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

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IN THE MATTER OF ADVICE LETTER NO. 1906-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 8-ELECTRIC TARIFF TO REVISE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL ELECTRIC RATE SCHEDULES, AND MAKE OTHER TARIFF PROPOSALS EFFECTIVE DECEMBER 31, 2022.	**) PROCEEDING NO. 22AL-XXXXE**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF KYLE L. WILLIAMS</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

November 30, 2022

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

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DIRECT TESTIMONY AND ATTACHMENTS OF KYLE L. WILLIAMS

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kyle L. Williams. My business address is 9500 Interstate 76, Henderson, Colorado 80640.

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

A. I am employed by Public Service Company of Colorado (“Public Service” or the “Company”) as General Manager, Power Generation.

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 General Manager, Power Generation, I am responsible for providing management for the Public Service Generation Business Area, which is within the

Energy Supply Business Area (also referred to as "Energy Supply") of Xcel Energy Services Inc. ("XES").[1] A description of my qualifications, duties, and responsibilities is set forth in my Statement of Qualifications at the conclusion of my testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

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

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

A. Yes, I am sponsoring Attachments KLW-1 through KLW-6, which are as follows:

- Attachment KLW-1: Capital Additions January 1, 2021 – December 31, 2023;
- Attachment KLW-2: Cabin Creek Hydroelectric Facility Upgrade Project 2021 Annual Progress Report
- Attachment KLW-3: July 1, 2021 through June 30, 2022 Operations and Maintenance by Cost Element;
- Attachment KLW-4: July 1, 2021 through June 30, 2022 Operations and Maintenance by FERC Account;
- Attachment KLW-5: Colorado Air Quality Enterprise Fee Scenario Outline; and
- Attachment KLW-6: Public Service Historical Annual Generation Overhaul Expense.

[1] In my Direct Testimony, "Generation Business Area" is also referred to as "Generation", "Energy Supply" or the "Energy Supply Business Area."

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

A. I first provide background on the Generation function and its activities in Section II. In Section III, I provide an overview of the Generation Business Area's capital budgeting process, project development, and budget management processes. In Section IV, I discuss the Generation Business Area's capital additions included in the Test Year,[2] followed by Section V, which presents the O&M expense for the Generation Business Area. Finally, in Section VI, I discuss compliance and other items related to the Generation Business Area. I conclude with a discussion of the 2022 Comanche 3 Generator outage in Section VII.

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

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

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

II. GENERATION FUNCTIONS AND ACTIVITIES

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

A. In this section of my Direct Testimony, I provide an overview of the functions and activities carried out by Public Service's Generation Business Area.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S GENERATION BUSINESS AREA AND THE XES ENERGY SUPPLY ORGANIZATION.

A. Public Service's Generation Business Area activities are to a large extent centrally managed by the XES Energy Supply organization. By coordinating activities through XES, the Xcel Energy Inc. ("Xcel Energy") utility companies share best practices and achieve greater efficiencies. The focus of Energy Supply is to help coordinate and provide support services for the construction, operation, maintenance, decommissioning, and dismantling of the electric generating facilities of Public Service and its sister utility companies within Xcel Energy's system in a safe, reliable, cost-effective, and environmentally-sound manner.

Q. PLEASE DESCRIBE PUBLIC SERVICE'S GENERATION PORTFOLIO.

A. In general, Public Service serves its electric retail and wholesale customers in Colorado with power purchased pursuant to long-term power purchase agreements ("PPAs") or power generated by the Company's own power plants. The focus of my Direct Testimony is limited to Company-owned generation.[3]

[3] We recover the vast majority of our capacity and energy costs associated with our purchased power resources through a combination of the Purchased Capacity Cost Adjustment ("PCCA") and Electric Commodity Adjustment ("ECA") riders, respectively, which are annually reviewed by the Commission in a combined proceeding.

Public Service's Company-owned generation fleet at the end of 2022 will have a summertime net dependable capacity of approximately 5,141 megawatts ("MW"), and 1,100 MW nameplate wind generation. The Company has access to an additional 5,474 MW of summer net dependable capacity through PPAs. The Company-owned generating facilities use a variety of fuel sources including coal, natural gas, water (hydro), and wind. The current fuel sources for our generation fleet for are shown in Table KLW-D-1 below:

TABLE KLW-D-1:
Summary of Company-Owned Generation Capacity (2022)

Type	2022 Total MWs (approximate)
Coal	1,655
Gas	3,251
Hydro	235
Wind	1,100

Q. PLEASE IDENTIFY THE CURRENT PRIMARY GENERATING UNITS IN PUBLIC SERVICE'S GENERATION PORTFOLIO.

A. Public Service's current generation fleet includes the following facilities (capacity values presented as 2022 net dependable summer capacity as of October 25, 2022):

<u>Coal</u>:

- *Comanche Generating Station:* A three-unit, 1,410 MW generating facility located in Pueblo, Colorado, in which Public Service has rights to 1,160 MW of net dependable summer capacity. Public Service operates Unit 3 of this station on behalf of itself and other owners.

- *Craig Generating Station*: A three-unit, 1,285 MW generating facility located in Craig, Colorado, in which Public Service has rights to 82 MW of net dependable summer capacity from two units. This facility is operated by Tri-State Generation and Transmission Association, Inc. ("Tri-State") as part of the Yampa Project. The Yampa Project constructed Craig Station from 1974 to 1984; construction was completed on Unit 2 in 1979, Unit 1 in 1980 and Unit 3 in 1984. Unit 3 is owned solely by Tri-State.

- *Hayden Generating Station*: A two-unit, 441 MW generating facility located in Hayden, Colorado. Public Service operates this plant on behalf of itself and three other co-owners as part of the Yampa Project. Public Service has rights to 233 MW of net dependable summer capacity from the two units.

- *Pawnee Generation Station*: A one-unit, 505 MW generating facility located in Brush, Colorado.

Natural Gas:[4]

- *Blue Spruce Energy Center*: A two-unit, 264 MW simple-cycle plant that is capable of running on natural gas or fuel oil and is located near Aurora, Colorado.

- *Cherokee Generating Station*: A four-unit, 886 MW facility located just north of downtown Denver. Originally built as a coal-fired plant, which has since undergone a complete restructuring as a result of the Clean Air-Clean Jobs Act ("CACJA"). Three new natural gas combined cycle ("CC") units, which are Units 5, 6, and 7, came online in 2015, capable of producing almost 576 MW of cleaner energy. Original coal-fired Units 1, 2, and 3 have been retired. Unit 4 was fuel-switched from coal to natural gas at the end of 2017, and, as of 2018, has an updated net dependable capacity of 310 MW.

- *Fort St. Vrain Generating Station:* A six-unit, 973 MW site consisting of a 3x1 combined cycle power block and two simple cycle units. The site is located near Platteville, Colorado. Fort St. Vrain Unit 1 was repowered by the addition of three natural gas fired turbines in 1997 to 2001 after the nuclear plant was decommissioned in 1989.

- *Fort Lupton Generating Station*: A two-unit simple cycle combustion turbine station capable of producing 88 MW. The units are dual fuel capable with natural gas as the primary fuel and fuel oil as the backup. The facility is located just outside of Fort Lupton, Colorado.

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[4] Numbers provided for natural gas combustion turbine sites are in Summer Net Dependable Capacity.

- *Manchief Generating Station*: A two-unit, 250 MW simple cycle facility located just outside of Brush, Colorado. Units 11 and 12 are simple-cycle combustion turbines that use natural gas as a fuel. They have a capacity of approximately 135 MW each. Public Service acquired Units 11 and 12 in May 2022 pursuant to its 2016 Electric Resource Plan ("2016 ERP") (Proceeding No. 16A-0396E) and Decision No. R20-0108 issued in Proceeding No. 19A-0409E.

- *Rocky Mountain Energy Center ("RMEC")*: A three-unit, 580 MW combined-cycle generating facility located near Hudson, Colorado consisting of two combustion turbines driving a steam turbine.

- *Valmont Generating Station*: A three-unit, 123 MW generating facility located in Boulder, Colorado. Units 6, 7, and 8 are simple-cycle combustion turbines that use natural gas as a fuel with a capacity of 43 MW, 40 MW, and 40 MW, respectively. Public Service acquired units 7 and 8 in June 2020 pursuant to its 2016 ERP and Decision No. R20-0108 issued in Proceeding No. 19A-0409E.

- *Peaking Units:* Public Service owns three additional dual fuel natural gas, with fuel oil back up, simple-cycle combustion turbine peaking units. These include the 14 MW Fruita facility and Alamosa Units 1 and 2, which are 13 MW and 14 MW, respectively.

<u>Hydro</u>:

- *Ames Hydro Generating Station*: A 2.8 MW generating facility located near Ophir, Colorado.

- *Cabin Creek Hydroelectric Station*: A two-unit, 323 MW pumped storage generating facility located near Georgetown, Colorado.

- *Georgetown Hydro Generating Station*: A two-unit, 1.6 MW generating facility located in Georgetown, Colorado.

- *Salida Generating Station*: Unit 2 is a 0.6 MW facility located in Poncha Springs, Colorado.[5]

- *Shoshone Generating Station*: A two-unit, 15 MW run of the river generating facility located in Glenwood Springs, Colorado.

- *Tacoma Hydro Generating Station*: A two-unit, generating facility located north of Rockwood, Colorado, which can produce a total of 4.5 MW.

[5] Salida Unit 1 is in the process of being decommissioned.

<u>Wind</u>:

- *Rush Creek Wind Project ("Rush Creek"):* A 600 MW (gross capacity) wind farm located on the eastern plains of Colorado in Cheyenne, Elbert, Kit Carson, and Lincoln Counties. Rush Creek began commercial operation in late 2018.
- *Cheyenne Ridge Wind Project ("Cheyenne Ridge")*: A 500 MW (gross capacity) wind farm located on the eastern plains of Colorado in Cheyenne and Kit Carson counties. Cheyenne Ridge began commercial operation in August 2020.

Q. HOW DOES PUBLIC SERVICE MEET THE REMAINDER OF ITS RESOURCE NEEDS?

A. Public Service meets a substantial portion of its generation needs through long-term PPAs. Public Service has 5,474 MW of nameplate generating capacity under contract to meet our customers' energy needs during this rate case period. This includes 2,994 MW of wind, 1,305 MW of solar and 225 MW of energy storage solutions collocated with some solar plants.

Q. DID THE COMMISSION RECENTLY APPROVE THE EARLY RETIREMENT AND/OR CONVERSION OF THE COMPANY'S COAL GENERATING UNITS YOU LISTED ABOVE?

A. Yes. The Commission recently approved several actions regarding our coal fired facilities as part of Phase I of the Company's ongoing 2021 Electric Resource Plan and Clean Energy Plan ("2021 ERP & CEP"), Proceeding No. 21A-0141E. Specifically, the Commission approved[6] the following actions:

- Conversion of Pawnee to natural gas no later than January 1, 2026;
- Retirement of Hayden 2 in 2027 and Hayden 1 in 2028;

[6] Decision No. C22-0459 in Proceeding No. 21A-0141E.

- Retirement of Craig 2 in 2028; and
- Retirement of Comanche 3 by January 1, 2031 and reduced operations beginning in 2025.[7]

Q. IS THE RECOVERY OF COSTS ASSOCIATED WITH THE EARLY RETIREMENT AND CONVERSION OF THE COMPANY'S REMAINING COAL UNITS ADDRESSED AS PART OF THIS PROCEEDING?

A. No. As part of its Phase I Decision in the 2021 ERP & CEP, the Commission approved the Company's cost recovery proposal for the early retirement of Comanche 3 and directed the Company to file a separate Application specifically to address coal plant cost recovery issues associated with the early retirement of Craig 2, Hayden 1 and 2, and the conversion of Pawnee. Accordingly, the Company filed a separate Application regarding these issues on November 16, 2022 in Proceeding No. 22A-0515E.

[7] Early retirement of Comanche 1 (on or before December 31, 2022) and Comanche 2 (on or before December 31, 2025) was approved as part of the Company's 2016 ERP in Proceeding No. 16A-0396E.

III. GENERATION 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 discuss the Generation Business Area's project development, budgeting, and management processes.

A. Overview of the Generation Business Area's Capital Investments

Q. HOW DOES THE GENERATION BUSINESS AREA CATEGORIZE ITS CAPITAL ADDITIONS?

A. At a very high level, Generation Business Area capital additions can be categorized as follows:

- *Renewable/New Generation*: These are capital dollars used to support the construction or purchase of new generating units, or the decommissioning of old generating units, which are retired subject to changing system requirements and other factors. Changes to system requirements may result from new environmental mandates, the end of the useful life of a facility, or changes in the level of energy resources needed to serve customers. In May 2022, the Company added new generation to its portfolio by closing on the purchase of the Manchief Generating Station that is collocated on the property of the Pawnee Generating Station.

- *Environmental Improvement:* Our plants may require new systems and components to continue to operate reliably and consistently in compliance with existing and new environmental standards issued by the United States Environmental Protection Agency, the Colorado Department of Health and Environment ("CDPHE"), or any other regulatory bodies, along with standards directly contained in statute. This type of capital addition can include converting generating units from one fuel to another, or the addition of new environmental technology such as scrubbers and other emissions controls. One example of an Environmental Improvement Project is the Waste Water Treatment project at Cherokee. This project is designed to eliminate water being discharged to the river in response to new discharge limitations imposed on our permit.

- *Reliability/Performance Enhancement*: Our generating stations are large, complex machines that require regular upkeep to ensure the continued safe, reliable, and efficient operation of Public Service's existing generation fleet. In order to keep pace with regular upkeep, the

Generation Business Area budgets dollars to replace boiler, turbine, and auxiliary system components. The Company's flex projects at Fort St. Vrain and Cherokee are examples of projects that enhance unit reliability and or performance.

B. Energy Supply's Budget Development and Management

Q. PLEASE SUMMARIZE HOW ENERGY SUPPLY DEVELOPS ITS CAPITAL BUDGET.

A. Each generating facility develops its own list of capital projects. Those projects are then submitted to the Energy Supply Projects group for evaluation and ranking based on the project's operational and financial merits.

Q. WHAT IS THE PRIMARY FOCUS OF ENERGY SUPPLY IN EVALUATING AND RANKING PROPOSED PROJECTS?

A. The most important objective of developing our capital budget and prioritizing projects is ensuring that the Company will continue to deliver electric service in a safe, reliable, and cost-effective manner.

Q. WHAT CRITERIA DOES ENERGY SUPPLY USE TO EVALUATE AND RANK PROPOSED PROJECTS?

A. Energy Supply has specific evaluation criteria that it uses to review and prioritize each capital project. Listed alphabetically, not in order of importance, these criteria are based on:

- Capacity;
- Efficiency;
- Environmental compliance, and/or regulation (*e.g.*, Regional Haze, Colorado Section 9 – Waste Impoundments, Standards for the Disposal of Coal Combustion Residuals in Landfills and Surface Impoundments);

- Financial merit (such as net present value or present value of revenue requirements);
- Legislative commitments;
- Operational factors such as the impact on outage rates, equipment condition;
- Reliability; and
- Safety.

Q. DO PLANTS HAVE ACCESS TO SPECIFIC DATA THAT ASSISTS THEM IN DEVELOPING PROPOSED PROJECTS?

A. Yes. Plants rely on specific operational and other equipment condition monitoring data that allows them to identify and quantify how the projects meet the criteria identified above. Additionally, plant personnel work with Original Equipment Manufacturers ("OEMs") and third-party vendors to gain more specific understanding of the benefits and merits of various proposed projects during the project creation phase.

Q. DO PROPOSED PROJECTS HAVE VARYING TIMELINES?

A. Yes. The Generation Business Area evaluates projects that may be completed within a single year (for example, replacing the bags in a Fabric Filter Dust Collector, or a replacement emissions monitoring system), as well as those that will require multiple years to complete. Examples of multi-year projects include control system replacements, ash cell construction, wastewater treatment facility installation, and major hydroelectric plant upgrades.

Q. WHAT OCCURS AFTER ENERGY SUPPLY DEVELOPS A RANKED LIST OF PROJECTS?

A. The ranked list of projects becomes part of the overall Xcel Energy enterprise-wide budgeting process, which is described by Company witness Mr. Adam R. Dietenberger. Mr. Dietenberger also explains that generally, there are more projects and work to be done than there is the capacity to fund, resulting in assessment and prioritization across business areas and operating companies and ultimately a capital budget specific to the Company (and its Generation Business Area). The ranked list of projects is then evaluated against the available budget for each of the next two years, the unit planned outage schedule, and any known regulatory factors such as new environmental regulations. These two years of ranked projects, coupled with an additional three years of unranked projects allows the Company to develop a capital project and budget plan that covers a five-year period, with associated five-year capital expenditures and estimated in service dates.

Q. ARE PROJECTS REVIEWED IN SUBSEQUENT YEARS?

A. Yes. As each new fiscal year arrives, the Energy Supply Regional Planning Committee ("RPC") reviews and validates the ranked list of projects for the next two fiscal years, adjusting schedules and/or budgets as required to account for evolving conditions and factors. In addition to the two years of ranked projects, the three years of unranked projects are re-evaluated and adjusted and a prioritized list of projects that meets the planned budget for the next five years is produced. The five years of proposed project planning information, capital expenditures, and estimated in-service dates are recorded and refined in the Unifier Enterprise Project Management ("EPM") System. As each project is reviewed by the RPC, the specific ranking criteria and supporting information are reviewed and verified. The verified information is entered into the EPM System, where the numerical ranks are calculated and projects are prioritized against other submitted projects. The RPC continually meets throughout the year to assess and make adjustments to projects currently under way. As each project is reviewed by the RPC, the specific criteria and supporting information are reviewed and verified.

Q. WHAT PROCESS DOES ENERGY SUPPLY FOLLOW TO MANAGE AND CONTAIN ITS GENERATION CAPITAL COSTS?

A. Capital budgets are finalized in the first quarter of the year prior to their execution. Part of the project development process includes the identification of key schedule dates and budgetary milestones. Once a capital project has been approved for execution, it is assigned to a Project Manager ("PM"), well in advance of the first planned activities required to commence the project.

Q. PLEASE DESCRIBE THE PM'S RESPONSIBILITIES.

A. The PM is responsible for working with the plant to review and more fully develop the project deliverables, schedule, and monthly cash flow requirements for the assigned project. The PM typically will contact vendors and contractors to firm up cost and schedule and begin engineering and purchasing activities.

Q. DO PMS WORK CLOSELY WITH PLANT MANAGEMENT?

A. Yes. Typically, each plant holds monthly capital project review meetings where plant management and PMs discuss current and pending capital projects from a scheduling and budget perspective. If the PM identifies specific information related to changes in cost or the schedule, the PM advises management and recommends options for consideration. Management then responds as appropriate depending on the specifics of the information provided.

Q. WHAT IF AN UNEXPECTED EVENT OCCURS AFTER PROJECTS HAVE BEEN SELECTED FOR A GIVEN YEAR?

A. Many of the Company's generation capital needs are predictable and fairly consistent year to year. Further, the Energy Supply Projects group is expected to manage the capital budget. The most important budget management tool is good project planning. If we plan, budget, and implement our projects well, little additional management of the overall capital budget needed. However, unexpected events can and do occur and the Company has processes in place to address these situations.

Q. PLEASE EXPLAIN HOW THE COMPANY ADDRESSES UNEXPECTED EVENTS.

A. The approach depends on the nature of the unexpected event. If there is an unexpected failure of a large component at an existing plant, such as a generator rotor, we must address this event and the resulting expenditure when it occurs. The total budget for the year is reviewed, and depending upon the timing of the failure, some projects may be postponed, or a budget adjustment may be requested to cover the additional funds for that year without impacting current year projects. For other smaller items, a portion of the budget is set aside to accommodate lower-cost emergent or unexpected events. Events such as these may include small valve or pump failures that are not individually budgeted, but instead are budgeted as a broader category of “emergent” projects.

Further, in the case of an unexpected event, we look to reduce the costs of other budgeted projects or defer them altogether if necessary and possible.

Q. IS DELAY ALWAYS AN OPTION TO ADDRESS AN UNEXPECTED EVENT?

A. No. Sometimes we must continue with certain projects as budgeted since they are necessary for the continued reliable operation of our plants, or because putting them on hold would unnecessarily incur costs despite the need for additional expenditures elsewhere. Conversely, if budgeted projects are delayed or deferred, we generally will assign funds to other projects to implement because the number of projects that would be eligible for approval generally exceeds the capital funds available.

Q. CAN YOU GIVE AN EXAMPLE OF AN UNEXPECTED EVENT THAT OCCURRED SINCE THE 2021 ELECTRIC PHASE I?

A. Yes. During normal operation of Fort Lupton Unit 1, a lube oil leak was detected in the generator collector cab. The unit was removed from service in February 2022 and the team performed a borescope inspection, which revealed 9” of oil inside the generator belly. Electrical testing on the generator sections showed winding issues on the rotor and a full rotor rewind was needed to return the unit to service. This project went through the emergent capital process.

IV. GENERATION 2022-2023 CAPITAL ADDITIONS

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

A. The purpose of this section of my Direct Testimony is to present the Generation Business Area's 2022 and 2023 capital additions. I begin with an overview of the Generation Business Area's 2022 and 2023 capital additions and then provide details, organized by the three capital categories described below.

A. Overview of 2022-2023 Capital Additions

Q. PLEASE SUMMARIZE THE GENERATION BUSINESS AREA'S 2022-2023 CAPITAL ADDITIONS.

A. Table KLW-D-2 summarizes the Generation Business Area's capital additions for 2022-2023. I have also provided 2021 actual capital additions for reference. Additional data is provided in Attachment KLW-1.[8]

[8] This attachment reflects the year that each project has been or will be placed in service.

TABLE KLW-D-2:
Generation Business Area Capital Additions
Public Service Electric
(Dollars in Millions)

Category	**2021** (Actual)	**2022** 1/1 – 6/30 (Actual)	**2022** 7/1 – 12/31 (Forecast)	**2022** Total	**2023** (Forecast)
Renewable / New Generation*	$65.7	$81.4	$19.2	$100.6	$67.1
Environmental Improvement	4.3	4.6	2.9	7.5	39.9
Reliability / Performance Enhancement	158.1	29.5	119.7	149.2	81.2
Total**	**$228.1**	**$115.5**	**$141.8**	**$257.3**	**$188.2**

* Excludes approximately $4.9 million of 2021 and $8.4 million of 2023 community solar garden plant additions that are not included in the Company's base rate recovery request in this Proceeding.
** There may be differences between the sum of the individual category amounts and Total amounts due to rounding.

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

A. As I mentioned earlier, the Generation 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 Generation Business Area projects Public Service has placed into service in the first half of 2022 or will place into service on or before December 31, 2023.

B. <u>Renewable/New Generation Capital Additions</u>

Q. WHAT ARE THE MAJOR 2022-2023 RENEWABLE/NEW GENERATION CAPITAL ADDITIONS?

A. The major 2022 and 2023 Renewable/New Generation capital additions are: acquisition of the Manchief Generating Station and the Cabin Creek Hydroelectric Facility Upgrade Project ("Cabin Creek Facility Project").

Q. WAS THE ACQUISITION OF MANCHIEF PART OF AN APPROVED RESOURCE PLAN?

A. Yes. The acquisition of Manchief was a component of the Company's Preferred Colorado Energy Plan Portfolio ("CEPP"), which was approved in the 2016 ERP. As part of the CEPP, Public Service was authorized to acquire a total of approximately 340 MW[9] of existing natural gas generation assets. After the 2016 ERP, Public Service applied for CPCNs to acquire Valmont Units 7 and 8 and Manchief Units 11 and 12.[10] The Company's application was granted pursuant to Decision No. R20-0108, which approved the Unanimous Comprehensive Settlement Agreement among the parties to the proceeding. Notably, the Commission also issued a presumption of prudence for the acquisitions of both Valmont and Manchief consistent with Commission Rule 3617(d).[11]

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[9] Summer Net Dependable Capacity.
[10] Proceeding No. 19A-0409E.
[11] Decision No. 20-0108 at 2, ¶1 (mailed Feb. 19, 2020).

Q. PLEASE DISCUSS THE MANCHIEF ACQUISITION AND THE RELATED CAPITAL ADDITIONS THE COMPANY IS SEEKING TO RECOVER IN THIS RATE CASE.

A. As noted above, the Company received approval, with a presumption of prudence, to purchase the 260 MW Manchief facility in Phase II of its 2016 ERP and in Proceeding No. 19A-0409E. The Company acquired Manchief in May of 2022 for a price of $45.2 million, which is consistent with the amount deemed reasonable by the Recommended Decision that went into effect by operation of law.[12] The Company anticipates incurring an additional $6.4 million in costs following acquisition, for facility preparations, unit controls upgrade, static frequency converter ("SFC") replacements, emissions monitoring upgrades, and employee training.[13]

Q. WHY IS THE COMPANY INCURRING ADDITIONAL POST-ACQUISITION COSTS FOR MANCHIEF?

A. These costs are for controls and other equipment upgrades needed to align the units with the Company's standards or to improve reliability. Some of these upgrades/improvements include installing a new Continuous Emissions Monitoring System ("CEMS"), new Combustion Turbine Controls, upgraded protection relays, new SFCs, and remote operated cooling valves.

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[12] Proceeding No. 19A-0409E, Decision No. R20-0108, at 15, ¶¶39-40 and 18, ¶50 (mailed Feb. 19, 2020).
[13] Approximately $5.5 million of these costs are within the Reliability/Performance Enhancement category, with approximately $0.9 million being within the Environmental Improvement category.

Q. WHAT IS THE CABIN CREEK FACILITY PROJECT?

A. As discussed above, the Cabin Creek Hydroelectric Facility ("Cabin Creek") is a pumped storage facility. In Proceeding No. 15A-0304E, the Company received approval for two projects at Cabin Creek: (1) upgrades to Units A and B to increase generating capacity and improve efficiency (the "Upgrade Project"), and (2) the extension of the upper reservoir dam to allow for additional storage capacity (the "Upper Reservoir Expansion Project").[14]

Q. WHAT IS THE CURRENT STATUS OF THE CABIN CREEK FACILITY PROJECT?

A. Unit A was placed in-service on July 30, 2021. The Company began construction on the Unit B upgrades in February 2021 and expects Unit B to be placed in-service in the second quarter of 2023. The Upper Reservoir Expansion Project work started in August, 2021 and the project is forecast to be in-service by July 31, 2023.[15]

Q. HAS THE COMPANY EXPERIENCED CHALLENGES IN COMPLETING THE CABIN CREEK FACILITY PROJECT?

A. Yes. The challenges were discussed in the Company's March 31, 2022 Annual Progress Report filed in Proceeding No. 15A-0304E, a copy of which is provided

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[14] Proceeding No. 15A-0304E, Decision C15-0955 (mailed Aug. 31, 2015). The Upgrade Project and the Upper Reservoir Expansion Project are collectively known as the "Cabin Creek Facility Project". Public Service has categorized the Cabin Creek Facility Project as New Generation/Renewable Energy since the Upgrade Project resulted in increased capacity and because both aspects of the Cabin Creek Facility Project were addressed together in Proceeding No. 15A-0304E. The Company notes, however, that the Upper Reservoir Expansion Project is reliability-driven.

[15] *See* Proceeding No. 15A-0304E, Cabin Creek Hydroelectric Facility Upgrade Project, 2021 Annual Progress Report (Mar. 31, 2022).

as Attachment KLW-2 to my Direct Testimony in this Proceeding. Some of those challenges are unrelated to the Cabin Creek Facility Project, including a rotor problem in early 2021 at Unit B that caused an acceleration of the Unit B part of the Upgrade Project.

The Company has experienced issues that have adversely impacted project schedule and ultimate completion of the Upgrade Project. These include defects and deficiencies of the existing isolated phase bus, overheating of components at or near the isolated phase bus, turbine shaft seal installation defect, plant gantry crane break downs, turbine guide bearing babbitt damage, turbine oil deflector leak, excessive runout at pony motor slip ring, and field lead connection. Further, discovery of damage and wear of the existing equipment, discovery of asbestos needing abatement, and challenges with manufacturing and installation all contributed to the Upgrade Project taking longer than anticipated.

The Upper Reservoir Expansion Project was developed from a conceptual design. As the project moved into more advanced stages, the scope and scale of the project has grown to meet safety and adequacy requirements as part of the Federal Energy Regulatory Commission ("FERC") licensing process. For example, as the detailed design developed, both the height of the parapet wall extension and the duration of the construction increased, which presents problems given the limited window for construction at the high elevation for the facility, Finally, like other work in 2021, the Cabin Creek Facility Project also experienced delays to due precautions and restrictions associated with the COVID-19 Pandemic.

Q. WHAT IS THE ANTICIPATED COST OF THE CABIN CREEK FACILITY PROJECT?

A. Public Service estimates that total costs for the Upgrade Project will be approximately $89.9 million and approximately $10.1 million for the Upper Reservoir Expansion Project.

Q. HOW DO THOSE COSTS COMPARE TO WHAT WAS INITIALLY PRESENTED IN PROCEEDING NO. 15A-0304E?

A. The total estimated cost of the Cabin Creek Facility Project detailed in our Application in Proceeding No. 15A-0304E was approximately $88.1 million, consisting of approximately $87 million for the Upgrade Project and approximately $1.1 million for the Upper Reservoir Expansion Project.

Q. WHAT HAS CAUSED THE INCREASE IN THE EXPECTED COST OF THE UPGRADE PROJECT?

A. The largest deviation from the amounts presented in Proceeding No. 15A-0304E is for Specialty Contracts. This item in the budget has increased primarily due to the identification of work necessary for the remaining balance of plant electrical work, modernization of the fire protection equipment for the new transformers, concrete work at the auxiliary transformer, and improvements at the isolated phase bus. That being said, the current expected cost is generally consistent with the amounts presented in Proceeding No. 15A-0304E.

Q. WHAT HAS CAUSED THE INCREASE IN THE EXPECTED COST OF THE UPPER RESERVOIR EXPANSION PROJECT?

A. The estimate for the Upper Reservoir Expansion Project in Proceeding No. 15A-0304E was developed from a conceptual design. The initial $1.1 million was a preliminary estimate and as work moved forward, the scope and scale of the project changed, as discussed above. Notably the overall height of the parapet wall was increased after engineering computations determined the maximum flood water elevations. This increased height necessitated the addition of support buttresses to the wall. This also meant additional requirements to ensure the project met requirements as part of the FERC licensing process. This changed the overall scope to be larger than estimated which led to increases in cost compared to the original preliminary estimate.

Q. IS THE CABIN CREEK FACILITY PROJECT STILL BENEFICIAL TO CUSTOMERS?

A. Yes. In Proceeding No. 15A-0304E, the Company demonstrated that the Cabin Creek Facility Project resulted in over $300 million of net customer benefits. While the costs of the Upper Reservoir Expansion Project component are higher than anticipated, overall, the Cabin Creek Facility Project will still result in significant customer benefits, even at the estimated final cost of completion.

Q. COULD YOU PROVIDE OTHER EXAMPLES OF RENEWABLE/NEW GENERATION CAPITAL COSTS FOR WHICH THE COMPANY IS SEEKING RECOVERY?

A. Yes. While the acquisition of the Manchief Generating Station and the Cabin Creek Facility Project account for the vast majority of Renewable/New Generation capital additions in this Proceeding, the Company is seeking to recover the cost of several other smaller Renewable/New Generation capital additions. For example, the Company is seeking to recover capital costs for material, repair, and replacement costs associated with ongoing operations at Rush Creek and Cheyenne Ridge. This includes, for example, costs for gearbox replacements, transformer replacements, tools, and parts.

C. Environmental Improvement Capital Additions

Q. WHAT ARE THE PRIMARY 2022-2023 ENVIRONMENTAL IMPROVEMENT CAPITAL ADDITIONS?

A. The Company's major 2022-2023 Environmental Improvement capital projects include:

- Pawnee Landfill Cell #2;
- Selective Catalytic Reduction ("SCR") Replacement projects;
- RMEC Waste Water project; and
- CEMS analyzer replacements at both Manchief units and Fort St. Vrain.

Q. IS THERE A COMMON THEME AMONG THESE PROJECTS?

A. Yes. Generally speaking, this work is needed to maintain compliance with applicable state and federal environmental regulations.

Q. PLEASE ELABORATE ON THE PAWNEE LANDFILL CELL #2 CONSTRUCTION PROJECT.

A. Pawnee Station disposes of generated fly ash in on-site landfills. The currently active landfill cell is forecasted to reach capacity in 2023. In order to continue plant operation while maintaining environmental compliance, a new landfill must be constructed and be done so in accordance with State Section 9 Solid Waste requirements, as well as the Pawnee Engineering Design and Operations Plan. To satisfy the volume requirements, the existing East Landfill Cell 1 is to be expanded westward into the footprint of existing evaporation Pond D, which is no-longer needed. The expansion will provide sufficient volume to meet Pawnee's disposal requirements until gas conversion, which is anticipated to be completed in 2025.

Q. WHAT ARE THE SCR REPLACEMENT PROJECTS?

A. Coal and gas-fired generating stations use SCR catalyst to aid in removing NOx emissions from flue gas streams in order to comply with associated air permits. The SCR controls use a nitrogen-based reagent, along with a catalyst, to capture NOx. When these layers of catalyst become saturated and therefore no longer perform as designed, they are replaced with new catalyst. The Test Year capital additions include SCR replacements at Pawnee (2022) and RMEC (2023).

Q. WHAT IS THE RMEC WASTE WATER PROJECT?

A. The waste water project at RMEC pertains to the Zero Liquid Discharge ("ZLD") system. The ZLD provides the plant with purified reclaimed water by processing the cooling tower wastewater. This water is primarily used to supply makeup water to the Heat Recovery Steam Generators and is required for power generation from

Rocky Mountain Unit 3. The current ZLD equipment has reached end of life and is unable to supply enough water during peak seasons, causing reliability issues when generation is needed the most.

Q. PLEASE ELABORATE ON THE CEMS REPLACEMENT PROJECTS.

A. CEMS instruments measure various types of emissions, including SO_2, NOx, CO, CO_2, O_2, Hg, Particulate, Opacity and Stack Flow flue gas constituents, that are released into the atmosphere under Public Service's coal- and gas-fired plants' air permits. Failed or obsolete CEMS instruments must be replaced because the generation unit cannot run without them. CEMS instrument replacements are managed using a targeted replacement schedule to ensure proactive management of the equipment based on experience and industry best practices. Depending on the type of monitor used for the constituents noted above, this schedule cycle ranges from five to 15 years.

Q. COULD YOU PROVIDE OTHER EXAMPLES OF ENVIRONMENTAL IMPROVEMENT PROJECTS FOR WHICH THE COMPANY IS SEEKING RECOVERY?

A. Yes. Other types of Environmental Improvement capital costs included in this Proceeding are scrubbers, baghouse bag replacements, repair and replacement parts, and materials/supplies needed to maintain compliance with applicable air, waste, water, and other environmental permits and compliance requirements.

Q. ARE THERE ANY ENVIRONMENTAL IMPROVEMENT PROJECTS FROM ATTACHMENT KLW-1 THAT THE COMPANY IS NOT SEEKING TO RECOVER IN THIS PROCEEDING?

A. Yes. After finalizing the cost of service, the Company determined it would not seek base rate recovery in this Proceeding for the Valmont Groundwater Mitigation project.[16] Rather, the Company intends to bring forward a different cost recovery proposal in a separate filing. Mr. Freitas explains that the Company will include an adjustment in Rebuttal Testimony to remove this project from the cost of service.

D. Reliability/Performance Enhancement Capital Additions

Q. WHAT ARE THE MAJOR CATEGORIES OF RELIABILITY/PERFORMANCE ENHANCEMENT CAPITAL ADDITIONS?

A. Reliability/Performance Enhancement projects can be broken out into three general categories: (1) Combustion Turbine Part Replacement; (2) Emergent Projects; and (3) General/Other Projects.

Q. PLEASE DESCRIBE COMBUSTION TURBINE PART REPLACEMENT PROJECTS.

A. Public Service performs combustion turbine parts replacements on interval schedules driven by operating hours and number of turbine starts. OEMs set the criteria for these intervals based on the model of the turbine.

[16] This project will implement corrective action measures required by the Coal Combustion Residuals Rule to mitigate groundwater impacts.

Q. ARE THERE ANY PLANNED 2022 OR 2023 COMBUSTION TURBINE PART REPLACEMENT PROJECTS?

A. Yes. Fort St. Vrain Unit 2, Cherokee Unit 5, Blue Spruce Unit 2 and RMEC Units 1 and 2 had or will have Flex, Major, and Hot Gas Path projects in 2022 and 2023. Several of these projects include the removal of the existing controls, which were due for replacement under their replacement schedules, with new controls installed.

Q. WHAT ARE FLEX, MAJOR AND HOT GAS PATH COMBUSTION TURBINE PART REPLACEMENT PROJECTS?

A. As discussed in more detail below, “flex” combustion turbine part replacement projects are upgrades of our combustion turbine units that allow them to operate in a more “flexible” mode that better accommodates net-load changes resulting from more renewable generation resources on the system. These upgrades may include faster ramp rates, shorter start up duration, lower minimum or higher maximum load capabilities to mention a few.

A “Major” project on a combustion turbine includes removal and replacement of all combustion hardware and some of the turbine components based on service life. This is similar to a “hot gas path” with the addition of removal of the rotor from the turbine shell to permit inspection of the axial multi stage air compressor. These projects occur on each gas turbine at approximately 48,000 hours (depending upon OEM hours recommendations). Recent “majors” have occurred at Cherokee Units 5 and 6 and Ft. St. Vrain Unit 2.

Finally, a “hot gas path” (“HGP”) inspection is similar to the “major” with the exception being that the rotor and axial compressor section is not opened for inspection. Recent “hot gas path” outages have occurred at Ft St Vrain Units 3, 5, and 6, Blue Spruce Unit 1, and Rocky Mountain Unit 2. For our base loaded and shoulder loaded units, these outages (i.e. majors and HGP) occur on an approximate three-year basis alternating between the two types of outages. For the units in service during our peak periods, outage dates are driven by the hours and/or the starts the unit sees. Energy Supply monitors these intervals closely to ensure that parts are used as effectively as possible.

Q. IS PUBLIC SERVICE UNDERTAKING OTHER UPGRADES TO COMBUSTION TURBINE UNITS?

A. Yes. In addition to these recurring parts replacements, Public Service also has been performing upgrades of our combustion turbine units to allow them to operate in a more “flexible” mode that better accommodates net-load changes resulting from more renewable generation resources on the system.

Q. CAN YOU PROVIDE AN EXAMPLE OF A FLEXIBILITY UPGRADE?

A. Yes. Fort St. Vrain Unit 2 underwent one such flexibility upgrade in 2022 during its planned major overhaul, in addition to receiving a newly refurbished rotor. The refurbished rotor was installed along with new turbine shells and flexibility upgrade components. Each of these parts replacement or upgrade projects may include replacing high wear parts such as turbine buckets/blades and nozzles, fuel nozzles and other components such as compressors, gas control valves, fuel piping systems, and control systems to support the new components and their expanded capabilities.

In addition to the recent work performed on Fort St. Vrain Unit 2, similar work has been done with Units 3 and 4 at that site. The upgraded parts and control systems have allowed those units to reach higher max load numbers as well as lower turndown or minimum load numbers. This, coupled with improved ramp rates within the expanded load range, has allowed the Fort St. Vrain combined cycle block to better cover the rapid system swings seen as wind resources ramp up and down as the winds come and go. These upgrades have allowed Fort St. Vrain to have an effective range of approximately 40 MW all the way up to 1,020 MW in the summer and approximately 1,140 MW in the winter. Upgrades like these allow our fleet to better service our customers for a lower installed price than installing complete generating units to cover the additional load and flexibility demands.

Q. ARE FLEXIBILITY UPGRADES A PART OF THE GENERATION BUSINESS AREA'S CAPITAL ADDITIONS?

A. Yes. The Company has or expects to place approximately $90 million in flexibility upgrade capital additions in service between January 1, 2020 and December 31, 2023. Again, these kinds of investments complement growth in renewable generation resources on the system. Generally, the "flex" upgrade work is a one-time event per unit and is not a reoccurring cost. However, these upgrades come with the installation of cutting edge parts and technologies that are covered under various patents and thus have less of a support base outside of the OEM. This means that hot gas and major outages are incrementally more expensive due to the additional costs of the higher performance parts and less competition in the market to supply and refurbish those components.

Q. CAN YOU ELABORATE ON HOW THESE INVESTMENTS COMPLEMENT THE GROWTH IN RENEWABLE GENERATION RESOURCES?

A. Yes. Our turbine flexibility projects have focused on increasing load range, ramp rates, startup times, and low load capabilities. With renewables sometimes exceeding net generation demands, the Company needs to pull as much dispatchable generation offline to realize the best reduction in carbon emissions and fuel savings to drive the best customer value for the renewable energy inputs. Removing a unit from the grid or backing it down to the minimum are two frequently used system management options. However, with the variability of wind, enough generation needs to be available to cover the drop off in generation as winds die down. By having lower minimum loads, a unit can remain online to cover any drop offs in renewable generation allowing for more renewable generation to be delivered. Additionally, by having a larger range, an individual site can cover a larger spread of MWs as the net generation demand shifts from dispatchable resources to renewables and vice versa. These shifts can sometimes be rapid and the improved ramp rates allow dispatchable units to move through their load range faster, ensuring that generation and load are balanced as the shift occurs. Additionally, with fast or reduced start times, some gas turbines can be taken offline and left off longer, allowing for better penetration by our renewable resources increasing customer value.

Q. ARE THERE OTHER BENEFITS OF THE FLEXIBILITY UPGRADES?

A. Yes. The recent flexibility upgrades also increased the capacity of the affected units in a highly-economical manner.

Q. PLEASE DESCRIBE THE EMERGENT PROJECT SUBCATEGORY.

A. As discussed in Section III.B, above, unexpected capital needs do arise after establishing a list of specific projects for a given year. We therefore dedicate a portion of our capital budget to emergent work.

Q. WHAT KIND OF WORK IS INCLUDED IN THE EMERGENT PROJECT SUBCATEGORY?

A. This type of work includes responding to failures of equipment such as instrument air compressors, control valves, gearboxes, pumps, and motors, and other replacements or major repairs determined through the course of testing, monitoring equipment, and in some cases in service failures. The Company works hard to prevent failures on critical equipment and if prudent allow other components to run to failure if the costs of a rebuild are close to the costs of replacement for instance.

Q. HOW IS THE LEVEL OF EMERGENT WORK DETERMINED?

A. Even with Public Service's many years of operating experience and the knowledge that equipment failures can and will occur, the specific types of equipment that will fail are not always readily predictable. That being said, we generally rely on our many years of experience operating generation plants to set aside appropriate budget amounts to offset these costs so that budgets can remain stable and more accurately account for these projects.

Q. CAN YOU PROVIDE EXAMPLES OF "EMERGENT" PROJECTS?

A. Yes. Earlier in my Direct Testimony I discussed at a high level the Fort Lupton Unit 1 emergent project. Below are three additional examples of Generation Business Area capital projects that fall within the Emergent category:

- *Ft Lupton Unit 2 Stator Re-wedge and Rotor Rewind:* The Ft Lupton Unit 1 generator had significant repair work performed in Spring 2022 based on a lube oil leak in the generator section (discussed earlier). Due to this, Unit 2 underwent a thorough inspection since the units are of similar age and operating history. Based on the findings from this inspection, Unit 2 was determined to require significant work. This generator scope of work included: seals refurbishment, wedge replacement, oil system repair, bearing seal replacement, and a possible rotor rewind. This work was required to ensure safe and reliable unit operation.

- *Fort St. Vrain Cooling Tower Blowdown Pond Liner:* The CDPHE Section 9 regulation provides the regulatory framework for waste impoundments that include the Fort St. Vrain cooling tower blowdown pond. The regulation requires Energy Supply to inspect all liners at regular intervals and to provide downgradient groundwater analytical data from the surrounding monitoring wells. Liner damage was noted during inspection and constituents of concern were detected above regulatory limits in a downgradient monitoring well that had no previous detections. Based on the detection and the observed degradation of the liner, the Company has committed to replacing the liner in 2023 and is reporting monitoring results on a more frequent basis.

- *Shoshone Medium Voltage Cable Replacement*: Located in the Glenwood Canyon, Shoshone feeds power onto two redundant lines at 115kV and 69kV respectively. The cables feeding the 115kV line from the plant were found to be at end of life and were removed from service. This in turn caused the 115kV line to be out of service until replacement could take place. Due to wildfire risks, the redundant 69kV line had to be removed from service during high fire risk times to mitigate the potential for that line to start a fire. Having both lines out of service effectively removed Shoshone from the system along with customer loads along those lines causing extended customer outages. The work was approved as emergent work and once completed resulted in reduced customer outages and increased reliability of the output from the plant.

Q. PLEASE DESCRIBE THE "GENERAL/OTHER" PROJECT SUBCATEGORY.

A. This category includes all other projects needed to improve reliability or performance that are not included in the aforementioned categories.

Q. COULD YOU PROVIDE EXAMPLES OF "GENERAL" PROJECTS?

A. Yes. Below are several examples of Generation Business Area capital projects that fall within the General category:

- *FSV Cooling Tower Replacement:* The Ft. St. Vrain Unit 1 cooling tower was in degraded condition causing unit derates and reliability concerns. The site, in coordination with our Projects and Performance Optimization organizations, initially considered a phased repair approach to address issues with the tower as compared to complete replacement. As one of those projects was attempted, it became apparent that each cell would effectively be completely rebuilt in place. It was determined the most cost-effective solution was to demolish the old tower and build a new one on the existing water basin. In addition to upgrading the tower internals for better performance, the new tower received uprated forced draft fan/motor combinations that helped ensure more operating margin in the tower so that the added potential output from the steam turbine could be realized. Final tower performance testing showed that the tower is overperforming compared to design parameters which lead to better plant fuel efficiency and lower emissions rates.

- *Cabin Creek Isolated Phase Bus Duct:* After the commissioning of Unit A, the Isolated Phase Bus Duct was found to be overheating. Various repairs and improvement options were tested, and the results lead to the determination that the most cost-effective approach was to completely remove the old system and install a modern and proven Isolated Phase Bus Duct system to ensure reliability of the units at their new output levels.

- *Comanche Unit 3 Startup Boiler:* Through Decision No. C18-0761, Public Service received approval to decommission Comanche Units 1 and 2. These units share a common auxiliary steam system that is used to provide steam to Unit 3 during start-up operations. Once Units 1 and 2 are retired, if Unit 3 is offline there will be no source of auxiliary steam to support startup. While the unit can be started without this system, the duration of those starts is significantly extended and presents heightened potential for reliability issues for the unit. As a result, the Company will install a startup boiler.

- *Pawnee Circulating Water Tunnel Re-lining:* The Pawnee unit was commissioned in the early 1980's and has provided reliable and cost-effective generation to customers ever since. During routine inspections, with heightened awareness due to similar degradation issues at the Hayden Station, it was determined that the circulating water tunnels at Pawnee were headed towards failure. Various options were considered to determine the best cost benefit and installation of a structural lining was chosen over coating or complete replacement. The lining that was installed will ensure reliable service of the unit into the future at a price that was significantly less than a wholesale replacement effort.

- *Cherokee Waste Water Project*: As a part of the Denver metro area water program, the wastewater permit at Cherokee was revised for discharges associated with Total Inorganic Nitrogen ("TIN"), sulfate, chloride, selenium and E.coli. The TIN, sulfate and chloride limits came into effect on January 1, 2022 and the selenium and E.Coli limits will be in effect starting January 1, 2023. Cherokee was unable to meet these revised permit limits without the need for additional water treatment. A study was conducted and the installation and operation of a ZLD treatment facility was the most economical option that would meet ongoing permit requirements through the life of the plant. Newly installed systems include holding ponds, clarifiers, Reverse Osmosis filters and multi-media filters.

Q. ARE THE GENERATION BUSINESS AREA CAPITAL ADDITIONS THAT PUBLIC SERVICE IS SEEKING TO RECOVER AS PART OF THIS ELECTRIC RATE PROCEEDING REASONABLE AND PRUDENT?

A. Yes. These capital additions are needed to provide safe and reliable electric service to our customers throughout Colorado. As previously explained, Public Service has a thorough process in place to evaluate and prioritize capital projects for its Generation Business Area. Each project that we are seeking recovery for has been vetted through our internal review process and identified as needed to continue providing safe and reliable service. Therefore, the Generation Business Area capital additions that we are seeking to recover through base rates are reasonable and prudent and should be approved for recovery.

V. <u>GENERATION O&M</u>

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

A. The purpose of this section of my Direct Testimony is to support the Company's Generation Business Area O&M expense through June 30, 2022, as adjusted for: (1) items described below; (2) continuation of amortization of certain one-time costs, also discussed below; and (3) labor and non-labor costs as discussed and quantified by Company witnesses Mr. Michael P. Deselich and Mr. Freitas, as the appropriate level of Generation Business Area O&M expense in the Test Year.

Q. CAN THE GENERATION BUSINESS AREA'S O&M EXPENSES BE PLACED IN SEPARATE CATEGORIES?

A. Yes. The Generation Business Area performs a variety of work to support the Company's generating fleet. This work generally falls into six categories.

- *Internal Labor*: Internal labor includes costs for the labor force that runs our plants and supports the Generation Business Area's activities. It includes salaries, hourly regular, and overtime pay and ensures we have personnel available to operate our plants at all hours of the day.

- *Contract Labor*: This includes costs for outside contractors, experts, and other third-party assistance that we employ to augment our internal core operations and maintenance competencies. Examples include crews we hire to help with overhaul work, experts from our equipment manufacturers to provide expertise on the plants they helped engineer and construct, and third-party contractors who assist with environmental, health, and safety compliance issues as they arise.

- *Base Commodities*: This category primarily includes costs for chemicals and water used in the generation process and to control emissions. The chemicals for which we incur the most costs include ammonia, lime, sulfuric acid, and mercury absorbent, which are needed to run our fossil fuel fleet.

- *Materials*: This category includes costs for all non-chemical material costs we incur to operate and maintain our plants. This includes everything from steel to non-capital replacement parts to personal protective equipment.

- *Craig Partnership*: This category includes costs paid to Tri-State to operate the Craig Station.

- *Other*: This category includes all other costs we incur to operate and maintain our generation plants. This includes transportation fleet costs, utility costs for the plants such as gas, electric and sewer bills, fees (*e.g.*, environmental fees), and other, smaller miscellaneous O&M costs.

Q. ARE INTERNAL LABOR COSTS DEPENDENT ON COMMITMENTS UNDER COLLECTIVE BARGAINING AGREEMENTS?

A. Yes. These costs are influenced by commitments made as part of our collective bargaining agreements. Company witness Mr. Deselich provides additional details regarding the influence of collective bargaining agreements on the Company's proposed revenue requirement.

A. Overview of Generation O&M

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

A. Table KLW-D-3 summarizes the Generation Business Area's Test Year O&M expense. Attachments KLW-3 and KLW-4 provide additional detail of Generation's Test Year O&M expenses by cost element and FERC account.

TABLE KLW-D-3:
Generation Business Area Test Year O&M Expenses
Public Service Electric
(Dollars in Millions)

Category	Test Year Amount
12-Months Ended June 20, 2022	$146.5

Test Year Adjustments	$4.2
Amortized One-Time Expenses	$8.9
Total*	**$159.6**
*There may be differences between the sum of the individual category amounts and totals due to rounding.	

Q. ARE THESE O&M EXPENSES REASONABLE AND NECESSARY TO SUPPORT THE COMPANY'S GENERATION FLEET?

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

Q. HAS GENERATION BUSINESS AREA O&M BEEN IMPACTED BY INFLATION OR SUPPLY CHAIN DISRUPTIONS?

A. Yes. Generation Business Area O&M has felt significant impacts due to inflation and supply chain disruptions. In particular, chemicals have seen large price increases recently, which are critical to the operation of certain generating facilities. Ammonia, lime, and powder activated carbon are all examples of chemicals that have seen double digit percentage increases over the last year. As a result, chemicals costs for the 12-months ended June 30, 2022 are approximately $1.4 million greater than the actual amount for the 12-months ending December 31, 2021,[17] despite the quantity of Test Year chemicals being less than the amount consumed during the 12-months ended December 31, 2021 based on generation

[17] The $1.4 million figure incorporates the Comanche 3 chemicals Test Year adjustment, discussed below.

levels. The rising costs of chemicals further supports the inflation adjustment discussed in the Direct Testimony of Mr. Freitas.

B. Historical O&M

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

A. The Generation Business Area's actual O&M costs for the 12 months ended June 30, 2022 were $4.1 million lower than those for the 12 months ended December 31, 2021. Table KLW-D-4, below identifies the differences in historical O&M by cost category.

TABLE KLW-D-4:
Comparison of Historical Generation Business Area O&M Expenses
Public Service Electric
(Dollars in Millions)

Category	12-Months Ending December 31, 2021	12-Months Ending June 30, 2022	Difference
Internal Labor	$59.8	$60.2	$0.4
Contract Labor	$55.2	$50.9	($4.3)
Base Commodities	$11.0	$11.7	$0.7
Materials	$6.7	$6.3	($0.4)
Craig Partnership	$3.8	$3.8	($0.0)
Other	$13.9	$13.5	($0.4)
Total*	**$150.4**	**$146.5**	**($4.1)**
*There may be differences between the sum of the individual category amounts and totals due to rounding.			

Q. CAN YOU PROVIDE MORE INFORMATION REGARDING CAUSES OF THE CHANGES IN HISTORICAL O&M?

A. Yes. There is one noteworthy variance between actual O&M expenses for the 12 months ended December 31, 2021 and the 12 months ended June 30, 2022, which was in the contract labor category.

Q. PLEASE DESCRIBE THAT VARIANCE.

A. There was a decrease of $4.3 million in contract labor. The majority of this variance is cause by three noteworthy items: (1) favorable back feed power cost within our wind farms; (2) emergent work in the first half of 2021 within our Hydro facilities with no comparable work in the first half of 2022; and (3) emergent pond work at RMEC in the first half of 2021 with no comparable spend in the first half of 2022.

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

Q. IS THE COMPANY PROPOSING ANY INDIVIDUAL ADJUSTMENTS TO GENERATION BUSINESS AREA O&M EXPENSE AS PART OF ESTABLISHING THE TEST YEAR REVENUE REQUIREMENT?

A. Yes. The Company is proposing five individual adjustments to actual Generation Business Area O&M for the 12 months ended June 30, 2022: (1) a Comanche 3 chemicals adjustment to reflect the lower than usual chemicals that were purchased in the first half of 2022 due to the Comanche 3 outage; (2) an adjustment relating to Vestas liquidated damages; (3) an adjustment to account for increasing air quality fees; (4) an adjustment for costs associated with a new Cherokee wastewater facility; and (5) an adjustment for the retirement of Comanche 1. In total, these adjustments increase Test Year O&M expense by approximately $4.2 million, as shown in Table KLW-D-5.

TABLE KLW-D-5:
Test Year Adjustments
Public Service Electric
(Dollars in Millions)

O&M Expense	Adjustment*
Comanche 3 Chemicals	$0.8
Vestas Liquidated Damages	$5.9
Air Quality Fees	$0.2
Cherokee Wastewater Facility	$0.4
Comanche 1 Retirement	($3.1)
Total Adjustments	**$4.2**

*Does not include one-time adjustments, discussed in the following section. These are new O&M costs additional to what was spent since June 30, 2022.

Q. PLEASE ELABORATE ON THE COMANCHE 3 CHEMICALS ADJUSTMENT.

A. This adjustment is intended to reflect the amount of chemicals to be consumed during a normal year of operations. As discussed in Section VII below, Comanche 3 was offline for a portion of the 12 months ended June 30, 2022 due to an energization of the "A" phase of the generator that caused reverse current flow. This led to arcing incidents within the generator that damaged the generator rotor necessitating a complete rewind of the rotor. As a result, data for the 12-months ended June 30, 2022 reflects a period during which Comanche 3 was offline, which also means the historical data includes a reduced amount of chemicals and materials use. The $0.8 million adjustment ensures the Test Year reflects chemical expenses that would be incurred in a typical year.

Q. HOW DID THE COMPANY ESTABLISH THE AMOUNT OF THE COMANCHE 3 CHEMICALS ADJUSTMENT?

A. The Company calculated this adjustment by taking the generation forecast of Comanche 3 for the period that it was offline and applying the chemical costs.

Q. WHY IS THE PROPOSED COMANCHE 3 CHEMICALS ADJUSTMENT AMOUNT REASONABLE AND APPROPRIATE?

A. Public Service's fossil fuel generation fleet requires the use of a number of chemicals to operate safely and reliably. Examples of necessary chemicals and their applications include:

- *Ammonia:* Primarily used in SCR systems to control NOx emissions in the exhaust stream in order to meet permit limits.
- *Lime:* Lime is made into a slurry and injected into scrubber modules to remove sulfur dioxides from flue gases.
- *Sulfuric Acid:* Used to control the pH in open cell cooling towers as the water evaporates.

The adjustment ensures that the Test Year reflects an amount of chemicals and materials that would be expected to be used during a normal operation period.

Q. WHY IS THE COMPANY PROPOSING AN ADJUSTMENT RELATED TO VESTAS LIQUIDATED DAMAGES?

A. Xcel Energy has O&M service agreements with wind service providers to both maintain and operate our wind facilities. There is an "availability covenant" within many of these agreements that provides for a Projected Average Availability ("PAA") for a given production period. If the contractual Measured Average Availability ("MAA") is less than the PAA for a given production period, availability damages are owed to Xcel Energy.[18] Xcel Energy received $5.9 million in

[18] Average availability is reflected in percentage of actual energy produced out of the sum of actual energy produced and energy deficit from downtime.

liquidated damage payments from our wind service providers related to a MAA deficit for Cheyenne Ridge.[19]

Q. WHY IS THIS ADJUSTMENT REASONABLE AND APPROPRIATE?

A. This payment is a considered a one-time event and lowered our O&M expense during the 12-months ended June 30, 2022. The adjustment ensures that the Test Year reflects an amount of wind O&M while rates are in effect.

Q. PLEASE ELABORATE ON THE ADJUSTMENT RELATED TO AIR QUALITY FEES.

A. Public Service is assessed annual air quality fees by the Colorado Air Quality Enterprise ("CAQE"). Beginning in July 2021, the CDPHE's Air Quality Enterprise Division began assessing Public Service air quality fees, which are driven by Senate Bill 20-204. These air quality fees are expected to be approximately $295,000 in 2022 and will grow in subsequent years – to approximately $394,000 in 2023 and $492,000 in 2024 and beyond. Because only a portion of these fees are reflected in actual O&M for the 12-months ended June 30, 2022, Public Service is proposing an adjustment of $242,296 so the Test Year reflects expected 2023 air quality fees. Attachment KLW-5 to my Direct Testimony shows the go-forward CAQE air quality fees.

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[19] For wind facilities that are recovered through the ECA, these liquidated damages were passed back to customers through that mechanism during 2022 first quarter filed rates. The Company received additional credits for Cheyenne Ridge and Rush Creek in September 2022. Mr. Freitas explains the Company is proposing to record these credits as a regulatory liability and amortize them over a period of months.

Q. WHY IS THE PROPOSED ADJUSTMENT REASONABLE AND APPROPRIATE?

A. This adjustment is reasonable because there is certainty as to what these costs will be over the next several years, and these costs are necessary to ensure compliance with state environmental regulations.

Q. WHY IS THE COMPANY PROPOSING AN ADJUSTMENT RELATED TO THE CHEROKEE WASTEWATER FACILITY?

A. Cherokee Station holds a discharge permit issued by the Colorado Water Quality Control Division. New permit limits went into effect January 1, 2022, meaning the actual O&M expense for the 12-months ended June 30, 2022 reflects only six months under the current standards.

The Company complies with the new permit limits using a new wastewater treatment system, the annualized costs of which are expected to be approximately $2.3 million. The Company is proposing an approximate $0.4 million adjustment so the Test Year appropriately reflects ongoing O&M costs associated with the wastewater treatment facility.

Q. WHY IS THE PROPOSED ADJUSTMENT AMOUNT REASONABLE AND APPROPRIATE?

A. This adjustment is reasonable because it is necessary to ensure compliance with state environmental regulations, and it is expected to be incurred on a going-forward basis.

Q. PLEASE ELABORATE ON THE COMANCHE 1 RETIREMENT ADJUSTMENT.

A. This adjustment is needed to make sure the Test Year only reflects costs representative of the period when rates will be in effect. Comanche 1 will be retired by December 31, 2022, meaning it will not be providing service when rates from this Proceeding go into effect.

Q. HOW DID THE COMPANY ESTABLISH THE AMOUNT OF THE COMANCHE 1 RETIREMENT ADJUSTMENT?

A. The Company calculated this adjustment by identifying and summing all O&M expenses that were specific to Comanche Unit 1 in the 12-months ended June 30, 2022.

Q. WHY IS THE PROPOSED COMANCHE 1 RETIREMENT ADJUSTMENT AMOUNT REASONABLE AND APPROPRIATE?

A. With the pending retirement of Comanche 1, the cost that has historically been spent on the unit will no longer occur. However, Comanche 1 and Comanche 2 share infrastructure and have many common systems that will need to be maintained such as waste water, service water, and compressed air. As such, we will still need to maintain these systems and retain an appropriate staffing level to ensure safe and reliable operations of Comanche 2.

D. <u>Amortized One-Time O&M Costs</u>

Q. PLEASE DESCRIBE ONE-TIME GENERATION BUSINESS AREA O&M COSTS AMORTIZED IN THE TEST YEAR.

A. The 2021 Electric Phase I revenue requirement included recovery of one-time O&M costs for Comanche 1 and 2 ash pond costs incurred due to environmental permitting and regulatory actions.[20] These were one-time, non-recurring costs that the Company amortized over a period of 36 months.[21] The Company requests that amortization continue, resulting in approximately $8.9 million being included in the Test Year, as discussed by Mr. Freitas in his Direct Testimony.

Q. WHY DOES THE COMANCHE 1 AND 2 ASH POND AMORTIZATION NEED TO CONTINUE?

A. There are two reasons. First, the 2021 Electric Phase I revenue requirement reflected a 36-month amortization of the estimated Comanche 1 and 2 ash pond costs. With new rates from this Proceeding going into effect before the end of that 36-month period, there are remaining costs still needed to be recovered. Second, the costs estimated in the 2021 Electric Phase I were lower than actuals and our estimated costs of the Comanche 1 and 2 ash pond activities are higher than the amounts included in the 2021 Electric Phase I due to the extension of the need for the ash pond system.

Q. WHY ARE THE ACTUAL AND ESTIMATED COSTS OF THE COMANCHE 1 AND 2 ASH POND ACTIVITIES HIGHER THAN THE AMOUNTS INCLUDED IN THE 2021 ELECTRIC PHASE I?

A. The awarded bid for the Comanche 1 and 2 ash pond work presented a dual solution to required ash pond work: (1) a temporary, bridge system that was expected to be used for approximately three months; followed by (2) a pre-

[20] Proceeding No. 21AL-0317E, Hrg. Ex. 120 at 151:17-152:4 (Blair Direct); Hrg. Ex. 108 at 72:1-74:5 (Williams Direct). As discussed in the 2021 Electric Phase I, the Comanche 1 and 2 ash pond costs are one-time costs are needed to achieve compliance with state and federal regulations, while facilitating safe and reliable operations at the Comanche 1 and 2 plants.
[21] Proceeding No. 21AL-0317E, Hrg. Ex. 143 at 17: 8 (Table DAB-S-2) (Blair Settlement Testimony).

packaged system that would be used into March 2023.[22] The Company estimated the costs of the dual solution to be $12.9 million, and it was this amount that was included in the 2021 Electric Phase I (amortized over 36 months).

Unfortunately, the project did not proceed as intended. The temporary system was extended due to construction delays as a result of prolonged contract negotiations with the construction and operation vendor and difficulties obtaining materials during the COVID-19 pandemic, at a cost of approximately $1.9 million. Also, the Company subsequently determined that it would need the temporary system until the retirement of Comanche 2 at a cost of approximately $6.9 million, due to the permit and time it would take to construct a new lined pond, as opposed to the original estimated end date of March 2023. We now anticipate the total cost of the Comanche 1 and 2 ash pond work to be $21.8 million, with costs running through the end of 2025.

[22] Proceeding No. 21AL-0317E, Hrg. Ex. 108 at 73:8-22 (Williams Direct).

VI. COMPLIANCE AND OTHER ITEMS

A. Generation Retirements/Decommissioning

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

A. In this section of my Direct Testimony, I discuss the retirements that have occurred or are expected to occur through the end of the Test Year, as well as decommissioning.

Q. WHAT DECOMMISSIONING STUDY IS THE COMPANY USING FOR PURPOSES OF THIS ELECTRIC RATE CASE?

A. As discussed in the 2021 Electric Phase I, Public Service retained Burns & McDonnell to conduct a Decommissioning Cost Study ("Decommissioning Study") for the Company's generation fleet, which was provided as Attachment KLW-1 to my Direct Testimony in that Proceeding. The Decommissioning Study reviewed each of the Company's generation facilities and prepared estimates of the costs to decommission each of the facilities at the end of their useful lives. As discussed by Company witness Mr. Mark P. Moeller in his Direct Testimony, the Company is proposing to continue using the depreciation rates approved in the 2021 Electric Phase I in this Proceeding.

Q. PLEASE PROVIDE AN UPDATE ON CURRENT DECOMMISSIONING ACTIVITIES.

A. Decommissioning activities are currently underway relative to Zuni Station.[23] The main decommissioning activities began in approximately September 2021. The primary focus of the work has been abating the legacy asbestos materials on the site. These materials are primarily found in the Unit 1 and Unit 2 boilers, and flue gas ductwork systems. Various equipment and the former fuel oil storage tank have been removed from site and demolition of Unit 2 flue gas ductwork is partially completed.

Q. HAVE THERE BEEN ANY SIGNIFICANT GENERATION RETIREMENTS SINCE THE 2021 ELECTRIC PHASE I, AND ARE THERE ANY PLANNED THROUGH THE END OF 2023?

A. Yes. Company's Comanche Unit 1 will be retired by December 31, 2022.

B. <u>Generation Overhaul Expense</u>

Q. WHAT ARE GENERATION OVERHAUL EXPENSES?

A. Generation overhaul expenses are a type of O&M expense stemming from the need to refurbish, replace parts, or otherwise maintain generating units to continue to produce the planned capacity and maintain reliability of those units.

[23] Decommissioning of the Zuni Station was approved by the Commission via a Unanimous and Comprehensive Settlement Agreement in Proceeding No. 20A-0268E. The Settlement Agreement was approved without modification by Decision No. R20-0888 (mailed Dec. 14, 2020), which became a Commission decision by operation of law.

Q. IS THE COMPANY REQUIRED TO PRESENT CERTAIN GENERATION OVERHAUL EXPENSE INFORMATION IN ITS PHASE I ELECTRIC RATE CASES?

A. Yes. Decision No. C20-0096 requires the Company "to provide information in its future rate case filings regarding its historical generation overhaul expense."[24]

Q. HAS THE COMPANY PREPARED THE INFORMATION REQUIRED BY DECISION NO. C20-0096?

A. Yes. Consistent with Decision C20-0096, the Company is providing historical generation overhaul expense for 2014 through 2021 as Attachment KLW-6 to my Direct Testimony.

Q. HOW DID THE COMPANY DEVELOP ATTACHMENT KLW-6?

A. As I explained in the 2019 Electric Phase I rate case, our new SAP accounting system does not have the functionality to pull overhaul data from prior to 2017. Therefore, for data prior to 2017, Public Service manually pulled generation project and overhaul O&M data from a previous rate case filing. For data after 2017, the Company obtained this from its existing SAP system.

Q. IS PUBLIC SERVICE PROPOSING ANY ADJUSTMENTS BASED ON THE HISTORICAL GENERATION OVERHAUL EXPENSE PROVIDED IN ATTACHMENT KLW-6?

A. No. With the exception of Comanche 3, for which overhaul expenses associated with the four plus month outage event ending in June of 2021 have been offset by

[24] Proceeding No. 19AL-0268E, Decision No. C20-0096, at ¶ 290 (mailed Feb. 11, 2020).

an anticipated insurance accrual, the historical generation overhaul expenses provided in Attachment KLW-6 are comparable with the generation overhaul expenses incurred during the twelve months ended June 30, 2022, and therefore no O&M adjustment is necessary in this proceeding to account for any year-to-year variability in generation overhaul expenses.

VII. COMANCHE 3 GENERATOR OUTAGE

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

A. In this section of my Direct Testimony, I discuss the outage Public Service experienced at its Comanche Unit 3 from January 2022 to June 2022 (the "Comanche 3 Generator Outage"), resulting from the time it took to inspect the steam turbine generator after an event that occurred on January 28, 2022. The event occurred when the generator was damaged after the generator was unintentionally energized while the unit was offline. Later, I will explain the operational changes Xcel Energy has made in its thermal generating fleet using a multi-departmental approach, consistent with its commitment to continuous improvement.

Q. PLEASE PROVIDE BACKGROUND ON THE COMANCHE 3 UNIT.

A. The Comanche Unit 3 is a 750 MW coal-fired unit in Pueblo, Colorado that sits adjacent to the Comanche Units 1 and 2 on the same plot of land. Public Service owns a 500 MW share in the unit, and Holy Cross Energy and CORE Electric Cooperative own the remaining 250 MW. Public Service received a CPCN to construct and own Comanche Unit 3 in Proceeding Nos. 04A-214E et al. by Decision No. C05-0049, issued on January 21, 2005, and the unit went into service in 2010. As described in Decision No. C05-0049, Comanche 3 employs supercritical pulverized coal technology, which allows for faster start-up duration than any other pulverized coal technology, while also lowering emissions.[25]

[25] *See* Proceeding Nos. 04A-214E *et al.*, Decision No. C05-0049, at ¶ 4 (mailed Jan. 21, 2005).

Q. PLEASE PROVIDE AN OVERVIEW OF THE JANUARY 28, 2022, EVENT AND SUBSEQUENT COMANCHE 3 GENERATOR OUTAGE.

A. During a planned unit outage, the “A” phase of the generator was inadvertently energized from the substation. This energization caused a reverse current flow into the offline generator. The induced currents from this back-feed within the generator caused numerous indications of arcing throughout the generator rotor. These indications were observed via bore scope inspection techniques conducted after partial disassembly of the generator. It was determined that the prudent course of action was to pull the generator rotor to allow for more detailed inspections and further testing.

Testing and inspections conducted after removal of the rotor led to the determination that the damage was extensive enough to warrant a complete disassembly and re-winding of the rotor. The rotor was sent to a vendor shop for disassembly, inspection, and repair procedures. After being fully disassembled, the arc damaged areas were identified and addressed through various methods to reduce stress concentrations in the rotor. Additional Non-Destructive Examination was performed to ensure integrity of the rotor prior to rewinding activities being commenced. The retaining rings were further inspected after removal and found to be unusable due to arcing causing pits in these highly stressed components. As a result, new retaining ring forgings were obtained, and replacements manufactured.

After all inspections, repairs, and rewinding activities were completed, the rotor was electrically tested, and spin balanced at full speed prior to being shipped to the site for reinstallation and final assembly of the generator.

Q. DID PUBLIC SERVICE UTILIZE VENDORS TO ASSESS THE DAMAGE AND MAKE NECESSARY REPAIRS?

A. Yes. Public Service hired third party vendors (Mitsubishi and General Electric) to identify the damage and to repair it as expeditiously as possible. Both vendors have expertise in generator repairs, making their retention the best course of action in this particular situation.

Q. WHEN WAS COMANCHE 3 RETURNED TO SERVICE?

A. The unit was returned to service on June 16, 2022.

Q. PLEASE DESCRIBE OPERATIONAL CHANGES IMPLEMENTED AS A RESULT OF THIS INCIDENT.

A. Subsequent to this event, a team of people from across Energy Supply, as well as our Transmission Substations Business Area, reviewed the incident and conducted an Event Learning. One of the key learnings from this was that communications between work groups was a significant contributor to the incident. As a result, two nearly identical policies were drafted and put in place by each Business Area to address work activities and communications protocol between the two work groups for all future substation work associated with a generating unit. In addition to these two new policies, extensive training was conducted by a core team from Energy Supply and the Transmission Substations Business Areas to educate all employees on the new requirements involved in generation site associated substation work.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Kyle L. Williams

I began my career with American Electric Power ("AEP") in 1994 as a Plant Engineer at the Muskingum River Plant in Beverly, Ohio. I worked various power plant positions with AEP until 2010. In 2010, I took a position with Luminant at the Monticello Steam power plant in Mt. Pleasant, Texas as maintenance superintendent, later to be promoted to Operations Manager at Big Brown Power Plant. In 2013, I accepted a position at Prairie State Generating Company in Marissa, Illinois as the General Manager of power production. In 2014, I moved to Xcel Energy as the Director of Comanche Station and was then promoted to General Manager of Public Service Generation in 2017. I have a Bachelor of Science in Mechanical Engineering from Ohio University and a Master of Business Administration from Franklin University. Overall, I have been working in the electric utility industry in generation of electricity for over 28 years.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * *

IN THE MATTER OF ADVICE LETTER NO. 1906-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 8-ELECTRIC TARIFF TO REVISE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL ELECTRIC RATE SCHEDULES, AND MAKE OTHER TARIFF PROPOSALS EFFECTIVE DECEMBER 31, 2022.	**) PROCEEDING NO. 22AL-XXXXE**

AFFIDAVIT OF KYLE L. WILLIAMS
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO

I, Kyle L. Williams, 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 Henderson, Colorado, this 21 day of November, 2022.

Kyle L. Williams
General ~~Manager, Power Generation~~

Subscribed and sworn to before me this 21 day of November, 2022.

Joan K. Pierce
Notary Public

My Commission expires March 7, 2024

JOAN K PIERCE
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20164009218
MY COMMISSION EXPIRES MARCH 7, 2024