adhere to corporate governance to seek "re-approval" of projects outside the allowed variances.

Transmission also compares year-to-date actual performance with year-to-date and year-end forecasts. We identify deviations and recommendations to make sure financial targets are reviewed and approved. Changes are reported to the Financial Performance and Planning Business Area, which monitors capital spending. The Transmission Business Area is expected to manage its capital budget once that budget has been developed, vetted, and approved.

Q. HOW IS THE COMMISSION INFORMED OF TRANSMISSION PROJECTS?

A. On an annual basis, Public Service provides the Commission with its Rule 3206 Report, which identifies new construction or expansion of transmission facilities planned for the upcoming three calendar years. The report consists of three major sections: (1) new projects; (2) projects presumed to be in the ordinary course of business; and (3) projects previously reported. The intent of Rule 3206 is to have utilities apprise the Commission of planned transmission projects, and to allow the Commission to verify or determine which projects require or do not require a CPCN. Public Service submits its Rule 3206 Report annually on April 30, and filed its most recent Rule 3206 Report in Proceeding No. 21M-0005E.[1]

[1] The Commission noticed the Company's Rule 3206 Report filing on May 13, 2021 (mailed date) by Decision No. C21-0290-I, instructing interested parties to file comments on or before June 15, 2021. No parties filed comments and the Commission has not issued a final decision.

Additionally, Rules 3625, 3626, and 3627 set forth requirements for transmission planning applicable to Commission-regulated utilities. These rules require these utilities to establish a process to coordinate the planning of additional electric transmission in Colorado in a comprehensive and transparent manner. The process is to be conducted on a statewide basis and takes into account input received from interested stakeholders. The Commission's rules require periodic reporting to the Commission. Public Service and the other Commission-regulated utilities jointly submit a Rule 3627 10-Year Transmission Plan bi-annually on February 1 in even years, the most recent of which was filed in Proceeding No. 20M-0008E.[2] These Rule 3267 Plans are the result of a cooperative effort between Black Hills Colorado Electric, LLC d/b/a Black Hills Energy, Tri-State, and Public Service. The Commission is further informed of our transmission projects through the Company's annual Transmission Cost Adjustment ("TCA") filing, which occurs in November, as well as individual CPCN filings made with the Commission as appropriate.

Q. CAN YOU FURTHER DESCRIBE THE TCA?

A. Certainly. The TCA is the mechanism through which the Company recovers its transmission capital expenses. Each year the Company requests recovery of its transmission capital expenses through its TCA filings, where the Commission has the opportunity to review the Company's forecasted transmission capital expenses. The Company's TCA was approved by Decision No. C07-1085 in

[2] By Decision No. R21-0073, the Commission found the Joint Utilities' Rule 3627 10-Year Transmission Plan to be adequate and in compliance with Rule 3627. Decision No. R21-0073, at ordering ¶ 1 (mailed Feb. 11, 2021) (the Recommended Decision went into effect by operation of law).

Proceeding No. 07A-339E, and the TCA tariff is set forth on Sheet Nos. 142-142C, COLO. PUC No. 8 - Electric. Among other things, the TCA tariff provides that "[w]henever the Company implements changes in base rates as the result of a final order in an electric Phase I rate case, it shall simultaneously adjust the TCA to remove all costs that have been included in base rates." Here, Public Service is proposing to roll into base rates the rolling balance of costs currently being recovered through the TCA. Company witness Ms. Blair discusses the Company's proposed TCA roll-in in more detail in her Direct Testimony.

IV. TRANSMISSION CAPITAL ADDITIONS AND FORECASTED ADDITIONS FOR SEPTEMBER 1, 2019 TO DECEMBER 31, 2022

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 Transmission Business Area's capital additions and projected capital additions over the period September 1, 2019 to December 31, 2022.

Q. WHAT IS THE TOTAL DOLLAR AMOUNT OF TRANSMISSION CAPITAL ADDITIONS THAT YOU ARE SUPPORTING IN THIS CASE?

A. As reflected in Attachments CLP-1 and CLP-2, the Company is seeking recovery of $523.5 million for Transmission Business Area capital additions for September 1, 2019 to December 31, 2022. In this section, I discuss the Company's September 1, 2019 to December 31, 2022 capital additions.

Q. PLEASE EXPLAIN THE INFORMATION PROVIDED IN ATTACHMENTS CLP-1 AND CLP-2.

A. Attachment CLP-1 shows the Transmission Business Area's capital additions for plant placed into service from September 1, 2019 through December 31, 2020, and Attachment CLP-2 shows the Transmission Business Area's capital additions for plant projected to be placed into service from January 1, 2021 through December 31, 2022. Table CLP-D-1 below provides the total capital additions from these periods broken out into the groupings identified above. Throughout my Direct Testimony, capital additions data from 2019 and 2020 represent actual costs, while 2021 and 2022 capital additions include actual plant in service for January 2021 and budgeted data for the remainder of 2021 and all of 2022.

TABLE CLP-D-1:
Transmission's 2019-2022 Capital Additions*
Public Service - Electric
(Dollars in Millions)

Category	9/1/2019 through 12/31/2019 Actual	2020 Actual	2021 (January Actual + Forecast)	2022 Forecast	Total
Asset Renewal	$36.2	$57.0	$71.6	$85.5	$250.3
Reliability Requirements	$11.1	$14.7	$30.2	$48.9	$104.9
Regional Expansion	$82.0	$4.2	$(0.3)[3]	--	$85.9
Interconnection	$1.3	$32.3	$3.0	--	$36.5
Physical Security and Resiliency	$0.3	$8.0	$9.4	$18.5	$36.1
Communication Infrastructure	$0.7	$1.2	$2.2	$5.7	$9.7
Total	$131.6	$117.3	$116.0	$158.5	$523.5

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

The figures in Table CLP-D-1 are stated on a Public Service – Electric basis with no common electric/gas projects. As I mentioned earlier, the Transmission Business Area's capital additions tend to be either (1) large, multi-year investments or (2) smaller, annual capital investments. Below I discuss some of the largest Transmission projects Public Service has placed into service or will place into service during the period September 1, 2019 to December 31, 2022. Namely,

[3] The $300,000 credit is due to reclassification of CWIP to RWIP during project close-out.

below I identify and discuss the projects that comprise approximately 80 percent (or more) of Public Service's total capital additions for each of the categories described above between September 1, 2019 and December 31, 2022.

A. Asset Renewal

Q. PLEASE DISCUSS THE PRIMARY DRIVERS OF TRANSMISSION CAPITAL ADDITIONS RELATED TO ASSET RENEWAL SINCE SEPTEMBER 1, 2019 AND PROJECTED THROUGH DECEMBER 31, 2022.

A. The total capital additions for Asset Renewal projects for September 1, 2019 to December 31, 2022 are $250.3 million. Examples of major projects related to Asset Renewal over this period include:

- *ELR Projects:* End-of-Life Replacement ("ELR") projects encompass a variety of breaker, relay, transformer, and line structure component replacements. The Company identifies facilities in need of replacement or refurbishment based on multiple factors. For transmission lines, these factors include: the importance of a particular line to reliably serve customers, the line's age and condition, and the line's reliability history. These factors are assigned different weights to determine which lines are in the greatest need for replacement. The Company prioritizes substation assets based on system criticality and asset condition. The priority list is then used to determine the urgency of each replacement and identifies specific projects. The Company plans to place in service $73.6 million attributable to ELR projects from September 1, 2019 through 2022.

- *Storms and Emergency ("S&E") Public Service (Subs and Line):* S&E (Subs and Line) are projects associated with necessary work in response to weather events, accidents, and other unscheduled maintenance work that if not completed puts the system at imminent risk of failure. The Company routinely experiences the need to perform work in this category. The Company plans to place in service $46.1 million attributable to the S&E (Subs and Line) from for September 1, 2019 through 2022.

- *Public Service Major Line Rebuilds and Refurbishment:* Major Line Rebuilds and Refurbishment projects include large scale projects for refurbishing or rebuilding lines that have reached end of life. Projects are identified through field inspections and involve multiple replacements or require a total rebuild of the line. The Company plans to place in service $35.6 million attributable to Major Line Rebuild & Refurbishment projects from September 1, 2019 through 2022. All other Rebuild and Refurbishment projects specifically identified elsewhere in my testimony are not included in the total $35.6 million identified here.

- *9255 Major Line Rebuild:* The rebuild is approximately 20 miles long between Otero tap and Malta Substation. This portion of Circuit 9255 contains wood structures from the 1960s with heavily deteriorated poles and cross-arms. Single circuit 115kV self-weathering steel H-frame structures, 477 kcmil Hawk Aluminum Conductor Steel Supported ("ACSS") conductor, 48 Fiber optical ground wire ("OPGW"), and 3/8" Extra High Strength ("EHS") Steel will be installed for this rebuild. The total capital addition amount projected to be placed in service for this project in 2022 is $19.2 million.

- *9205 Boulder Hydro - Structure 1398 Aging Line Rebuild:* The rebuild is approximately 3.5 miles long. This portion of Circuit 9205 contains deteriorating structures that date back to 1910. Single circuit 115kV self-weathering steel monopoles will be installed as well as new 477 kcmil Hawk ACSS conductor and 48 Fiber OPGW. This project includes a rebuild of the 9205 line between Eldorado Substation and the "National Center for Atmospheric Research ("NCAR") Tap Structure," rebuild of the 9205 line between the "NCAR Tap Structure" and the NCAR Substation, replacement of five structures for "Line Capacity," and replacement of three additional structures that are at the end of their useful life. The Company plans to place in service $11.7 million attributable to this rebuild from September 1, 2019 through 2022.

- *Public Service Transmission Relocation Program:* Asset Renewal projects also include relocations required by road construction projects. The Company works with federal, state, and local highway road departments to identify needed relocations. The Company plans to place in service $6.9 million attributable to Relocation from September 1, 2019 through 2022.

- *Transmission UAV Flights:* In 2019, the Company started using Unmanned Aerial Vehicles ("UAV") (drones) to inspect our transmission facilities. In 2020, we inspected over 2,400 miles of line on the Public Service Transmission System. The Company plans to place in service $6.2 million attributable to UAV Flights from September 1, 2019 through 2022.

Q. IS IT YOUR CONCLUSION THAT THE ASSET RENEWAL PROJECT CAPITAL ADDITIONS OVER THIS PERIOD FOR WHICH THE COMPANY IS SEEKING RECOVERY IN THIS PROCEEDING HAVE BEEN REASONABLY AND PRUDENTLY INCURRED?

A. Yes.

B. <u>Reliability Requirements</u>

Q. PLEASE DISCUSS THE PRIMARY DRIVERS OF PUBLIC SERVICE'S TRANSMISSION CAPITAL ADDITIONS RELATED TO RELIABILITY REQUIREMENTS FROM SEPTEMBER 1, 2019 THROUGH DECEMBER 31, 2022.

A. Total capital additions for Reliability Requirements projects during this timeframe are $104.9 million. Illustrative examples of projects related to Reliability Requirements during this period include:

- *Steamboat Springs Transformer Replacements:* The scope of this project includes replacing/upgrading existing (2) 50 Megavolt-ampere ("MVA") transformers with 120 MVA transformers to support current and future load requirements (mainly Yampa Valley Electric) and system reliability. Project was initiated in December 2018. The Company will have placed $14.3 million for this project in service from September 1, 2019 through 2022.

- *Distribution Capacity Planning ("DCP") Timnath:* This is a multi-year project, with portions of the project placed in-service as they are put to use each year. The projected capital additions for this project in 2022 are $10.9 million. The original project work orders refer to this project as DCP Timnath because it is a new distribution substation near Timnath, Colorado. As the project developed, it became known as the Avery Substation Project. The project consists of building a new Avery Substation in Weld County approximately three miles south of the Platte River Power Authority Ault – Timberline 230 kV line. The new Avery substation will tap the Ault – Timberline 230 kV transmission line using 230 kV double-circuit transmission and an in-and-out termination configuration. The substation will include a three-breaker ring design and a single 230/13.8 kV, 28 MVA transformer but built to accommodate two 230/13.8 kV, 28 MVA transformers for future load growth. This project is needed to serve new load growth and development in the Timnath area. A CPCN was granted for this project by Decision No. C15-0461 in Proceeding No. 15A-0159E.

- DCP High Point #1: The DCP High Point project is projected to cost $10.8 million for its transmission component. This project is necessary to accommodate several large residential and commercial developments being planned between Pena Boulevard and Powhaton Road, which include the following: Pena Station, High Point, Painted Prairie, Harvest Mile, Porteos, Aurora Highlands, and others. Situated on over 7,500 acres, these developments will include approximately 24 million square feet of commercial space, 5,000 hotel rooms, and 22,000 residential dwelling units for a projected load of over 100 MVA. The project consists of the High Point Distribution 230/13.8 kV, 50 MVA Substation Project, which includes approximately 3.5 miles of new 230 kV double-circuit transmission line that will tap into the existing 5277 Spruce-Green Valley 230 kV transmission line. The Company applied for a CPCN for this project in Proceeding No. 20A-0082E, and the Commission granted the CPCN by Decision No. R20-0725 (exceptions denied in Decision No. C20-0886). The DCP High Point project's transmission component was projected to cost $10.7 million as presented in the CPCN proceeding, and Decision No. R20-0725 approved the CPCN with an eight percent contingency for the project's costs. Decision No. R20-0725 also directed Public Service "to specifically identify the actual costs for the Project, individually and in total, in at least as much detail as provided in this proceeding."[4] I discuss this requirement later in this Section, and Company witness Ms. Betty L. Mirzayi discusses the DCP High Point project in more detail in her testimony.

- *Spill Prevention, Control, and Containment ("SPCC") Improvements:* The SPCC program is a multi-year program implemented by Xcel to comply with Federal environmental regulatory and Xcel Energy environmental policy requirements. A number of substations have been identified that need capital improvements to construct new secondary containments around oil filled electrical equipment to prevent an oil spill from reaching the waters of the United States. The Company will have placed $10.4 million for this project in service from September 1, 2019 through 2022.

[4] Proceeding No. 20A-0082E, Decision No. R20-0725, ¶ 71 (mailed Oct. 12, 2020).

- *Pawnee – Daniels Park Reconductor:* The scope of work for this project includes rebuilding/reconductoring of approximately 66 miles of total line on Circuit 5457 (Pawnee-Missile Site) and Circuit 5113 (Missile Site-Daniels Park), which are single circuit 230 kV lines. Capital additions from September 1, 2019 through 2022 will be $9.5 million.

- *Transmission Upgrades — all FAC-008 Facility Ratings Projects*: These projects consist of work required to comply with NERC Reliability Standards FAC-008. The Company plans to place in service $9.0 million from September 1, 2019 through 2022.

- *Joint Facilities USA Agreement(s) ("JF-USA"):* The JF-USA provides the foundation for assigning costs with respect to capital additions associated with facilities jointly owned by two or more Colorado utilities. One example is "FSVR 5313 Relay NS Sub" project, which will cost $0.7 million to upgrade the existing line relaying on the 230kV line 5313 from Fort Saint Vrain to WAPA's Ault Substation. The breaker failure relaying on breakers 5313 and 5308 will also be upgraded. The existing line protection on the line to WAPA utilizes a microwave circuit for pilot protection. Due to operational failure of the line protection equipment, WAPA has requested that Xcel upgrade the line protective relaying. The Company will have placed $5.8 million for similar Joint Facility projects in service from September 1, 2019 through 2022.

- *Cherokee 115kV Bus Modification:* This project will consist of installing two new transmission lines between the Cherokee North and Cherokee South switchyards, one for each of the East & West 115kV buses. Each line will be equipped with a circuit breaker located at either end (i.e. in the North or South switchyard) in order to function as a Bus-Tie for its respective 115kV bus. Public Service will place $5.1 million in capital additions for the Cherokee 115kV Bus Modification projects from September 1, 2019 through 2022.

- *DCP Dove Valley #1:* This project consists of adding a new distribution substation, including initial installation of a 230/13.8 kV, 50 MVA distribution transformer. The new substation will be located in the southern metropolitan area near the City of Lone Tree, Colorado and is needed to provide additional capacity for load growth and redundancy around the area. Public Service projects $5.0 million in capital additions in 2022 for this project, all of which will be spent on Right of Way ("ROW").

Q. ARE THERE ANY PROJECTS LISTED ABOVE FOR WHICH THERE ARE ADDITIONAL REQUIRED SHOWINGS RESULTING FROM PRIOR REGULATORY DECISIONS THAT YOU WOULD LIKE TO DISCUSS?

A. Yes. As I noted above, the Commission issued a CPCN for the DCP High Point #1 project in Proceeding No. 20A-0082E by Decision No. R20-0725, which directed Public Service "to specifically identify the actual costs for the Project, individually and in total, in at least as much detail as provided in this proceeding."[5] Company witness Ms. Mirzayi provides the detailed project costs in Attachment BLM-4 to her Direct Testimony in this case. Attachment BLM-4 also includes a comparison of the final project costs with the costs presented in Proceeding No. 20A-0082E.

Q. PLEASE IDENTIFY THE AMOUNT OF THE CAPITAL ADDITIONS FROM SEPTEMBER 1, 2019 THROUGH 2022 FOR DCP HIGH POINT #1.

A. In Proceeding No. 20A-0082E, Public Service provided the transmission cost component for the project broken out by facilities cost and land rights cost. The capital additions for these categories are $8.0 million and $2.8 million, respectively, over this time period. This yields a total project plant addition cost of $10.8 million, which is $100,000 over the point cost estimate presented in Proceeding No. 20A-0082E for the transmission component of the project. The total transmission component of the project cost is therefore within the eight percent contingency approved in Proceeding No. 20A-0082E.

[5] Proceeding No. 20A-0082E, Decision No. R20-0725, ¶ 71 (mailed Oct. 12, 2020).

Q. IS IT YOUR CONCLUSION THAT THE TRANSMISSION COSTS ASSOCIATED WITH THE HIGH POINT PROJECT ARE REASONABLE AND PRUDENT?

A. Yes. The Company has managed within its forecasted budget presented in the CPCN proceeding and I conclude that the Transmission costs associated with this project are reasonable and prudent.

C. <u>Regional Expansion</u>

Q. PLEASE DISCUSS THE PRIMARY DRIVERS OF TRANSMISSION CAPITAL ADDITIONS RELATED TO REGIONAL EXPANSION FROM SEPTEMBER 1, 2019 THROUGH DECEMBER 31, 2022.

A. Total capital additions for Regional Expansion projects for September 1, 2019 to December 31, 2022 are $85.9 million. All of these capital additions relate to the Senate Bill 07-100 ("SB 07-100") Pawnee-Daniels Park project, a multi-year project consisting of new 345 kV transmission lines and substations between our Pawnee Substation near Brush, Colorado, and the Daniels Park Substation south of the Denver metro area. The 125-mile project is part of the Company's SB 07-100 portfolio of transmission plans and is a critical component of our long-range transmission plan. The project allows for the interconnection and delivery of new generation resources, including renewable energy, to Public Service customers to meet new load growth and improve system reliability. The Commission approved the Company's CPCN application for the project on April 9, 2015 in Proceeding No. 14A-0287E (Decision Nos. R14-1405 and C15-0316). The CPCN was granted on the condition that construction not begin until 2020, which corresponded to an in-service date of 2022. In late 2015, however, Congress extended the Production

Tax Credit ("PTC") for new wind generation projects – with a declining recovery schedule for projects that start construction after 2016. As a result, Public Service filed a Petition for Variance (Proceeding No. 16V-0314E, later consolidated with Proceeding No. 16A-0117E) requesting that the Commission modify its previous decision and accelerate the in-service date to October 2019 and the construction start date to 2017 for the Smoky Hill to Daniels Park portion of the project, which includes the Harvest Mile substation. In September 2016, Public Service, along with multiple parties, agreed to a settlement that included moving the in-service date of the entire project to October 2019.[6] The settlement agreement was approved by the Commission on September 30, 2016. On October 20, 2016 the Commission issued its written approval in Decision No. C16-0958.

Q. PLEASE PROVIDE MORE DETAIL ON THE PAWNEE-DANIELS PARK PROJECT COSTS.

A. The Company placed $85.9 million attributable to the Pawnee-Daniels Park Project in service between September 1, 2019 and December 31, 2022, which accounts for approximately 50 percent of all project construction (the remainder was placed in service prior to September 1, 2019). In its CPCN Application, the Company estimated the Pawnee-Daniels Park Project would cost $178 million plus or minus 30 percent (*i.e.*, between $124.6 and $231.4 million). In its Decision granting the Company a CPCN for Pawnee-Daniels Park, the Commission directed Public Service to file semi-annual compliance filings until the project is complete.[7] Among

[6] See Non-Unanimous Settlement Agreement (Sep. 2, 2016), consolidated Proceeding Nos. 16A-0117E, 16V-0314E, approved by Decision No. C16-0958 (mailed Oct. 20, 2016).
[7] Proceeding No. 14A-0287E, Decision No. R14-1405, ordering ¶ 7 (mailed Nov. 25, 2014).

other things, the Commission directed the Company to provide the monthly actual expenses incurred and monthly budgeted expenditures by activity, an explanation of any changes to the overall budget for the project, and efforts to reduce the cost of the project. The Company has complied with this requirement and since filed five semi-annual status reports. The Company filed its last status report on January 23, 2020, which is provided as Attachment CLP-3 to my Direct Testimony. As reflected in that report, the Company completed the Pawnee-Daniels Park project in late 2019, with the last segment energized on December 26, 2019. The total capital placed in service for the project was $169.4 million (including the amounts placed in service before September 1, 2019), which was within five percent of the original project estimate.

D. <u>Interconnection</u>

Q. PLEASE DISCUSS THE PRIMARY DRIVERS OF TRANSMISSION CAPITAL ADDITIONS RELATED TO INTERCONNECTION FROM SEPTEMBER 1, 2019 THROUGH DECEMBER 31, 2022.

A. Total net capital additions for Interconnection projects for September 1, 2019 to December 31, 2022, were $36.5 million. Illustrative examples of projects related to Interconnection over this period include:

- *Colorado Energy Plan Portfolio Rush Creek II Switching Station:* The Shortgrass Switching Station (formerly known as the CEP Rush Creek II Switching Station) is located approximately 12 miles east of Hugo in Lincoln County, Colorado, and Public Service received a CPCN for this project by Decision No. C19-0175 in Proceeding No. 18A-0860E. The Shortgrass Switching Station is a 345 kV electrical hub that allows for interconnecting multiple transmission elements, such as transmission lines. Although the terms substation and switching station are often used interchangeably, a switching station differs from a substation in that there are no transformers and the equipment operates at a single voltage level. The Shortgrass Switching Station includes 345 kV circuit breakers, switches, relays, communications equipment, and an equipment enclosure. This project represents $27.2 million in capital additions between September 1, 2019 and December 31, 2022, but the Company is only seeking recovery in this rate case of the $22.4 million in capital additions for the switching station itself, which is attributable to the CPCN received in Proceeding No. 18A-0860E. The remaining $4.8 million of the total costs for the Shortgrass Switching Station is for voltage control reactors, and attributable to the projects approved for a CPCN in Proceeding No. 19A-0728E. The Company is not seeking base rate recovery of these voltage control costs in this proceeding because the entire voltage control project will not be in service until 2023, and Public Service will not seek recovery until the entire project is in service, as I discuss in more detail below.[8]

In Proceeding No. 18A-0860E, the Company estimated the switching station would cost $13.9 million in capital expenditures +/- 30 percent. Cost variances from the CPCN proceeding were driven by scope additions discovered during detailed engineering, which took place after the CPCN filing. The largest scope change was a permit requirement where Lincoln County required Public Service to maintain an 11-mile stretch of dirt road (approximately $4 million). Additional scope costs contributing to the variance also included costs to upgrade remote substations, transmission lines, civil construction, and communications equipment that were not part of the original scope. Variances are also driven by the fact that the CPCN presented figures in terms of capital expenditures; Company witness Ms. Laurie Wold discusses the difference between a capital expenditure and capital addition in her Direct Testimony.

- *GI 2013 4 US DOE NREL NWTC Project:* The key project related to Interconnection in 2019 is the National Renewable Energy Laboratory ("NREL") substation project, which will enable NREL's National Wind Technology Center ("NWTC") to interconnect to Public Service's transmission system via a new customer-owned 115 kV transmission line. This project represents $11.3 million in capital additions between September 1, 2019 and December 31, 2022. This project is in the

[8] Proceeding No. 19A-0728E, Decision No. C20-0648, ordering ¶ 2 (mailed Sept. 10, 2020) (ordering "Public Service in its next base rate case filing following the date that all facilities associated with the Voltage Control and GDT CPCNs are in service, to specifically identify the actual costs for the Voltage Control and GDT projects, individually and in total, in at least as much detail as provided in this proceeding").

ordinary course of business, and the Commission has determined a CPCN is not required.[9]

Q. YOU MENTIONED THAT THE COMPANY REMOVED COSTS ASSOCIATED WITH THE VOLTAGE CONTROL FACILITIES INCLUDED IN CPCN PROCEEDING NO. 19A-0728E FROM ITS REQUESTED RECOVERY IN THIS PROCEEDING. ARE THERE ANY OTHER PROJECTS PUBLIC SERVICE HAS REMOVED FROM ITS COST OF SERVICE?

A. Yes. In addition to the voltage control facilities approved in Proceeding No. 19A-0728E, Public Service also removed costs associated with the Greenwood-Denver Terminal Transmission Line approved in 20A-0063E. These two proceedings were consolidated, where all projects/facilities were evaluated on a portfolio basis. The Company is not forecasting the entire portfolio will be in service prior to 2022. Therefore, Public Service will seek base rate recovery of these costs as part of a future proceeding. Public Service has also removed from its cost of service the remaining network upgrades and interconnection facilities needed to implement the 2016 Electric Resource Plan, including those identified in the Company's recently-filed CPCN in Proceeding No. 21A-0298E, since final CPCNs have not been issued.

[9] Proceeding No. 17M-0005E, Decision No. C17-0539, ordering ¶ 4 (mailed June 30, 2017).

E. Physical Security and Resiliency

Q. PLEASE DISCUSS THE PRIMARY DRIVERS OF TRANSMISSION CAPITAL ADDITIONS RELATED TO PHYSICAL SECURITY AND RESILIENCY FROM SEPTEMBER 1, 2019 THROUGH DECEMBER 31, 2022.

A. Total capital additions for Physical Security and Resiliency projects for September 1, 2019 to December 31, 2022, were $36.1 million. Transmission is focused on maintaining the physical security of our assets. High voltage transformers make up less than three percent of transformers in U.S. electric power substations, but they carry 60 to 70 percent of the nation’s electricity. Because they serve as vital nodes and carry bulk volumes of electricity, these transformers are critical elements of the nation’s electric power grid. They are also the most vulnerable to intentional damage from malicious acts. In April 2013, a substation in California was subject to a coordinated military-type sniper attack that disabled high voltage transformers and rendered this substation useless. Federal regulatory agencies have responded to these growing threats by adopting physical security standards for transmission facilities. On March 7, 2014, FERC issued an Order on Reliability Standards for Physical Security Measures, resulting in NERC standard CIP-014[7] addressing risks due to physical security threats and vulnerabilities. To address these threats and meet these new NERC standards, we are making necessary investments to make our grid more resilient so that we can respond quickly to physical security threats.

Q. PLEASE IDENTIFY ILLUSTRATIVE EXAMPLES OF PHYSICAL SECURITY AND RESILIENCY PROJECTS OVER THE PERIOD SEPTEMBER 1, 2019 THROUGH 2022 FOR WHICH THE COMPANY REQUESTS RECOVERY.

A. Two illustrative projects fall into the 80 percent categorization:

- *Public Service Physical Security:* As an example, the Company identified four substations as needing both security cameras and physical infrastructure upgrades which include upgrading the substation fence, installation of lighting, camera installation, and significant security related improvements around the Electrical Equipment Enclosure ("EEE"). These specific capital additions are projected to cost $9.7 million. The total capital additions placed in service for September 1, 2019 through 2022 are $22.5 million.

- *Public Service Operational Technology ("OT") Cyber Security:* Install a Real-time Automation Controller ("RTAC") at the Boone Substation. The scope of this project is to increase visibility into substation network environments with the addition of a SEL-3555 RTAC. Each EEE at a site will have a RTAC installed. The RTAC will be connected to the substation network behind the firewall as well as a SEL-2407 clock device and other devices as determined for each site. The total capital additions to be placed in service for September 1, 2019 through 2022 are $6.5 million.

F. Communication Infrastructure

Q. PLEASE DISCUSS THE PRIMARY DRIVERS OF TRANSMISSION CAPITAL ADDITIONS RELATED TO COMMUNICATION INFRASTRUCTURE FROM SEPTEMBER 1, 2019 THROUGH DECEMBER 31, 2022.

A. Total net capital additions for Communication Infrastructure projects for September 1, 2019 to December 31, 2022, are $9.7 million. The Communication Network program aims to privatize Xcel Energy's communication network infrastructure across the Public Service territory, wherever possible, at all transmission and distribution substations for SCADA, teleprotection, and remote engineering access. Specifically, the program addresses aging analog circuit technology and other technology that is anticipated to become obsolete within five years. The Company will then build secure communication architecture for OT and information technology ("IT") networks physically isolated from each other to support islanding of the energy management system ("EMS") for further cyber security resilience. The program will enable the Company to reduce dependency on third-party circuit providers, which will improve the Company's troubleshooting response time and reduce circuit down time. As a result, we need to invest in Company-owned and controlled communication infrastructure in OPGW that will serve our operational and system protection needs without the reliance and vulnerability exposure from a publicly available third-party network. Similarly, cyberattacks pose a threat to the reliability of our transmission system as hackers could cause system outages by disabling telecommunications or key pieces of equipment.

Q. WHAT DO YOU CONCLUDE REGARDING THE TOTAL CAPITAL ADDITIONS FOR THE TRANSMISSION BUSINESS AREA CAPITAL PROJECTS THAT WENT INTO SERVICE OR ARE PROJECTED TO GO INTO SERVICE FROM SEPTEMBER 1, 2019 TO DECEMBER 31, 2022?

A. I conclude that these capital additions have been prudently incurred, are reasonable in cost, and used and useful in support of Public Service's ability to provide safe and reliable electric service to its customers. The projects placed in service during this time period were necessary to renew Public Service's transmission system assets as they require replacing from routine aging and damage, to ensure continued reliability on Public Service's transmission system, and to develop the Pawnee-Daniels Park project for delivering power from new generation resources to the Company's customers. Additionally, the capital additions for the projects discussed in this section were needed to interconnect new generation resources, maintain the security and resiliency of the Company's transmission system, and maintain and upgrade the Company's transmission communication infrastructure.

V. TRANSMISSION 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 provide an overview of the Transmission Business Area's O&M expenses during the proposed test year period, followed by a discussion of the actual 2020 Transmission Business Area O&M expenses, and proposed adjustments for transmission wheeling services, which the Company proposes to use as the primary basis for establishing Transmission O&M levels included in the 2022 FTY. I also describe the drivers of O&M increases between 2018, the last test year upon which current base rates are set, and 2022, where applicable.

Q. FOR BACKGROUND, DOES THE COMPANY RECOVER TRANSMISSION O&M EXPENSES THROUGH THE TCA?

A. No. The TCA is only used for recovery of capital expenses for transmission projects. O&M expenses are recovered through base rates.

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

A. I describe above the various work that is performed by the Transmission Business Area. To perform this work, the Transmission Business Area generally incurs O&M expenses each year in the following six categories:

- *Internal Labor:* Costs related to the O&M portion of salaries, straight time labor, overtime, premium time, and employee expenses for internal employees.

- *Contract Labor and Consulting:* Costs related to the use of contract labor and consultants, which allows Public Service to increase and decrease staffing levels as workloads require rather than adding more full-time staff, and to retain the services of experts as needed for specific tasks or project efforts.

- *Fees:* Fees the Company is required to pay include regulatory fees, license fees and permits related to railroads and land, environmental fees, and professional association dues that are necessary for the operation of our business.

- *Materials:* Costs related to consumables, hardware, and refurbished materials used in substation maintenance and repair operations, as well as tools, small equipment, and supporting supplies.

- *Fleet:* Costs for the internal fleet assets as directed to O&M accounts on an hourly basis including cars, trucks, construction equipment, and trailers.

- *Other:* Includes miscellaneous other costs such as use costs, maintenance costs, employee expenses, rents, network communication costs and office supplies.

Q. WHAT WERE TRANSMISSION'S ACTUAL 2020 O&M COSTS?

A. Our actual O&M expenses for 2020 totaled $27.4 million. Table CLP-D-2 below breaks down the amount of overall O&M costs by the categories I discussed above. Attachments CLP-4 and CLP-5 provide an accounting of these expenses by Cost Element and FERC account, respectively.

TABLE CLP-D-2:
Transmission 2020 Actual O&M Expenses*
Public Service Electric
(Dollars in Millions)

Cost Category	2020
Internal Labor	$16.2
Contract Labor and Consulting	$4.5
Fees	$3.1
Materials	$1.4
Fleet	$0.9
Other	$1.2
Total	**$27.4**

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

Q. WHAT ARE THE DRIVERS BETWEEN TRANSMISSION'S 2018 O&M COSTS USED IN THE 2019 ELECTRIC PHASE I AND THE 2020 O&M COSTS THAT WILL BE REFLECTED IN THE 2022 FTY?

A. The drivers are shown in Table CLP-D-3 below.

**TABLE CLP-D-3:
Drivers of Transmission O&M Expenses from 2018 Historical Test Year ("HTY") to 2020 Actuals*
Public Service Electric
(Dollars in Millions)**

Driver	2018 HTY	Driver Amount	2020 Actual
Internal Labor	$18.6	$(2.4)	$16.2
Contract Labor and Consulting	$4.3	$0.2	$4.5
Fees	$3.8	$(0.7)	$3.1
Materials	$2.3	$(0.9)	$1.4
Fleet	$1.9	$(1.0)	$0.9
Other	$1.9	$(0.7)	$1.2
Total Electric	**$32.7**	**$(5.3)**	**$27.4**

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

Q. CAN YOU PROVIDE MORE INFORMATION REGARDING THE MAIN DRIVERS SHOWN IN TABLE CLP-D-3?

A. As shown in Table CLP-D-3, changes in O&M expenses primarily fell within the Internal Labor, Fees, Materials, Fleet, and Other categories. I discuss the main drivers for each of these O&M categories below.

- *Internal Labor:* Public Service experienced a decrease of $2.4 million primarily due to repurposing crews to capital projects for which the crews direct charge their labor to specific projects. The percentage of labor charged to O&M decreased from 2018 to 2020, as more base labor was charged to capital. Additionally, Public Service adopted continuous improvement efforts in 2019 which has led to lower O&M expense.

- *Fees:* Public Service experienced a $0.7 million decrease in fees, which was primarily driven by switching reliability coordinators (from Peak Reliability to Southwest Power Pool Reliability).

- *Materials:* Public Service experienced a $0.9 million decrease in materials, which was driven by enhanced scrutiny and application of the Company's repair versus replace model. Historically, equipment would be repaired if needed. The Company has improved usage of its model to determine whether it is more cost efficient to repair or replace a given unit. As the system ages, more equipment will be replaced instead of repaired.

- *Fleet:* Public Service experienced a $1.0 million decrease, which was driven by a concerted effort to assign fleet costs to work being performed, and the work primarily has been capital.

- *Contract Services:* Public Service experienced a $0.2 million increase in contract services, which is not a material change compared to previous years.

- *Other:* Public Service experienced a $0.7 million decrease primarily due to an overall decrease in employee expenses due to COVID-19 ($653,000 reduction period over period for total employee expenses). Primary drivers for employee expense reductions were reduced costs related to travel (airfare, car rentals, hotels, meals, and conference seminars). Travel-related employee expenses decreased 61 percent period over period.

Q. DO THESE COSTS CONTAIN ANY WILDFIRE MITIGATION O&M COSTS?

A. No. Company witness Ms. Johnson sponsors and discusses all O&M costs (transmission and distribution) associated with the Company's wildfire mitigation efforts.

Q. ARE THE $27.4 MILLION IN 2020 O&M EXPENSE THAT YOU DESCRIBE IN TABLE CLP-D-3 ABOVE REFLECTED IN THE COMPANY'S 2022 FTY COST OF SERVICE PRESENTED BY MS. BLAIR?

A. Yes, it is used as the representative level of Transmission O&M for the 2022 FTY. As reflected in Attachments CLP-4 and CLP-5, the Company is seeking $27.4 million for Transmission O&M.

Q. ARE YOU PROPOSING ANY ADJUSTMENTS TO THE COMPANY'S 2020 O&M EXPENSES TO BE REFLECTED IN THE FTY FOR TRANSMISSION O&M EXPENSES?

A. Yes. Public Service is proposing an FTY adjustment for wheeling costs, which I discuss in Section VI below.

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

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

Q. IS THE COMPANY'S 2020 TRANSMISSION O&M A REASONABLE BASIS ON WHICH TO ESTABLISH TRANSMISSION'S O&M COSTS FOR THE 2022 FTY?

A. Yes. The Company's 2020 Transmission O&M costs are reasonably representative of the Company's forecasted O&M costs.

VI. TRANSMISSION WHEELING SERVICES COSTS

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

A. In this section of my Direct Testimony, I describe Public Service's use of third-party wheeling service to transmit power to serve its customers as well as the costs for these services. My Direct Testimony provides support for the FTY adjustments for Transmission Wheeling Services included in the 2022 FTY cost of service study sponsored by Ms. Blair.

Q. ARE WHEELING COSTS PART OF THE TRANSMISSION AREA'S CAPITAL AND O&M BUDGETS?

A. No. These costs are not part of the capital and O&M budgets I describe above. These costs are incurred by our Commercial Operations area to provide transmission access to serve our retail customers and provide transmission service to import power into the Public Service system.

Q. WHAT IS WHEELING SERVICE?

A. Wheeling is an industry term used to describe the transmission of electricity by an entity that does not own or directly use the electricity that it is transmitting. When a public utility requires use of the transmission or distribution assets of another system in order to deliver electricity to its electric customers, it is required to pay a wheeling charge. In the context of my Direct Testimony, I use the term wheeling to describe the arrangements that Public Service has entered into with its neighboring utilities to utilize their transmission and/or distribution systems to serve Public Service customers in a cost-effective way.

Q. WHY DO UTILITIES ENGAGE IN TRANSMISSION WHEELING?

A. Because the electric grid is an interconnected network, utilities often find that it is more cost effective to purchase transmission service from others to serve their electric customers rather than to construct new facilities. Generally, utilities will utilize wheeling when it is less expensive to purchase wheeling service or where the construction of new facilities is impractical. Utilities may also purchase wheeling service from others to serve customers during outage conditions.

Q. DO UTILITIES PURCHASE TRANSMISSION SERVICE FOR REASONS OTHER THAN SERVING THEIR ELECTRIC CUSTOMERS?

A. Yes. In addition to wheeling energy to serve customers, utilities also purchase wheeling service from others to import generation or to access generation markets. For example, a utility (or developer) may purchase transmission service to import generation from a new wind farm or other generator if the generation resource is not directly interconnected to the utility's core transmission network. A utility may also purchase Point-to-Point ("PTP") transmission service to access market hubs outside of its geographic network so that it may have access to those hubs rather than construct its own native generation. For the purposes of my Direct Testimony, I include these generation-related uses of third-party transmission service when I use the term wheeling.

Q. DOES PUBLIC SERVICE PURCHASE WHEELING SERVICE?

A. Much like other electric utilities, Public Service engages in a number of wheeling transactions to both serve its retail native load, as well as to provide transmission paths into Public Service's network for its generation and market access. In each case, Public Service's use of wheeling service avoids the need to construct duplicative assets that would either be costlier than purchasing wheeling service or are impractical to build or acquire.

Q. WHAT ARE THE WHEELING TRANSACTIONS IN WHICH PUBLIC SERVICE ENGAGES?

A. Attachment CLP-6 identifies Public Service's wheeling transactions for which recovery is being requested in base rates, along with a description of each transaction. As reflected in Attachment CLP-6, the Company is seeking to recover $21.9 million in wheeling expense.

Q. HAVE WHEELING COSTS INCREASED SINCE 2018?

A. Yes. Public Service's 2020 wheeling costs, not including adjustments, were approximately $8.8 million higher than the wheeling costs included in the 2019 Electric Phase I that used calendar 2018 level of expense.

Q. WHAT DROVE THIS INCREASE IN COSTS FROM 2018 TO 2020?

A. Changes in wheeling costs from 2018 to 2020 were primarily driven by the following:

- *Public Service – Four Corners-Craig 188 MW PTP:* The 188 MW Point-to-Point reservation has allowed Public Service to lower the reserves it carries with its own resources, which lower the Company's production costs. The cost of the reservation has increased by approximately $2 million as a result of an increase in the Public Service firm PTP transmission rate.

- *Point-to-Point Purchases:* As a result of elevated system conditions during 2020, $5.9 million of PTP transmission service was procured on other transmission systems. The costs of the reservations when combined with the associated energy purchased are recovered through the Electric Commodity Adjustment ("ECA") as described below.

Q. IS PUBLIC SERVICE UTILIZING 2020 ACTUAL WHEELING COSTS TO ESTABLISH ITS COST OF SERVICE IN THIS PROCEEDING?

A. Yes, as Ms. Blair discusses, the 2022 FTY cost of service starts with 2020 actual O&M costs, but the level of wheeling expenses requested in this rate case has been adjusted for known FTY adjustments.

Q. DOES ATTACHMENT CLP-6 INCLUDE ALL WHEELING COST ADJUSTMENTS INCLUDED IN THE 2022 FTY?

A. No. In addition to the FTY adjustments to 2020 costs I discuss below, Public Service has excluded certain wheeling costs collected through the ECA.

Q. WHAT FTY ADJUSTMENTS TO THE COST OF WHEELING SERVICES IS PUBLIC SERVICE PROPOSING TO MAKE?

A. Public Service has proposed four types of FTY adjustments: (1) Economic Purchases, (2) Trading Activity, (3) Sales for Resale, and (4) Prior-Year True-Ups.

Economic purchases refers to the procurement of point to point transmission service on other transmission systems due to elevated system conditions; to the extent these costs, when combined with the associated energy purchase, are deemed economic, they are recovered through the ECA. Accordingly, wheeling expenses were adjusted by $3,039,304 to exclude such costs incurred in 2020.

Trading Activity refers to wheeling charges associated with proprietary and/or off-system trading activity (which are included in the calculation of trading margins and shared with customers through the ECA); therefore, an adjustment of $929,956 is necessary to exclude these amounts from wheeling expense.

Sales for resale refers to PTP transmission service that is procured from Tri-State in order to serve a wholesale customer, and approximately $367,000 of associated wheeling expense has been excluded.

Prior-period true-ups includes an adjustment of $1,171,609 to exclude accounting adjustments recorded in 2020 related to the true-up of Public Service's 2018 and 2019 Transmission Integration and Equalization Agreement with Holy Cross Electric Association, Inc.

In total, Public Service proposes a net decrease of $3,280,125 to the Company's 2020 actual Transmission O&M levels to account for its adjustments, which is reflected in the column "2022 Adjusted" in the table included on page 2 of Attachment CLP-6.

VII. TRANSMISSION CAPACITY RESERVATION DEFERRAL

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

A. In this section of my Direct Testimony, I discuss the background and costs associated with the Company's request to defer costs associated with certain summer Transmission capacity reservations the Company plans to make for the next five years.

Q. PLEASE SUMMARIZE THE TRANSMISSION CAPACITY DEFERRAL PUBLIC SERVICE IS REQUESTING.

A. Over the past two summer periods, Public Service has been able to reserve various amounts of firm transmission service on a monthly basis, primarily from WAPA. However, beginning late last year other parties purchased this transmission service for summer 2021, and there are two long-term requests being analyzed by WAPA for long-term (five-year) service.

Q. WHY DOES PUBLIC SERVICE NEED ADDITIONAL FIRM TRANSMISSION IMPORT CAPABILITY?

A. During peak demand periods in the summer, additional transmission capacity is necessary for times when Public Service needs additional resources to serve load. This can occur on days with light winds (and therefore low wind generation output) or if one of Public Service's thermal generation facilities experiences an outage. Public Service has only minor (60 MW) transfer rights across the TOT[10] 3 path

[10] The term "TOT" is a carry-over term from when power flow computer models only permitted three letters. TOT stands for "total" and signifies the total transmission capacity attributable to several transmission lines running in parallel.

which consists of the transmission lines between Wyoming/Nebraska and Colorado. Additionally, these rights are held as Transmission Reliability Margin for an operating reserve activation from the Northwest Power Pool ("NWPP"). Public Service is usually able to obtain energy and capacity resources on the north side of this path during constrained periods, but with limited transmission capacity is reliant upon non-firm transmission being available in real time. Furthermore, having access to additional firm transmission service across TOT 3 would increase the capability to rely on the NWPP when an activation due to a Public Service generator outage is required.

Q. WHAT ARE THE COSTS PUBLIC SERVICE IS SEEKING TO DEFER?

A. To make a long-term reservation of firm point-to-point service, the customer is required to pre-pay one month of service. For a 110 MW reservation at WAPA's current rates, this amounts to $475,733. In addition, Public Service will need to pay a per-reservation application fee of $3,500 ($7,000 total) and study costs of approximately $50,000 ($100,000 total), for a grand total of $582,733 to be paid in 2022. Public Service will request 110 MW from various delivery points for five years of service starting June 1, 2023. Annual costs at WAPA's current rates would be approximately $5.7 million, as reflected in Attachment CLP-7 to my Direct Testimony. Accordingly, Public Service is seeking Commission approval to track and defer the application fee, study, and reservation costs of approximately $5.7 million per year associated with these transmission reservations.

VIII. RECOMMENDATIONS AND CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. As part of approving the cost of service developed by Ms. Blair, I recommend that the Commission authorize base rate recovery of the September 1, 2019 through December 31, 2022 capital additions and 2020 O&M expense to be included in the 2022 FTY. I also recommend that the Commission authorize the FTY adjustments for Transmission Wheeling Services included in the Company's cost of service.

Q. DOES THIS CONCLUDE YOU DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Connie L. Paoletti

Connie L. Paoletti is the Manager of Transmission Planning for Public Service Company of Colorado. In this position, Connie has responsibility for overseeing the engineering group responsible for planning the transmission system and is also responsible for the development of Transmission budgets, regulatory compliance and portions of the operations and maintenance ("O&M") of Public Service's transmission system. Since 2015, Connie has had responsibility for overseeing transmission policy and projects involving participation with other utilities, including conducting strategic analyses for potential transmission projects, evaluating and negotiating joint agreements, and engaging in stakeholder outreach. Connie served as the Public Service Transmission witness in the 2019 Phase I Electric Rate Case proceeding, the 2017 Phase I Electric Rate Case proceeding, and the 2016 Electric Resource Plan proceeding

Connie joined Xcel Energy in 2002. From early 2002 through the end of 2014, Connie was a Senior Originator in the Commercial Operations group. In that role, she worked on long-term structured transactions within the Midwest and West regions. From 1998 to 2001, Connie was employed by the Princeton Energy Programme as an instructor on energy risk management. Between 1986 and 1998, Connie was employed by Dow Chemical, Phillips Petroleum, and Reliant Energy in the Technical Sales, Trading and Origination roles.

Connie graduated from the Illinois Institute of Technology in 1986 with a Bachelor of Science degree in Chemical Engineering.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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

AFFIDAVIT OF CONNIE L. PAOLETTI
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO

I, Connie L. Paoletti, 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 1st day of July 2021.

Connie L Paoletti

Connie L. Paoletti
Manager, Transmission Planning

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

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

Dawn Moffit
Notary Public

My Commission expires 4.22.2024