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

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

DIRECT TESTIMONY AND ATTACHMENTS OF CONNIE L. PAOLETTI

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

May 20, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
2014 Electric Rate Case	Proceeding No. 14AL-0660E
ANSI	American National Standards Institute
ARCM	Adaptive Reliability Centered Maintenance
BES	Bulk Electric System
CACJA	Clean Air-Clean Jobs Act
CCOD	City and County of Denver
CDOT	Colorado Department of Transportation
CIP	Critical Infrastructure Protection
CPUC or Commission	Colorado Public Utilities Commission
CPCN	Certificate of Public Convenience and Necessity
ECA	Electric Commodity Adjustment
ELR	End of Life Replacement
FERC	Federal Energy Regulatory Commission
GIS	Gas-Insulated Substation
HMI	Human Machine Interface
HTY	Historical Test Year
HVDC	High Voltage Direct Current
IRP IC	Integrated Resource Plan Interconnection
kV	Kilovolt

Acronym/Defined Term	**Meaning**
LIDAR	Light Detection and Ranging
MHT	Mountain Hazard Tree
MVAr	Mega Volt Amps Reactive
MWTG	Mountain West Transmission Group
NERC	North American Electric Reliability Corporation
OATT	Open Access Transmission Tariff
O&M	Operations and Maintenance
OPGW	Optical Ground Wire
Peak Reliability	Reliability Coordinator
PRPA	Platte River Power Authority
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
RTO	Regional Transmission Organization
RTU	Remote Terminal Unit
SB 07-100	Senate Bill 07-100
SCADA	Supervisory Control and Data Acquisition
S&E	Storms and Emergency
TCA	Transmission Cost Adjustment

Acronym/Defined Term	**Meaning**
TIE Agreement	Transmission Integration and Equalization Agreement
Tri-State	Tri-State Generation and Transmission Association, Inc.
WAN	Wide Area Network
WAPA	Western Area Power Administration
WECC	Western Electric Coordinating Council
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services Inc.

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DIRECT TESTIMONY AND ATTACHMENTS OF CONNIE L. PAOLETTI

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, Denver, Colorado 80202.

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

A. I am employed by Xcel Energy Services Inc. ("XES"). XES is a wholly owned subsidiary of Xcel Energy Inc. ("Xcel Energy"), and provides an array of support services to Public Service Company of Colorado ("Public Service" or the "Company") and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis. My title is Manager, Regional Transmission Initiatives.

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, Regional Transmission Initiatives for XES, I am responsible for overseeing transmission policy and managing 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 also engaging in stakeholder outreach. A description of my qualifications and responsibilities is set forth after the conclusion of my Direct Testimony in my Statement of Qualifications.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to support (1) the $788.1 million in Transmission plant additions for 2014 through 2018 (since the Company's last electric rate case in Proceeding No. 14AL-0660E ("2014 Electric Rate Case"), where a 2013 Historical Test Year ("HTY") was approved), and (2) the $20.1 million in Transmission plant additions for 2019, all of which are appropriately allocated to Public Service retail electric and included in the 2018 HTY cost of service that is presented by Company witness Ms. Deborah A. Blair. Company witness Ms. Laurie J. Wold has calculated the monthly plant balances to develop the plant-related roll forward, which in turn is used by Company witness Ms. Blair to incorporate the year-end plant in service balances into the 2018 HTY cost of service.

I also support the $32.7 million in 2018 Operations & Maintenance ("O&M") expenses (pre-adjustment) that are included in the 2018 HTY cost of service, as well as one known and measurable adjustment attributable to the Mountain West Transmission Group.

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. In addition, I support the known and measurable adjustment for Transmission Wheeling Services included in the 2018 HTY.

Finally, I describe the activities undertaken by the Company's Transmission Business Area to enhance its efforts to address the heightened risk of wildfires within the Company's service territory, and provide an overview of forecasted O&M expenses related to Public Service's Transmission Wildfire Mitigation Plan which includes $3.1 million of O&M expenses for 2019 included in the 2018 HTY cost of service. The Company's updated wildfire mitigation strategy is described in more detail by Company witness Ms. Brooke A. Trammell.

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

A. Yes, I am sponsoring Attachments No. CLP-1 through CLP-6, which were prepared by me or under my direct supervision. The attachments are as follows:

- Attachment CLP-1: Transmission Capital Additions 2014–2018;
- Attachment CLP-2: Transmission Capital Additions 2019;
- Attachment CLP-3: Pawnee Daniels Park Semi-Annual Report (Jan. 19, 2019);
- Attachment CLP-4: Transmission O&M Expenses by Cost Element;
- Attachment CLP-5: Transmission O&M Expenses by FERC Account; and
- Attachment CLP-6: Public Service Wheeling Expense.

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

A. As part of approving the cost of service developed by Ms. Blair, I recommend that the Colorado Public Utilities Commission ("CPUC" or the "Commission") approve the 2014 through 2019 capital additions and 2018 O&M expense, as well as one known and measurable adjustment associated with the Company's Transmission Business Area's projects described below. Next, I support the Company's known and measurable adjustment for Transmission Wheeling Services included in the Company's cost of service. Finally, I recommend the Commission approve the Company's request related to recovery of Wildfire Mitigation Plan O&M expenses, which comprise an adjustment to 2018 O&M expenses for known and measurable costs.

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 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 over 4,700 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 Western Area Power Administration ("WAPA"). The Company's 232 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 energy needs of our customers in a safe and reliable manner.

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

A. The key functions of the Transmission Business Area are as follows:

- *Substation Operations & Maintenance:* Responsible for substation field engineering, which includes routine and emergency maintenance and operational activities for all Company substations. The organization also provides construction support for capital projects, field implementation of certain North American Electric Reliability Corporation ("NERC") and Critical Infrastructure Protection ("CIP") compliance activities, and commissioning new substation facilities. Commissioning of Public Service substation facilities involves ensuring that our substation facilities meet the operational and reliability requirements of the Federal Energy Regulatory Commission ("FERC") and NERC, as well as Public Service. The Quality Assurance/Quality Control ("QA/QC") process performed by Company Commissioning Engineers and Technicians thoroughly tests the equipment and control systems of our electric substations prior to energizing. These processes establish the baseline performance expected by our O&M organizations, and confirm the performance for compliance standards.

- *Transmission Strategy and Planning:* 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; (3) resolving wholesale customer transmission service concerns; (4) developing Public Service's reliability-centered maintenance programs that ensure the health and reliability of existing assets; and (5) managing participation in key regional projects throughout the Company's service territory, as well as other regional projects on and adjacent to Public Service's transmission system.
- *Transmission Construction and Line Operations:* Provides field services for construction, maintenance, and emergency repairs for transmission assets.
- *System Sustainability Initiatives:* Provide electric material and design standards for the design, construction, and maintenance of our transmission assets by interpreting industry standards (such as the American National Standards Institute ("ANSI")).
- *Transmission Portfolio Delivery:* 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:* Primarily responsible for the NERC Balancing Authority and Transmission Operations function for Public Service's transmission system.

- *Transmission Business Operations:* Directs the Transmission Business Area's efforts pertaining to compliance with NERC CIP requirements and achievement of business performance goals.
- *Transmission Investment Development:* Focuses on the Company's policies and procedures in the competitive transmission acquisition processes, pursuant to the various requirements of FERC Order No. 1000.[1]

[1] In July 2011, the FERC issued Order No. 1000. *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 76 Fed. Reg. 49,842 (August 11, 2011) (subsequent history omitted). The stated purpose was to increase regional transmission development by eliminating long-standing monopolies and create competition and incentives for innovative, cost-effective projects. The Order is a Final Rule that reforms the electric transmission planning and cost allocation requirements for public utility transmission providers subject to FERC jurisdiction.

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, 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?

A. Our capital additions fall into two types. The first are large capital projects that expand the transmission system's capabilities and 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, Transmission also completes many smaller capital projects each year. While smaller projects make up a majority of the projects we complete each year, they typically also represent only a small part of our overall capital budget. Some examples of such 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.

Q. WHAT ARE THE CORE CAPITAL BUDGET GROUPINGS THAT REFLECT THE TRANSMISSION BUSINESS AREA'S GOALS AND INITIATIVES YOU IDENTIFIED ABOVE?

A. Based on these drivers, our capital projects fall into six capital budget groupings depending on the main purpose of the project. These groupings are: (1) Regional Expansion; (2) Reliability Requirement; (3) Asset Renewal; (4) Interconnection; (5) Communication Infrastructure; and (6) Physical Security and Resiliency.

Below I provide more detail on each of these categories:

- *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 we seek a Certificate of Public Convenience and Necessity ("CPCN") from the Commission.
- *Reliability Requirement:* A key focus of the Transmission Business Area is maintaining the reliability and resilience of the transmission system. Major

transmission line projects provide necessary upgrades to the regional transmission system to support local reliability, regional reliability, and renewable and other generation outlets. In general, our transmission capital additions expand the transmission system infrastructure and upgrade the transmission system to improve load serving capabilities and accommodate new generation, including renewable generation.

The Transmission organization is continually studying the transmission system to assess performance and compliance with reliability criteria and standards. These studies analyze the impacts of forecasted load growth, existing and anticipated generation needs, and public policy implications, to determine whether transmission upgrades are necessary. 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. Any entity found non-compliant with NERC Standards may be subject to fines of up to $1.2 million per violation, per day.

This category also includes investments related to the implementation of current CIP standards. CIP compliance requirements address threats to both the cyber and physical security of the BES.

- *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 (through 2018) and tools that support capital additions and line relocations.

Generally speaking, transmission assets have long expected lives, which allows some flexibility as to when replacements are made. This gives us the opportunity to prioritize replacements to address unplanned replacements due to storms or other urgent priorities. However, persistent delay in asset renewal investments can lead to a substantial backlog of replacement needs, higher maintenance expenses, higher risk of equipment failure, and obsolescence. We therefore try to invest steadily in this area to maintain the reliability of our system.

- *Interconnection:* This category includes projects that we are 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.
- *Communication Infrastructure:* This category includes the fiber optic buildout on the transmission system to improve connectivity for all business areas. This category also includes required communication infrastructure upgrade projects to allow the digital transfer of Supervisory Control and Data

Acquisition ("SCADA") data and tele-protection services as telecommunication service providers are retiring the existing obsolete "frame relay" and analog connections. Reducing dependencies on outside telecommunication providers improves system reliability.

- *Physical Security and Resiliency:* Grid security has two critical aspects: physical security and grid resiliency. While physical security addresses threats to utility infrastructure such as transmission substations, 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. The driver to implement a category relating to this group of projects was prompted by FERC's decision to adopt NERC's CIP-014 in May 2014 which included reliability standards to address physical security threats and vulnerabilities. This category includes projects that address these NERC standards, improving the physical security and resiliency of our transmission grid.

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

A. Transmission's annual capital budget is based on collaboration between corporate management of overall Company finances and the business needs that are identified by Transmission.

At the same time, 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 Company utilizes a multi-step project lifecycle process that takes a project from the identification of a need, through mitigation development / alternative evaluation / preliminary scope development / 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 doing 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 prioritized based on if they are mandated and or otherwise required, or if Public Service has discretion in deploying the projects. 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 PUBLIC SERVICE FOLLOW TO MANAGE AND CONTAIN ITS TRANSMISSION BUSINESS AREA CAPITAL COSTS?

A. From a financial perspective, capital projects are reviewed 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 help 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 Business Area 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.

Review is 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. Changes are reported to the Financial Performance and Planning 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 our 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 such as Public Service apprise the Commission of planned transmission projects, and to allow the Commission to verify or determine which projects require a CPCN or otherwise may be pursued in the ordinary course of business under the applicable CPCN statute and rules. Public Service submits its Rule 3206 Report annually on May 1.

Additionally, in 2011, the Commission adopted Rules 3625, 3626, and 3627, which set forth requirements for transmission planning applicable to Commission-regulated utilities. The 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 is to take into account the needs of all stakeholders. The rules require periodic reporting to the Commission. Public Service submits its Ten-Year Transmission Plan for the State of Colorado bi-annually on February 1 in even years. These plans are the result of a cooperative effort among Black

Hills Colorado Electric Utility Company, L.P. d/b/a Black Hills Energy, Tri-State, and Public Service. The Commission is also informed about our transmission projects through our annual Transmission Cost Adjustment ("TCA") filings.

IV. TRANSMISSION 2014–2018 CAPITAL ADDITIONS

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

A. The purpose of this section of my testimony is to provide an overview of the Transmission Business Area's capital additions since the Company's 2014 Electric Rate Case, which included a 2013 HTY.

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

A. As reflected in Attachment CLP-1, the Company is seeking recovery of $788.1 million for Transmission Business Area capital additions for 2014-2018, and, as shown in Attachment CLP-2, the Company is seeking recovery of $20.1 million for capital additions that will go into service in 2019. Below I primarily discuss the Company's 2014-2018 capital additions. I address the Company's 2019 planned in-service capital additions in more detail in Section V, below. As discussed in more detail in the Direct Testimonies of Company witnesses Ms. Blair and Ms. Michelle M. Applegate, the Company's 2014-2018 Transmission capital additions are being recovered through the TCA, and the Company is proposing in this rate review to roll those amounts into base rates. With respect to 2019 Transmission capital additions the Company is only seeking to recover capital amounts not currently being recovered through the TCA.

Q. PLEASE EXPLAIN THE INFORMATION PROVIDED IN ATTACHMENT CLP-1.

A. Attachment CLP-1 shows the Transmission Business Area's capital additions for plant placed into service from 2014 through 2018. Table CLP-D-1 below provides the total capital additions placed into service from 2014 to 2019 broken out into these groupings:

Table CLP-D-1:
(Total Company)
Transmission Capital Additions 2014-2018
(Dollars in Millions)

Category	2014	2015	2016	2017	2018
Regional Expansion	$ 23.0	$ 2.1	$ 0.0	$ 8.0	$ 72.7
Reliability Requirements	$ 61.4	$ 64.3	$ 88.2	$ 49.8	$ 156.4
Asset Renewal	$ 36.9	$ 41.6	$ 42.1	$ 41.6	$ 62.7
Interconnection	$ (0.9)	$ 2.8	$ 4.9	$ (0.6)	$ 3.6
Communication Infrastructure	$ 0.0	$ 0.6	$ 0.0	$ 0.9	$ 2.6
Physical Security and Resiliency	$ 0.0	$ 0.0	$ 2.3	$ 0.3	$ 20.9
Total*	**$120.4**	**$111.3**	**$137.6**	**$100.0**	**$318.8**

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

As I mentioned earlier, however, 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 since the 2013 HTY.

1. <u>Regional Expansion</u>

Q. PLEASE DISCUSS THE PRIMARY DRIVERS OF TRANSMISSION CAPITAL ADDITIONS RELATED TO REGIONAL EXPANSION SINCE THE 2013 HTY.

A. Total capital additions for Regional Expansion projects for 2014 through 2018 were $105.7 million. Three-quarters of these capital expenditures 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 – albeit 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.[2] 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 $79.7 million attributable to the Pawnee-Daniels Park Project in service between 2014 and 2018, which accounts for approximately 50 percent of all project construction (the remainder will go in service in 2019). In its CPCN Application, the Company estimated the Pawnee-Daniels 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.[3] Among 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 three semi-annual status reports.

[2] 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).
[3] Proceeding No. 14A-0287E, Decision No. R14-1405, ordering ¶ 7 (mailed Nov. 25, 2014).

The Company filed its last status report on January 14, 2019, which is provided as Attachment CLP-3 to my Direct Testimony. As reflected in that report, the Company has been able to realize cost savings in several areas and currently projects the total Pawnee-Daniels Park Project costs will be approximately 14 percent under the cost estimate submitted with the CPCN Application.

Q. IS IT YOUR CONCLUSION THAT THE PAWNEE-DANIELS PARK COSTS FOR WHICH THE COMPANY IS SEEKING RECOVERY IN THIS PROCEEDING HAVE BEEN REASONABLY AND PRUDENTLY INCURRED?

A. Yes. As explained above and in the Company's detailed semi-annual status reports, I conclude that the Pawnee-Daniels Park capital costs have been reasonably and prudently incurred.

Q. ARE THERE OTHER PROJECTS RELATED TO REGIONAL EXPANSION?

A. Yes. Illustrative examples of projects related to Regional Expansion since the 2013 HTY include:

- *Clean Air – Clean Jobs Act ("CACJA") Transmission Investment:* The CACJA Transmission Investment project involved multiple transmission network upgrades to bring new generation on line at Cherokee generating station and upgrades to the existing Arapahoe Substation due to the shutdown of the Arapahoe coal-fired plant. The Transmission capital additions associated with this project were not included in the CACJA Rider. The Company has placed $18.2 million in service attributable to the CACJA Transmission Investment since its 2014 Electric Rate Case.

- *SB 07-100 Pawnee-Smokey Line:* Although the Pawnee – Smokey Hill 345 kV transmission line and Pawnee Substation project were placed in service in 2013, this scope of work for the Pawnee-Smokey Hill project was for the replacement of a failed 345/230kV autotransformer at Pawnee Substation. The Commission granted a CPCN for the 345 kV transmission line and the substation in Decision No. C09-0048. The Company has placed $6.7 million attributable to the SB Pawnee-Smokey Line project in service since its 2014 Electric Rate Case.

2. <u>Reliability Requirements</u>

Q. PLEASE DISCUSS THE PRIMARY DRIVERS OF PUBLIC SERVICE'S TRANSMISSION CAPITAL ADDITIONS RELATED TO RELIABILITY REQUIREMENTS SINCE THE 2013 HTY.

A. Total capital additions for Reliability Requirements projects for 2014 through 2018 were $420 million. Illustrative examples of projects related to Reliability Requirements since the 2013 HTY include:

- *Rush Creek Wind Project Gen-Tie:* The Rush Creek Wind Project includes a 600 megawatt (MW) wind farm, an approximately 83 mile 345 kV transmission line (or "Gen-Tie"), and two new substations in eastern Colorado. The 345 kV Gen-Tie connects the wind farm to our existing Missile Site Substation in Arapahoe County. The final segment of the Gen-Tie was energized in August 2018, and the Company placed $105.7 million into service in 2018. The wind farm covers 95,000 acres in Elbert, Lincoln, Kit

Carson, and Cheyenne Counties. The transmission line route passes through Lincoln, Elbert, and Arapahoe Counties. The Rush Creek Wind Project was approved by the Commission in Proceeding No. 16A-0117E. Company witnesses Ms. Trammell, Ms. Michelle M. Applegate, Ms. Blair, and Mr. Kyle I. Williams provide more detail regarding the Rush Creek Wind Project.

- *Rifle-Parachute 230 kV Line:* The Rifle PS – Parachute 230 kV line #2 project was placed in service in 2016 to improve reliability and accommodate load growth on the Western Slope of Colorado. Some capital expenditures carried over into 2017 primarily for restoration and revegetation activities. The Company has placed $32.8 million attributable to the Rifle-Parachute 230 kV Line project in service since the last rate case.
- *Two Basins:* The Two Basins project is necessary to accommodate the City and County of Denver's ("CCOD") Two Basins storm water drainage project which will provide 100-year storm protection for certain areas of the city. This drainage project is also a consequence of the Colorado Department of Transportation's ("CDOT") I-70 expansion project. The project consists of the relocation of three existing 115 kV transmission lines (both overhead and underground lines) exiting the North Substation. The Company placed $22.9 million attributable to the Two Basins project in service since the last rate case.
- *Capitol Hill Gas Insulated Substation ("GIS") Conversion Project:* The Capitol Hill GIS project is a multi-year project to upgrade the Capitol Hill Substation,

with portions of the project placed in-service as they are put to use each year. Capitol Hill Substation is on the edge of downtown Denver, only a few blocks from the Colorado State Capitol Building, and is surrounded by businesses and residences that make expansion impossible. Rather than build a new substation on a new plot of land, a six-phase construction plan was developed to incrementally transform the 115-kV three-position single bus into a new 115-kV GIS configured in a six-position ring bus. This increases system reliability and frees up space for a third switchgear and capacitor bank to serve future load. The Company placed $18.3 million attributable to the Capitol Hill GIS project in service since the last rate case.

3. <u>Asset Renewal</u>

Q. PLEASE DISCUSS THE PRIMARY DRIVERS OF TRANSMISSION CAPITAL ADDITIONS RELATED TO ASSET RENEWAL SINCE THE 2013 HTY.

A. Total capital additions for Asset Renewal projects for 2014 through 2018 were $224.9 million. Illustrative examples of projects related to Asset Renewal since the 2013 HTY include:

- *Public Service Line Capacity:* Routine work orders are utilized to address capacity limitations in transmission facilities rated at 100 kV or above. This work was performed in response to NERC's 2010 Facilities Rating Alert which requires Public Service to identify and remediate any capacity limitations of the overhead transmission system. Capacity limitations were identified through the use of 3-D Light Detection and Ranging ("LIDAR") models that verify our capacity ratings. The Company placed $53.2 million in service since the last rate case, for 2014 through 2018.

- *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 placed $36.5 million attributable to Major Line Rebuild projects in service and $15.5 million attributable to Major Line Refurbishment projects in service since the 2014 Electric Rate Case.
- *ELR Projects:* End-of-Life Replacement ("ELR") projects encompass a variety of breaker, relay, transformer, and line structure component replacements. The Company's System Sustainability group 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 receive different weights to determine which lines are in the greatest need for replacement. The System Sustainability group 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 placed $42.3 million attributable to ELR projects in service since the 2014 Electric Rate Case, for 2014 through 2018.

- *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 placed $27.2 million attributable to the S&E (Subs and Line) projects in service since the 2014 Electric Rate Case, for 2014 through 2018.

4. Interconnection

Q. PLEASE DISCUSS THE PRIMARY DRIVERS OF TRANSMISSION CAPITAL ADDITIONS RELATED TO INTERCONNECTION SINCE THE 2013 HTY.

A. Total net capital additions for Interconnection projects for 2014 through 2018 were $9.7 million. Illustrative examples of projects related to Interconnection since the 2013 HTY include:

- *GI 2016-3 Missile Site Substation 345KV Wind IA Project:* This project is associated with the construction of the new Rush Creek 345 kV line bay at Missile Site Substation to interconnect with a 600 MW wind farm owned by Public Service (otherwise known as the Rush Creek Wind Farm). The scope of work included breakers switches, and dead-end structures. The Company placed $2.5 million in service in 2018.
- *IRP Jackson Fuller/Golden West:* The Integrated Resource Plan Interconnection ("IRP IC") Jackson Fuller/Golden West project involved the construction of required interconnection and network facility upgrades needed

to allow for the interconnection of 250 MW of new wind generation into the Jackson-Fuller Substation. The work included installation of switches, breakers, high side metering, communications equipment, and other related hardware. The Company placed $2.2 million in service in 2015.

- *IRP IC Comanche/Comanche Solar PV LLC:* This project constructed a new 230 kV bay at the Comanche Substation in order to interconnect with a 120 MW solar power plant owned by a third party (Sun Edison). The scope of work included breakers, switches, and dead-end structures. The Company placed $2.2 million in service in 2016.
- *GI 2014-5 Titan Solar Project:* The Titan Solar Project constructed a new 230 kV bay at the Missile Site Substation to connect a radially fed 50 MW solar power plant owned by a third party. The scope of work included installing breaker, switches, and dead ends. The Company placed $1.1 million in service in 2018.

5. <u>Communication Infrastructure</u>

Q. PLEASE DISCUSS THE PRIMARY DRIVERS OF TRANSMISSION CAPITAL ADDITIONS RELATED TO COMMUNICATION INFRASTRUCTURE SINCE THE 2013 HTY.

A. Total capital additions for Communication Infrastructure projects for 2014 through 2018 were $4.2 million. Most of these capital expenses relate to Public Service Sub Network Groups. In the past, the Company has relied on third-party telecommunication providers for the infrastructure necessary for our SCADA and tele-protection circuits (i.e., communication circuits between our substations and between our substations and our control center). However, many of the telecommunication companies are phasing out their dedicated frame relay and analog wide area network ("WAN") technology and replacing it with Ethernet or other broadband services. These new services, while capable of carrying large volumes of data, are not suited to carrying the small amount of data that we transmit at the latencies acceptable for the tele-protection of our transmission system. As a result, we need to invest in Company-owned and controlled communication infrastructure in optical ground wire ("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. Every day, there are coordinated attempts to infiltrate communication systems and disrupt the grid. Federal regulatory agencies have responded to these growing threats by adopting cybersecurity standards for transmission facilities. In April 2014, FERC adopted NERC CIP Version 5 standards for cybersecurity. The Company-owned telecommunications network we are investing in enables the Company to respond to these new NERC standards by removing our exposure to cybersecurity threats from the publicly available service provided by third-party telecommunication providers. To meet these needs, Public Service is undertaking the Communications Project. The Company placed $4.0 million in service attributable to a number of Sub Communication Network Group projects since the 2014 Electric Rate Case, for 2014 through 2018.

6. <u>Physical Security and Resiliency</u>

Q. PLEASE DISCUSS THE PRIMARY DRIVERS OF TRANSMISSION'S CAPITAL ADDITIONS RELATED TO PHYSICAL SECURITY AND RESILIENCY SINCE THE 2013 HTY.

A. Total capital additions for Physical Security and Resiliency projects for 2014 through 2018 were $23.5 million. Most of these capital expenses relate to physical security. 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 17 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 addressing risks due to physical security threats and vulnerabilities. To address these threats and meet these new NERC standards, we are beginning to make necessary investments to make our grid more resilient so that we can respond quickly to physical security threats. The Company has placed $21.7 million attributable to the Physical Security projects in service since the 2014 Electric Rate Case.

Q. WHAT DO YOU CONCLUDE REGARDING THE COSTS FOR THE TRANSMISSION BUSINESS AREA CAPITAL PROJECTS THAT WENT INTO SERVICE IN 2014-2018?

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

V. TRANSMISSION 2019 CAPITAL ADDITIONS

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

A. The purpose of this section of my Direct Testimony is to provide an overview of the Transmission Business Area's planned capital additions, which are not eligible for recovery through the TCA and that will go in service in 2019.

Q. PLEASE DESCRIBE THE CAPITAL ADDITIONS THE TRANSMISSION BUSINESS AREA WILL PLACE INTO SERVICE IN 2019 THAT YOU ARE SUPPORTING FOR RECOVERY IN THIS PROCEEDING.

A. Table CLP-D-2 below shows the Company's planned 2019 capital additions by budget group.

Table CLP-D-2:
(Total Company)
Transmission Capital Additions 2019
(Dollars in Millions)

Category	2019**
Regional Expansion	$ 2.2
Reliability Requirements	$ 5.5
Asset Renewal	$ 6.6
Interconnection	$ (0.1)
Communication Infrastructure	$ 3.6
Physical Security and Resiliency	$ 2.3
Total*	**$20.1**

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

**Does not include 2019 Transmission capital additions being recovered through the TCA

As reflected in Table CLP-D-2, I am supporting $20.1 million in Transmission-related capital additions that will be placed in service in 2019, and which are not being recovered through the TCA. These are projects that are classified as Electric General and Electric Intangible Plant (per FERC's Uniform System of Accounts), and which the Company does not recover through the TCA. Generally, examples of these types of projects include communication equipment related to Transmission assets, software, and generation step-up equipment, which are often referred to as "transmission serving production." As discussed by Ms. Blair, generation serving production assets are considered production-related for ratemaking purposes. Below I describe these capital additions by budget group, providing an overview of projects valued at approximately $500,000 or more, which reflects approximately 90 percent of the Transmission Business Area's planned portfolio of non-TCA projects.

1. Regional Expansion

Q. PLEASE DISCUSS THE PRIMARY REGIONAL EXPANSION PROJECTS THE COMPANY IS SEEKING RECOVERY FOR IN 2019.

A. The Company is planning to place $2.2 million in capital additions in service related to Regional Expansion in 2019. The key project related to Regional Expansion in 2019 is the Pawnee-Daniels Park Project. As I noted above, the Pawnee-Daniels Park Project was initiated in 2017 and is scheduled for completion in 2019. This portion of the Pawnee-Daniels Park Project includes communication equipment to control structure lights required by the Federal Aviation Administration and the installation of communications equipment at for the 230 kV and 345 kV expansions at the three Pawnee-Daniels Park substations. This project represents $2.2 million in capital additions that will go in service in 2019.

2. Reliability Requirements

Q. PLEASE DISCUSS THE PRIMARY RELIABILITY REQUIREMENTS PROJECTS THE COMPANY IS SEEKING RECOVERY FOR IN 2019.

A. The Company is planning to place $5.5 million in capital additions in service for Reliability Requirements in 2019. Key projects include:

- *Public Service Staging Yard:* This project consists of constructing a material staging yard for the transmission line construction and substation construction organizations to receive and stage materials for project work. This project will be placed in-service in August 2019 and represents a capital addition of $2.1 million.
- *Lamar – Upgrade High Voltage Direct Current ("HVDC"), Human Machine Interface ("HMI"), Controls:* This project will enhance reliability and stability at the Lamar HVDC facility. Portions of this project have been designed to address network changes that have occurred since the Company last implemented control modifications at Lamar HVDC, including the Twin Buttes wind farm interconnection, the Buffalo Dunes wind farm interconnection, general network topology modifications, and contingency conditions. This project was placed in-service in March 2019 and represents $1.5 million in 2019 capital additions.
- *Burlington:* This project consists of installing real-time boundary area metering at Burlington for load control and resource operations. This project represents $0.6 million in capital additions the Company plans to place in service in 2019.
- *Boundary Area Frequency Metering:* This project consists of an upgrade to the Public Service frequency monitoring system at its Lookout Center. This project

represents $0.5 million in capital additions the Company plans to place in service in 2019.

3. <u>Asset Renewal</u>

Q. PLEASE DISCUSS THE PRIMARY TRANSMISSION ASSET RENEWAL PROJECTS THE COMPANY PLANS TO PLACE IN SERVICE IN 2019.

A. The Company is planning to place $6.6 million in Transmission Asset Renewal projects in service in 2019. Key projects related to Asset Renewal include:

- *Public Service Lookout Training Center:* This project consists of constructing a new Substation Technical Asset Center ("STAC") facility, which will allow for a consistent process for the building and testing of Relay Panels prior to shipment to substations for installation. The project represents approximately $2.2 million in capital additions that will be placed in service in 2019.
- *Synchrophasors – Public Service:* The Synchrophasor Project will install a synchrophasor system to improve transmission operations by improving visibility into system events, voltage analysis and performance, frequency response, and power system restoration. This project will protect the data coming from the substation in accordance with Xcel Energy's cybersecurity guidelines. This project represents $1.7 million in capital additions that will be placed in service in 2019.
- *RTU – EMS Upgrade – Public Service*: This project will replace end-of-life remote terminal unit ("RTU") SCADA control systems. This project represents

approximately $1.6 million in capital additions that will be placed in service in 2019.

4. <u>Communication Infrastructure</u>

Q. PLEASE DISCUSS THE PRIMARY COMMUNICATION INFRASTRUCTURE PROJECTS THE COMPANY PLANS TO PLACE IN SERVICE IN 2019.

A. The Company plans to place $3.6 million in Communication Infrastructure projects in service in 2019. As I explained above, the Public Service Substation Communication Network Groups constitute a phased in approach to address exposure to cybersecurity threats from publicly-available service provided by third-party telecommunication providers. The combined phases of these projects will be placed in-service throughout 2019 and will include $3.6 million in capital additions.

5. Physical Security and Resiliency

Q. PLEASE DISCUSS THE PRIMARY PHYSICAL SECURITY AND RESILIENCY PROJECTS THE COMPANY PLANS TO PLACE IN SERVICE IN 2019.

A. The Company plans to place $2.3 million in Physical Security and Resiliency projects in service in 2019. As I explained above, federal regulatory agencies and the Transmission Business Area are focused on maintaining the physical security of transmission facilities. Public Service is making necessary investments to ensure the grid is more resilient in response to physical security threats. Key 2019 projects related to Physical Security and Resiliency include:

- *Public Service Physical Security Communications* – This project consists of installing lighting and cameras pursuant to NERC physical security of substation standards. This project comprises $1.5 million in capital additions that will be placed in service in 2019.
- *Lock and Key System Colorado* – This project consists of installing smart locks at substations pursuant to critical infrastructure standards. This project comprises $0.7 million in capital additions in 2019.

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

A. Yes.

VI. TRANSMISSION O&M

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

A. The purpose of this section of my testimony is to provide an overview of the Transmission Business Area's O&M expenses since the 2013 HTY, followed by a discussion of the actual 2018 Transmission Business Area O&M expenses, and proposed adjustments, which the Company proposes to utilize as the primary basis for establishing Transmission O&M levels included in rates. I also describe the drivers of O&M increases between 2013 and 2018, where applicable.

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

A. I described 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 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 the 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. As explained in more detail in the Direct Testimony of Company witness Mr. Adam R. Dietenberger, beginning in 2019, Fleet O&M has moved to the Shared Corporate Services Business Area.
- *Other*: Includes miscellaneous other costs such as use costs, maintenance costs, employee expenses, rents, network communication costs and office supplies.

Q. PLEASE PROVIDE AN OVERVIEW OF PUBLIC SERVICE'S TRANSMISSION AREA O&M EXPENSES BETWEEN THE 2013 HTY AND ITS 2018 HTY.

A. Table CLP-D-3, below, identifies changes in O&M expense between the 2013 HTY and 2018 HTY by the categories I identified above. Attachment CLP-4 and Attachment CLP-5 provide an accounting of these expenses by Cost Element and by FERC account respectively.

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

Cost Category	2013	2018	Difference
Internal Labor	$19.7	$18.6	($1.1)
Contract Labor and Consulting	$6.6	$4.3	($2.3)
Fees	$2.7	$3.8	$1.1
Materials	$2.6	$2.3	($0.3)
Fleet	$1.7	$1.9	$0.2
Other	$1.6	$1.9	$0.3
Total	**$34.9**	**$32.7**	**($2.2)**
*There may be differences between the sum of the individual category amounts and Totals due to rounding.			

Q. WHAT ARE THE MAIN FACTORS THAT DROVE CHANGES IN THE ABOVE-REFERENCED COST CATEGORIES BETWEEN THE 2013 HTY AND 2018 HTY?

A. Below is a description of key drivers, broken down by O&M category:

- *Internal Labor*: We experienced a decrease of $1.1 million primarily due to repurposing crews to capital projects for which the crews direct charge their labor to specific projects, as well as a decrease in emergent work, which is generally performed through overtime labor causing an increase in labor.
- *Contract Labor and Consulting*: Public Service experienced a $2.3 million decrease, which was primarily due to bringing our system and substation Adaptive Reliability Centered Maintenance ("ARCM") program fully on-line with the assistance of contractors to perform the non-BES maintenance.

Contract staff was used due to internal resource constraints in 2013. The Company also used contract labor in 2013 to perform LIDAR surveys on transmission lines below 100 kV that have not been previously inspected utilizing this technology. Since 2013, maintenance has been performed using existing internal resources and non-BES maintenance costs have decreased.

- *Fees*: Public Service experienced a $1.1 million increase, this was driven by the bifurcation of Western Electric Coordinating Council ("WECC") into WECC and Peak Reliability in 2014 to remedy a gap in regional oversight, and provide dedicated entities as a regional reliability entity (WECC) and reliability coordinator ("Peak Reliability").
- *Materials:* Public Service experienced a $300,000 decrease in materials, which was driven by changes within the Company's capitalization policy allowing us to capitalize certain assets more appropriately versus expensing during the first year of use.
- *Fleet*: Public Service experienced a $200,000 increase, which was driven by an increase in costs of using fleet vehicles over a five-year period.
- *Other:* Public Service experienced a $300,000 increase due to increased water use costs, maintenance costs, trash removal costs, and space rental costs.

Q. ARE THE $32.7 MILLION IN 2018 O&M EXPENSE YOU DESCRIBE IN TABLE CLP-D-3 ABOVE REFLECTED IN THE COMPANY'S 2018 HTY COST OF SERVICE PRESENTED BY MS. BLAIR?

A. Yes. As reflected in Attachment CLP-4, the Company is seeking $32.7 million for Transmission O&M, subject to one adjustment discussed below. Attachment CLP-4 provides an accounting of these expenses by Cost Element, and Attachment CLP-5 provides the O&M by FERC account.

Q. ARE YOU PROPOSING KNOWN AND MEASURABLE ADJUSTMENTS TO THE COMPANY'S 2018 HTY COST OF SERVICE?

A. Yes. The Company is proposing one Transmission adjustment to the 2018 HTY cost of service in the amount of $50,518 related to the Mountain West Transmission Group ("MWTG"). On April 20, 2018, Public Service announced that continued engagement in MWTG was not in the best interests of customers.[4] During the 2018 HTY, Public Service incurred employee expenses, consulting, and legal fees associated with the MWTG initiative to join the Southwest Power Pool Regional Transmission Organization. These costs are excluded from the cost of service as a result of the Company's withdrawal from the initiative.

[4] *See* Press Release, Xcel Energy Inc., *Xcel Energy to end participation in MWTG, Regional Transmission Organization ("RTO") effort* (April 20, 2018); *see also* Proceeding No. 16I-0816E, Comments of Public Service Company of Colorado, at 2 (filed June 27, 2018).

Q. IS THE 2018 TRANSMISSION O&M EXPENSE, SUBJECT TO THE MWTG ADJUSTMENT, A REASONABLE BASIS ON WHICH TO ESTABLISH O&M COSTS FOR THE TEST YEAR?

A. Yes.

Q. ARE THESE O&M EXPENSES REASONABLE AND NECESSARY TO CARRY OUT THE 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.

VII. 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 known and measurable adjustment for Transmission Wheeling Services included in the 2018 HTY 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 our 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 our retail native load, as well as to provide transmission paths into Public Service's network for our 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 more costly 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 the 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 $16.4 million in wheeling expense.

Q. HAVE WHEELING COSTS INCREASED SINCE THE 2013 HTY?

A. Yes. Public Service's 2018 HTY wheeling costs were approximately $10 million higher than the wheeling costs included in the 2013 HTY cost of service.

Q. WHAT DROVE THIS INCREASE IN COSTS FROM THE 2013 HTY TO THE 2018 HTY?

A. Changes in wheeling costs from 2013 to 2018 were primarily driven by the following:

- *Public Service – Four Corners-Craig 188 MW PTP:* As described by Company witness Ms. Blair, the cost of this transmission reservation was inadvertently excluded from the revenue requirement in prior rate cases.
- *WAPA – NITS:* Public Serviced tied its Rosedale substation in the Greeley area to a WAPA 115kv line for reliability purposes. This connection, which went into service in November 2015, increased Public Service's flows across WAPA's system by approximately 30MW, resulting in an increase in the Public Service load ratio share on the WAPA system. The increase in the load ratio share coupled with ongoing rates increases resulted in an increase in wheeling costs on the WAPA system from 2013 to 2018.
- *Tri-State – Lamar to Midway PTP:* During 2013, transmission service necessary to import the output of the Colorado Green and Twin Buttes wind farms beyond Public Service's owned capacity rights on the Lamar-to-Midway path was provided under a 1979 agreement which expired in 2014. As a result, Public Service began procuring PTP transmission service from Tri-State at the posted rate under Tri-State's OATT beginning October 1, 2014, to import the full output of the wind farms. I note that at the time of this cost increase, which resulted from the expiration of an agreement, Tri-State was also required to begin procuring NITS on Public Service's system, resulting in additional transmission revenues from Tri-State, which was credited in the retail cost of service.

- *Holy Cross – Transmission Integration and Equalization Agreement ("TIE Agreement"):* As described above, the TIE Agreement cost amounts result from the net payment to equalize costs of the Public Service-Holy Cross integrated system on a load ratio share basis. In recent years, Public Service's investments in its transmission system have been comparatively larger than investments made by Holy Cross, thus increasing Holy Cross' payments to Public Service and reducing Public Service's Transmission expense.

Q. IS PUBLIC SERVICE UTILIZING 2018 ACTUAL WHEELING COSTS TO ESTABLISH ITS COST OF SERVICE IN THIS PROCEEDING?

A. Yes, as Ms. Blair discusses, the 2018 HTY cost of service starts with 2018 actual costs but the level of wheeling expenses requested in this rate review has been adjusted for known and measurable changes.

Q. DOES ATTACHMENT CLP-6 INCLUDE ALL WHEELING COST ADJUSTMENTS INCLUDED IN THE 2018 HTY?

A. No. In addition to the known and measurable adjustments to 2018 costs I discuss below, Public Service has excluded certain wheeling costs collected through the Electric Commodity Adjustment ("ECA").

Q. WHAT KNOWN AND MEASURABLE CHANGES TO THE COST OF WHEELING SERVICES IS PUBLIC SERVICE PROPOSING TO MAKE?

A. Public Service has proposed six types of known and measurable adjustments: (1) Economic Purchases, (2) Trading Activity, (3) Sales for Resale, (4) Penalty Distributions, (5) Prior-Year True-Ups, and (6) Rate Updates.

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 $526,567 to exclude such costs incurred in 2018.

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 $102,371 is necessary to exclude these amounts from wheeling expense. Sales for resale refers to point-to-point transmission service that is procured from Tri-State in order to serve a wholesale customer, and $348,451 of associated wheeling expense has been excluded.

Non-recurring penalty distributions refers to an event in July 2018 where WAPA utilized Public Service's transmission system without sufficient reserved capacity, resulting in a significant unreserved use penalty paid by WAPA to Public Service (which, pursuant to Public Service's OATT, was distributed to nonoffending transmission customers, including Public Service's Commercial Operations). This unusual event was the result of a personnel error by WAPA, and is not expected to recur; therefore, wheeling expense has been adjusted by $317,691 to eliminate the effect of this non-recurring item.

Prior-period true-ups includes an adjustment of $149,842 to exclude accounting adjustments recorded in 2018 related to the true-up of Public Service's 2017 transmission formula rate and the Holy Cross TIE Agreement.

Rate updates refers to adjusting the Four Corners-Craig 188 MW PTP reservation, WAPA NITS, PRPA NITS and Tri-State Lamar to Midway, and Tri-State Berthoud to incorporate current rates in effect as of January 2019, which have generally increased. This results in increases of $322,608, $112,620, $48,556, $77,616 and $48,959, respectively.

In total, Public Service proposes a net increase of $100,503 for known and measurable changes, which is reflected in the column "2018 HTY (Normalized)" included in page 2 of Attachment CLP-6.

VIII. WILDFIRE MITIGATION

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

A. The purpose of this section of my Direct Testimony is to provide an overview of the Transmission Business Area's updated Wildfire Mitigation Plan. Specifically, I present the Company's planned 2019 capital and O&M costs, and also address planned capital and O&M costs for 2020–2023.

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

A. As discussed by Ms. Trammell, the Company is seeking recovery of 2019 Transmission O&M associated with its wildfire mitigation efforts through this rate review, and deferred accounting treatment for 2020–2023 Transmission O&M associated with its wildfire mitigation efforts. The Company plans to recover its Transmission capital expenditures associated with its wildfire mitigation plan through the TCA.

Q. PLEASE DESCRIBE TABLES CLP-D-4 AND CLP-D-5.

A. Tables CLP-D-4 and CLP-D-5 contain the Company's planned incremental Transmission O&M expense and capital additions from 2019-2023. The category for Identified Replacements shows Public Service's anticipated capital additions and O&M expense in 2019–2021 to address potential issues that were identified as part of Transmission's most recently completed inspections. The Expected Replacements category shows Public Service's anticipated capital additions and

O&M expense in 2022 and 2023, based on historical deterioration rate data. The forecast for 2022–2023 is based on the currently anticipated work that will be necessary in those years based on historical deterioration rate data. I discuss each of these categories in more detail below.

Q. WHAT PROJECTED TRANSMISSION O&M EXPENSE ASSOCIATED WITH THE WILDFIRE MITIGATION INITIATIVE IS PUBLIC SERVICE SEEKING IN 2019 AND 2020-2023?

A. As shown in Table CLP-D-4 below, the Company is seeking a total of $3.1 million in incremental Transmission Wildfire O&M expense for 2019. With respect to 2020 through 2023, we are seeking deferred accounting treatment. The Company is forecasting approximately $5.3 million in O&M expense for 2020 and 2021, and $1.5 million in O&M expense for 2022 and 2023.

Table CLP-D-4

Wildfire Mitigation Programs Transmission Incremental O&M Public Service Electric (Dollars in Millions)					
	2019	**2020**	**2021**	**2022**	**2023**
Annual visual inspection	0.0	0.2	0.2	0.2	0.2
Infrared Inspection	1.4	0.0	0.0	0.0	0.0
Structure Wind Strength Review	0.6	1.3	0.7	0.0	0.0
Replacement of high priority structural components (Identified Replacements)	0.8	1.1	1.1	0.0	0.0
Replacement of high priority structural components (Expected Replacements)	0.0	0.0	0.0	0.2	0.2
Mountain Hazard Tree Program	0.2	0.2	0.2	0.2	0.2
ROW Vegetation Type Conversion	0.1	0.2	0.2	0.2	0.2
Total*	**3.1**	**2.9**	**2.4**	**0.8**	**0.8**
*There may be differences between the sum of the individual category amounts and Totals due to rounding.					

Q. WHAT PROJECTED TRANSMISSION CAPITAL ADDITIONS ASSOCIATED WITH ITS WILDFIRE MITIGATION INITIATIVE IS PUBLIC SERVICE SEEKING IN 2019–2023?

A. Table CLP-D-5, below, contains the Company's projected incremental Transmission capital additions associated with its Wildfire initiative for 2019-2023. The Company is providing these figures for illustrative purposes only. he Company is not requesting recovery of these capital additions in this rate review but will instead seek recovery through its TCA.

Table CLP-D-5

Wildfire Mitigation Programs Transmission Incremental Capital Additions Public Service Electric (Dollars in Millions)					
	2019	**2020**	**2021**	**2022**	**2023**
Replacement of high priority structural components (Identified Replacements)	9.5	17.4	18.5	0.0	0.0
Replacement of high priority structural components (New Replacements)	0.0	0.0	0.0	1.0	1.0
Total*	**9.5**	**17.4**	**18.5**	**1.0**	**1.0**
* There may be differences between the sum of the individual category amounts and Total amounts due to rounding.					

Q. WHAT DO YOU MEAN BY "INCREMENTAL" CAPITAL AND O&M?

A. As I discuss below, the Company has engaged in wildfire mitigation activities as part of Transmission's existing programs. The dollar figures shown in the Tables above are part of our enhanced efforts and thus reflect incremental amounts above the Company's normal expenditures for these activities. The Company's routine expenditures for these activities are reflected in its actual 2018 O&M expenses, with the exception of the infrared inspections and wind strength reviews, which are new inspection and review programs, and, therefore, not included in 2018 actual O&M expenses.

Q. STARTING WITH THE COMPANY'S CURRENT EFFORTS, WHAT SORT OF WILDFIRE MITIGATION PROGRAMS DOES TRANSMISSION MAINTAIN TODAY?

A. Transmission's programs with respect to wildfire mitigation can generally be divided into three categories: inspection and modeling, replacement, and vegetation management.

Q. DOES THE COMPANY MAINTAIN THESE PROGRAMS IN THE NORMAL COURSE OF BUSINESS?

A. Yes. The Company historically has maintained these programs. Other areas have been identified and initiated as part of the Company's wildfire mitigation efforts, which I discuss below and Mr. Nickell discusses in his Direct Testimony. As explained by Ms. Trammell, the Company believes it is prudent to accelerate certain activities in the coming years, as the risk of wildfires continues to grow and the Company needs to ensure it can continue to provide safe and reliable power to the communities we serve, particularly in high wildfire risk areas. Because of heightened risks, Transmission is undertaking new inspection and review activities, such as its infrared inspections and wind resiliency reviews, as discussed in more detail below.

Q. HOW DID THE TRANSMISSION BUSINESS AREA CREATE ITS ENHANCED WILDFIRE MITIGATION PLAN?

A. Similar to Distribution, the first step in this process was to identify the high risk areas. We did this by using data provided by the Colorado Wildfire Risk Assessment Portal to identify wildfire risk zones. Risk Management has assigned a wildfire risk score to every structure within Public Service's service territory (ranging from 1 to 5, 1 being the lowest risk and 5 being the highest). The Company has also incorporated a 1,000-foot buffer zone around each high-risk structure (risk level 3, 4, and 5). These high-risk structures are mostly located in the western reaches of the Company's service territory, including the Front Range foothills and mountain regions.

Q. WHAT TYPES OF WILDFIRE MITIGATION ACTIVITIES IS TRANSMSSION PLANNING TO UNDERTAKE OR ACCELERATE IN THE COMING YEARS AS PART OF THIS INITIATIVE?

A. The Company proposes to perform additional and/or accelerated activities in its wildfire mitigation programs starting in 2019. The inspection and modeling programs include: annual visual inspections and infrared inspections. The Company's inspection activities inform the activities that the Company will need to undertake as part of the Replacement program.

Q. PLEASE DESCRIBE THE ANNUAL VISUAL INSPECTIONS.

A. Annual visual inspections consist of a holistic visual inspection of transmission line assets performed either on foot or from a helicopter. Inspectors are equipped with various inspection tools such as high-power binoculars and Mobile Data Terminals or tablet computers to identify replacements and create replacement notifications. Aerial inspections focus on the larger issues, such as pole condition or broken cross arms, while foot inspections allow for more detailed inspection from the ground.

Q. WHAT WILL THE COMPANY DO ON AN ACCELERATED BASIS?

A. The current inspection plan requires all transmission lines greater than 200 kV to be inspected annually. Lines lower than 200 kV have a longer interval between inspections and the inspection frequency is determined based on line location, electrical performance, asset conditions, accessibility and resource availability.

Due to the heightened risks of wildfire, the Company will annually inspect the circuits identified in its wildfire risk zones on foot to reduce wildfire risk.

Q. PLEASE DESCRIBE THE INFRARED INSPECTIONS.

A. Circuits that cross wildfire risk zones will be inspected using thermal imaging technology (infrared or "IR") to identify thermal "hot spots" on transmission line components. These hot spots often indicate faulty or failing components such as conductor splices, connectors, and hardware. IR inspection can be performed from the ground or from a helicopter.

The IR inspections constitute a new program for Public Service. Consistent with Distribution, Transmission is planning on completing one IR inspection in 2019. Transmission will then evaluate the inspection results to determine the appropriate future inspection frequency. IR inspection is commonly accepted by the industry as one of the best practices to reduce wildfire risk, because it allows detection of certain replacements that are difficult or impossible to identify during visual inspection.

Q. PLEASE DESCRIBE THE ACTIVITIES WITHIN TRANSMISSION'S REPLACEMENT PROGRAM AND THE ACCELERATED WORK TRANSMISSION WILL UNDERTAKE.

A. Our Replacement program includes the replacement or repair of high priority structural components for identified replacements. This is sometimes also referred to as "Priority Replacements" because the Transmission group identifies and replaces known replacements. These are identified in the Tables above as Identified Replacements and New Replacements. Typically, high priority replacements are addressed through the Company's existing planned asset renewal programs such as End of Life Replacement, Major Line Refurbishment, Major Line Rebuild, or Priority Replacement Program, with prioritization based on circuit location, electrical performance, and asset condition. The Company will address the replacements identified within the wildfire risk zone on an accelerated basis as part of its wildfire risk mitigation plan (from 2019–2021).

Q. ARE THE REPLACEMENT ACTIVITIES CLASSIFIED AS CAPITAL OR O&M?

A. The Replacement category includes both capital costs and O&M expenses. The replacement of major structural components, such as poles and cross arms (or the entire structure), qualifies as a capital expenditure. O&M expenses include replacing or repairing minor structural components such as braces, insulators, or ground wires.

Q. PLEASE DESCRIBE THE VEGETATION MANAGEMENT PROGRAMS.

A. Vegetation management activities include the Mountain Hazard Tree Program and Right of Way ("ROW") Vegetation Type Conversion.

Q. PLEASE DESCRIBE THE MOUNTAIN HAZARD TREE PROGRAM.

A. The Company's Mountain Hazard Tree ("MHT") Program involves the mitigation of hazard trees adjacent to both electric distribution and transmission facilities in areas that have been impacted by the mountain pine beetle epidemic. The enhanced mitigation will expand the existing scope and scale of the existing program to include more primary voltage line miles (due to revised wildfire risk zone mapping) as well as the addition of patrolling secondary voltages (street wire and service lines) spans. The forecast of $200,000 per year is based on a forecasted cost per unit and targeted annual production volume for the additional activity.

Q. PLEASE DESCRIBE THE ROW VEGETATION TYPE CONVERSION.

A. ROW vegetation type conversion involves changing vegetation cover type from easements edge-to-edge to less woody vegetation, and more prairie and shrubs within the Company's easements located within the wildfire risk zones. In other words, the vegetation cover is changed in order to mitigate risks that could arise from vegetation in close proximity to the Company's facilities.

Q. PLEASE DESCRIBE THE STRUCTURE WIND STRENGTH REVIEW PROGRAM.

A. Wind strength review involves modeling Transmission line structures located within the wildfire risk zones using finite element analysis software to evaluate their capacity against high-wind load cases. Typically, existing circuit's wind strength is evaluated when there is planned work to be done on that circuit. However, the Company will preemptively perform analyses of the assets located within the wildfire risk zones as part of the wildfire risk mitigation plan. Wind strength review is commonly accepted by the industry as one of the best practices to reduce wildfire risk, because it verified and ensures structure strength against high wind loads. The Structure and Wind Strength Program constitutes a new program for Public Service.

Q. HAS THE COMPANY, AND WILL THE COMPANY, MANAGE ITS PROJECTED WILDFIRE MITIGATION COSTS RELATED TO O&M COSTS IN 2019 TO ENSURE THE FINAL, ACTUAL COSTS IN THE 2018 HTY ARE REASONABLE AND PRUDENT?

A. Yes.

IX. RECOMMENDATIONS AND CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. In sum, as part of approving the cost of service developed by Ms. Blair, I recommend that the Commission approve the 2014–2019 capital additions and 2018 O&M expense, along with the known and measurable MWTG adjustment. I also recommend the Commission approve the known and measurable adjustment for Transmission Wheeling Services included in the Company's cost of service. Finally, I recommend the Commission approve the Company's request related to recovery of Wildfire Mitigation Plan O&M expenses

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Statement of Qualifications

CONNIE L. PAOLETTI

Connie L. Paoletti is the Manager of Regional Transmission Initiatives for Xcel Energy Services. In this position, Connie has 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 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

* * * *

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

AFFIDAVIT OF 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 13 day of May, 2019.

Connie L. Paoletti
Connie L. Paoletti
Manager, Regional Transmission Initiatives

Subscribed and sworn to before me this 13th day of May, 2019.

C M Falce
Notary Public

My Commission expires 6/24/2020

CHRISTINA M FALCE
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 19904006701
MY COMMISSION EXPIRES JUNE 24, 2020