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

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

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

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

July 2, 2021

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

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LIST OF ATTACHMENTS

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
2016 ERP	2016 Electric Resource Plan
2019 Electric Phase I	Proceeding No. 19AL-0268E
2021 ERP & CEP	2021 Electric Resource Plan and Clean Energy Plan
AEP	American Electric Power
AFUDC	Allowance for Funds Used During Construction
B&W	Babcock and Wilcox
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
CACJA	Clean Air-Clean Jobs Act
CAQE	Colorado Air Quality Enterprise
CC	Combined Cycle
CCR	Coal Combustion Residuals
CDPHE	Colorado Department of Health and Environment
CEC	Colorado Energy Consumers
CEMS	Continuous Emissions Monitoring System
CEPP	Preferred Colorado Energy Plan Portfolio
Cheyenne Ridge	Cheyenne Ridge Wind Project
Cheyenne Ridge Settlement	Corrected Non-Unanimous Comprehensive Settlement Agreement, Proceeding No. 18A-0905E
COD	Commercial Operation Date
Commission	Colorado Public Utilities Commission
CPCN	Certificate of Public Convenience and Necessity
CT	Combustion Turbine

Acronym/Defined Term	**Meaning**
Decommissioning Study	Burns & McDonnell Decommissioning Cost Study
Depreciation Study	Public Service Electric and Common Utility Plant Depreciation Rate Study
EAF	Equivalent Availability Factor
EAFPM	Equivalent Availability Factor Performance Mechanism
ECA	Electric Commodity Adjustment
EFOF	Equivalent Forced Outage Factor
EGPM	Electric Generation Performance Mechanism
Energy Supply	Energy Supply Business Area
EPA	Environmental Protection Agency
EPM	Enterprise Project Management
FTY	Future Test Year
Gen-Tie	Generation Tie-line
GWh	Gigawatt-hour
HDPE	High-density Polyethylene
HRSG	Heat Recovery Steam Generator
HTY	Historical Test Year
LPA	Low-pressure A
LPB	Low-pressure B
MW	Megawatt
NERC	North American Electric Reliability Corporation
O&M	Operations and Maintenance
OEM	Original Equipment Manufacturer
PCCA	Purchased Capacity Cost Adjustment

Acronym/Defined Term	**Meaning**
PM	Project Manager
PPA	Power Purchase Agreement
Public Service or Company	Public Service Company of Colorado
RFP	Request for Proposals
RMEC	Rocky Mountain Energy Center
RPC	Regional Planning Committee
Rush Creek	Rush Creek Wind Project
SCC	Stress Corrosion Cracking
SCR	Selective Catalytic Reduction
SDA	Spray Dryer Absorber
Staff	Commission Staff
Staff Report	Confidential Staff Report filed on March 1, 2021 in Proceeding No. 20I-0437E
Tri-State	Tri-State Generation and Transmission Association, Inc.
XES	Xcel Energy Services Inc.
Xcel Energy	Xcel Energy Inc.

**BEFORE THE PUBLIC UTILITIES COMMISSION
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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 within the Energy

Supply Business Area ("Energy Supply") of Xcel Energy Services Inc. ("XES"). 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 plant additions and operations and maintenance ("O&M") expenses that are allocated to Public Service retail electric and included in the 2022 Future Test Year ("FTY") cost of service that is presented by Company witness Ms. Deborah A. Blair. The Company's last electric rate case was Proceeding No. 19AL-0268E (the "2019 Electric Phase I"), in which a Current Test Year ending August 31, 2019 was approved. I therefore provide support for Generation Business Area capital additions placed into service since the Company's 2019 Electric Phase I, from September 1, 2019 through the year-end 2022 FTY. The Company's Generation Business Area plant additions since the 2019 Electric Phase I total $1.31 billion through December 31, 2022.

I also support the $163.8 million (adjusted) in Generation Business Area O&M expenses included in the 2022 FTY. Generation O&M in this rate case is based on the Company's 2020 actual O&M ($150.1 million), plus $13.7 million in 2022 FTY adjustments. Therefore, I discuss the Generation Business Area's 2020 O&M expenses, along with adjustments for: Comanche 3 chemicals and materials, the Manchief and Valmont Generating Station acquisitions, air quality fees, the Cheyenne Ridge Wind Project ("Cheyenne Ridge"), Pawnee water costs, and Cherokee wastewater costs. I additionally support two one-time adjustments totaling $13.5 million for the Comanche Coal Ash Ponds and Manchief contractor/start-up costs, which the Company proposes to amortize over three years. Company witness Ms. Blair supports the Company's overall FTY development.

I also discuss the Company's approach to capital and O&M spending on its existing fossil fuel fleet, in light of proposed early retirements that are likely to arise from the Company's 2021 Electric Resource Plan and Clean Energy Plan ("2021 ERP & CEP").[1] Additionally, I discuss the Company's response to the 2020 Comanche 3 Outage and provide certain information requested by the Staff Report investigating the Comanche 3 Outage. I discuss the Company's pending insurance claim related to the Comanche 3 June Outage Event,[2] and explain that aside from the insurance deductible, Public Service is not asking customers to pay for any base rate costs associated with the June Outage Event that it anticipates recovering from its insurers.

Next, with respect to the 2020 Comanche 3 Outage, I describe the Company's comprehensive response taken as part of its commitment to continuous improvement; I also discuss the actions and costs associated with the Comanche 3 Outage. Because Public Service is not seeking recovery in this

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[1] *In the Matter of the Application of Public Service Company of Colorado for Approval of Its 2021 Electric Resource Plan and Clean Energy Plan*, Proceeding No. 21A-0141E (filed Mar. 31, 2021).

[2] As explained later in testimony, the "Comanche 3 Outage" refers to the outages that occurred at the Comanche 3 unit from January 2020 to January 2021, while the "June Outage Event" refers specifically to Comanche 3's outage event beginning June 2, 2020, for which the Company has a pending insurance claim.

Proceeding of costs that are the subject of a pending insurance claim[3] associated with the June Outage Event (beyond the insurance deductible), and because any replacement power costs associated with the Comanche 3 Outage will be addressed in the Company's forthcoming 2020 Electric Commodity Adjustment ("ECA") prudence review proceeding, Public Service recommends no specific actions with respect to the Comanche 3 Outage as part of this Proceeding.

Finally, with respect to the Company's fossil fuel units, I propose a performance incentive metric, and I explain why the Company's proposed metric is tailored to fit with the Company's generation fleet, particularly in light of the Company's fleet transition to incorporate higher levels of renewable generation.

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

A. Yes, I am sponsoring Attachments KLW-1 through KLW-13, which were prepared by me or under my direct supervision. The attachments are as follows:

- Attachment KLW-1: Burns & McDonnell Decommissioning Study;
- Attachment KLW-2: Generation Capital Additions for September 1, 2019 – December 31, 2020;
- Attachment KLW-3: Generation Capital Additions for January 1, 2021 – December 31, 2022;
- Attachment KLW-4: Cheyenne Ridge October 2020 Construction Progress Report;

[3] As discussed in Sections VI and VII, Public Service and its partners at Comanche 3 expect to receive insurance proceeds that will offset the O&M expenses and capital costs required to repair the damage resulting from the June 2020 incident at Comanche 3.

- Attachment KLW-5: Cheyenne Ridge Plant Balance 2020-2022
- Attachment KLW-6: Cheyenne Ridge Production Data, August 2020 through May 2021;
- Attachment KLW-7: Generation 2020 O&M Expenses by Cost Element;
- Attachment KLW-8: Generation 2020 O&M Expenses by FERC Account;
- Attachment KLW-9: 2022 FTY Generation Adjustments by Cost Element and FERC Account;
- Attachment KLW-10: Colorado Air Quality Enterprise Fee Scenario Outline;
- Attachment KLW-11: Cheyenne Ridge Annualized O&M;
- Attachment KLW-12: Public Service Historic Annual Generation Overhaul Expense;
- Attachment KLW-13: Comanche 3 Capital Additions, September 2019 through April 2021; and,
- Attachment KLW-14: 2020 Zuni Decommissioning Cost Study.

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

A. As part of approving the FTY cost of service developed by Ms. Blair, I recommend that the Colorado Public Utilities Commission ("Commission") approve the September 1, 2019 to December 31, 2022 Generation Business Area capital additions and the Company's 2022 FTY cost of service as described in detail below, and approve the $163.8 million in Generation's 2020 O&M, which serves as the basis for the 2022 FTY. All of these are appropriately allocated to Public Service retail electric and included in the cost of service that is presented by Ms.

Blair. I additionally recommend the Commission approve the Company's proposed performance incentive mechanism for certain fossil fuel units.

II. GENERATION BUSINESS AREA 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.

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. Energy Supply is also responsible for electric generation dispatch and environmental compliance oversight for Xcel Energy's generating plants.

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. 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 ECA riders, respectively, which are annually reviewed by the Commission in other proceedings.

Public Service's Company-owned generation fleet has a net maximum capacity of approximately 6,300 megawatts ("MW"), and the Company has access to another 5,400 MW of summer net dependable nameplate 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 (2021)

Type	**2020**
	Total MWs (approximate)
Coal	1,980
Gas	2,900
Hydro	325
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 2021 net dependable summer capacity as of November 25, 2020):

<u>Coal:</u>

- *Comanche Generating Station:* A three-unit, 1,410 MW generation station located in Pueblo, Colorado, in which Public Service has rights to 1,160 MW. 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 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, 440 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 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 located in Aurora, Colorado.

- *Cherokee Generating Station:* A four-unit, 886 MW facility located just north of downtown Denver and originally built as a coal-fired plant, which has since undergone a complete restructuring as a result of 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, 968 MW combined and simple cycle generating plant located in Platteville, Colorado. Fort St. Vrain Generating Station was repowered with natural gas after the nuclear plant was decommissioned in 1989.

- *Fort Lupton Generating Station:* A two-unit, 88 MW facility located just outside of Fort Lupton, Colorado.

[4] While not included in this list, Public Service plans to acquire the two-unit Manchief generation facility (254 MW) in May 2022. This resource was selected as part of Public Service's 2016 Electric Resource Plan ("2016 ERP").

- *Rocky Mountain Energy Center ("RMEC"):* A three-unit, 580 MW combined-cycle generating facility located in Hudson, Colorado.

- *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, and they have 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 Electric Resource Plan ("2016 ERP") and Decision No. R20-0108 issued in Proceeding No. 19A-0409E.

- *Peaking Units:* Public Service owns three additional natural gas-fired simple-cycle combustion turbine peaking units, including the 14 MW Fruita facility and Alamosa Units 1 & 2, which are 13 MW and 14 MW, respectively.

Hydro:

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

- *Cabin Creek Generating Station:* A two-unit, 323 MW 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. Decommissioning of Salida Unit 1 is in progress.

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

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

Wind:

- *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:* 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. Specifically, Public Service has over 6,650 MW of nameplate generating capacity under contract to meet our customers' energy needs. These generating capacity contracts will include approximately 3,000 MW of nameplate wind generation and approximately 730 MW of nameplate solar generation by 2022. To respond to customers' increased interest in renewable resources, Public Service has also steadily increased its renewable energy offerings in recent years. For instance, customers have the opportunity to participate in Public Service's Windsource and Renewable*Connect programs. Both these initiatives are available to residential and business customers alike, leveraging renewable generation (wind and solar) without additional cost to non-participants. Renewable*Connect allows Public Service customers to cover up to 100 percent of their energy usage by choosing to buy solar from the 50 MW Titan solar array in Deer Trail, Colorado. Similarly, customers enrolled in Windsource support wind energy generated from wind resources in Colorado at a nominal fee per 100 kWh block.

Q. PLEASE DESCRIBE, AT A HIGH LEVEL, PUBLIC SERVICE'S ENERGY TRANSITION AND POTENTIAL IMPACTS ON THE COMPANY'S GENERATION FLEET.

A. Public Service's generation portfolio is in the midst of a major energy transition.

As part of the Preferred Colorado Energy Plan Portfolio ("CEPP") approved in the Company's 2016 ERP, the Commission approved:

- the early retirement of 660 MW of coal-fired generation at Comanche 1 and 2, representing approximately one-third of the Company's remaining coal fleet;
- the addition of over 1,100 MW of wind resources;
- the addition of approximately 700 MW of new solar resources; and
- the addition of 275 MW of battery storage.

While some of these new resources, like Cheyenne Ridge, have come online, others are still under construction and development. Subsequent to the 2016 ERP, in 2019, the Colorado legislature passed House Bill 19-1261 and Senate Bill 19-236, which among other things, required the Company to reduce carbon emissions associated with electricity sales by 80 percent relative to 2005 levels by 2030 and make progress toward achieving 100 percent clean energy by 2050.

On March 31, 2021, Public Service filed its 2021 ERP & CEP, initiating Proceeding No. 21A-0141E.[5] As explained in that proceeding, Public Service's preferred plan for Phase I of the 2021 ERP & CEP would meet or exceed the requirements of Senate Bill 19-236 through the (modeled based on generic resources) acquisition of 2,300 MW of wind, 1,600 MW of solar, 400 MW of storage, and 1,300 MW of flexible dispatchable generation, with 1,158 MW of distributed energy resources coming online by 2030. The 2021 ERP & CEP also

[5] Public Service does not anticipate a decision in Phase I of the 2021 ERP & CEP until the first part of 2022.

contemplates changes to Public Service's coal fleet, including early retirement (Hayden 1 and 2 and Craig 1 and 2), conversion to natural gas (Pawnee), and reduced operations (Comanche 3), as I describe in more detail below. Although the 2021 ERP & CEP is likely to dramatically change Public Service's generation resource mix, the Company does not anticipate these changes will dramatically impact Energy Supply's existing budgeting and financial planning processes for capital costs and O&M expenses and thus this rate case. However, the energy transition will impact the timing and types of projects we undertake going forward. In Section IV, I discuss how the Company is planning, from a capital and O&M budgeting and financial planning process, for these anticipated changes to its generation portfolio.

III. GENERATION BUSINESS AREA CAPITAL BUDGET, PROJECT SELECTION, AND FUNDING PROCESS

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. I also provide an overview of the primary drivers of the Generation Business Area's capital additions placed in service and projected to be placed into service from September 1, 2019 through December 31, 2022.

Q. WHAT ARE THE PRIMARY DRIVERS THAT GENERALLY AFFECT PUBLIC SERVICE'S GENERATION CAPITAL SPEND?

A. At a very high level, the Generation Business Area generally makes capital investments to its fleet for three purposes:

- *Renewable/New Generation:* These are capital dollars used to support the construction of new generating units, or the decommissioning of old generating units, which are 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. One example of a Renewable/New Generation Project is Cheyenne Ridge, which was approved as part of the Company's 2016 ERP and subsequently granted a Certificate of Public Convenience and Necessity ("CPCN") in Proceeding No. 18A-0905E. Cheyenne Ridge was one of the projects selected and approved in the Company's 2016 ERP.

- *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 Environmental Protection Agency ("EPA") the Colorado Department of Health and Environment ("CDPHE"), and any other regulatory bodies or set forth in statutes. 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.

- *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 rotor replacement and refurbishment projects at Fort St. Vrain are examples of reliability/performance enhancement projects the Company has undertaken.

Q. ARE PUBLIC SERVICE'S GENERATION CAPITAL AND O&M NEEDS READILY PREDICTABLE?

A. Many of the Company's Generation capital needs are readily predictable and are fairly consistent year to year. However, not all capital costs and O&M expenses can be readily predicted as unexpected issues and events do occur.

Q. PLEASE SUMMARIZE HOW PUBLIC SERVICE DEVELOPS ITS CAPITAL BUDGET FOR ITS GENERATION BUSINESS AREA.

A. Capital projects are submitted to the Generation Business Area by our plants, which we then evaluate, and rank based on their operational and financial merits. The most important objective of developing our capital budget and prioritizing projects is ensuring that the Company will continue to deliver safe, reliable, and cost-effective electric service. As the plants identify and develop capital projects, specific operational and other data is available that allows them to identify and quantify how the projects meet specific criteria, as discussed below.

Generation has specific evaluation criteria that it uses to review and prioritize each capital project, including:

- Efficiency;
- Reliability;

- Capacity;
- Safety;
- Legislative commitments;
- Financial merit (such as net present value or present value of revenue requirements);
- Operational factors such as the impact on outage rates, equipment condition; and,
- Environmental compliance, and/or regulation (*e.g.*, Regional Haze, Colorado Section 9 – Waste Impoundments, Standards for the Disposal of Coal Combustion Residuals ("CCR") in Landfills and Surface Impoundments).

The Generation Business Area evaluates projects that may be completed in a single year (for example, replacing the bags in a Fabric Filter Dust Collector), as well as those that will require multiple years to complete. Recent examples of multi-year projects include construction of a new lime spray dryer, control system replacements, installation of new turbine cases, and rotor refurbishments.

The Generation Business Area develops a ranked list of projects, and the list is then evaluated against the available budget for the next year, the planned unit outage schedule for the next several years and known regulatory factors such as new environmental regulations. This capital budget process allows the Company to develop a capital plan that covers a five-year period, with associated five-year capital expenditures and estimated in service dates. As each new fiscal year arrives, the Public Service Regional Planning Committee ("RPC") reviews and validates the list of projects for the next fiscal year, makes adjustments to schedules and/or budgets as required to account for evolving conditions and factors, and proposes a list of projects that meets the planned budget for the next five years. The most recent five years of planning information, capital expenditures, and estimated in-service dates are developed and recorded in the Unifier Enterprise Project Management ("EPM") System. As each project is reviewed by the RPC, the specific criteria and supporting information are reviewed and verified. The verified information is entered into the EPM, where numerical ranks are calculated, and a project is prioritized along with 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 PUBLIC SERVICE FOLLOW TO MANAGE AND CONTAIN ITS GENERATION CAPITAL COSTS?

A. Capital budgets are finalized at least one 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"), typically three to six months in advance of the first planned activity required to commence the project. The PM is responsible for working with the plant to review and more fully develop the project schedule and monthly cash flow requirements for the assigned project. The PM will typically contact vendors and contractors to firm up cost and schedule data and begin engineering and purchasing activities. Typically, each plant holds monthly capital project review meetings where plant management and project managers 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.

The Generation Business Area 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, there is little additional management of the overall capital budget needed. However, unexpected events can, and do, occur.

Q. CAN YOU GIVE AN EXAMPLE OF AN UNEXPECTED EVENT THAT OCCURRED SINCE THE 2019 ELECTRIC PHASE I?

A. Yes. The Comanche 3 Outage event during 2020 was an unexpected event. As I discuss in more detail in Section VIII below, the investigation initiated by the Commission in Proceeding No. 20I-0437E resulted in a report by Commission Staff ("Staff") analyzing the cause of the outage, recommending next steps, and discussing potential follow-on regulatory approaches to address the outage, among other things ("Staff Report").[6] Public Service later provided its Response to the Staff Report, in which the Company charted a path forward for Comanche 3.[7] As discussed in Section VIII, the Company has taken a variety of operational, personnel, and other steps as part of its commitment to continuous improvement to make sure Comanche 3 continues to be available to serve customers cost

[6] *See* Proceeding No. 20I-0437E, Confidential Staff Report Volume 1 & Volume 2 (filed Mar. 1, 2021).
[7] *See* Proceeding No. 20I-0437E, Response of Public Service Company of Colorado Pursuant to Decision No. C21-0185-I (filed Apr. 28, 2021).

effectively and reliably going forward.

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

A. When such events occur, the Company accommodates the emerging work needs and budget. For example, if there is an unexpected failure of a large component at an existing plant, such as a cooling tower circulating water pump, we must address this event and the resulting expenditure when it occurs. Some of our routine work orders exist to meet these needs for lower-cost projects, such as a valve failure, that are not individually budgeted, but instead 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. However, 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 will generally assign funds to other projects to implement because the number of projects that would be eligible for approval generally exceeds the capital funds available.

IV. PUBLIC SERVICE'S ENERGY TRANSITION

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

A. In this section of my Direct Testimony, I discuss the potential for additional coal unit retirements and/or conversions to natural gas, and the effect of those potential retirements on the manner in which Public Service plans its Generation capital and O&M spending.

Q. HAS PUBLIC SERVICE PROPOSED ADDITIONAL COAL PLANT RETIREMENTS AND/OR NATURAL GAS CONVERSIONS?

A. Yes. Public Service's 2021 ERP & CEP filed in Proceeding No. 21A-0141E charts a path for reaching (and exceeding) an 80 percent carbon emissions reduction by 2030 compared to 2005 levels, consistent with Senate Bill 19-236. Public Service has proposed a path that will fundamentally change Public Service's generation fleet while at the same time achieving significant carbon emission reductions. As I mentioned earlier, the Company's preferred plan in its 2021 ERP & CEP includes adding 2,300 MW of wind, 1,600 MW of large-scale solar, 400 MW of battery storage, and we expect an additional 1,158 MW of dispatchable generation. Public Service's proposal also includes an approach to address all of Public Service's remaining coal units, and it provides for early retirement, conversion to natural gas, or altered operations at Public Service's existing coal-fired generation units. Under the Company's preferred plan in its 2021 ERP & CEP, the Company estimates an emission reduction of 84 percent by 2030 from 2005 levels.

Q. PLEASE DISCUSS THE COMPANY'S PROPOSALS WITH RESPECT TO ITS COAL UNITS IN ITS ONGOING 2021 ERP & CEP.

A. In the Company's 2021 ERP & CEP, Public Service has proposed the following actions:

- Proposed retirements of Craig Unit 1 in 2025 and Craig Unit 2 in 2028;
- Proposed retirements of Hayden Unit 1 in 2028 and Hayden Unit 2 in 2027;
- Reduced operations at Comanche Unit 3 starting in 2030 with a proposed early retirement in 2040, representing a 30-year acceleration on its retirement date; and,
- A proposed conversion to natural gas at Pawnee.

The Company's proposal in its ongoing 2021 ERP & CEP proceeding has not yet been approved by the Commission. A final decision in Phase I of the 2021 ERP & CEP is likely by the first quarter of 2022, so the Company and other stakeholders will not know the outcome of the 2021 ERP & CEP Phase I until near the end of this rate proceeding.

Q. HOW DO THE COMPANY'S PROPOSED EARLY RETIREMENTS AND CONVERSIONS IMPACT THE WAY THE COMPANY MANAGES ITS GENERATION CAPITAL AND O&M BUDGETING AND PLANNING PROCESSES?

A. Energy Supply's overarching objective is ensuring the Company continues to provide safe, reliable, and cost-effective electric service. Public Service is held to these standards until the day a unit or plant closes. It is therefore important that we maintain every unit within our generation fleet in safe working condition for its entire used and useful life. While the Company's Energy Supply group considers a number of criteria in determining which capital projects to undertake at its generation plants, the planned retirement date of a plant or unit is an important factor we take into account in developing our capital budgets to ensure safe, reliable, and cost-effective service. For example, we considered the Commission-approved early retirement dates for Comanche 1 and 2 in re-evaluating the scope of planned capital projects in developing our capital budgets for those units. If earlier retirement dates are approved for other plants, Energy Supply will then take those new retirement dates into account in re-evaluating planned capital projects and developing our capital budgets. While projects for soon-to-be retired units are evaluated using the same criteria I identified above in Section III, a unit's retirement date may impact the scoring of, and weight applied to, each criterion. This in turn may result in a lower probability of a project related to a soon-to-be retired unit being completed. That said, the Company certainly places increased scrutiny on its capital and O&M costs used to support its remaining fossil fuel fleet as it seeks to transition to cleaner resources.

With respect to O&M budgets, expenses tend to fall into two categories, including (1) O&M base budget work, and (2) larger, O&M projects. With respect to Generation's base budget work, which would include, for example, labor, parts, supplies, materials, and chemicals, the Company reviews historical averages over previous years and then extrapolates the budget forward based on known changes. For example, if chemical costs increase, the Company will adjust its budget accordingly. The Company will take into account anticipated plant retirements or other operational changes in setting its base budget and prioritizing its base budget spend, but base budgets are unlikely to change significantly based on a pending or anticipated retirement since these costs are needed to safely and reliably operate Generation plants through the end of their useful lives.

With respect to larger O&M projects, the Company analyzes projects using a cost-benefit analysis that is similar to the one it uses for capital project selection and prioritization. Like the capital budgeting process, the O&M project budgeting and planning process takes into account anticipated plant retirements and/or operational changes.

Q. HAS THE COMPANY MODIFIED ITS CAPITAL AND O&M BUDGETS PRESENTED IN THIS PROCEEDING TO ACCOUNT FOR ITS PROPOSED 2021 ERP & CEP RETIREMENTS AND CONVERSIONS?

A. In line with the discussion above, the Generation Business Area has not made major modifications to its O&M and capital budgets to address the proposed retirements and conversions contained in the Company's ERP & CEP. This is due to (1) the fact that these proposals are pending before the Commission and are not likely to be approved for some time, and (2) while the Generation Business Area is – and will remain – extremely vigilant in deciding which capital and O&M projects to pursue with respect to its fossil fuel fleet, it still has an obligation to safely and reliably operate each and every unit until it is no longer in service.

V. <u>GENERATION RETIREMENTS AND DECOMMISSIONING STUDY</u>

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

A. In this section of my Direct Testimony, I discuss the updated Decommissioning Study that the Company retained Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") to conduct. I also discuss the retirements that have occurred or are expected to occur through the end of the 2022 FTY.

Q. HAS PUBLIC SERVICE HAD ANY NEW OR UPDATED DECOMMISSIONING STUDIES PREPARED FOR THIS ELECTRIC RATE CASE?

A. Yes. Public Service retained Burns & McDonnell to conduct a Decommissioning Cost Study ("Decommissioning Study") for the Company's generation fleet, which is provided as Attachment KLW-1 to my Direct Testimony. 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.

Q. WAS ENERGY SUPPLY INVOLVED IN THE PREPARATION OF BURNS & MCDONNELL'S DECOMMISSIONING STUDY?

A. Yes. As reflected throughout Attachment KLW-1, while Burns & McDonnell prepared the Decommissioning Study independently, Company personnel remained available and involved throughout the process to coordinate site visits, answer questions, and provide any available data, feedback, or other information requested by Burns & McDonnell to facilitate its study. Burns & McDonnell's site visits occurred in February 2020 and were accompanied by Public Service personnel and individuals from NorthStar Demolition and Remediation LP, which is a demolition contractor.

Q. PLEASE PROVIDE AN OVERVIEW OF THE DECOMMISSIONING STUDY.

A. The Decommissioning Study contains site-specific decommissioning cost estimates for Public Service's generation fleet. The cost estimates contain site-specific attributes, such as pond areas, coal storage yard sizes, and number of stacks. Units studied include the Company's coal-fired units, natural gas fired units, hydroelectric facilities, wind farms, and solar farms. The Decommissioning Study then estimates the decommissioning costs, salvage credits, and net project costs for decommissioning each facility on a plant-by-plant basis.

Q. WHAT PURPOSE DOES THE DECOMMISSIONING STUDY SERVE IN THIS PROCEEDING?

A. As Mr. Dane Watson, Managing Partner of Alliance, discusses in his Direct Testimony, the purpose of the Burns & McDonnell Study is to establish the updated decommissioning cost estimates (*i.e.*, production plant net salvage amounts) for Public Service's steam, hydro, and other production plants that Alliance relied on in preparing Public Service's Electric and Common Utility Plant Depreciation Rate Study ("Depreciation Study"), provided as Attachment DAW-1 to Mr. Watson's Direct Testimony.

Q. HAVE THERE BEEN ANY SIGNIFICANT GENERATION RETIREMENTS SINCE THE 2019 ELECTRIC PHASE I, AND ARE THERE ANY PLANNED THROUGH THE END OF 2022?

A. Yes. The Company retired its Ponnequin wind farm in 2019 and completed all work associated with the Ponnequin wind farm retirement in 2020. The Company retired its Zuni plant in 2019; decommissioning work on that facility begins in 2021 and will be completed in 2023. Last, the Company's Comanche 1 Unit will be retired on December 31, 2022.

Q. CAN YOU PROVIDE AN OVERVIEW OF THE REGULATORY BACKGROUND SURROUNDING THE ZUNI RETIREMENT?

A. Yes. Zuni was an electric generating station in Denver consisting of two steam production units that retired from electric production in 2015 and steam heat production that retired in late 2019. In Proceeding No. 20A-0268E, the Company filed an application requesting approval of its decommissioning plan for Zuni in accordance with the process and structure approved by the Commission in the Company's 2009 electric rate case, Proceeding No. 09AL-299E.[8] Through the Commission-approved Settlement Agreement reached in Proceeding No. 20A-0268E,[9] the parties unanimously agreed to terms by which the Company would begin the decommissioning process for Zuni through issuance of a Request for Proposals ("RFP"). Under the terms of the Settlement Agreement, the Company also agreed "to make a presentation in direct testimony in its next Phase I electric rate case to provide an update on the progress of completing actual decommissioning of Zuni as it relates to the current amortization recovery approved."[10]

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[8] *See* Proceeding No. 09AL-299E, Decision No. C09-1446, at ¶ 117 (mailed Dec. 24, 2009).
[9] 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.
[10] Proceeding No. 20A-0268E, Unanimous and Comprehensive Settlement Agreement, at 16 (filed Dec. 4, 2020).

Q. PLEASE PROVIDE AN UPDATE ON THE COMPANY'S PROGRESS TOWARD COMPLETING ACTUAL DECOMMISSIONING OF ZUNI.

A. The Company is currently decommissioning the Zuni Generating Station, but it is early in the process. The projected costs for the Commission-approved decommissioning plan is $22.7 million.[11] The $22.7 million project cost estimate was updated in Proceeding No. 20A-0268E based on the Zuni Decommissioning Cost Study performed by Burns & McDonnell and included as Attachment KLW-14. Initial gas purge work has begun at the facility, and the Company is negotiating with a contractor to abate the plant asbestos and to demolish the structure. The main decommissioning activities are not scheduled to begin until July of this year, with expected demolition completion in March 2023. The progress of completing actual decommissioning of Zuni is preliminary (approximately $300,000 through January 2021). For the revised amortization of the Zuni regulatory asset, please refer to Ms. Laurie J. Wold's Attachment LJW-7.

Q. WITH RESPECT TO THE OTHER RETIREMENTS THAT WILL OCCUR THROUGH THE END OF 2022, HOW ARE THESE ADDRESSED IN THIS PROCEEDING?

A. The Burns & McDonnell Study I mentioned above contemplates the updated and expected decommissioning activities and costs associated with the Company's generation fleet, including the unit retirements that will occur through the end of 2022. Witness Mr. Watson has incorporated the decommissioning and net salvage

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[11] *See* Proceeding No. 20A-0268E, Unanimous and Comprehensive Settlement Agreement, at ¶ 6 (filed Dec. 4, 2020), approved by Decision No. R20-0888, at ordering ¶¶ 1–2 (mailed Dec. 14, 2020).

values identified in the Burns & McDonnell Study into the depreciation rates that he supports in this case.

VI. GENERATION CAPITAL ADDITIONS FROM SEPTEMBER 1, 2019 THROUGH DECEMBER 31, 2022

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

A. The purpose of this section of my testimony is to present the Generation Business Area's capital additions since the Company's 2019 Electric Phase I, beginning September 1, 2019 and projected through December 31, 2022, for which Public Service is also seeking approval to recover through base rates in this Proceeding.

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

A. As reflected in Attachment KLW-2, the Company is seeking recovery of $847.0 million for the Generation Business Area capital additions (*i.e.*, plant in service) placed in service between September 1, 2019 and December 31, 2020. As shown in Attachment KLW-3, the Company is seeking recovery of $464.0 million for capital additions that are forecasted to be placed in service between January 1, 2021 and December 31, 2022. Each of these attachments reflects the year that each project has been or will be placed in service. Table KLW-D-2 below provides the total Generation Business Area capital additions from September 1, 2019 to December 31, 2022, broken out into the categories identified in Section III above. Throughout my Direct Testimony, capital additions data from 2019 and 2020 represent actual costs, while 2021 and 2022 capital additions include actual plant in service for January 2021 and budgeted data for the remainder of 2021 and all of 2022.

TABLE KLW-D-2:
Generation's 2019-2022 Capital Additions*
(Dollars in Millions)

Category	9/1/2019 through 12/31/2019 Actual	2020 Actual	2021 (January Actual + Forecast)	2022 Forecast	Total
Renewable / New Generation	$5.3	$761.3	$59.0	$99.5	**$925.1**
Environmental Improvement	$4.9	$2.3	$5.2	$10.4	**$22.8**
Reliability / Performance Enhancement	$11.9	$61.3	$165.4	$124.5	**$363.1**
TOTAL	**$22.1**	**$824.9**	**$229.7**	**$234.3**	**$1,311.0**

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

The figures in Table KLW-D-2 are stated on a Total Company 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 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 projects Public Service has placed into service or will place into service before December 31, 2022.

A. Renewable/New Generation Capital Additions

Q. WHAT ARE THE MAJOR GENERATION CAPITAL ADDITIONS RELATED TO RENEWABLE/NEW GENERATION PROJECTED THROUGH 2022?

A. The major projects comprising the Company's capital additions and projected capital additions to Renewable/New Generation between September 1, 2019 and December 31, 2022 include Cheyenne Ridge, the Valmont and Manchief acquisitions, and the Cabin Creek upgrade/expansion.

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

A. Cheyenne Ridge consists of a 500 MW wind farm and a 65-mile 345 kV generation tie-line ("Gen-Tie")[12] needed to connect the wind farm to Public Service's transmission system. In Phase II of the Company's 2016 ERP, the Commission authorized Public Service to own Cheyenne Ridge as part of its CEPP. In the Phase II decision, the Commission required Public Service to file an application for a CPCN and required Public Service to propose a ratepayer protection mechanism in the CPCN proceeding, along with cost recovery proposals. The CPCN proceeding concluded with a Corrected Non-Unanimous Comprehensive Settlement Agreement ("Cheyenne Ridge Settlement"), which was approved by Decision No. C19-0367. The Cheyenne Ridge Settlement includes a presumption of prudence, consistent with Rule 3617(d), for a point cost of $743 million (including the Gen-Tie), and provides that Public Service is to bring forward the actual costs

[12] Because the Gen-Tie is a transmission asset that directly serves only one generation project, its costs have been recovered through the ECA.

for recovery in the next rate case following the commercial operation of the project (*i.e.*, this rate case).[13] As part of the Cheyenne Ridge Settlement, the Company agreed to submit quarterly reports in Proceeding No. 18A-0905E on Cheyenne Ridge's progress during construction.[14] Among other things, the quarterly reports provided status updates on major contracts; engineering, procurement, and construction activities; project costs; and project schedule. The Company filed its last status report in the Cheyenne Ridge Proceeding on October 30, 2020, which is attached to my Direct Testimony as Attachment KLW-4.

Q. WHEN DID CHEYENNE RIDGE GO INTO SERVICE?

A. Cheyenne Ridge achieved commercial operation in August 2020, approximately three months ahead of schedule.

Q. WHAT WERE THE TOTAL CAPITAL COSTS INCURRED TO PLACE CHEYENNE RIDGE IN SERVICE?

A. The total capital costs associated with in-servicing Cheyenne Ridge, including the transmission Gen-Tie, were $735.6 million. Of this, $674.9 million was for the generation portion, and $60.2 million was for the Gen-Tie.[15] These capital costs include land and land rights, wind turbines, electronics and communications equipment, roads, capital costs associated with construction of the operating and maintenance building, collection substations, and other materials and parts

[13] Proceeding No. 18A-0905E, Decision No. C19-0367, at ¶¶ 22, 39 (mailed Apr. 25, 2019). This is subject to two exceptions I describe below.
[14] Proceeding No. 18A-0905E, Corrected Non-Unanimous Comprehensive Settlement Agreement, at 7 (Mar. 15, 2019).
[15] Energy Supply technically manages the budget for the Cheyenne Ridge Gen-Tie, as it is classified as Energy Serving Production, but Company witness Ms. Connie L. Paoletti supports the reasonableness and prudency of these costs since the asset is managed by the Company's Transmission Department.

needed to construct Cheyenne Ridge. The October 2020 Cheyenne Ridge Construction Progress Report filed in Proceeding No. 18A-0905E (Attachment KLW-4) provides additional information concerning the various cost categories that comprise Cheyenne Ridge, and Attachment KLW-5 to my Direct Testimony provides additional detail regarding the $735.6 million in total capital costs.

Q. ARE THERE ANY ADDITIONAL PROVISIONS FROM THE CHEYENNE RIDGE SETTLEMENT YOU WOULD LIKE TO DISCUSS?

A. Yes. As I noted above, the Cheyenne Ridge Settlement contains several provisions relevant to this Proceeding. First, the Commission issued Public Service a presumption of prudence for base rate recovery of capital costs up to $743 million to develop the project, but the Commission required that Public Service bring forward the actual point cost for evaluation in this proceeding.[16] Second, the parties to the Cheyenne Ridge Settlement agreed that wind production from Cheyenne Ridge would be "evaluated in the first electric base rate proceeding filed after commercial operation of the Project."[17]

Q. REGARDING THE FIRST POINT, WHAT IS PUBLIC SERVICE REQUESTING WITH RESPECT TO COST RECOVERY FOR CHEYENNE RIDGE IN THIS PROCEEDING?

A. As explained in Company witness Mr. Berman's Direct Testimony and consistent

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[16] Proceeding No. 18A-0905E, Decision No. C19-0367, at ¶¶ 22, 39 (mailed Apr. 25, 2019); Proceeding No. 18A-0905E, Corrected Non-Unanimous Comprehensive Settlement Agreement, at 4 (Mar. 15, 2019) ("The Settling Parties agree that the point cost for capital costs establishing a presumption of prudence in this proceeding for the Project will be $743 million, inclusive of Allowance for Funds Used During Construction ("AFUDC").").

[17] Proceeding No. 18A-0905E, Corrected Non-Unanimous Comprehensive Settlement Agreement, at 13 (Mar. 15, 2019).

with the Cheyenne Ridge Settlement, Public Service requests to move the costs associated with Cheyenne Ridge from the ECA into base rates. As reflected in Attachment KLW-5, the total costs to construct and place Cheyenne Ridge in service are $735.6 million, including both the generator costs and transmission Gen-Tie costs. These costs are lower than the $743 million presumed prudent in Decision No. C19-0367. The Company therefore requests the Commission find these costs reasonable and prudent and authorize base rate recovery.

Q. ARE THERE ANY PARTICULAR FACTORS THAT CONTRIBUTED TO THE COST SAVINGS ON THE CHEYENNE WIND PROJECT?

A. There is not any one dominant cost category where Public Service achieved dramatic changes, but rather a number of project components that collectively resulted in consequential savings. As explained in the October 2020 Cheyenne Ridge Construction Progress Report (Attachment KLW-4), the Company sought to reduce project costs wherever feasible and reviewed its detailed project budget line items on a regular basis to identify potential cost savings opportunities. Any significant cost savings that were identified over the course of construction are accounted for in the cost estimates reported in Attachment A to the October 2020 Cheyenne Ridge Construction Progress Report. From July 1, 2020 through September 30, 2020, cost savings were realized by a reduction in AFUDC, lease costs, and project labor costs due to achieving an early Commercial Operation Date ("COD"). Additionally, more resources were devoted to complete wind turbine construction more quickly, and crew schedules were adjusted to start earlier in the day to avoid seasonal weather patterns and minimize schedule delays. Other cost savings were driven by permitting and environmental compliance savings.

Q. REGARDING THE SECOND POINT YOU MENTIONED ABOVE, PLEASE DISCUSS THE CHEYENNE RIDGE WIND PRODUCTION EVALUATION AGREED TO AND APPROVED IN THE CHEYENNE RIDGE PROCEEDING, PROCEEDING NO. 18A-0905E.

A. Under the Cheyenne Ridge Settlement, the Commission will evaluate wind production at Cheyenne Ridge in the first general rate case following the COD.[18] As Mr. Berman explains, given the timing of this rate case filing and the fact that the Company does not yet have a full year of production data for Cheyenne Ridge, we are proposing the Commission take no action regarding the wind production levels and revisit this issue in the Company's next-filed rate case after at least a full year of production data is available.

Q. WHAT HAS THE ACTUAL PERFORMANCE OF THE WINDFARM BEEN SINCE COMMERCIAL OPERATION IN AUGUST 2020?

A. Attachment KLW-6 and Table KLW-D-3 below reflect the actual MWh production data, by month, for Cheyenne Ridge from its COD in August 2020 through May 2021.

The Cheyenne Ridge wind farm has produced 1,456.5 gigawatt-hours ("GWh") in its first ten months of commercial operation. Based on this information,

[18] Proceeding No. 18A-0905E, Corrected Non-Unanimous Comprehensive Settlement Agreement, at 13 (Mar. 15, 2019).

the annualized wind production can be estimated at 1,747.9 GWh. The monthly average capacity factor, through May 2021, is also listed in Table KLW-D-3 below.

TABLE KLW-D-3:
Cheyenne Ridge Total Production

Month	Total Production (MWh)	Capacity Factor (%)
8/20	150,292	8.23%
9/20	152,663	44.41%
10/20	88,638	24.93%
11/20	150.510	43.71%
12/20	173,213	48.74%
1/21	136,946	38.50%
2/21	100,043	30.93%
3/21	185,881	52.34%
4/21	162,438	47.25%
5/21	155,919	43.88%

Q. WHAT DID THE COMPANY FORECAST THE ANTICIPATED PRODUCTION AND CAPACITY FACTOR WOULD BE FOR THE CHEYENNE RIDGE FARM IN ITS CPCN PROCEEDING?

A. The Company bid for a wind farm with a capacity of 500 MW, and an expected annual GWh production of 2,220 GWh. This converts to a net capacity factor of 50.85 percent.

Q. CAN YOU ELABORATE ON WHY THE INITIAL PRODUCTION LEVELS HAVE BEEN LOWER THAN WHAT WAS FORECASTED IN THE CHEYENNE RIDGE CPCN PROCEEDING?

A. Yes. I would first reiterate that this is a limited data set since it only includes the first ten months of commercial operation. However, the main driver of this variance was mechanical issues associated with the wind turbines that resulted in more downtime than initially anticipated. Because the turbines are still under warranty, Public Service is working with Vestas to address and resolve these issues, and we anticipate production will increase as the mechanical issues are resolved. Additionally, curtailments driven by system conditions on the Rush Creek/Cheyenne Ridge Gen-Tie have also lowered total production. Further compounding these issues, unfavorable wind conditions at Cheyenne Ridge have also lowered total generation production amounts. The Company is continuing to work proactively to address these issues and anticipates that production levels will increase with time. Company witness Mr. Berman addresses the Company's recommendation in more detail.

Q. TURNING TO THE NEXT PLANT IN THIS CATEGORY, PLEASE DISCUSS THE VALMONT AND MANCHIEF ACQUISITIONS.

A. In Phase II of Public Service's 2016 ERP, the Commission approved the Company's CEPP. As part of the CEPP, Public Service was authorized to acquire 340 MW of existing natural gas generation assets. Valmont Units 7 and 8 (approximately 80 MW combined) and Manchief Units 11 and 12 (approximately 260 MW)[19] (discussed below) comprised this 340 MW. After the 2016 ERP, Public Service applied for CPCNs to acquire Valmont Units 7 and 8 and Manchief Units 11 and 12. The applications were considered in Proceeding No. 19A-0409E, which was resolved through a Settlement Agreement granting Public Service the requested CPCNs.[20] Notably, the Commission also issued a presumption of

[19] The capacities for Valmont and Manchief referenced in Proceeding No. 19A-0409E were based on winter net dependable capacity, rather than the summer net dependable capacity presented here and earlier in my Direct Testimony.

[20] The Settlement Agreement was approved by Decision No. R20-0108 (mailed Feb. 19, 2020).

prudence for the acquisitions of both Valmont and Manchief consistent with Commission Rule 3617(d). Specifically, Recommended Decision No. R20-0108, which went into effect by operation of law, found "the ALJ agrees and finds that the acquisition of Valmont and Manchief will have a presumption of prudence consistent with Rule 3617(d) of the Rules Regulating Electric Utilities, 4 CCR 723-3."[21]

Q. WHAT WAS THE FINAL PURCHASE PRICE FOR VALMONT?

A. The acquisition closed on June 1, 2020, and the final acquisition price was $18.5 million. This price was deemed prudent pursuant to the Recommended Decision, which explained:

> The Settling Parties believe exercise of the Early Purchase Option for Valmont is consistent with Public Service's approved resource plan and is cost-effective and beneficial for customers. They agree that exercise of the Early Purchase Option to acquire Valmont two years earlier than initially approved in Phase II is prudent from an operational and customer perspective. First, the Settling Parties assert that an analysis developed by Public Service projects that on a present value basis, the cost to customers of the Early Purchase Option is about $1 million lower than the cost associated with a May 2022 purchase. The Early Purchase Option price is as low as $18.5 million if exercised by May 1, 2020, but increases on a sliding scale over time up to $19.9 million by May 1, 2022.[22]

Q. ARE THERE ANY ADDITIONAL COSTS ASSOCIATED WITH THE VALMONT ACQUISITION PUBLIC SERVICE IS SEEKING TO RECOVER THROUGH THIS PROCEEDING?

A. Yes. Public Service has incurred approximately $400,000 in transition costs,

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[21] Proceeding No. 19A-0409E, Decision No. R20-0108, at ¶ 39 (mailed Feb. 19, 2020).
[22] Proceeding No. 19A-0409E, Decision No. R20-0108, at ¶ 42 (mailed Feb. 19, 2020).

including labor and facility preparations necessary to prepare the facility for transition of ownership and operations.

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 also 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 will acquire Manchief in 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.[23] The Company anticipates incurring an additional $1.6 million in costs following acquisition, for facility preparations and employee training, similar to Valmont.

Q. PLEASE DESCRIBE THE CABIN CREEK UPGRADE/EXPANSION AND THE RELATED CAPITAL ADDITIONS THE COMPANY IS SEEKING TO RECOVER IN THIS RATE CASE.

A. The Cabin Creek Unit A/B and Upper Reservoir upgrade/expansion project was approved in Proceeding No. 15A-0304E by Decision No. C15-0955 issued August 31, 2015.[24] In that proceeding, the Company applied for a CPCN to upgrade its Cabin Creek Hydroelectric Facility, which provides a pumped storage resource. Public Service sought to expand the facility's capacity from 324 MW to 360 MW

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[23] *See* Proceeding No. 19A-0409E, Decision No. R20-0108, at ¶¶ 39-40, 50 (mailed Feb. 19, 2020).
[24] Public Service has categorized the three projects as New Generation/Renewable Energy since the Cabin Creek Unit A/B projects resulted in increased capacity and because the three were addressed together in the Company's CPCN filing, the Company notes, however, that the Upper Reservoir project is reliability-driven.

and to expand the upper reservoir to allow for 112 MWh of additional energy generation per storage cycle. Public Service proposed expanding the Cabin Creek facility in tandem with upgrades needed at the facility to extend its life for an additional 40 years.

The Company initially estimated the cost to extend the life of the facility without upgrades would be $68.3 million, and the incremental cost to expand and upgrade the facility would be approximately $19.7 million, for a total estimated cost of $88 million. The Company later filed an Amended Application in that proceeding reducing the total cost estimate to approximately $86.9 million, including approximately $18.6 million in incremental upgrade/expansion costs, which was granted by Decision No. C15-0955. The Company also committed in its Amended Application to file annual status reports on the project, the most recent of which was filed on March 26, 2021 and showed an updated project budget of $88.2 million. The Company's annual status reports in Proceeding No. 15A-0304E provide additional details supporting revisions to the project's scope, construction timeline, and budget since the issuance of Decision No. C15-0955.

As stated in the Company's most recent annual report, the project is expected to be completed by August 2022. Work on Unit A is nearly complete, and the Company expects to place it in service imminently. The Upper Reservoir expansion is expected to go in service later this year, and the Company will begin construction on the Unit B upgrades in February 2022 with an expected in-service date in August 2022. In total, the project is projected to cost $45.5 million for the

Unit A upgrade, $43.3 million for the Unit B upgrade, and $2.9 million for the Upper Reservoir expansion.

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

A. Yes. Other Renewable/New Generation capital costs Public Service is seeking to recover in this Proceeding include, for example, 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.

B. <u>Environmental Improvement Capital Additions</u>

Q. WHAT ARE THE PRIMARY DRIVERS OF GENERATION CAPITAL ADDITIONS RELATED TO ENVIRONMENTAL IMPROVEMENT SINCE THE COMPANY'S 2019 ELECTRIC PHASE I AND PROJECTED THROUGH 2022?

A. The major projects comprising the Company's capital additions and projected additions to Environmental Improvement between September 1, 2019, and December 31, 2022 include:

- The Pawnee "L" Pond stabilization/recap project;
- Projects related to the Cherokee process water ponds;
- Selective Catalytic Reduction ("SCR") catalyst replacements at Comanche, Hayden, and Pawnee; and,
- Continuous Emissions Monitoring System ("CEMS") analyzer replacements at the Fort St. Vrain, Hayden, and Valmont stations.

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

Q. PLEASE ELABORATE ON THE CAPITAL ADDITIONS RELATED TO THE PAWNEE "L" POND STABILIZATION/RECAP PROJECT.

A. Prior to this stabilization project, Pawnee generating station's pond "L" was capped per Colorado solid waste regulations.[25] That original cap's integrity became compromised due to unexpected settlement of evaporation pond solids. These solids were previously disposed of in the disposal cell but later caused sink holes to form that damaged the disposal cell cap. State regulations required corrective action, and this project was initiated to replace the cap after an evaluation of the existing cap showed repair to not be feasible, due to the level of damage to the cap and potential instability of the waste material. To comply with State regulations, Public Service stabilized the waste in the disposal cell, replaced and re-graded the soil cover, and recapped it with a high-density polyethylene ("HDPE") system to meet solid waste regulation permeability and final surface stabilization requirements. This work represented $4.0 million in capital additions placed in service in 2019.

Q. PLEASE ELABORATE ON THE CAPITAL ADDITIONS RELATED TO THE CHEROKEE PONDS PROJECTS.

A. Under the Colorado State Section 9 Regulation and federal regulations, Public Service was required to close several of the Cherokee generating site's ponds.

[25] The "L" pond is the name of one of the ponds located at Pawnee, where pond names are given letter names ("A", "B", "C", etc.).

These process water ponds were not lined and did not meet requirements of the State's new Section 9 Regulation. Public Service's closure plan was approved by the State upon issuance of these new regulations and closure of these ponds satisfied that approved plan. The site ponds included three ash ponds, the cooling tower retention pond, two polishing ponds and the emergency spill pond. Closure included removal of all waste that had settled in the ponds and confirmation of such removal by sampling and visual certification. Other work for this project includes the conversion of the west ash pond into a stormwater pond. The Company anticipates placing $3.1 million in service in 2021 for these projects.

Q. PLEASE ELABORATE ON THE CAPITAL ADDITIONS RELATED TO SCR CATALYST REPLACEMENT PROJECTS.

A. Coal and gas-fired generating stations use SCR catalyst to aid in removing NOx emissions from flue gas streams to allow compliance 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. In 2020 and 2021 SCR catalyst was, or is planned to be, replaced at Comanche, Hayden, and Pawnee generating stations. The Company placed $7.0 million in 2020 for Comanche 3 and Hayden, and anticipates placing $2.2 million in service in 2022 for Pawnee.

Q. PLEASE ELABORATE ON THE CAPITAL ADDITIONS RELATED TO THE CEMS ANALYZER 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. As these instruments fail or become obsolete, they 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 include: 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.

C. <u>Reliability/Performance Enhancement Capital Additions</u>

Q. WHAT ARE THE PRIMARY DRIVERS OF GENERATION CAPITAL ADDITIONS RELATED TO RELIABILITY/PERFORMANCE ENHANCEMENT SINCE THE COMPANY'S 2019 ELECTRIC PHASE I AND PROJECTED THROUGH 2022?

A. Reliability/Performance Enhancement projects can be broken out into three general categories: Combustion Turbine Part Replacement, Emergent Projects, and General/Other Projects.

Q. PLEASE DESCRIBE THE COMBUSTION TURBINE PART REPLACEMENTS PROJECTS THE COMPANY UNDERTAKES AND IS SEEKING RECOVERY OF IN THIS PROCEEDING.

A. Public Service performs combustion turbine parts replacements on interval schedules driven by operating hours and number of turbine starts. Original Equipment Manufacturers ("OEMs") set the criteria for these intervals based on the model of the turbine. Fort St. Vrain Units 5 and 6 and Blue Spruce Units 1 and 2 had Hot Gas Path parts replaced in 2019 and 2021. These projects included the removal of the existing controls, which were due for replacement under their replacement schedules, with new controls installed. In addition to these recurring parts replacements, Public Service has also been performing (and will continue to perform) 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. Fort St. Vrain Unit 4 underwent one such flexibility upgrade in 2020 in addition to receiving a new rotor. The removed rotor will be refurbished and installed in Fort St. Vrain Unit 2 in 2022, along with new turbine shells and flexibility upgrades. Each of these parts replacement or upgrade projects may include replacing high wear parts such as turbine buckets/blades and nozzles, combustion nozzles and other components such as compressors, gas control valves, and fuel piping systems to support the new components. This work represented approximately $5.7 million in capital additions placed in service in 2019 and $34.7 million in 2020. The Company anticipates placing approximately $70.0 million in service in 2021 and $72.0 million in service in 2022.

Q. PLEASE DESCRIBE THE EMERGENT PROJECTS THE COMPANY IS SEEKING RECOVERY OF IN THIS PROCEEDING.

A. A portion of our capital budget is dedicated to emergent work that occurs at our plants and is budgeted based on our many years of experience operating generation plants. This type of work includes responding to failures of equipment such as air compressors, control valves, gearboxes, pumps, and motors, and other replacements or repairs determined through the course of testing and monitoring equipment on a regular basis. Even with Public Service's many years of operating experience, while we can expect that equipment failures can and will occur, the specific types of equipment that will fail are not always readily predictable. We have used our past experience to set aside appropriate budget amounts to offset these costs so that budgets can remain stable and more accurately account for these projects. This work represented $4.0 million in capital additions placed in service in 2019 and $7.0 million in 2020. The Company anticipates placing $7.0 million in service in 2021 and $10.2 million in service in 2022.

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

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

- *Hayden Foxboro Cyber Security Suite Project:* In 2020, Xcel Energy's Enterprise Security Services Group identified a potential cyber vulnerability associated with the Hayden plant and installed a new security suite.

- *Shoshone Hydro Plant Unit A and B Exciter Replacement:* A 2020 flood damaged the excitation systems of Unit A and Unit B. Repair and replacement will include new exciter and support equipment such as control cabinets and junction boxes. Damaged exciter equipment will be removed and disposed of. All equipment will be functionally tested upon completion of work.

- *Blue Spruce #1 and #2 Generator Core Tightening and Lamination Projects:* During the Spring 2021 maintenance outage, inspection of the stator iron discovered that it was loose via a knife check, and iron dusting was found around the turbine end windings. This indicated decay of the core material. This project included removing the generator rotor, replacing its wedges, and tightening the generator stator core, which mitigated damage to core iron. At Unit 1, this project included installation of a new rotor after electrical testing indicated an internal electrical failure was imminent. Replacement was deemed to be more cost effective given the duration of the repair.

Q. PLEASE DESCRIBE THE "GENERAL/OTHER" PROJECTS THE COMPANY IS SEEKING RECOVERY OF IN THIS PROCEEDING.

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 SEVERAL "GENERAL" PROJECTS?

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

- *Cherokee Wastewater*: To meet new CDPHE discharge requirements that will become effective on January 1, 2022, this project will cease the discharging of process water into the South Platte River. Cherokee Plant process water will now be treated with a series of filters and reverse osmosis vessels, stored, and reused for plant system support as needed. Discharge of some treated wastewater will still be allowed under the new requirements, though to a lesser extent compared with the current design and practice. The Company anticipates placing $42.2 million in service for this project in 2021 to accommodate the CDPHE's January 1, 2022 compliance date.

- *Ames and Tacoma*: These facilities are two of Public Service's hydroelectric generation stations. The existing Ames penstock is over 65 years old and has developed several leaks and noted areas of thinning. The original Tacoma wood flow line was replaced with steel pipe in 1924 and cement lined in the 1960s. It has also developed significant leaks. The Ames hydro penstock and Tacoma hydro flow line replacements will provide reliable water transportation systems from the storage sources to the hydro plants. The Company anticipates placing $5.1 million in service in 2021 for the Tacoma project and $7.9 million in service in 2022 for the Ames project.

- *Rocky Mountain Energy Center Superheater Replacement:* In the RMEC thermal design, the Heat Recovery Steam Generator ("HRSG") uses the heat from combustion turbine exhaust gases to convert water to steam, which in turn drives the plant's steam turbine. The HRSG superheater section (*i.e.*, the boiler) is original equipment and was installed in 2002; at approximately 20 years old, it has reached the end of its life, recently experiencing periodic overheating occurrences and tube leaks. Performance testing shows component degradation is approaching a point where replacement is necessary. To continue to generate steam, which enhances the unit's efficiency, requires replacement of tubing and piping sections. The Company anticipates placing $4.5 million in service for this project in 2021.

Q. PLEASE EXPLAIN WHY THE $1.31 BILLION IN GENERATION CAPITAL ADDITIONS THAT PUBLIC SERVICE IS SEEKING TO RECOVER AS PART OF THIS ELECTRIC RATE PROCEEDING ARE REASONABLE AND PRUDENT.

A. These capital additions are reasonable and prudent because they are needed to safely and reliably provide electric generation 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 as needed to reliably and safely operate our generation fleet; therefore, the $1.31 billion in capital additions that we are seeking base rate recovery of through this proceeding are reasonable and prudent and should be approved for recovery. Additionally, the Cheyenne Ridge, Valmont, and Manchief capital additions are presumed prudent up to their cost estimates pursuant to the CPCN proceedings discussed earlier in this section.

D. <u>Hydropower Study Deferral</u>

Q. WHAT COSTS IS PUBLIC SERVICE PROPOSING TO DEFER WITH REGARD TO ITS HYDROPOWER STUDY?

A. As Company witness Ms. Brooke A. Trammell discusses in her Direct Testimony, the Company is requesting approval to defer approximately $550,000 for contractor costs related to the study and development of a potential pumped hydro resource.

Q. CAN YOU PLEASE ELABORATE?

A. Yes. As the Company adds more intermittent renewable resources to its generation portfolio, storage resources become even more valuable. As Ms. Trammell discusses in more detail in her Direct Testimony in the Company's ongoing 2021 ERP & CEP and in this Proceeding, Public Service is seeking policy support and direction from the Commission to investigate the technological and economic feasibility of future generation resources that will facilitate progress toward our carbon emission reduction goals and maintain system reliability as more clean energy resources are added to the system. One of the specific generation resources/technologies the Company is investigating is pumped storage hydropower technologies, which can take many years (potentially over a decade) to develop. As Ms. Trammell explains in the 2021 ERP & CEP, by starting to pursue these technologies now, Public Service expects to achieve an in-service date of 2034, with preliminary activities associated with performing in-depth environmental studies and geologic exploration to start in 2022.

To advance these efforts, in 2019 Public Service commissioned a third-party engineering firm to study potential sites and options for a pumped hydro facility. The contractor's scope of work involved a screening study to evaluate and rank potential sites identified by Public Service personnel. Subsequently, the contractor performed on-site surface geological surveys for a limited suite of projects based on the rankings and further information provided in the screening study. Through working with the consultant, we have identified a potential site and have engaged the consultant to conduct a "pre-feasibility study" to further evaluate the identified site. This pre-feasibility study includes a number of components including:

- Technical studies, including site configuration, evaluation of site access, preliminary layout of dams and reservoirs, evaluation of basin hydrology, determination of turbine characteristics, powerhouse type and location, evaluation of water conveyance systems, surge protection requirements, and water supply;
- Development of high-level cost estimates;
- Overview of environmental and regulatory considerations; and,
- Development of an integrated project schedule.

Q. WHAT ARE THE CONTRACTOR COSTS ASSOCIATED WITH THE HYDRO WORK THAT THE COMPANY IS SEEKING TO DEFER IN THIS PROCEEDING?

A. The contracted-for amount for the pre-feasibility study is $553,110.

Q. WHY IS THIS DEFERRAL REASONABLE AND APPROPRIATE?

A. These study costs are readily known and easily tracked because we have a contract in place and will be incurring most costs during the 2021 calendar year. Because developing pumped hydro facilities requires such a long lead time given the land, water, and other environmental permitting approvals required, the Company might not be able to recover the costs for studies for many years. Moreover, as the Company transitions its generation fleet and pursues new zero-emission technologies, the Company believes it is appropriate for the Commission to support its efforts by approving a cost recovery framework that will assist the Company in investigating the feasibility of long lead time resources, like pumped storage hydropower. As I note above, the pre-feasibility study costs are readily known and easily trackable as they are being incurred pursuant to a contract. Thus, authorizing deferral of these capital costs is reasonable and appropriate as it provides timely cost recovery for tangible actions that will support the Company's ongoing emissions reductions efforts that are driven by Colorado's state policy goals as well as the Company's corporate goals of achieving zero carbon emissions by 2050.

VII. GENERATION O&M

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

A. In this section of my Direct Testimony, I discuss the Generation Business Area's 2020 O&M expenses and FTY adjustments, which the Company proposes to use to establish the Generation O&M levels included in the 2022 FTY for purposes of setting base rates. I describe the drivers of Generation O&M costs since the 2019 Electric Phase I, which was based off 2018 O&M levels.

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

A. To support the Company's generating fleet, a variety of O&M work is performed by the Generation Business Area. The costs to perform this work generally fall into six categories.

- *Internal Labor:* This includes costs for the labor force that runs our plants and supports the Generation Business Area's activities. Our Internal Labor budget includes planned overtime, and excluding overhaul related work, ensures we have personnel available to operate our plants at all hours of the day. Internal Labor is the largest component of our O&M costs. These costs are also influenced by commitments made as part of our collective bargaining agreements.

- *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 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.

A. Variance Between 2018 Historical Test Year ("HTY") and 2020 O&M

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

A. The Company's actual Generation O&M expenses in 2020 totaled $150.1 million. Table KLW-D-4 below identifies the amount of overall O&M costs by the categories I discuss above. Attachments KLW-7 and KLW-8 to my Direct Testimony provide a list of these expenses by Cost Element and FERC account, respectively.

TABLE KLW-D-4:
Generation 2020 Actual O&M Expenses*
Public Service Electric
(Dollars in Millions)

Cost Category	2020
Internal Labor	$59.4
Contract Labor	$59.2
Base Commodities	$11.5
Materials	$15.3
Craig Partnership	$4.5
Other	$0.2
Total	**$150.1**

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

Q. WHAT AMOUNT IS PUBLIC SERVICE PROPOSING FOR PURPOSES OF ESTABLISHING THE 2022 FTY?

A. Public Service is proposing to include $163.8 million in the Cost of Service for Generation O&M for the 2022 FTY, a change of $13.7 million from 2020 actuals. Public Service is additionally proposing $13.5 million in one-time adjustments, to be amortized over three years for the Comanche 1 & 2 bottom ash solution. I discuss all adjustments in more detail below.

Q. IS THE $163.8 MILLION IN REQUESTED O&M COSTS FOR THE 2022 FTY REFLECTED IN THE COST OF SERVICE PRESENTED BY MS. BLAIR?

A. Yes.

Q. WHAT ARE THE DRIVERS BETWEEN GENERATION'S 2018 O&M COSTS USED IN THE 2019 ELECTRIC PHASE I AND THE 2020 O&M COSTS?

A. Overall, the Generation Business Area's O&M costs increased by $6.6 million between 2018 and 2020. This is due to several factors, including generation unit/plant retirements and new renewable generation coming online, along with the Comanche 3 Outage, which took the unit out of service for much of 2020. The drivers are shown in Table KLW-D-5 below.

TABLE KLW-D-5:
Drivers of Generation O&M Expenses from 2018 HTY to 2020 Actuals*
Public Service Electric
(Dollars in Millions)

Driver	2018 HTY	Driver Amount	2020 Actual
Internal Labor	$63.4	$(4.0)	$59.4
Contract Labor	$34.6	$24.6	$59.2
Base Commodities	$11.1	$0.4	$11.5
Materials	$23.9	$(8.6)	$15.3
Craig Partnership	$4.4	$0.1	$4.5
Other	$6.1	$(5.9)	$0.2
Total	**$143.5**	**$6.6**	**$150.1**
*There may be differences between the sum of the individual category amounts and totals due to rounding.			

Q. CAN YOU PROVIDE MORE INFORMATION REGARDING THE SPECIFIC DRIVERS SHOWN IN TABLE KLW-D-5?

A. There are three noteworthy variances from the 2018 to 2020 O&M categories; as discussed below, the $6.6 million overall increase largely reflects increases in Contract Labor related to the Comanche 3 Outage and maintenance at new wind facilities. Many of these costs are offset by decreases in Materials and Other, including the expected insurance reimbursement related to the June Outage Event.

First, there was an increase of $24.6 million in contract labor. Most of this was due to wind additions and repairs at Comanche 3 (though, as explained below, the Comanche 3 increase has been offset by the expected insurance reimbursement). With respect to the two Company-owned wind farms, Rush Creek and Cheyenne Ridge, Rush Creek was in-service for only a portion of 2018, but it was in service for the full year in 2020, while Cheyenne Ridge was in service only for a portion of 2020. Public Service relies on a contract with Vestas to operate and maintain both wind farms, and therefore the 2020 actual O&M levels for contract labor were higher than 2018. As I discuss below, similar to how Rush Creek O&M was addressed in the 2019 Electric Phase I Proceeding, Public Service is proposing an adjustment to set O&M for Cheyenne Ridge based on a projected annualized level given that the facility has not been in service for a full year.

Second, there was a decrease of $8.6 million in materials costs. This amount was spread around the Company's fossil fuel sites as Public Service executed on several initiatives to maximize efficiency with respect to equipment repair and replacement schedules. For example, the Company began monitoring its filter systems to determine when the filters needed to be exchanged, instead of changing them on a regularly scheduled rotation. The Company has also been implementing Preventative Maintenance rationalization and equipment monitoring efforts to reduce costs and facilitate risk-based decision-making to better align asset management and prioritization. The Company performed a review of critical Preventative Maintenance to determine if the frequency was correct and monitoring was adequate. The Company has also utilized its monitoring and diagnostic center to assist in determining when work on equipment should be completed.

The third O&M category that experienced a noteworthy variance was the "Other" category, which experienced a decrease of $5.9 million. The primary driver of this decrease is Comanche 3 O&M costs that have been offset due to the Company's pending insurance claim, which I discuss in more detail below.

B. 2022 FTY Adjustments

Q. IS THE COMPANY PROPOSING ANY FTY ADJUSTMENTS TO ITS 2022 FTY COST OF SERVICE?

A. Yes. There are several forecasted adjustments Public Service is proposing to its 2020 Generation O&M levels for purposes of setting rates on a going forward basis, totaling approximately $13.7 million. Attachment KLW-9 to my Direct Testimony provides a list of these FTY adjustments by Cost Element and FERC account.

Q. PLEASE DESCRIBE NEW OR INCREMENTAL COSTS THAT THE GENERATION FUNCTION WILL INCUR DURING THE FTY.

A. The Company proposes the following new or incremental FTY O&M adjustments for its 2022 FTY: (1) a Comanche 3 chemicals and materials adjustment to reflect the lower than usual chemical and material inventories that were purchased in 2020 due to the Comanche 3 Outage, (2) an adjustment to reflect appropriate going-forward levels of O&M for the Manchief and units that have recently been acquired, (3) an adjustment to account for increasing air quality fees, (4) an adjustment to establish an annualized level of O&M for Cheyenne Ridge, (5) an adjustment to address an accounting error that incorrectly booked certain water costs associated with the Pawnee facility, and (6) an adjustment for costs associated with a new Cherokee wastewater facility. Table KLW-D-6 below provides a breakdown of these FTY adjustments, and Table KLW-D-7 shows the all-in impact on the Company's requested 2022 FTY. Note that these tables do not include two one-time adjustments, which I discuss in the next section of my testimony.

TABLE KLW-D-6:
FTY Adjustments to Generation's 2020 O&M
Public Service Electric
(Dollars in Millions)

O&M Expense	2022 FTY Adjustment*
Comanche 3 Chemicals and Materials	$1.9
Manchief and Valmont O&M	$0.7
Air Quality Fees	$0.3
Cheyenne Ridge O&M Annualization	$9.1
Pawnee Water Costs	$0.3
Cherokee Wastewater Facility	$1.4
Total 2022 FTY Adjustments	**$13.7**
*Does not include one-time adjustments, discussed in the following section. These are new O&M costs additional to what was spent and/or in-serviced since 2020.	

TABLE KLW-D-7:
FTY Adjustments to Generation's 2020 O&M (Total)
Public Service Electric
(Dollars in Millions)

	Total*
2020 Actual O&M	$150.1
FTY Adjustments*	$13.7
Total 2022 FTY Adjusted O&M	**$163.8**
*Does not include one-time adjustments, discussed in the following section.	

Q. PLEASE ELABORATE ON THE FTY ADJUSTMENT RELATED TO COMANCHE 3 CHEMICALS AND MATERIALS.

A. Because Comanche 3 was out of service during much of 2020, the Company did not incur expenses for chemicals and materials that would have typically been incurred at the unit. An adjustment of approximately $1.9 million is necessary to reflect chemicals and materials expenses which would be incurred in a typical year. The Company calculated this FTY adjustment by taking the two-year historical average of Comanche 3 chemical costs between 2018 and 2019 when Comanche 3 was operating normally.

Q. WHY IS THE PROPOSED FTY 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.

Q. NEXT, PLEASE ELABORATE ON THE ADJUSTMENT RELATED TO THE MANCHIEF AND VALMONT UNITS.

A. The Company acquired Valmont in June 2020 and will be acquiring Manchief in 2022. Therefore, the O&M expenses that Public Service will incur at these plants are not accurately reflected in the Company's 2020 O&M actual expenses. To calculate a reasonable and representative level of O&M on a going-forward basis, Public Service has calculated its projected 2022 level of O&M for Valmont, which does not include start-up costs. For Manchief, since this unit will not go into service until 2022, Public Service is proposing to set O&M based on its forecasted 2023 level of O&M, plus the forecasted O&M spend associated with overhauls in 2022. The Company proposes a total adjustment of $0.7 million, for both Valmont and Manchief, which Public Service believes is a reasonable level of O&M on a going-forward basis.

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 Colorado Department of Public Health and Environment's Air Quality Enterprise Division will begin assessing Public Service air quality fees, which are driven by Senate Bill 20-204 signed into law in June 2020. These air quality fees are expected to be approximately

$295,000 in 2022 and grow in subsequent years – approximately $394,000 in 2023 and $492,000 in 2024 and beyond. Because these fees are not reflected in actual O&M amounts spent in 2020, Public Service is proposing an adjustment of $0.3 million to reflect the expenses for the 2022 FTY. Attachment KLW-10 to my Direct Testimony shows the expected going-forward CAQE air quality fees.

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. Although the proposed adjustment of $300,000 is conservative, it will be recurring, and therefore this adjustment is an appropriate basis on which to set rates going forward.

Q. PLEASE ELABORATE ON THE CHEYENNE RIDGE O&M ADJUSTMENT.

A. Cheyenne Ridge was not placed in service until August 2020, and therefore the Company does not yet have a full year of actual O&M data for the wind farm. Because 2020 only includes five months of historic data for Cheyenne Ridge, the full level of O&M necessary to maintain the wind facility is not included in base O&M for this case. Public Service has calculated a total projected annualized level of O&M of approximately $13.2 million for Cheyenne Ridge.

To calculate this adjustment, Public Service subtracted the $4 million in 2020 actual O&M from the 2020 forecasted amount of approximately $13.2 million to reach the adjustment of $9.1 million. Public Service therefore proposes an adjustment of $9.1 million, based on an annualization of the 2020 expenses and forecasted into 2022 as reflected in Attachment KLW-11 to my Direct Testimony, to accurately reflect Cheyenne Ridge O&M expense in 2022 and on a going forward basis.

Q. WHY IS THIS ADJUSTMENT REASONABLE AND APPROPRIATE?

A. Annualizing the Cheyenne Ridge 2020 O&M expense using the above approach reasonably estimates Cheyenne Ridge's going forward O&M expense based on a full year of operation.

Q. PLEASE ELABORATE ON THE ADJUSTMENT RELATED TO PAWNEE WATER COSTS.

A. In preparing its rate case filing, Public Service identified an inadvertent accounting error reflecting $313,000 of water costs that were not appropriately booked to the Generation Business Area. To adjust for this error, Public Service proposes an adjustment of $0.3 million.

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

A. These costs were related to the use and acquisition of water at the Pawnee facility, which is necessary to operate the plant. The Company also expects these costs to recur on a going-forward basis and therefore it is reasonable to include these costs in base rates.

Q. PLEASE ELABORATE ON THE ADJUSTMENT RELATED TO THE CHEROKEE WASTEWATER FACILITY.

A. The Company expects the Cherokee generating unit's wastewater O&M costs in 2020 to be lower than in 2022 due to significant changes to the wastewater system that are driven by environmental regulatory requirements.

Cherokee Station holds a discharge permit issued by the Colorado Water Quality Control Division, and there are several parameters with a future permit limit that cannot be met with current treatment. The new treatment system will need to eliminate a continuous discharge to the South Platte River because the treated water can be utilized by the plant. Clean water from the system will be sent to a treated water tank for use in plant systems. The first permit limit becomes effective January 1, 2022. It is expected that the wastewater treatment system will be completed and available for testing at the end of September 2021.

O&M costs to operate the new system will increase due to the increased complexity of the new system as compared to Cherokee's existing wastewater treatment. These additional wastewater processes were not part of the 2020 O&M expenses at the facility, but will be required going forward with the installation and operation of the new facility. Going forward, wastewater handling costs will be approximately $1.4 million. The Company is therefore proposing this FTY adjustment as it is reflective of updated, 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.

C. One-Time O&M Costs

Q. IN ADDITION TO THESE FTY ADJUSTMENTS, ARE THERE ANY OTHER O&M COSTS THAT NEED TO BE ACCOUNTED FOR?

A. Yes. There are two categories of one-time O&M costs that are not reflected in the Company's 2020 actual O&M or 2022 FTY O&M. These include the Comanche 1 and 2 ash pond costs that have been incurred due to environmental permitting and regulatory actions, and the contractor/start-up costs associated with the Manchief acquisition. Because these are one-time, non-recurring costs, they are not appropriate for an adjustment to base rates. Therefore, as Company witness Ms. Blair discusses in her Direct Testimony, the Company is proposing to amortize and recover these costs over a three-year period. Table KLW-D-8 below provides a breakdown of these one-time O&M adjustments.

**TABLE KLW-D-8:
2022 FTY One-Time O&M Adjustments
Public Service Electric
(Dollars in Millions)**

O&M Expense	One-Time O&M Adjustment (Unamortized)
Comanche 1 and 2 Ash Ponds	$12.9
Manchief Contractor/Start-Up Costs	$0.6
Total	**$13.5**

Q. PLEASE ELABORATE ON THE ONE-TIME COSTS FOR THE COMANCHE 1 AND 2 ASH PONDS.

A. In August of 2020, the EPA amended its regulations regarding CCR to prevent unlined ponds from continuing to operate after April 11, 2021 unless they are lined. The previous CCR rule allowed the operation of unlined ponds under certain conditions, as long as the pond did not indicate a presence of contamination. The Comanche 1 and 2 bottom ash pond met these previous conditions, as well as other conditions in the rule until the rule changed in August 2020. The rule change did not allow the Comanche 1 and 2 bottom ash pond to continue to operate as originally planned. Furthermore, due to Colorado State Section 9 requirements regarding surface impoundments, the existing bottom ash pond could not be replaced with a new pond and meet the April 11, 2021 compliance date due to the permitting process, environmental monitoring and construction timeline required for the pond work (approximately 18 to 24 months). Once the pond is replaced, Section 9 requirements will then apply, which will require extensive monitoring and other requirements to secure a permit for operation.

Q. HOW HAS THE COMPANY GONE ABOUT ADDRESSING THESE COMPLIANCE ISSUES?

A. To evaluate the issue, Public Service's Environmental Services team retained HDR Engineering and identified the options for addressing this compliance requirement. Among other things, HDR Engineering determined that a new lined ash pond could not be designed, permitted and constructed in time to meet the April 2021 deadline. Accordingly, HDR Engineering identified two options:

- The Company could cease running Comanche Unit 1 and Unit 2 until a "pre-packaged" ash treatment system was brought on-line; or,
- Public Service could find an alternative, temporary solution that would allow Unit 1 and Unit 2 to continue running and avoid violation of the EPA regulatory due date of April 11, 2021.

Public Service then initiated an RFP to ascertain potential costs and options.

Q. WHAT WAS THE OUTCOME OF THE RFP?

A. Four bids were received in January 2021, only two of which were technically viable. Of the two viable bids, WesTech submitted the bid that was ultimately awarded, which offered a dual solution to the problem. This includes:

- Constructing a temporary system to be utilized for the three-month period of mid-March 2021 – mid-June 2021 consisting of complex equipment and 24x7 labor to operate the non-automated system. This was a "bridge system" to operate in compliance with the CCR Rule from April 11, 2021 until mid-June, when a "pre-packaged system" could be completed.
- A pre-packaged system expected to be utilized for the 19-month period of mid-August 2021 to mid-March 2023. This equipment is less complex, is automated, and is less expensive to operate.

Public Service, in conjunction with WesTech, will continue to evaluate long-term solutions and costs and will determine the appropriate solution in light of proposed generation plant retirements

Q. WHAT ARE THE TOTAL ONE-TIME COSTS PUBLIC SERVICE IS SEEKING TO RECOVER IN THIS PROCEEDING ASSOCIATED WITH THE ASH POND?

A. For the Company to achieve compliance, it will incur $12.9 million in one-time costs that are not reflected in the Company's 2020 actual O&M or 2022 FTY O&M.

Q. WHY IS THE PROPOSED AMOUNT REASONABLE AND APPROPRIATE?

A. These one-time costs are needed to achieve compliance with state water/environmental regulations, while facilitating safe and reliable operations at the Comanche 1 and 2 plants. They are therefore appropriate for one-time recovery.

Q. FINALLY, PLEASE ELABORATE ON THE ONE-TIME CONTRACTOR/START-UP COSTS FOR MANCHIEF.

A. As part of the Manchief acquisition, Public Service will employ a contractor for initial O&M work at the generation unit. The contractor's total cost in 2022 will be approximately $580,000 that was not reflected in the Company's adjusted 2020 O&M. The contractor's scope of work will include short-term operations and training to Public Service personnel as part of the transfer.

Q. WHY IS THE PROPOSED AMOUNT REASONABLE AND APPROPRIATE?

A. These one-time costs are needed to prepare Manchief for operating on a going forward basis. As I discussed above, the Commission approved the Manchief acquisition in the Company's 2016 ERP.

Q. HOW DOES PUBLIC SERVICE PROPOSE RECOVERING COSTS ASSOCIATED WITH THE COAL ASH PONDS AND THE MANCHIEF CONTRACTOR/START-UP COSTS?

A. As described in Ms. Blair's Direct Testimony, Public Service requests that these one-time costs totaling $13.5 million be amortized over three years in order to minimize the impact to ratepayers.

D. Generation Overhaul Expense

Q. IN THE 2019 ELECTRIC PHASE I THE COMMISSION REQUIRED THE COMPANY "TO PROVIDE INFORMATION IN ITS FUTURE RATE CASE FILINGS REGARDING ITS HISTORIC GENERATION OVERHAUL EXPENSE."[26] CAN YOU PROVIDE SOME BACKGROUND ON GENERATION OVERHAUL EXPENSE AND THIS REQUIREMENT?

A. Yes. Generation overhaul expense is 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 reliability of those units. In the 2019 Electric Phase I, the Colorado Energy Consumers ("CEC") expressed concern about the Company's lack of data on generation overhaul expense separate from its overall production O&M expense, which CEC argued was necessary to ascertain "what portion of the total expenses should be normalized to account for the year-to-year variability in generation overhaul expense"[27] as part of setting the Company's test year O&M. As I explained in my Rebuttal Testimony in the 2019 Electric Phase I, providing historic generation data prior to 2017 is a difficult and time-consuming process due to the nature of the Company's FERC accounting and limitations in Public Service's new general ledger accounting system, which involved a vendor change and went into service in 2017.[28]

As a result of the 2019 Electric Phase I, the Company ultimately conducted a special study to provide the requested information on generation overhaul

[26] Proceeding No. 19AL-0268E, Decision No. C20-0096, at ¶ 290 (mailed Feb. 11, 2020).
[27] *See* Proceeding No. 19AL-0268E, Decision No. C20-0096, at ¶ 287 (mailed Feb. 11, 2020).
[28] *See* Proceeding No. 19AL-0268E, Rebuttal Testimony of Kyle L. Williams, at 34:1-35:12.

expense,[29] and stated in discovery that it would be willing to provide this information in the future. In its decision in that proceeding, the Commission agreed that information on historic generation overhaul expense "is necessary in a rate case proceeding for assessing the reasonableness of the related cost components within any given test period,"[30] and required the Company to provide this information in Public Service's next-filed rate case.

Q. IS THE COMPANY PROVIDING ITS HISTORIC GENERATION OVERHAUL EXPENSE IN THIS RATE CASE?

A. Yes. Consistent with the Commission's decision in the 2019 Electric Phase I, the Company is providing historic generation overhaul expense for 2013 through 2020 as Attachment KLW-12 to my Direct Testimony.

Q. HOW DID THE COMPANY DEVELOP ATTACHMENT KLW-12?

A. As I explained in the 2019 Electric Phase I, 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 HISTORIC GENERATION OVERHAUL EXPENSE PROVIDED IN ATTACHMENT KLW-12?

A. No. With the exception of Comanche 3, for which overhaul expenses associated

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[29] Proceeding No. 19AL-0268E, Rebuttal Testimony of Kyle L. Williams, at 35:12-16.
[30] Proceeding No. 19AL-0268E, Decision No. C20-0096, at ¶ 290 (mailed Feb. 11, 2020).

with the June Outage Event have been offset by an anticipated insurance accrual, the historical generation overhaul expenses provided in Attachment KLW-12 are comparable with the generation overhaul expenses incurred during 2020, and therefore no O&M adjustment is necessary in this proceeding to account for any year-to-year variability in generation overhaul expenses.

Q. IS THE COMPANY'S 2020 GENERATION O&M, SUBJECT TO THE FTY ADJUSTMENTS AND ONE-TIME COSTS YOU IDENTIFIED ABOVE, A REASONABLE BASIS ON WHICH TO BASE O&M COSTS FOR THE 2022 FTY?

A. Yes.

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

A. Yes.

VIII. <u>COMANCHE 3 OUTAGE</u>

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 3 unit from January 2020 to January 2021 (the Comanche 3 Outage), resulting from the time it took to inspect the steam turbine after an outage that occurred on January 13, 2020, and the event that occurred on June 2, 2020 (the June Outage Event). The June Outage Event occurred when the steam turbine, steam turbine bearings, and generator equipment were damaged after the turbine lube oil system was unintentionally isolated. Next, I explain the operational changes Public Service has made in its thermal generating fleet using a multi-disciplinary approach, consistent with its commitment to continuous improvement. I then discuss how the Comanche 3 Outage affects this proceeding.

Q. PLEASE PROVIDE BACKGROUND ON THE COMANCHE 3 UNIT.

A. The Comanche 3 unit is a 750 MW coal-fired unit in Pueblo, Colorado that sits adjacent to the Comanche 1 and 2 units on the same plot of land. Public Service owns a 500 MW share in the unit, and Holy Cross Energy and Intermountain Rural Electric Cooperative own the remaining 250 MW. Public Service received a CPCN to construct and own the Comanche 3 generation unit 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.[31]

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMANCHE 3 OUTAGE AND THE COMPANY AND COMMISSION'S ACTIONS IN RESPONSE.

A. Comanche 3 experienced two events that led to outages spanning from January 2020 to January 2021. In the first event on January 13, 2020, a loud noise was heard coming from the Low Pressure B section of the turbine. This noise accompanied by a step change in vibration levels indicated an equipment issue and required Public Service to stop operations for inspection of the turbine. The inspection revealed a failed turbine blade along with damage to turbine blade shrouds and rubbing damage to seals in the lower portion of the casing. This damage required substantial turbine repairs and renovations, including replacement of the four rows of damaged turbine blades due to signs of Stress Corrosion Cracking ("SCC") in those blades. In the interest of efficiency, while the unit was out of service, Public Service opted to accelerate a number of other maintenance activities including the rest of the steam turbine major overhaul that had previously been planned to occur as part of an already-scheduled outage in 2021. The original, planned outage duration was 65 days, but the actual outage duration was driven by extended lead times related to sourcing the rows of replacement turbine blades. The same or similar lead time would have impacted the Company's actions had it discovered the damaged blades through the course

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

of regular inspection, as well. Consequently, Comanche 3 was out of service until June 1, 2020. On June 2, 2020, when Public Service had completed repairs and was bringing the unit up to speed for synchronization with the grid, the Comanche 3 control room received a high turbine lube oil temperature alarm, at which point the turbine was tripped off. The high temperature alarm that resulted in the operators tripping the unit was due to cooling water flow issues for the lube oil coolers. This issue was resolved, and the unit start-up was resumed. Subsequent actions, however, inadvertently caused the lube oil to shut off to the turbine while it was near synchronous speed. Public Service hired third party vendors to identify the damage and to repair it as expeditiously as possible. Ultimately, Comanche 3 remained offline to undergo assessment and repairs until it was brought back on-line on at the beginning of 2021.

On October 28, 2020, the Commission opened an investigatory docket, Proceeding No. 20I-0437E, for the purpose of authorizing Staff to complete an investigation into the history and continuing operation of the Comanche 3 generating station. Over the course of several months, Public Service cooperated with Staff in its investigation. Staff filed its report detailing the findings of its investigation on March 1, 2021, and Public Service filed its Response to the Report on April 28, 2021.

Q. WHAT HAD COMANCHE 3'S OPERATIONS BEEN LIKE PRIOR TO THE COMANCHE 3 OUTAGE?

A. As Staff noted in its report in Proceeding No. 20I-0437E, and as the Company further explained in its Response, new plants often experience an initial "shakedown period" due to troubleshooting new technology/designs and resolving operator error. This was the case for Comanche 3, which experienced design issues and operational challenges during the early years of its life; however, as the Staff Report acknowledged, these issues largely abated following replacement of the unit's Finishing Superheater, and between 2016 and 2019 Comanche 3 performed strongly with an average availability factor of 85.95. Prior to the Comanche 3 Outage, Comanche 3 had become one of the most reliable and cost-effective generating units on our system.

Q. PLEASE DISCUSS WHAT STEPS PUBLIC SERVICE HAS TAKEN IN RESPONSE TO THE COMANCHE 3 OUTAGE.

A. As discussed in more detail in Public Service's Response to the Staff Report, Public Service has taken numerous steps as part of its commitment to continuous improvement and through a multi-disciplinary set of teams to ensure reliable operations at Comanche 3—and across its entire generation fleet. The Company pursued corrective actions using the following teams: (1) Configuration Management Team; (2) Technical Improvement Team; (3) Human Performance Team; (4) Recovery Team; and the (5) Start-Up Team. The Company also filed two insurance claims associated with the January and June 2020 events. However, the approximately $1.5 million in total insured costs associated with the January outage were lower than the $2 million[32] deductible for combined property damage and extra expenses, so the Company withdrew its insurance claim. As I

[32] Public Service's share of the $2 million deductible is $1.3 million based on its ownership share of Comanche 3.

discuss below, the claim associated with the June Outage Event is still pending and undergoing investigation through the insurance adjuster. The claim is worth approximately $28 million.

Q. CAN YOU DESCRIBE EACH OF THE FIVE TEAMS' CORRECTIVE ACTIONS?

A. Yes, the full description of the corrective actions is available in the Company's Response, with a high-level overview below.

- *Configuration Management Team:* The Configuration Management Team developed robust checklists for a variety of systems at Comanche 3, including the turbine lube oil system that caused the June 2020 outage. The team identified twenty-five systems critical to startup and operation on Unit 3 and incorporated them into the Configuration Management Procedure. Additionally, the team also created a single master configuration checklist to validate proper alignment of all systems prior to the unit returning to service.

- *Technical Improvement Team:* The Technical Improvement Team was tasked with reviewing the design of the Comanche 3 turbine lube oil system as well as the lube oil cooler 6-way valve in order to implement design changes that would mitigate identified vulnerabilities. The team identified and implemented several design changes to mitigate vulnerabilities on the turbine lube oil system, which make the system more robust.

- *Human Performance Team:* The Human Performance Team was tasked with undertaking a systematic approach to analyzing whether human performance affected the January and June outages, and if so, identifying these factors and proposing changes to mitigate future vulnerabilities. The team identified both verbal and written communication issues and provided several recommendations for improvement. One such improvement is to use a new tiered decision-making tool for equipment manipulation and status control called "STAR." STAR stands for "Stop," "Think," "Act," "Review." "Stop" means to pause before performing the operation/manipulation, especially at critical steps, decision points, or touchpoints. "Think" means to focus attention on the step to be performed, verify the action is appropriate for equipment/system status, anticipate expected results of the action and their indications, and consider what actions to take should an unexpected result occur. "Act" means to compare the component label or other instructions with the checklist procedure, read the component label, and perform the action—without losing physical contact with the component. Finally, "Review" means to verify that the anticipated result was obtained and to perform a contingency if the expected result does not occur. The team also comprehensively analyzed all of

Comanche 3's systems to determine whether any single-point vulnerabilities remain after completion of recommended system modifications at the unit. The Company is now undertaking the same review across its entire generation fleet, which is ongoing through 2021, and is applying lessons learned from the Comanche 3 teams to other units, including Comanche 1 and 2. This includes working to eliminate any gaps in communications protocols and procedures, implementing additional operator/personnel training and human factored labeling, and promoting continuous improvement through a fleet-level Energy Supply Business Unit Human Performance team.

- *Recovery Team:* The Recovery Team was tasked with scoping, initiating, and overseeing the repair activities externally and internally at Comanche 3 as well as returning the plant to service. The effort was successful, as Comanche 3 returned to service in January 2021.

- *Start-up Team:* The Start-up Team was tasked with reviewing current start-up procedures and amending or adding procedures to ensure comprehensive set up start-up and testing procedures were in place at Comanche 3. The team was to identify gaps within the existing unit startup process and create procedures to close those gaps. This task was completed, and the revised start-up manual has been created and implemented. This work entailed the development and implementation of 11 comprehensive revised startup procedures prior to returning the unit to service. The eleven revised procedures are described in more detail in the Company's Response filed in Proceeding No. 20I-0437E.

Q. HAS PUBLIC SERVICE MADE ANY OTHER CHANGES TO REDUCE THE LIKELIHOOD OF A SIMILAR EVENT FROM OCCURRING?

A. Yes. The Company and Xcel Energy have also made personnel changes at several levels over the past year that will drive operational improvements both at Comanche 3 and across the Xcel Energy generation fleet. These personnel changes include:

- Appointing Timothy O'Connor, Chief Nuclear Officer at Xcel Energy, as Executive Vice President and Chief Generation Officer;

- Appointing Scott Sharp, Vice President and Director of Site Operations at Northern States Power's Prairie Island Nuclear Plant, as Xcel Energy's Vice President of Energy Supply Operations; and,

- Appointing Manny Zeringue, most recently Senior Plant Manager at the New Madrid Power Plant in Marston, Missouri, as the new Plant Director at Comanche Station.

As further discussed in the Company's Response in Proceeding No. 20I-0437E, each of these organizational changes will benefit future operations by leveraging these individuals' significant experience and adding to the Company's existing operational leadership and oversight.

Q. HOW HAS COMANCHE 3 BEEN OPERATING SINCE JANUARY 2021?

A. As the Company stated in its Response to the Staff Report, Comanche 3 has been operating since it returned to service following the Comanche 3 Outage. It served as a critical generation asset on our system during both Winter Storm Uri in February of this year and the recent June heat wave when Public Service experienced record demand.

Q. PLEASE DISCUSS THE PENDING INSURANCE CLAIM RELATED TO THE JUNE OUTAGE EVENT AT COMANCHE 3.

A. As I mentioned above, Public Service has filed a pending claim for the June Outage Event, valued at approximately $28 million and the Company is not seeking recovery for any of the proceeds that are subject to its pending insurance claim. The Company filed its claim on June 3, 2020, the day after the event occurred, and the insurance company appointed an adjuster on June 6, 2020. To date, there have not yet been any payments issued from commercial insurance markets for the June Outage Event, and it is still unknown when payments are anticipated or when the Company's claim will be finalized. When received, all insurance proceeds will be allocated among the three Comanche 3 owners based on percentage ownership share.

Q. EARLIER YOU MENTIONED THAT THE COMPANY WITHDREW ITS CLAIM FOR COSTS RELATED TO THE JANUARY 2020 OUTAGE. WHY?

A. The Company initially filed a claim for the January 2020 outage on January 30, 2020, and the insurer appointed an adjuster on February 4, 2020. However, after review of the damage and the Company's insurance policy, the insurance representatives stated that they would cover only the loss of the one blade, replacement of a total of six blades, and damage to the other blades in the L-0 row. In addition, they would cover only the open and close of the LP-A turbine. Taken together, these costs are worth less than the total $2 million deductible, so the Company determined it was not appropriate to pursue the claim and withdrew it. The insurance company has since closed the claim.

Q. DIDN'T THE STAFF REPORT IDENTIFY APPROXIMATELY $4.8 MILLION IN CAPITAL COSTS FOR THE BLADE REPAIRS AND REPLACEMENTS ASSOCIATED WITH THE JANUARY OUTAGE?

A. Yes, $4.8 million is reflective of Public Service's share of the total blade replacement capital costs, but not all of these replacements were the direct result of the initial blade failure that occurred in January of 2021. The Company's property insurance policy only covered replacement of the blade that failed and replacement of the six adjacent blades that were damaged. While the initial failure itself resulted in only a limited amount of collateral damage to the adjacent blades, as the Company conducted its own review of the turbine, it determined that all of the four rows of blades in the same location (L-1 or second to last stage) exhibited signs of stress corrosion cracking and were in need of replacement. The Company therefore determined to replace all L-1 blades while the unit was down. However, the Company's insurance policy does not insure against repairs resulting from normal wear and tear, deterioration, or defects, and the preventative replacement of these other blades therefore was not covered.

Q. IS PUBLIC SERVICE SEEKING COST RECOVERY FOR CAPITAL COSTS FOR THE BLADE REPAIRS AND REPLACEMENTS ASSOCIATED WITH THE JANUARY OUTAGE?

A. Yes. The repairs that are not covered by insurance were not directly caused by the blade failure that caused the January outage. Public Service is therefore seeking to recover these costs. While the Company became aware of the need for additional blade repairs and replacements during inspection after the initial blade failure, the unit had a major outage planned for the fall of 2020 and these blade replacements would have been identified and completed during that outage. The Company decided the most prudent response was to proactively undertake this necessary additional work while the unit was already down rather than carrying out a partial repair and waiting for the planned outage in the fall of 2020.

Q. ARE THERE ANY COSTS ASSOCIATED WITH THE PENDING INSURANCE CLAIM FOR THE JUNE OUTAGE EVENT PUBLIC SERVICE IS SEEKING RECOVERY OF IN THIS PROCEEDING?

A. Yes. The Company is seeking recovery of its share of the insurance policy deductible, which is approximately $1.3 million. Other than this amount, Public

Service is not seeking recovery in this Proceeding of costs or projects directly associated with the June Outage Event's pending insurance claim. However, Public Service is seeking to recover costs for capital projects that were previously planned but were accelerated due to the unplanned outage.

Q. PLEASE SUMMARIZE KEY FINDINGS FROM THE STAFF REPORT APPLICABLE TO THIS PROCEEDING.

A. The Staff Report identified several topics that Staff believes should be addressed in a rate case.[33] Specifically, Staff recommended the Company provide the following information separately for Comanche 3:

- Incremental capital additions since the last Phase I rate review proceeding;
- O&M expenses for Comanche 3 incurred during the test year period; and,
- Separate work papers that detail any revenue requirement components that include Comanche 3 costs, including in the amount of Comanche 3 in rate base, any and all capital additions since the last Phase I proceeding, and the O&M expenses included in the revenue requirement.

Q. HOW DOES PUBLIC SERVICE RESPOND TO STAFF'S RECOMMENDATIONS?

A. While the Company's full Response is available in Proceeding No. 20I-0437E, Public Service is providing the information Staff recommends for informational purposes in this rate case proceeding. Here, I discuss two of Staff's requests: the incremental capital additions since the 2019 Electric Phase I rate review proceeding and the O&M expenses for Comanche 3 incurred during the test year period. Company witness Ms. Blair discusses the revenue requirement

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[33] *See* Proceeding No. 20I-0437E, Staff Report, at 87.

components that include Comanche 3 costs, and she provides supporting workpapers, as requested by Staff.

Q. PLEASE ADDRESS STAFF'S REQUEST FOR INFORMATION ON COMANCHE 3 INCREMENTAL CAPITAL ADDITIONS SINCE THE END OF THE 2019 ELECTRIC PHASE I TEST YEAR.

A. The total capital additions at Comanche 3 from September 2019 to April 2021 were $25.8 million. I note, however, that Public Service is not requesting cost recovery for some of the projects listed below that are offset by insurance proceeds. Even though the projects that are offset by insurance proceeds are not included in the revenue requirement, I provide them for informational purposes and because Staff requested information on all incremental capital additions at Comanche 3. In the list below, I identify whether a project's costs are offset by insurance proceeds. I provide further detail here on the eight most significant capital additions (*i.e.*, those over $1 million), which comprise $23.9 million of the total additions, here:[34]

- *Spray dryer absorber ("SDA") scrubber vessels:* Based on industry experience with failure/collapses of other SDA vessels nationwide over the past decade, Comanche Plant, Engineering & Construction and Fleet Engineering recommended that the Unit 3 SDA vessels have ultrasonic thickness ("UT") inspections completed for the possible wall thinning. The UT readings indicated that there was severe thinning of the vessels' walls due to erosion and corrosion. The OEM, Babcock and Wilcox ("B&W"), also warned that, per their calculations, the vessels were in danger of collapse due to this wall thinning. This capital project involved completing the engineering design and installation of steel reinforcement (both interior and exterior) that was designed by B&W to prevent the possible collapse of the vessels. Exterior structural member reinforcement and a complete system of interior stainless steel

[34] Variances between figures presented in this testimony and the Staff Report for capital projects required to repair damage after the loss of oil incident in June 2020 result from differences in how the insurance deductible was accounted for. In the Staff Report, Public Service's share of the insurance deductible was included in each capital project cost proportionally, whereas the amounts listed here do not include any insurance deductible amounts.

corrosion liner plates were installed at each of the three vessels. Approximately $5.19 million in capital additions for this project were placed in service from September 2019 to April 2021.

- *Steam turbine L-1 blade replacement:* The L-1 blades on low-pressure A ("LPA") and low-pressure B ("LPB") turbines were replaced by Ethos Energy during the January outage. After the unit had half a blade broke off during operation in early January, the unit was tripped and work began on finding the root cause. The root cause analysis revealed that the blade failure was due to stress corrosion cracking around the lashing lugs/snubbers. Further investigation showed that both L-1 rows on LPA and LPB (total of four rows) had signs of stress corrosion cracking, which merited replacement to prevent such an incident from occurring again. Approximately $5.18 million in capital additions for this project were placed in service from September 2019 to April 2021.

- *Generator rotor rewind and blower (offset by insurance):* The rotor journals were significantly damaged when the lube oil system failed to provide oil to the journals, and they had to be repaired. Additionally, the generator rotor hydrogen blower rotating blades impacted the stationary blades during the event, distributing ferrous material throughout the generator. As a result, the blower had to be replaced due to the damage. Next, metallic and oily debris was identified beneath the rotor retaining rings and within the rotor winding cooling passages. The copper windings were removed, cleaned, and rewound with new insulation to mitigate the possibility that the debris would cause an in-service failure. Damaged portions of the rotor winding were replaced. The rotor forging was cleaned and inspected for defects. Weld repairs were made in eleven locations that had been damaged during the lube oil system failure event. Further, the collector end of the rotor shaft had bowed due to the heat experienced during the failure event, and the section was removed and a stub shaft was manufactured and installed. Approximately $3.6 million in capital additions for this project were placed in service from September 2019 to April 2021.

- *LPA and LPB turbine blade replacement (offset by insurance):* After the loss of oil incident in June 2020, the turbine unit was opened again by GE, and we found significant damage to the turbine and generator end rows L-3, L-4 and L-5 of the LPA turbine as well as the turbine and generator end rows L-4 and L-5 of the LPB turbine. Engineering analysis of the hardness readings and the severity of damage on the blades and shrouds warranted their replacement. These blades are an integral shroud style blade, meaning that the shroud is not a separate item. As a result, the entire blade had to be replaced. The blade replacement on the low-pressure turbines was performed by GE. Approximately $2.7 million in capital additions for this project were placed in service over this period.

- *Installation of a third layer SCR catalyst:* The ammonia use on the SCR unit at Comanche 3 had been rising, and testing of the catalyst showed it was reaching the end of its useful life. Replacement was required to ensure that the generation unit continued meeting Title V air permit limits. The top layer of catalyst was initially replaced in 2014, and was due for normal replacement again in 2020 based on the Xcel Energy Comanche 3 Catalyst Management. The scope of work included developing specification for the new catalyst, bidding out the supply, then hiring a contractor to remove the old catalyst and install the new catalyst. Approximately $1.8 million in capital additions for this project were placed in service over this period.

- *Cold end air heater basket replacement:* Inspections of the air heater baskets showed that they were at the end of their useful life. They were replaced with new enameled baskets that will help improve the life of the air heater baskets and protect against corrosion and erosion. This project included developing a specification for the baskets, obtaining a proposal for the supply of the baskets and then contracting for the supply of the baskets. The Company also contracted for the removal and installation of the new baskets. Approximately $1.8 million in capital additions for this project were placed in service over this period.

- *Turbine train seals replacement (offset by insurance):* After the loss of oil event in June 2020, an inspection revealed that all seals in the turbine train and generator (including the interstage, tip, gland, and oil seals) had been wiped. All gland packing, oil deflector, hydrogen gland, interstage and tip seals were replaced to restore OEM-level clearances. In the turbine, the replaced seals will force the steam to pass through the buckets, instead of going around. The replaced seals will therefore prevent a reduction in efficiency, an increasing heat rate, and a potential for steam swirl. Further, in the generator, these seals are responsible for keeping the hydrogen contained within the generator and not allowing it to leak out into atmosphere. The seals and install work was performed by GE and Ethos Energy. Approximately $1.5 million in capital additions for this project were placed in service over this period.

In addition to the projects above the $1 million threshold addressed above, please see Attachment KLW-13 in which I provide the capital additions for all Comanche 3 projects by month from September 2019 through April 2021.

Q. PLEASE ADDRESS STAFF'S REQUEST FOR INFORMATION ON COMANCHE 3'S O&M EXPENSES DURING THE TEST YEAR.

A. In 2020, Comanche 3 had $30.8 million in O&M expenses, as shown in Table KLW-D-9 below. As noted in Section VII's discussion of adjustments to the 2020 O&M expenses, because Comanche 3 did not operate extensively during 2020, base O&M expenses were lower in 2020 than would be expected in a year with typical operations. However, additional O&M expenditures were required to repair the unit.

Table KLW-D-9 identifies the O&M expenses incurred at Comanche 3 from 2017 to 2020, broken out into the same categories (where applicable) as I presented above for O&M expenses across the Company's entire Generation Business Area. These categories are Internal Labor, Contract Labor, Base Commodities, Materials, and Other. The biggest change in O&M expense in 2020 was for Contract Labor resulting from repair operations.

TABLE KLW-D-9:
2017-2020 Actual Energy Supply O&M Expenses – Comanche 3 Only*
Public Service Share
(Dollars in Millions)

Cost Category	2017	2018	2019	2020
Internal Labor	$6.9	$6.9	$6.6	$6.3
Contract Labor	$6.8	$2.6	$4.6	$20.3
Base Commodities	$9.0	$9.7	$8.4	$7.4
Materials	$3.0	$2.8	$3.0	$3.7
Other	$4.1	$4.5	$3.9	$(6.8)**
Total	**$29.8**	**$26.5**	**$26.6**	**$30.8**
*There may be differences between the sum of the individual category amounts and totals due to rounding.				
**As discussed below, this amount is negative because it includes $10.6 million from insurance policy proceeds attributable to Public Service's share of O&M.				

Q. PLEASE DESCRIBE THE 2020 O&M EXPENSE ASSOCIATED WITH THE JUNE OUTAGE EVENT THAT IS EXPECTED TO BE COVERED BY INSURANCE PROCEEDS.

A. The total 2020 O&M expense associated with the June Outage Event is $15.8 million across the entire Comanche 3 unit. Public Service's share of this expense is $10.6 million, and as this amount is expected to be covered by insurance policy proceeds the Company has subtracted it from the actual 2020 O&M expenses used in the FTY. I show this amount broken out by category in Table KLW-D-10 below.

TABLE KLW-D-10:
Public Service's Share of 2020 Insurable O&M Expenses at Comanche
Public Service Electric
(Dollars in Millions)

Cost Category	2020
Internal Labor	$0.2
Contract Labor	$9.1
Materials	$1.0
Other	$0.3
Total	**$10.6**

Q. HAS THE COMPANY MADE ANY ADJUSTMENTS TO THE COMANCHE 3 O&M LEVELS IN DEVELOPING ITS REVENUE REQUIREMENT?

A. Yes, as discussed above in Section VII, the Company is proposing an adjustment of $1.9 million to the actual 2020 O&M of $30.8 million, to account for the costs of chemicals and materials that would have been incurred in a year with typical operations at Comanche 3.

Q. DOES THE COMANCHE 3 OUTAGE RAISE ANY REPLACEMENT POWER COST RECOVERY ISSUES IN THIS PROCEEDING?

A. No. Any questions surrounding replacement power will be properly addressed before the Commission and parties in the Company's 2020 ECA prudence review proceeding later this year.

IX. ELECTRIC GENERATION PERFORMANCE MECHANISM

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

A. In this section of my Direct Testimony, I discuss the Company's proposed performance mechanisms for various fossil generation units included in the Electric Generation Performance Mechanism ("EGPM"). The Staff Report resulting from the Comanche 3 investigation undertaken in Proceeding No. 20I-0437E recommended that the Commission establish a performance standard for Company-owned units.[35] Public Service's Response to the Staff Report acknowledged that performance mechanisms can be useful, but identified several reasons for only applying a performance mechanism to certain existing generation facilities.

First, regarding new Company-owned generation to be acquired, such metrics should be developed through the individual regulatory proceedings pertaining to the generation facility at issue. This allows for individual analysis of the particular generation facility/unit and tailoring a performance mechanism best suited to that resource. As the Company's Response to the Staff Report noted, the Company's recent Rush Creek and Cheyenne Ridge Wind Projects are instructive. The Cheyenne Ridge CPCN application proceeding allowed for development of a performance mechanism for that project. Thus, the Company proposes developing such metrics in individual follow-on CPCN proceedings for new Company-owned generation.

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[35] *See* Proceeding No. 20I-0437E, Staff Report, at 86.

Second, regarding existing Company-owned generation, this proceeding presents the best avenue for determining a performance mechanism, but the Company does not recommend applying such a mechanism to certain of its existing coal, wind, and small combustion turbine ("CT") units, for the reasons I describe in more detail below. The Company proposes the new EGPM be applied to the units listed below. For some units, Public Service proposes an Equivalent Availability Factor ("EAF")-based metric, and for other units, Public Service proposes an Equivalent Forced Outage Factor ("EFOF")-based metric. I describe EAF and EFOF in more detail later in this section.

Units with EAF-Based Performance Metric:

- Comanche 3 coal unit
- Pawnee coal unit
- Cherokee 5-7 combined cycle
- Fort St. Vrain 1-4 combined cycle
- Rocky Mountain Energy Center combined cycle

Units with EFOF-Based Performance Metric:

- Blue Spruce 1 and 2 large CT units
- Ft. St. Vrain 5 and 6 CT units
- Manchief 11 and 12 CT units
- Cabin Creek A and B pumped storage units

Public Service proposes the EAF-based performance metric for Pawnee, Comanche 3, Cherokee, Fort St. Vrain, and Rocky Mountain Energy Center that reflects their relatively low order in the generation "stack." Similarly, for the CT units and the pumped storage units, Public Service proposes the EFOF-based performance metric that reflects the peaking nature of the CTs and pumped storage. The performance metrics Public Service proposes will provide additional incentive for Public Service to ensure its generation units are available to deliver reliable power and are in operation at the times they are needed most, while at the same time providing cost-effective service.

Q. DOES THE COMPANY ALREADY EMPLOY ANY PERFORMANCE METRICS FOR ANY OF ITS GENERATION UNITS?

A. Yes. The Company has a performance metric for Rush Creek. The performance metric for Rush Creek is intended to ensure that the Company is properly maintaining the wind farm by comparing performance relative to wind speed during the early years of operation with performance relative to wind speed during later years of operations. To accomplish this, generation and wind speed paired data will be gathered for the first five years after the COD to determine a baseline for generation expectations and derive an empirical relationship between the wind speeds and expected generation (otherwise called a generation curve). During years 13 through 25 of operation, the wind speed/generation data set will be compared to the generation curve derived during the first five years of operation to determine if the Company should be allowed a full recovery of the capital investment.

The Company is also required to report the generation performance compared to the expected generation curve in an annual report each year that Rush Creek is in service, which started in June 1, 2020.

The Company also already has an existing performance incentive in place for Cheyenne Ridge pursuant to the Settlement Agreement approved in Proceeding No. 19A-0905E.

Q. PLEASE SUMMARIZE THE PERFORMANCE INCENTIVE PUBLIC SERVICE IS PROPOSING IN THIS PROCEEDING FOR COMANCHE 3, PAWNEE, AND THE COMBINED CYCLE UNITS LISTED ABOVE.

A. The Company is proposing to use an EAF based on historical data for each of these units to set a baseline expectation for unit performance moving forward. EAF is the fraction (multiplied by 100) of a given operating period (a year, under Public Service's proposal) during which a generation unit is available without any outages (including planned, unplanned, and seasonal) or equipment deratings.[36] Using an EAF factor for these units that are needed as "baseload" generation throughout much of the year helps to quantify whether the Company has been successful in maintaining a reliable, cost-effective generation fleet for its customers.

To craft its EAF-based metric, the Company reviewed historical data from 2014-2020 to determine the group weighted average EAF for the combined cycle units,[37] Pawnee, and Comanche 3, then evaluated one standard deviation from the historical data to determine an applicable bandwidth in which these units can

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[36] *See* North American Electric Reliability Corporation ("NERC") Performance Indexes and Equations, at F-7, https://www.nerc.com/pa/RAPA/gads/DataReportingInstructions/Appendix_F_Equations_2021_DRI.pdf.

[37] Cherokee units 5,6, and 7 did not go into service until the fall of 2015. 2015 was also a partial operating year and excluded from the calculation, therefore this total only represents the Cherokee combined cycle for 2016-2020.

reasonably be expected to perform. For this case, the Company is proposing that the group of baseload generation units can reasonably be expected to have an EAF between 82.26 and 87.48 annually.

Public Service made a one-time exclusion to this data set, eliminating the Comanche 3 Outage data from the set, as the Company determined this was not a good representation of expected performance from the plant. The EAF of 0 (throughout the year) was replaced with the average EAF performance for Comanche 3 through the years 2014-2019. The exclusion to this data set reflects more accurate performance that can be expected in future years, and also increases the EAF metric that the Company must meet. Incorporating a long-duration outage into the data set would have artificially lowered the performance metric by utilizing an outlier value which was reflective of a one-time unanticipated event, not anticipated future performance.

Q. HOW WILL THE PROPOSED EAF-BASED PERFORMANCE INCENTIVE ENCOURAGE PUBLIC SERVICE TO MAINTAIN A RELIABLE AND COST-EFFECTIVE BASELOAD GENERATION FLEET?

A. Availability factor is one of the most accurate measures of performance for baseload generation units. They are expected to be available and generally on-line through the majority of the year and are not often subject to the seasonality of lower loads during moderate weather times, which drive down electric demand. These units are also usually the largest and most cost-effective units in the Public Service generation "stack." Therefore, these units are needed to serve customer load for much of the year, and customers benefit from these units being reliably available.

Q. PLEASE SUMMARIZE THE PERFORMANCE INCENTIVE PUBLIC SERVICE IS PROPOSING IN THIS PROCEEDING FOR THE LARGE CT UNITS AND PUMPED STORAGE UNITS LISTED ABOVE.

A. The Company is proposing to use an EFOF based on historical data for each of the large CT units and pumped storage units listed above to set a baseline expectation for unit performance moving forward. EFOF is the fraction (multiplied by 100) of a given period (a year, under Public Service's proposal) during which a generating unit is unavailable due to forced outages and forced deratings.[38] Using an EFOF for these peaking units that are generally needed only during certain high-demand times throughout the year helps to quantify whether or not the Company has been successful in maintaining a reliable, cost-effective generation fleet for customers, while not incurring unnecessary costs to accelerate unit availability during seasons—like spring and fall—when these units are not crucial to serve load. A higher EFOF represents a higher rate of forced outage; therefore, the higher values here will be described as "minimum" performance expected, with the lower values as "maximum" performance expected.

The Company reviewed historical data from 2014 to 2020 to determine the weighted average EFOF for the selected units, then evaluated one standard deviation from the historical data for the minimum performance expectation (in this

[38] *See* NERC Performance Indexes and Equations, at F-8, https://www.nerc.com/pa/RAPA/gads/DataReportingInstructions/Appendix_F_Equations_2021_DRI.pdf.

case, the higher value) and one-half standard deviation (in this case, the lower value) to determine an applicable bandwidth in which these units can reasonably be expected to perform. This historical data range is a large enough data set to encapsulate any weather variances and unanticipated events affecting the operation of the generation plants, while also reflective of the changing operations of these "peaking" units as Public Service's portfolio adds additional renewable energy resources. For this case, the Company is proposing that the group of large CT generation units can reasonably be expected to have an EFOF between 2.33 and 0.56 annually.

As with the EAF data set above, Public Service excluded two data points from this data set, eliminating two long-duration planned outages for Cabin Creek A and B, as the Company determined this was not a good representation of expected performance from the plant.

- Cabin Creek A – an average EFOF from 2014-2017 was applied to 2018-2020
- Cabin Creek B – an average EFOF from 2014-2019 was applied to 2020

The exclusion to this dataset more accurately reflects performance that can be expected in future years, and also increases the EFOF metric that the Company must meet. Incorporating a long-duration outage into the data set would have artificially lowered the performance metric by utilizing an outlier value which was not reflective of anticipated future performance.

Q. HOW WILL THE PROPOSED EFOF-BASED PERFORMANCE INCENTIVE ENCOURAGE PUBLIC SERVICE TO MAINTAIN A RELIABLE AND COST-EFFECTIVE PEAKING GENERATION FLEET?

A. Public Service will be incentivized to keep these units available at the times they are needed most but will not be incentivized to incur extra repair costs during shoulder seasons. These peaking units are crucial to serve customer load during high-demand periods, particularly for Public Service through the summer and winter seasons, where air conditioning and heating drive up the demand for electricity. During the shoulder seasons and times of more moderate weather, electric demand and customer loads tend to be much lower. Additionally, these units generally have lower capacity and are less efficient than the larger base load generation units, which makes them less cost-effective units in Public Service's generation "stack." Therefore, these units will be needed to serve customer load for only some high-load portions of the year, and it does not make sense to spend additional money on expedited parts and overtime to make these units available during more temperate times throughout the year. Customers will benefit from these units being available when they are most crucial, while lowering O&M costs during times they are not crucial.

Q. WHAT DOES PUBLIC SERVICE PROPOSE SHOULD HAPPEN IF THE EAF OR EFOF FOR THE IDENTIFIED UNITS FALLS OUTSIDE OF THE BANDWIDTH YOU IDENTIFIED ABOVE?

A. Public Service proposes a symmetrical "carrot" and a "stick" approach whereby Public Service receives a financial incentive for overperforming and a disincentive for underperforming. For performance that is below the proposed bandwidth, the Company would be subject to a disincentive of $1.5 million per failed metric per year. For performance that exceeds the proposed bandwidth, Public Service would be entitled to an incentive payment of $1.5 million per metric that exceeded performance per year. The proposed carrot/stick mechanism is outlined below.

TABLE KLW-D-11:
Proposed Performance Metrics with Disincentives/Incentives

Proposed Metric	Bandwidth	Disincentive if Not Met	Incentive if Exceeded
EAF[39]	82.26 (minimum) 87.48 (maximum)	$1.5 million before-tax disincentive	$1.5 million before-tax incentive
EFOF[40]	2.33 (minimum) 0.57 (maximum)	$1.5 million before-tax disincentive	$1.5 million before-tax incentive

Q. WHY IS THE COMPANY PROPOSING THIS SPECIFIC DISINCENTIVE/INCENTIVE AMOUNT?

A. The disincentive / incentive amount proposed of up to $3 million per year matches the amount used in the Company's previous Equivalent Availability Factor Performance Mechanism ("EAFPM"). Additionally, the Company estimated the replacement costs for a 10-day outage for a unit during the summer months to derive an anticipated cost of replacement energy, resulting in an expense of approximately $3 million.

[39] A higher EAF represents higher availability of plants, therefore a higher value indicates better performance. For the EAF metric the Company earns an incentive for a higher value, and pays a disincentive for a lower value.
[40] A higher EFOF indicates a higher rate of forced outages on plants, therefore a lower value indicates better performance. For the EFOF metric the Company earns an incentive for a lower value, and pays a disincentive for a higher value.

Q. DO ANY OTHER WITNESSES DISCUSS REGULATORY TREATMENT SURROUNDING THE COMPANY'S PROPOSED PERFORMANCE INCENTIVE?

A. Yes. Company witness Mr. Berman discusses the Company's proposed compliance reporting in his Direct Case. Mr. Berman also discusses cost recovery associated with the proposed Generation performance incentive.

Q. HAS THE COMPANY PREVIOUSLY HAD A PERFORMANCE INCENTIVE IN PLACE?

A. Yes, the Company previously had the EAFPM in place. However, Public Service proposed discontinuing the EAFPM in the 2019 Electric Phase I, and the Commission approved eliminating the EAFPM.[41] Public Service proposed eliminating the EAFPM because Public Service's generation system had added more intermittent renewable generation after the EAFPM was originally implemented.[42] The EAFPM was applicable to most of the baseload generation units in Public Service's "stack," including: Cherokee 4, Comanche 1-3, Hayden 1-2, Fort St. Vrain combined cycle, and Rocky Mountain combined cycle. Since that proceeding, Public Service has proposed that many of these units retire soon, including Comanche 1 and 2[43] and Hayden 1 and 2.[44] The Company developed

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[41] *See* Proceeding No. 19AL-0268E, Decision No. C20-0096, at ¶ 306 (mailed Feb. 11, 2020).
[42] *See* Proceeding No. 19AL-0268E, Decision No. C20-0096, at ¶ 300 (mailed Feb. 11, 2020).
[43] *See* Proceeding No. 16A-0396E, Decision No. C18-0761, at ¶¶ 103–08, ordering ¶ 1 (mailed Sept. 10, 2018).
[44] *See* Proceeding No. 21A-0141E, Hr. Ex. 101, Direct Testimony and Attachments of Alice K. Jackson, at 4 (filed Mar. 31, 2021) (discussing the Company's approach for transitioning its coal fleet).

its performance incentive mechanisms proposed in this case with these changes in mind.

Q. WHY IS THE COMPANY'S PROPOSED EGPM MORE APPROPRIATE THAN THE EAFPM?

A. The biggest difference is the units that the EGPM will apply to and the two separate metrics employed. At times, the EAFPM provided contradictory signals to the Company, especially at generation units where retirement is on the near-term horizon. The EAFPM was also based on a rate where the denominator was all hours of the year by using an EAF as a benchmark.[45] Thus, the Company had an incentive to make sure units—even ones scheduled for near-term retirement or only needed seasonally—were available at all hours of the year, which in turn requires additional capital and O&M expense. The Company's proposed approach for peaking units, by contrast, will provide an incentive to make sure that generation units are available at the times they are required to serve load.

The Company's approach as described above, though still using an EAF measurement for many of the baseload units that are reasonably expected to be running during the majority of the year, is better tailored than the old EAFPM. First, the Company is not incentivized to spend additional money maintaining units that are scheduled to retire soon. Similarly, using a metric to differentiate the availability of peaking units that are generally only crucial during high-demand times will lessen the amount of money expended maintaining and keeping these

[45] *See* Proceeding No. 19AL-0268E, Decision No. C20-0096, at ¶ 297 (mailed Feb. 11, 2020).

units available during times when they are not expected to run, while also saving on costs to serve customers during high demand periods when these units are needed. Put simply, the proposed performance metric takes into account the economics of running a whole generation "stack" with prudently incurred costs, while incentivizing the Company to maintain the availability and reliability of its generation fleet and minimizing the cost impacts to customers.

Q. WHY ARE THE COMPANY'S PROPOSED PERFORMANCE INCENTIVES REASONABLE?

A. For the reasons I describe above, the EAF for the identified baseload units provides the Company with an incentive to maintain these units to be available at all times of the year to serve customers. The EFOF for the identified peaking units provides an incentive for the Company to maintain these units and make them available at the times of year when they are needed most.

Q. WHY DOES PUBLIC SERVICE RECOMMEND NOT APPLYING A PERFORMANCE MECHANISM TO EXISTING COAL (WITH THE EXCEPTION OF COMANCHE 3), WIND, AND SMALL CT UNITS?

A. There are several reasons. To begin, as noted above, Public Service has proposed retiring or converting to natural gas all of its coal units by 2030, with the exception of Comanche 3. Also, if Pawnee's conversion to natural gas is approved, then it will also operate in a way that it was not originally intended, making a performance mechanism potentially unfit for that unit. Additionally, the Company has already taken steps to minimize expenditures on existing coal units, which will impact plant availability, and including a performance mechanism could incent the Company to make expenditures on retiring assets that would not be prudent for ratepayers.

With respect to the non-coal units for which Public Service does not recommend applying a performance mechanism, wind assets already have an existing performance mechanism, and stacking multiple mechanisms may create conflicting incentives for the Company. For the older small gas-fired CTs, these are being evaluated for retirement and replacement, and so it may be inefficient to incentivize the Company to make additional capital and O&M expenditures on these units. The Company is already closely managing expenditures on these units and a performance mechanism is unnecessary. Additionally, for Valmont units 7 & 8, the Company had not had a PPA in place for these units since 2012, and accordingly will evaluate performance after more data becomes available.

X. RECOMMENDATIONS AND CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. As part of approving the cost of service developed by Ms. Blair, I recommend that the Commission approve the Generation Business Area 2019–2022 capital additions and 2020 O&M expense, as well as the FTY adjustments I discuss above. I also recommend that the Commission approve cost recovery for the Comanche 3 capital and O&M expenses not related to the Comanche 3 Outage and approve cost recovery of the insurance policy deductible described above. Last, I recommend that the Commission approve the Company's proposed performance incentive mechanism, which is tailored to address Public Service's generation fleet and the likely fleet changes resulting from the 2021 ERP & CEP.

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 an Master is Business Administration from Franklin University. Overall, I have been working in the electric utility industry in generation of electricity for