Exh. JRT-19

WUTC DOCKET: UE-200900 UG-200901 UE-200894
EXHIBIT: JRT-19
ADMIT ☑ W/D ☐ REJECT ☐

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-200900

DOCKET NO. UG-200901

DOCKET NO. UE-200894

(Consolidated)

EXH. JRT-19

JASON R. THACKSTON

REPRESENTING AVISTA CORPORATION

EXH. RJR-1T
DOCKETS UE-19___/UG-19___
2019 PSE GENERAL RATE CASE
WITNESS: RONALD J. ROBERTS

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-19____** **Docket UG-19____**

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF

RONALD J. ROBERTS

ON BEHALF OF PUGET SOUND ENERGY

JUNE 20, 2019

PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF
RONALD J. ROBERTS

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PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF RONALD J. ROBERTS

I. INTRODUCTION

Q. Please state your name, business address, and position with Puget Sound Energy.

A. My name is Ronald J. Roberts. My business address is 355 110th Ave NE Bellevue, WA 98004. I am Director of Generation and Natural Gas Storage for Puget Sound Energy ("PSE").

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes, I have. Please see the First Exhibit to the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-2, for an exhibit describing my education, relevant employment experience, and other professional qualifications.

Q. What are your duties as Director of Generation and Natural Gas Storage for PSE?

A. I plan, organize, and direct PSE's energy production including operations and maintenance ("O&M") of PSE's owned and jointly-owned generating facilities and PSE's thermal purchased power agreements. Furthermore, I assist PSE's Resource Acquisition team in performing due diligence evaluations of potential resource acquisitions. I am also responsible for overseeing the safe operation of

PSE's thermal, hydro, natural gas storage, and wind generation plants and optimizing their operation in a manner that will provide our customers with reliable and efficient power.

Q. Please summarize your testimony.

A. First, I discuss the test year operating and capital expenditures and the projected rate year operating and capital expenditures for PSE's interests in the Colstrip Steam Electric Station. Second, I provide an overview of the rate year production O&M expense and discuss the O&M expense for PSE's thermal, hydroelectric, and wind generation facilities, including major maintenance, as applicable.

II. OPERATING AND CAPITAL EXPENDITURES FOR THE COLSTRIP STEAM ELECTRIC STATION

A. Overview

Q. Please describe the Colstrip Steam Electric Station and PSE's interests therein.

A. Colstrip Units 1 & 2 consist of two coal-fired steam electric plant units located in eastern Montana about 120 miles southeast of Billings, Montana. Colstrip Units 1 & 2 began operation in 1975 and 1976, respectively, and each unit produces up to 307 megawatts ("MW") net. PSE and Talen Montana LLC ("Talen Montana") each owns a 50 percent, undivided interest in the generating plants and related facilities of Colstrip Units 1 & 2. Talen Montana is an independent power producer and is not subject to regulation by any state public service commission.

Colstrip Units 3 & 4 is comprised of two coal fired steam plant units adjacent to Colstrip Units 1 & 2 in Colstrip, Montana. Colstrip Units 3 & 4 began construction in 1979. Colstrip Unit 3 began commercial operation in 1984, and Colstrip Unit 4 followed with operations beginning in 1986. Each unit is capable of generating 740 MW of capacity. Colstrip Units 3 & 4 are jointly owned by six entities, five regulated utilities and one independent power producer. The list below provides the breakout by company and ownership share:

- Puget Sound Energy 25%
- Talen Energy 15%
- NorthWestern 15%
- Portland General Electric 20%
- Avista 15%
- PacifiCorp 10%

The above shows ownership across the two units. Talen Energy owns a 30 percent share of Colstrip Unit 3, and NorthWestern owns a 30 percent share of Colstrip Unit 4; however, they are parties to a reciprocal sharing agreement that realizes a 15 percent share for each unit's generation.

Please see the Second Exhibit to the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-3C, for additional details regarding the Colstrip Steam Electric Station and PSE's interests therein.

Q. Does PSE have any updates with respect to any of the Colstrip units?

A. Yes. On June 11, 2019, Talen Montana, the operator of the Colstrip Steam Electric Station, announced that Talen Montana and PSE will permanently retire Colstrip Units 1 & 2 effective December 31, 2019, and prior to the rate year in this proceeding. Colstrip Units 3 & 4 will remain in operation. Please see the Third Exhibit to the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-4, for a copy of the press release of Talen Montana announcing the early retirement of Colstrip Units 1 & 2. Please see the Fourth Exhibit to the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-5, for a copy of the press release of PSE regarding the early retirement of Colstrip Units 1 & 2.

B. Capital Expenditures for the Units of the Colstrip Steam Electric Station Over the Period Beginning October 1, 2016, and Ending December 31, 2018

1. Process for Development and Implementation of Capital Projects at Units of the Colstrip Steam Electric Station

Q. How are capital expenditures for the units of the Colstrip Steam Electric Station developed?

A. In general, the plant operator, Talen Montana, conducts assessments of equipment conditions and other factors affecting operations, such as pending regulations. Talen Montana monitors equipment conditions while the units are on-line and during outages and overhauls. Talen Montana then uses information gathered on equipment conditions to inform judgments as to when a particular component may need replacement.

Talen Montana solicits advice and assistance from numerous resources, including the original equipment manufacturers, equipment vendors, engineers at the Colstrip Steam Electric Station Project, engineers from other plants operated by affiliates of Talen Montana, and from the other Colstrip owners.

Talen Montana evaluates options and timing for capital expenditures and proposes capital additions as part of an annual budget. This proposed budget is then brought forward to the Owners' Committee (for Colstrip Units 1 & 2) and the Project Committee (for Colstrip Units 3 & 4) for discussion and, if warranted, further analysis, before it is voted upon by the appropriate committee.

Q. Please describe the Ownership Committee for Colstrip Units 1 & 2 and the Project Committee for Colstrip Units 3 & 4.

A. As discussed in greater detail in the Second Exhibit to the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-3C, the respective owners of the Colstrip units are governed by two ownership agreements:

(i) the Colstrip Units 1 & 2 Construction and Ownership Agreement for Colstrip Units 1 & 2; and

(ii) the Colstrip Units 3 & 4 Ownership and Operation Agreement for Colstrip Units 3 & 4.

The agreements set forth several key conditions.

- Ownership is as "tenants in common," without a right of partition, and the obligations of each owner are several and not joint.
- Assignment and ownership transfer to third parties is limited, with a right of first refusal for an existing owner to acquire any ownership offered for sale.

- The term of the agreements continues for as long as the units are used and useful or to the end of the period permitted by law.

- Each owner must provide enough fuel to operate its share of the units at minimum load.

- Failing to pay its share of project costs or failing to provide adequate fuel constitutes a default on the part of the owner.

- An owner must continue to pay its share of operating costs and coal costs until it has transferred its ownership to another entity.

- No single owner has the ability or right to shut down the plant, so to shut down and decommission any unit, all owners of that unit must unanimously agree.

- The agreements do not establish a "put" right for any owner.

Each agreement establishes a committee to guide operating decisions. The committee for Colstrip Units 1 & 2 is referred to as the "Owners' Committee" and the committee for Colstrip Units 3 & 4 is referred to as the "Project Committee." The Colstrip Units 3 & 4 Ownership and Operation Agreement for Colstrip Units 3 & 4 specifies a voting structure to be used by the Project Committee for approving annual budgets and other operating decisions.

Q. Does PSE have input into the decision to initiate a capital expenditure?

A. Yes. The committees meet monthly with Talen Montana. At those meetings, the committees challenge Talen to maintain capacity and reliability at the units and meet compliance requirements at reasonable costs. PSE's representative on the committees participates in those meetings and in the decision-making process.

Q. How is a capital expenditure approved?

A. Capital expenditures are approved as part of the annual budget process. Pursuant to the ownership agreements, and based on the information it has assembled and with input from the committees, Talen Montana submits an annual budget of capital expenditures to the committees.

To approve a budget for capital expenditures at Colstrip Units 1 & 2, an approval must, by necessity, be unanimous due to the fact that there are two owners, each with a 50 percent interest in the units.

To approve a budget for capital expenditures at Colstrip Units 3 & 4, at least 55% of the ownership and three members of the Project Committee (including the Operator) must vote in the affirmative.

Q. Are expenditures for capital projects revised or amended after an expenditure is approved?

A. Yes, if it is reasonable to do so. For example, overhauls for individual units are regularly scheduled to occur every three to four years and in those overhauls certain components are scheduled for inspection and many components are scheduled for repair or replacement. During the course of an overhaul, adjustments to work scopes are sometimes needed to address previously unknown factors. There are instances where equipment scheduled only for inspection requires some work and there are instances where components scheduled for work need either more or less work than anticipated to address actual conditions. As a result, some capital expenditures are adjusted to address conditions observed during the overhaul.

There are also times when there is an unexpected failure of some component that requires unbudgeted capital to be expended. In these instances, efforts are made to contain the unplanned costs within the overall budget. This balancing might involve changing the scope of or deferment of a planned project if it is reasonable to do so.

The situations discussed in these examples would serve to inform future budget proposals for the next unit scheduled for overhaul. It is reasonable to believe conditions observed at one unit could be displayed in the sister unit, so plans can be altered accordingly.

Q. Does Talen Montana use a project management process to manage projects?

A. Yes. Talen Montana, as plant operator, uses Primavera as a software solution to keep projects on budget and on schedule. Talen Montana employs a number of project management professionals and engineers who may be assigned to manage projects.

Q. Does Talen Montana keep PSE management informed during project implementation?

A. Yes. Talen Montana issues "Budget to Actual" reports to owners of Colstrip units on a monthly basis. The status of individual projects is provided as part of this report.

2. Capital Expenditures Associated with Units of the Colstrip Steam Electric Station that PSE Seeks to Place in Rate Base

Q. What capital investment does PSE seek Commission approval of in this case?

A. PSE has invested approximately $44 million of capital expenditures associated with the Colstrip units since PSE's last general rate proceeding in Dockets UE-170033 & UG-170034 (the "2017 GRC"). Please see the Fifth Exhibit to the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-6, for a list of the capital expenditures associated with the Colstrip units over the period beginning October 1, 2016, and ending December 31, 2018, that PSE seeks to include in rate base in this proceeding. Please note that the exhibit does not list projects individually when those projects are under $100,000 but, instead, aggregates those smaller projects.

For ease of reference, this testimony will address only the following seven projects with capital expenditures greater than $750,000:[1]

a. Colstrip Units 3 & 4 Water Management System;

b. Colstrip Unit 3 & 4 Coal Combustion Residuals Rule - B Cell Clearwell;

c. Colstrip Unit 3 & 4 Coal Combustion Residuals Rule - Bottom Ash Containment;

d. Colstrip Unit 3 SmartBurn Controls;

e. Colstrip Unit 3 Turbine Overhaul;

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[1] PSE elected to discuss the seven projects with capital expenditures of $750,000 so as to not burden the record in this proceeding with a discussion of all capital expenditures at the Colstrip Steam Electric Station. A capital expenditure of $750,000 represents less than 0.015 percent of PSE's rate base for electric operations.

f. Colstrip Unit 3 Gas Deflection Arch Replacement; and

g. Colstrip Unit 4 Turbine Overhaul.

Each of these projects is discussed below.

a. Capital Costs for Water Management System and Coal Combustion Residual Rule Requirements

Q. Please describe the capital costs associated with the Water Management System and Coal Combustion Residual Rule Requirements.

A. The capital costs for the water management system and the Coal Combustion Residual Rule requirements (i.e., the B Cell Clearwell, Bottom Ash Containment and Colstrip Unit 3 & 4 Coal Combustion Residual Rule capital costs) should be considered together because they are essential costs to meet regulatory obligations and environmental compliance requirements under the Agreed Order on Consent Regarding Impacts Related to Wastewater Facilities between the Montana Department of Environmental Quality and PPL Montana, LLC (now Talen Montana) and the Unites States Environmental Protection Agency Coal Combustion Residual Rule. Specifically, these projects are systematically replacing historical methods of water and waste management, resulting in multi-year capital projects that are on-going to address groundwater impact at the Colstrip Steam Electric Station.

Q. How are these projects replacing historical methods of water and waste management at the Colstrip Steam Electric Station?

A. Raw water is piped from the Yellowstone River to Castle Rock Lake, and ultimately to holding tanks at the plant site. This water is used in boilers, cooling towers and scrubber systems. Fly ash from the scrubber system is transported to the paste plants which then removes a portion of the excess water and deposits paste into disposal cells. Once the water decanted off, it is recirculated back to the plants for reuse. Water is reused or lost through evaporation processes (i.e., a zero discharge facility). Throughout the years, water has been lost through seepage from the ponds.

These capital projects also support the long-term management of coal combustion residuals as required by Federal regulations and continue efforts to meet the state and federal operational, and regulatory and environmental requirements and deadlines. Capital projects will continue until completed and the groundwater impact is mitigated to regulatory levels, regardless of when or if the units are shut down. The activities are evaluated by the Montana Department of Environmental Quality to meet the requirements of the Agreed Order on Consent Regarding Impacts Related to Wastewater Facilities.

Q. What was PSE's share of the capital costs of the water management system and Coal Combustion Residuals Rule projects between October 1, 2016, and December 31, 2018?

A. PSE's share of the capital costs of the water management system project at Colstrip Units 3 & 4 over the period beginning October 1, 2016, and ending December 31, 2018 was $8,302,574. *See* Exh. RJR-6 at 1.

Q. What was PSE's share of the capital costs of compliance with the Coal Combustion Residuals Rule over the period beginning October 1, 2016, and ending December 31, 2018?

A. PSE's share of the Coal Combustion Residuals Rule - B Cell Clearwell capital costs over the period beginning October 1, 2016, and ending December 31, 2018 was $3,557,111. *See* Exh. RJR-6 at 1. PSE's share of the Coal Combustion Residuals Rule - Bottom Ash Containment capital costs over the period beginning October 1, 2016, and ending December 31, 2018 was $1,577,032. *See* Exh. RJR-6 at 1.

In addition to the B Cell Clearwell and Bottom Ash Containment capital expenditures, PSE incurred over $1,685,201 in capital costs for other projects to comply with the Coal Combustion Residuals Rule. These projects include capital costs associated with (i) the G Cell Lining ($569,440); (ii) the BC/XT Solids Waste Storage Build ($568,871); (iii) the B Pond Construction ($445,171); and (iii) the G Cell design ($101,719). *See* Exh. RJR-6 at 1-2.

b. SmartBurn Controls

Q. Please describe the SmartBurn controls installed at the Colstrip units.

A. SmartBurn controls were originally developed as the part of Alliant Energy's Combustion Initiative Program focused on the reduction of nitrogen oxides ("NOx") by optimizing the combustion process in coal-fired generation plants. NOx is a haze-inducing pollutant produced during the combustion of coal that is regulated under the federal Regional Haze Rule.

SmartBurn controls use air staging technology to reduce the formation of NOx by reducing flame temperatures and improving the efficiency of the combustion of coal. The NOx emissions data received from the Colstrip units after the installation of SmartBurn controls would be used to determine the appropriate size of the technology needed to address the next expected step in NOx reduction—selective catalytic reduction.

Q. What is selective catalytic reduction?

A. Selective catalytic reduction is a post-combustion control technology based on the chemical reduction of NOx into molecular nitrogen (N_2) and water vapor (H_2O). Selective catalytic reduction typically combines a catalyst with ammonia injection to increase the NOx removal efficiency. The size, scope and amount of ammonia used by the selective catalytic reduction is directly related to the amount of NOx created during the earlier combustion process. Less NOx produced during the combustion phase results in the need for a smaller, and less costly selective catalytic reduction, and less chemicals to operate it.

Q. How might SmartBurn controls affect the later addition of selective catalytic reduction?

A. SmartBurn controls are not a replacement for selective catalytic reduction. SmartBurn controls prevent some of the NOx from even being produced. The combination of SmartBurn controls, and associated measured data, results in the need for a smaller and less expensive selective catalytic reduction to limit the amount of NOx produced and to ensure compliance with the Regional Haze Rule.

A smaller selective catalytic reduction requires less chemicals to operate, so a smaller amount of injected ammonia is needed, resulting in lower future operating costs. SmartBurn controls save future capital expenditures, reduce future O&M expenditures, and provide an earlier environmental benefit by reducing the production of NOx.

Q. Could you please provide additional background about when and why SmartBurn controls were installed on the Colstrip units?

A. Yes. In and around 2012, selective catalytic reduction emission controls were being ordered in many surrounding states and previous litigation against the owners of Colstrip units demanded a requirement of selective catalytic reduction for alleged "New Source Review" violations. The owners of Colstrip units decided to install SmartBurn controls in an effort to manage a future regulatory obligation, doing so in a strategic and cost-effective manner. SmartBurn controls were the last available, low cost, NOx pollution prevention emission control prior to the expected installation of a very expensive emission control (e.g., selective catalytic reduction).

Installation of SmartBurn controls at units of the Colstrip Steam Electric Station began in 2015. Colstrip Unit 2 was the first unit at which SmartBurn controls were installed, with the installation completed in 2015. Installation of SmartBurn controls was completed at Colstrip Unit 4 in 2016 and installation of SmartBurn controls was completed at Colstrip Unit 3 in 2017. The costs of the installation of SmartBurn controls at Colstrip Unit 2 and the majority of costs of the installation of SmartBurn controls at Colstrip Unit 4 were included in the 2017 GRC.

Q. What was known about NOx emissions requirements for the Colstrip units when the decision to install SmartBurn controls was made in 2012?

A. The Colstrip owners expected that future additional NOx reductions would be required for the units of the Colstrip Steam Electric Station. Colstrip owners anticipated a need to install selective catalytic reduction technology at the Colstrip units to meet the need for future additional NOx reductions. This was based on the Federal Implementation Plan for the State of Montana, finalized on September 18, 2012,[2] and the expectation of a Reasonable Progress Report in September 2017.[3]

Q. Did the owners of Colstrip expect SmartBurn controls to satisfy all future NOx emission reductions at the Colstrip units

A. No. SmartBurn controls reduce the first increment of NOx in the most cost-effective way, based on a review of the technology and the relatively low capital cost to install. Also, the use of SmartBurn controls was determined to be an integral part of any projected future control technology for the Colstrip units. SmartBurn controls reduce a significant amount of the target NOx reduction for a significantly lower cost than a full control modification approach. The early installation of SmartBurn controls also provides several years of operational

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2 *Approval and Promulgation of Implementation Plans; State of Montana; State Implementation Plan and Regional Haze Federal Implementation Plan; Final Rules*, 77 Fed. Reg. 57864 (Sept. 18, 2012) (revising 40 C.F.R. Part 52).

3 *See*, *e.g.*, Montana Department of Environmental Quality, *Regional Haze 5-Year Progress Report* (Aug. 2017), available at http://deq.mt.gov/Portals/112/Air/AirQuality/Documents/RegionalHaze/RegionalHaze_ProgressReport_8-2017.pdf.

boiler data that would allow for the design and eventual installation of the appropriately sized selective catalytic reduction or other control technology, once deemed appropriate. SmartBurn controls also provide an additional tool to maintain NOx emissions within the current operating requirements, as the plant ramps more frequently to support an increasing amount of variable generation in the region.

Q. Were there other benefits for the timing of installing SmartBurn controls?

A. Yes. SmartBurn controls were installed on the Colstrip units during previously scheduled outages thereby reducing implementation costs. If SmartBurn controls needed to be added at a later date for more near-term compliance needs, a separate outage might have been required in consecutive years—the first outage to install SmartBurn controls, and a second outage to install additional plant controls. Depending on market conditions at the time of the outage, the additional cost of an extra week long outage could be approximately one-half the cost of installing SmartBurn controls, depending upon market conditions at the time.

Finally, the operational effectiveness of SmartBurn controls may allow for a different and more cost-effective technology to be installed in place of selective catalytic reduction, because a lower amount of NOx is being produced by the plant. SmartBurn controls do not otherwise improve reliability or extend the life of the plant, so it has no bearing on the useful life of the plant or the Colstrip owner's decision to operate the plant. SmartBurn controls provide immediate environmental benefits through NOx reduction now and helps mitigate the cost of later selective catalytic reduction additions.

Q. Did the installation of SmartBurn controls result in verifiable NOx reductions?

A. Yes. The installation of SmartBurn controls has met the guaranteed emission rate reduction specified in the contract for this capital investment. The addition of SmartBurn controls on Colstrip Units 3 & 4 improved NOx removal from 80 percent to approximately 86 percent, or an 8 percent improvement.

Q. Did the owners of the Colstrip units consider alternatives to the installation of SmartBurn controls?

A. Yes. The owners of Colstrip units reviewed a wide variety of NOx control solutions over the years, including selective non-catalytic reduction, selective catalytic reduction, SmartBurn controls, and others.

Q. Can you please summarize your testimony concerning the installation of SmartBurn controls at the Colstrip units?

A. Yes. PSE agreed, based on the information available at the time, to invest in SmartBurn controls at the Colstrip units for the following reasons:

1. The Colstrip owners decided to install SmartBurn controls at the Colstrip units in 2012 for installation in 2016 and 2017. At the time the decision to install was made, the Colstrip owners anticipated a need to install selective catalytic reduction technology at the Colstrip units to meet the need for future additional NOx reductions related to compliance with the Regional Haze Rule.

2. SmartBurn controls will not extend the useful life or reliability of the Colstrip units.

3. SmartBurn controls have produced positive environmental results, lowering NOx emissions and providing data useful

> for designing and selecting the selective catalytic reduction technology for the next step in NOx reductions expected in the second half of the next decade.

Q. What was PSE's share of the capital costs of the installation of SmartBurn controls between October 1, 2016, and December 31, 2018?

A. PSE's share of the capital costs of the installation of SmartBurn controls over the period beginning October 1, 2016, and ending December 31, 2018, was (i) $322,644 for the installation of the controls at Colstrip Unit 4 and (ii) $3,825,074 for the installation of the controls at Colstrip Unit 3. *See* Exh. RJR-6 at 1. Please note that PSE incurred the majority of capital costs for installation of SmartBurn controls at Colstrip Unit 4 prior to October 1, 2016, and those costs were incorporated into rates in the 2017 GRC. In contrast, PSE incurred the majority of capital costs for installation of SmartBurn controls at Colstrip Unit 3 after October 1, 2016. This explains the difference in capital costs between the two units presented in this proceeding.

c. Colstrip Unit 3 Turbine Overhaul

Q. Please describe the turbine overhaul for Colstrip Unit 3.

A. The Colstrip Unit 3 turbine overhaul was part of the regular three-year scheduled maintenance work for each unit at the Colstrip Steam Electric Station. Industry and original equipment manufacturer practice supports a three- to four-year overhaul cycle. Other overhaul work for Colstrip Unit 3 included installation of SmartBurn controls (as previously discussed), cooling tower work, and boiler repairs.

The scope of the work on the turbine valve overhaul included high pressure pump repairs, intermediate pressure section repairs, and turbine accessory work. The turbine accessory work included items such as the feedwater heater replacement, auxiliary turbine valve work, and eddy current testing of feedwater heater.

Q. What was PSE's share of the capital costs of the turbine overhaul for Colstrip Unit 3 over the period beginning October 1, 2016, and ending December 31, 2018?

A. PSE's share of the capital costs of the capital costs of the turbine overhaul for Colstrip Unit 3 was $1,513,622 over the period beginning October 1, 2016, and ending December 31, 2018. *See* Exh. RJR-6 at 1.

d. Gas Deflection Arch Replacement

Q. Please describe the Gas Deflection Arch Replacement project.

A. The Gas Deflection Arch Replacement project replaced portions of the gas deflection arch of the boiler at Colstrip Unit 3 & 4. The gas deflection arch, or "nose", of the boiler deflects gas outwards in order to equalize gas flow into the superheater sections. This nose arch is subject to more erosion than some other areas due to slagging and soot blowing wear. Replacement of these areas prevents premature failure of the tubes that have been damaged by erosion. Erosion causes thinning of the tubes and can result in boiler tube leaks and subsequent unplanned outages that can cost hundreds of thousands of dollars per day. As a result, Talen Montana characterized this project as essential for reliable operation of Colstrip Units 3 & 4.

Q. What was PSE's share of the capital costs of the Gas Deflection Arch Replacement project over the period beginning October 1, 2016, and ending December 31, 2018?

A. PSE's share of the capital costs of the Gas Deflection Arch Replacement project was $1,066,583 over the period beginning October 1, 2016, and ending December 31, 2018. *See* Exh. RJR-6 at 1.

e. Colstrip Unit 4 Turbine Overhaul

Q. Please describe the turbine overhaul for Colstrip Unit 4.

A. The Colstrip Unit 4 turbine overhaul was part of the regular three-year scheduled maintenance work for each unit at the Colstrip Steam Electric Station. Industry and original equipment manufacturer practice supports a three- to four-year overhaul cycle.

Q. What was PSE's share of the capital costs of the turbine overhaul for Colstrip Unit 4 over the period beginning October 1, 2016, and ending December 31, 2018?

A. PSE's share of the capital costs of the capital costs of the turbine overhaul for Colstrip Unit 4 was $866,250 over the period beginning October 1, 2016, and ending December 31, 2018.

C. Pro Forma Adjustments for Units of the Colstrip Steam Electric Station

Q. How are operating budgets developed for the units of the Colstrip Steam Electric Station?

A. As previously mentioned, the budgets for Colstrip Units 1 through 4 are constructed by the plant operator (Talen Montana) and approved via a voting process by Owners Committee (for Colstrip Units 1 & 2) or the Project Committee (for Colstrip Units 3 & 4). The plant operator develops the proposed operating budgets for the upcoming five (5) years and capital budgets for the upcoming 10 years and presents the budgets to the respective committee by September 1 of each year. Approval of the plant operator's proposed budgets is done before November 1 of each calendar year. The vote implements the budgets for the immediately following year only with projections for the following years. Each owner's share of the budget is based on its ownership share of the units.

Q. How does PSE make and manage decisions with respect to the operating budgets for the units of the Colstrip Steam Electric Station?

A. PSE actively participates in the decision-making process at the Colstrip Steam Electric Station. PSE representatives review the budgets developed by Talen Montana. Additionally, PSE and other owner representatives meet monthly with Talen Montana to review plant operations, including operating projects. Projects may be added or removed throughout the year as appropriate.

<u>1. Pro Forma Adjustments for Colstrip Units 1 & 2</u>

Q. Please describe PSE's pro forma adjustments for Colstrip Units 1 & 2?

A. As previously mentioned, Talen Montana and PSE will permanently retire Colstrip Units 1 & 2 effective December 31, 2019, prior to the rate year in this proceeding. Accordingly, PSE's only pro forma for production O&M in this proceeding is $1,448,718, which amount represents the pro formed amortization expense associated with the outage at Colstrip Unit 1 in 2017 and the outage at Colstrip Unit 2 in 2018. There are no common costs included in the $1.5 million for Colstrip Units 1 & 2 (common costs for Colstrip Units 1 & 2 are included as an adjustment increasing the rate year production O&M for Colstrip Unit 3 & 4).

<u>2. Pro Forma Adjustments for Colstrip Units 3 & 4</u>

Q. Please describe PSE's pro forma adjustments for Colstrip Units 3 & 4?

A. PSE's share of the production and operating budget for Colstrip Units 3 & 4 for 2020 is projected to be $18,662,726. This amount includes pro formed rate year amortization of the outage of Colstrip Unit 3 in 2017 and the outage of Colstrip Unit 4 in 2020.

III. RATE YEAR PRODUCTION OPERATIONS AND MAINTENANCE EXPENSE

A. Overview

Q How has PSE prepared its rate year production O&M expense for the rate year?

A. PSE developed the rate year (i.e., May 1, 2020, through April 30, 2021) production O&M expense in accordance with the Final Order in Dockets UE-141141 *et al*. ("2014 PCORC") and the 2017 GRC. For most plants, PSE utilizes test year O&M expense and makes certain pro forma adjustments as allowed by the Commission.

Q. Please identify the basis used for rate year production O&M when rate year production O&M is not based upon test year expense.

A. Rate year O&M expenses for PSE's jointly-owned facility, the Frederickson 1 Generating Station, is developed from budgets and business plans provided by the plant operator and approved by the owners. For PSE's wind generating stations, rate year royalties, rents and contract maintenance expense was pro formed to reflect rate year projected wind generation. Rate year hydro license expense was pro formed based upon budgeted license O&M. Amortization of major maintenance for coal and gas fired generating facilities has been pro formed to reflect rate year amortization expense consistent with previous rate filings.

Q. What is PSE's production O&M expense for the rate year?

A. The rate year production O&M costs to be included in this filing are $116.3 million, a decrease of $29.6 million as compared to the 2017 GRC settlement production O&M costs of $145.9 million. Please see the Sixth Exhibit to the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-7, for a summary of the rate year production O&M costs.

Q. Please describe the nature of the pro forma adjustments made to production O&M costs in this filing.

A. The test year for this proceeding is January 1, 2018, through December 31, 2018. PSE has made certain adjustments to test year expenses in calculating the rate year production O&M expense as follows:

(i) reduced test year production O&M by $18.9 million to reflect removal of test year non-major maintenance O&M expense associated with Colstrip Units 1 & 2;

(ii) reduced test year O&M by $2.3 million to reflect a decrease in rate year amortization expense associated with Colstrip overhaul costs as discussed in more detail below;

(iii) increased test year O&M by $1.3 million to reflect reallocation to Colstrip Units 3 & 4 of that portion of common costs of Colstrip Units 1 through 4 allocated to Colstrip Units 1 & 2 in the test year, as adjusted for PSE's 25 percent ownership interest in Colstrip Units 3 & 4;

(iv) reduced test year O&M by $0.9 million to reflect rate year amortization of major maintenance of combustion turbine and combined cycle facilities as detailed in the Tenth Exhibit to the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-11, and discussed below;

(v) increased test year O&M by $1.8 million to reflect projected rate year contract maintenance costs under the

Vestas and Siemens maintenance contracts as well as rent and royalty payments for the Hopkins Ridge, Wild Horse/Wild Horse Expansion and Lower Snake River Phase I wind projects based upon forecasted rate year wind generation;

(vi) increased test year O&M by $0.2 million to reflect budgeted rate year hydro license expense; and

(vii) increased test year O&M by $0.1 million to reflect budgeted rate year O&M provided by the plant operator for the Frederickson 1 Generating Station.

Please see the Seventh Exhibit to the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-8, for a summary of the adjustments to test year expenses in calculating the rate year production O&M expense.

B. Thermal–Coal Resource O&M Expense

Q. What are the sources of O&M costs for the Colstrip Steam Electric Station?

A. In past several rate proceedings, PSE developed O&M costs for Colstrip Units 1 & 2 and Colstrip Units 3 & 4 from budgets and business plans provided by the plant operator and approved by owners. PSE developed fuel costs from annual operating plans prepared by the coal supplier, Western Energy Company. Due to significant uncertainties associated with the operation of the Colstrip facilities that may impact 2020 and 2021 budgets, however, PSE has elected to use test year O&M as the basis for rate year production O&M associated with the units of the Colstrip Steam Electric Station in this proceeding. Furthermore, PSE has allocated those test year common costs among Colstrip Units 1 through 4 to Colstrip Units 3 & 4 for the rate year.

With respect to overhaul costs for Colstrip units, the production O&M in this proceeding reflects the methodology as outlined in the Settlement Stipulation approved in the 2014 PCORC.[4] Accordingly, the rate year of May 1, 2020, through April 30, 2021, includes amortization associated with overhaul costs for Colstrip Units 1 & 2 incurred in 2017 and 2018, respectively, and overhaul costs of Colstrip Unit 3 incurred in 2017. Additionally, the rate year includes amortization related to a planned overhaul of Colstrip Unit 4 in 2020 (excluding management reserves) as projected in the plant operator's budget, amortized over a 36-month period.

Q. What Colstrip overhaul events were included in the rate year?

A. Please see the Eighth Exhibit to the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-9C, for a summary of the Colstrip overhaul events included in the rate year.

Q. What was the amount of non-overhaul related Colstrip O&M included in the rate year?

A. PSE's share of non-overhaul related Colstrip O&M included in the rate year amounts to $18.5 million for Colstrip Units 3 & 4 (excluding the adjustment for common O&M for Colstrip Units 1 through 4 discussed below). This compares with non-major O&M of $16.1 million for Colstrip Units 3 & 4 in the 2017 GRC

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[4] Appendix A of the Final Order No. 04 approving and adopting the Settlement Stipulation between PSE, Staff of the Washington Utilities and Transportation Commission, Public Counsel and Industrial Customers of Northwest Utilities in Docket No. UE-141141.

rate year. These amounts do not include any provision for management reserve. PSE has not included any non-overhaul O&M expense for Colstrip Units 1 & 2.

Q. What is the nature of the adjustment for common O&M for Colstrip Units 1 through 4 for the rate year?

A. PSE has added one-half of selected common O&M costs for Colstrip Units 1 through 4 that had been charged to Colstrip Units 1 & 2 in the test year the O&M costs for Colstrip Units 3 & 4 for the test year. The common facilities agreement covering O&M costs common to all units will terminate, and all of the common O&M costs would be charged to Colstrip Units 3 & 4. PSE's ownership share of Colstrip Units 1 & 2 is 50 percent (as compared to 25 percent for Colstrip Units 3 & 4); accordingly, only one half of the selected common facilities O&M charged to Colstrip Units 1 & 2 in the test year were added as an adjustment to O&M costs for Colstrip Units 3 & 4 for the test year.

C. Simple Cycle and Combined Cycle Combustion Turbine Generation Facilities O&M Expense

1. Non-Major Maintenance and Operating Expense of PSE's Simple Cycle and Combined Cycle Combustion Turbine Facilities

Q. What is the basis for the calculation of O&M expense, other than major maintenance, for PSE's owned and jointly-owned generation stations?

A. As discussed previously, PSE generally uses a test year level of production O&M expense to represent a normal level of operating expenses for PSE's owned and operated gas fired turbines. For PSE's jointly-owned gas fired turbine, the

Frederickson 1 Generating Station, the plant operator's budget, except for major maintenance costs, is used to represent the rate year level of production O&M expense. This methodology is consistent with the manner in which production O&M expense was determined in PSE's past several general rate case and power cost only rate case proceedings.

Q What was the amount of non-major maintenance related simple and combined cycle combustion turbine O&M included in the rate year?

A. The rate year non-major maintenance production O&M expense included in this proceeding is $40.8 million, an increase of $1.7 million relative to the 2017 GRC non-major maintenance production O&M costs of $39.1 million.

2. Major Maintenance of PSE's Simple Cycle and Combined Cycle Combustion Turbine Facilities

Q. What is the basis for major maintenance events and expenditures included in this filing?

A. Major maintenance included in this proceeding reflects the rate making treatment as established in the past several rate proceedings. In general, if the cost of a major maintenance event performed at any of PSE's gas fired generating facilities is $500,000 or greater, the costs incurred shall be deferred and amortized over the period until the next scheduled equivalent major maintenance event for that facility. The deferred amount will not be treated as a regulatory asset. If a major maintenance event occurs during the test year but does not meet the $500,000 threshold, the cost of the major maintenance will be included in test year production O&M expense as incurred. Amortization associated with events that have occurred prior to and during the test year have been included in the rate year to the extent that the associated amortization occurs within the rate year. Amortization that ends prior to the rate year is excluded from the rate year. Finally, amortization associated with major maintenance events that occur after the test year but that are known and measurable at the time of the evidentiary hearing are included in rate year production O&M expense.

Q. What is the cost for major maintenance associated with PSE's owned and jointly-owned simple and combined cycle combustion turbine facilities included in this proceeding?

A. PSE's rate year major maintenance expense is $7.6 million as compared to (i) $13.2 million in the 2017 GRC and (ii) $10.8 million in the test year. Please see the Ninth Exhibit to the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-10C, for amortization of major maintenance associated with PSE's owned and jointly-owned simple and combined cycle combustion turbine facilities included in the rate year in this proceeding.

Once the major inspection of Fredonia Unit #1 has been completed and the costs become known, PSE will recalculate the associated amortization based upon known and measurable costs and incorporated into this filing. Please see the Tenth Exhibit to the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-11, for a comparison of amortization of major maintenance associated with PSE's owned and jointly-owned simple and combined cycle combustion turbine facilities included in this proceeding to amortization of major maintenance associated with PSE's owned and jointly-owned simple and combined cycle combustion turbine facilities included in the 2017 GRC.

3. Status of Major Maintenance Contracts at Goldendale and Mint Farm

Q. What is the status of major maintenance contracts for PSE's thermal generating facilities?

A. PSE currently has long term major maintenance contracts with General Electric International to provide combustion turbine major maintenance services at the Goldendale Generating Station and Mint Farm Generating Station. The contracts were effective December 14, 2015, and are expected to expire in 2037.

D. Hydro Resource Generation Production O&M Expense

Q. How has PSE prepared its forecast of hydroelectric production O&M expense for the rate year?

A. PSE developed the rate year production O&M expense for hydroelectric projects in a manner consistent with the development of O&M expenses in the 2014 PCORC. PSE utilizes test year O&M expense and then makes certain pro forma adjustments as previously allowed by the Commission.

Q. What is PSE's forecast of hydro O&M for the rate year?

A. The forecast for rate year hydro production O&M costs is $16.5 million, a decrease of approximately $0.8 million relative to the 2017 GRC hydro production O&M costs of $17.3 million. Please see the Eleventh Exhibit to the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-12, for a comparison of hydro O&M costs included in this proceeding to hydro O&M costs included in the 2017 GRC.

Q. What is the nature of the adjustments PSE has made to test year hydro production O&M expense?

A. PSE has increased test year hydro production O&M expense by $158,453 to reflect budgeted rate year FERC license costs associated with the Baker Hydroelectric Project and the Snoqualmie Falls Hydroelectric Project.

Q. Please describe the adjustment to reflect rate year FERC license costs associated with the Baker Hydroelectric Project and the Snoqualmie Hydroelectric Falls Project.

A. The increase to test year O&M FERC license costs is a result of pro-formed costs to reflect budgeted license O&M costs during the rate year. This is consistent with treatment of license costs in the 2013 and 2014 PCORC and the 2017 GRC filings.

E. Wind Resource Production O&M Expense

Q. What is PSE's forecast of wind generation O&M for the rate year?

A. The forecast for rate year wind production O&M costs is $32.7 million, an increase of approximately $1.5 million relative to wind production O&M costs of $34.2 million in the 2017 GRC settlement. Please see the Twelfth Exhibit to the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-13, for a comparison of wind production O&M costs included in this proceeding to wind production O&M costs included in the 2017 GRC.

Q. What is the nature of the adjustments PSE has made to test year wind production O&M expense?

A. PSE has adjusted test year wind production O&M that total $2.7 million as described below:

(i) added $0.6 million to test year wind production O&M to reflect projected rate year contract maintenance costs under the Siemens maintenance contract for the Lower Snake River wind project (please see the discussion regarding the Siemens contract below);

(ii) added $0.8 million to test year wind production O&M to reflect projected rate year contract maintenance costs under the Vestas maintenance contracts for the Hopkins Ridge and Wild Horse/Wild Horse Expansion wind projects (please see the discussion regarding the Vestas contract extension below); and

(iii) added $0.4 million to test year wind production O&M expense to reflect projected rate year royalty costs under the royalty contracts for the Hopkins Ridge, Wild Horse/Wild Horse Expansion, and Lower Snake River Phase I wind projects based upon projected rate year wind generation.

Q. Please explain PSE's proposed adjustment to wind royalty expense.

A. Wind turbine production royalties represent variable dollar per MWh fees paid under contract to project stakeholders and land owners upon which the wind turbines are sited. These fees are based on the actual generation of PSE's wind turbines. Consistent with the treatment in the 2014 PCORC, and the 2017 GRC, PSE has pro formed the royalty costs based upon the wind generation included in the rate year projected power costs and the contracted rates in the rate year. The rate year royalty expenses for PSE's wind facilities have decreased to $7.2 million for the rate year, as compared to $7.3 million in the 2017 GRC (i.e., a rate year-to-rate year decrease of $0.1 million).

Q. Do the wind turbine production royalty payments reflect contract increases?

A. Yes. In accordance with the terms of PSE's development and land lease agreements with project stakeholders, the annual royalty rate paid per MWh of energy production is subject to an annual adjustment for inflation.

Q. How is routine and corrective maintenance provided for the wind turbines?

A. PSE's wind turbines at Hopkins Ridge, Wild Horse, and the Wild Horse Expansion are maintained by the manufacturer, Vestas, in accordance with the terms of the current service agreements. Siemens has been contracted to provide all maintenance services at the Lower Snake River Phase I facility.

IV. CONCLUSION

Q. Does this conclude your prefiled direct testimony?

A. Yes.

EXH. RJR-14T
DOCKETS UE-190529/UG-190530
UE-190274/UG-190275
2019 PSE GENERAL RATE CASE
WITNESS: RONALD J. ROBERTS

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-190529** **Docket UG-190530 (*Consolidated*)**
In the Matter of the Petition of **PUGET SOUND ENERGY** **For an Order Authorizing Deferral Accounting and Ratemaking Treatment for Short-life IT/Technology Investment**	**Docket UE-190274** **Docket UG-190275 (*Consolidated*)**

PREFILED REBUTTAL TESTIMONY (NONCONFIDENTIAL) OF

RONALD J. ROBERTS

ON BEHALF OF PUGET SOUND ENERGY

JANUARY 15, 2019

PUGET SOUND ENERGY

PREFILED REBUTTAL TESTIMONY (NONCONFIDENTIAL) OF RONALD J. ROBERTS

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PREFILED REBUTTAL TESTIMONY (NONCONFIDENTIAL) OF RONALD J. ROBERTS

I. INTRODUCTION

Q. Are you the same Ronald J. Roberts who submitted prefiled direct testimony on June 20, 2019, on behalf of Puget Sound Energy ("PSE") in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. This rebuttal testimony rebuts certain issues raised by Commission Staff with respect to the Colstrip Steam Electric Station and PSE's production operations and maintenance costs and suggests the following:

(i) The Commission should determine that the decision to invest in SmartBurn controls for Colstrip Unit 3 was prudent.

(ii) The Commission should allow PSE to continue to amortize major maintenance events for Colstrip Units 3 & 4 in rates.

(iii) The Commission should allow PSE to shift certain Colstrip common costs previously allocated to Colstrip Units 1 & 2 to Colstrip Units 3 & 4.

(iv) PSE did not include costs associated with the new coal supply agreement with Westmoreland Rosebud Mining Company because the prehearing conference order prohibited PSE from updating all but a limited subset of power costs in this proceeding.

(v) The Commission should address issues regarding the PSE Integrated Resource Plan Technical Advisory Group in the relevant Integrated Resource Plan docket.

(vi) The Commission should address any issue associated with the 2018 outages for Colstrip Units 3 & 4 in Docket UE-190882.

II. THE COMMISSION SHOULD DETERMINE THAT THE DECISION TO INVEST IN SMARTBURN CONTROLS FOR COLSTRIP UNIT 3 WAS PRUDENT

Q. Please describe Commission Staff's proposal regarding the SmartBurn investment in Colstrip Unit 3.

A. Commission Staff has proposed that the Commission disallow PSE's test year capital addition for SmartBurn technology:

> There is no evidence that SmartBurn is required to comply with Federal law regarding NOx levels. There was no documentation provided that supported the investment. Further, the investment is not currently providing any benefit to ratepayers, as NOx levels were decreased by only 0.01 lbs/MMBtu. Therefore, absent evidence of need, the Company's decision making process, or a substantial improvement in NOx levels, I recommend that the Commission reject $7.2 million of PSE's test year capital addition for SmartBurn.[1]

Q. Is Commission Staff correct that the SmartBurn technology is not required to comply with Federal law regarding NOx levels?

A. Commission Staff is technically correct that Federal law does not require SmartBurn technology to comply with NOx levels. That said, the Colstrip owners, in and around 2012-13, decided to install SmartBurn controls in response to

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[1] Gomez, Exh. DCG-1CT, at 19:20 – 20:4.

(i) orders requiring selective catalytic reduction emission controls in in many surrounding states and (ii) litigation against the owners of Colstrip units that demanded selective catalytic reduction for alleged "New Source Review" violations. At the time of the decision, the Colstrip owners anticipated that all four Colstrip units would continue to serve PSE's load for at least the next two decades.

Based on these orders and the then-ongoing litigation, the Colstrip owners believed that they would need to achieve NOx reductions at the Colstrip units. They decided to proceed with SmartBurn controls, which were the last available, low cost, NOx pollution prevention emission control (and were far less expensive than the installation of costly selective catalytic reduction emission).

Q. Did the owners of Colstrip expect SmartBurn controls to satisfy all future NOx emission reductions at the Colstrip units?

A. No. At the time the Colstrip owners made the decision to install the SmartBurn controls, they believed that the installation of such technology would be the first in a multistep process to address NOx emissions at the Colstrip units.

The owners of Colstrip units reviewed a wide variety of NOx control solutions over the years, including selective non-catalytic reduction, selective catalytic reduction, SmartBurn controls, and others. SmartBurn controls reduce a significant amount of the target NOx reduction for a significantly lower cost than a full control modification approach.

At the time, the Colstrip owners believed that achieving NOx emissions through an approach of gradualism was better for customers than immediately employing more effective—and more costly—technologies, such as selective catalytic reduction emissions. The early installation of SmartBurn controls also provides several years of operational boiler data that would allow for the design and eventual installation of the appropriately sized selective catalytic reduction or other control technology, once deemed appropriate.

SmartBurn controls also provide an additional tool to maintain NOx emissions within the current operating requirements, as the plant ramps more frequently to support an increasing amount of variable generation in the region. In short, the use of SmartBurn controls was determined to be the first step in an integral part of any projected future NOx control technology for the Colstrip units.

Finally, the operational effectiveness of SmartBurn controls may have allowed for a different and more cost-effective technology to be installed in place of selective catalytic reduction, because a lower amount of NOx is being produced by the plant. SmartBurn controls do not otherwise improve reliability or extend the life of the plant, so it has no bearing on the useful life of the plant or the Colstrip owner’s decision to operate the plant. SmartBurn controls provide immediate environmental benefits through NOx reduction now and helps mitigate the cost of later selective catalytic reduction additions.

Q. At the time the Colstrip owners decided to install SmartBurn technology on the units of the Colstrip Steam Electric Station, was it reasonable to anticipate that future additional NOx reductions would be required for those units?

A. Yes. It was reasonable for the Colstrip owners to anticipate that future additional NOx reductions would be required for the units of the Colstrip Steam Electric Station. At the time of the decision, the Colstrip owners anticipated a need to install selective catalytic reduction technology at the Colstrip units to meet the need for future additional NOx reductions. The expectation of the Colstrip owners was based upon the Federal Implementation Plan for the State of Montana, finalized on September 18, 2012,[2] and the expectation of a Reasonable Progress Report in September 2017.[3]

Q. Is Commission Staff correct that the SmartBurn technology is "not currently providing any benefit to ratepayers"?

A. No. It is not true that the SmartBurn technology is not currently providing any benefit to PSE's customers, as suggested by Commission Staff. The installation of SmartBurn controls has met the guaranteed emission rate reduction specified in

2 *Approval and Promulgation of Implementation Plans; State of Montana; State Implementation Plan and Regional Haze Federal Implementation Plan; Final Rules*, 77 Fed. Reg. 57864 (Sept. 18, 2012) (revising 40 C.F.R. Part 52).

3 *See, e.g.*, Montana Department of Environmental Quality, *Regional Haze 5-Year Progress Report* (Aug. 2017), available at http://deq.mt.gov/Portals/112/Air/AirQuality/Documents/RegionalHaze/RegionalHaze_ProgressReport_8-2017.pdf.

the contract for this capital investment. The addition of SmartBurn controls on Colstrip Units 3 & 4 improved NOx removal from 80 percent to approximately 86 percent, or an 8 percent improvement. Indeed, Commission Staff's own exhibit illustrates the downward slope in the average NOx emissions rates for Colstrip Units 3 & 4 precipitated by the installation of the SmartBurn controls.[4]

The installation of SmartBurn controls has demonstrated the capability for even greater NOx emissions reductions. For example, during the period July 2010 to April 2015, NOx emissions for Colstrip Unit 2 averaged 0.30 lbs./MMBtu. In the period after the installation of SmartBurn controls and prior to the retirement of Colstrip Unit 2, NOx emissions for Colstrip Unit 2 averaged 0.15 lbs./MMBtu. Thus, the SmartBurn controls reduced the NOx emissions for Colstrip Unit 2 by approximately 40 percent.

Q. Is Commission Staff correct that the NOx emissions achieved for Colstrip Unit 3 is more modest than the 50 percent reduction in emissions experienced at Colstrip Unit 2?

A. Yes. Commission Staff is correct that the improved NOx removal (from 80 percent to approximately 86 percent) for the Colstrip Unit 3 is modest, representing an observed decrease in NOx levels of 0.01 lbs/MMBtu. As previously mentioned, however, the installation of the SmartBurn technology but was the first step in what the Colstrip owners then-believed was a multistep

[4] *See generally* Gomez, Exh. DCG-9.

process to reduce NOx emissions at the units. The Colstrip owners then-believed that an approach of gradualism in the reduction of NOx emissions would be better for customers.

Q. Are there other reasons behind the modest reductions in NOx emissions at Colstrip Unit 3?

A. Yes. In considering data for the periods before and after installation of SmartBurn controls at Colstrip Units 3 & 4, the results are more modest, representing a reduction in NOx emissions of approximately 8 percent, for a number of reasons.

First, the data relied upon by Commission Staff represents the reduction the five-year rolling average for NOx emissions for Colstrip Units 3 & 4, but the compliance limits are based upon a much shorter 30-day rolling average for NOx emissions for Colstrip Units 3 & 4. The five-year rolling average NOx emissions for Colstrip Units 3 & 4 cited by Commission Staff, however, is lower than the 30-day rolling average NOx emission for Colstrip Units 3 & 4 and not a relevant basis for determining the prudence of the decision to install the SmartBurn controls because NOx emission limits are based on the 30-day rolling average for NOx emissions

Prior to installation of SmartBurn controls at Colstrip Unit 3 & 4, each unit had periods when its 30-day rolling average for NOx emissions was 0.174 lbs./MMBtu (as compared to the NOx limit of 0.18 lbs./MMBtu). The performance guarantee for the SmartBurn controls is a 30-day rolling average NOx emissions of 0.130 lbs./MMBtu. Thus, the SmartBurn controls were intended to reduce the 30-day rolling average NOx emissions (i.e., the basis for the NOx emissions limitation) for those units by approximately 25 percent when compared to the pre-installation period. Given (i) the compliance limit of 0.18 lbs./MMBtu on the 30-day rolling average of NOx emissions and (ii) Colstrip Units 3 & 4 had periods in which they were operating within 97 percent of this compliance limit, the Colstrip owners were justified in installing the SmartBurn controls to establish a better compliance margin and demonstrate reasonable progress towards the Regional Haze Rule.

Second, the SmartBurn controls met the performance guarantee of a 30-day rolling average NOx emissions of 0.130 lbs./MMBtu for Colstrip Units 3 & 4. A variety of other operational parameters (steam temperature, opacity, carbon monoxide levels, etc.) have not made it possible to always operate Colstrip Units 3 & 4 under conditions necessary to achieve these NOx emission levels, thereby resulting in the relatively modest emissions reduction of 8 percent cited by Commission Staff.

Q. Is there any validity to speculation by Commission Staff that the NOx emissions reductions achieved by Colstrip Units 3 &4 may be offset by actions taken to bring particulate emissions into compliance?

A. No. Commission Staff's suggestions that improvements to NOx emissions resulting from the installation of SmartBurn controls on Colstrip Units 3 & 4 will be completely erased (or even increased) as a result of actions taken to bring particulate matter into compliance[5] is without merit. Commission's Staff's speculation appears to be based entirely upon the following recommendation from a Root Cause Analysis report commissioned by the Colstrip Owners:[6]

> Change the objectives of furnace optimization: The burners are currently tuned to minimize slagging and NOX emissions, while also maintaining output. Recommend including control of PM as an objective of boiler operation. Status: In process.[7]

The Root Cause Analysis report, however, focuses exclusively on a recommendation for the compliance with the Mercury Air Toxics Standard (MATS) and does not purport to address any issues with regard the NOx emissions compliance or the interrelationship between the two standards. The plant operator (i.e., Talen Montana LLC ("Talen Montana")) must take into account and balance *all* regulations and laws to meet multiple compliance obligations associated with Colstrip Units 3 & 4.

Furthermore, as shown in Table 1 below, the evidence demonstrates that neither Colstrip Units 3 & 4 was in violation of NOx emissions limits during the relevant period studied in the Root Cause Analysis report:

Table 1. NOx Emission Levels for Colstrip Units 3 & 4 for Period September 2018 through October 2019

	Colstrip Unit 3 NOx Levels (lbs./MMBtu)	Colstrip Unit 4 NOx Levels (lbs./MMBtu)
September 2018	0.16	0.16

[5] *See* Gomez, Exh. DCG-1CT, at 14:18-22.

[6] *See* Gomez, Exh. DCG-5, for a copy of the Root Cause Analysis report.

[7] Gomez, Exh. DCG-1CT, at 14:12-16 (quoting from the Root Cause Analysis report provided as Gomez, , Exh. DCG-5, at 21 (emphasis added by Commission Staff)).

	Colstrip Unit 3 NOx Levels (lbs./MMBtu)	Colstrip Unit 4 NOx Levels (lbs./MMBtu)
October 2018	0.16	0.17
November 2018	0.16	0.16
December 2018	0.15	0.16
January 2019	0.17	0.17
February 2019	0.17	0.17
March 2019	0.16	0.16
April 2019	0.13	0.14
May 2019	0.13	0.14
June 2019	0.15	0.14
July 2019	0.16	0.15
August 2019	0.16	0.15
September 2019	0.15	0.15
October 2019	0.15	0.14

Q. In hindsight, is it fortuitous that the Colstrip owners pursued NOx emissions reductions based on an approach of gradualism?

A. Yes. In hindsight, it is fortuitous that the Colstrip owners pursued NOx emissions reductions based on an approach of gradualism. On May 7, 2019, Governor Inslee signed into law the Clean Energy Transformation Act, which, in part, prohibits PSE, beginning January 1, 2026, from serving load in the state with electricity generated by coal-fired resources. At the time of the installation of the SmartBurn controls, PSE did not know that it could not continue to rely on the Colstrip units to meet load after 2025. Indeed, PSE expected, at the time the decision was made to install SmartBurn controls, that all four Colstrip units would continue to serve PSE's load for at least the next two decades.

If PSE knew then what it knows now, it would have agreed with Commission Staff that the installation of the SmartBurn technology would not have been a good investment—and the alternatives advocated by stakeholders and considered by the Colstrip owners, such as selective catalytic reduction emission controls, would have looked even worse.

Q. Was the installation of the SmartBurn technology on Colstrip Unit 3 a prudent decision?

A. Yes. Notwithstanding the benefit of hindsight, the decision to proceed with the installation of SmartBurn technology at Colstrip Unit 3 was a prudent decision at the time the decision was made. The Colstrip owners knew that the Colstrip units would need to achieve NOx emission reductions if they were going to continue to serve load, and the SmartBurn technology was the first in a multi-step approach of gradualism to reduce NOx emissions. The SmartBurn technology has achieved its purpose—a modest eight percent reduction in NOx emissions. The fact that the technology has not reduced NOx emissions at a greater rate or the knowledge available only in hindsight that PSE can no longer consider Colstrip Unit 3 as a long-term resource to meet loads should not render the decision imprudent.

III. THE COMMISSION SHOULD ALLOW PSE TO CONTINUE TO AMORTIZE MAJOR MAINTENANCE EVENTS FOR COLSTRIP UNITS 3 & 4 IN RATES

Q. Does PSE agree with Commission Staff's recommendation[8] to defer inclusion of amortization of the major maintenance event scheduled for Colstrip Unit 4 and incorporate it into the PSE's next general rate proceeding at actual cost?

A. No. PSE disagrees with Commission Staff's argument to discontinue use of Talen Montana budgets for calculation of rate year major maintenance expense. Commission Staff appears to base its recommendation upon references to differences between major maintenance budgets and actual costs for Colstrip Units 1 & 2. Colstrip Units 1 & 2 are separate facilities from Colstrip Units 3 & 4 and subject to different ownership structures, different ownership and operations agreements, and different expected lives.

As Commission Staff's testimony correctly points out,[9] the scope of major maintenance events for Colstrip Units 1 & 2 for calendar years 2017 and 2018 varied significantly from that originally budgeted. The reason for this variance is simple and wholly unrelated to Colstrip Units 3 & 4—PSE and Talen Montana (the sole owners of Colstrip Units 1 & 2) agreed in a consent decree entered into in the second half of 2016 to retire Colstrip Units 1 & 2 by a date no later than July 2022. The major maintenance originally budgeted for Colstrip Units 1 & 2

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8 *See* Jing, Exh. JL-1CT, at 30:19 – 34:19.

9 *See id.* at 32:19 – 33:2.

for calendar years 2017 and 2018 was no longer necessary given the commitment to a near-term retirement date.

Furthermore, the budgeting process for Colstrip Units 3 & 4 is inherently more complicated due to the existence of six co-owners. As shown in the major maintenance expense the Ninth Exhibit to the Prefiled Direct Testimony of Jing, Liu, Exh. JL-10, the average variance between budget and actual for the outages for Colstrip Units 3 & 4 in calendar years 2014 and 2016 were 2.45 percent and 1.71 percent, respectively. The outage for Colstrip Unit 3 for calendar year was subject to a budget overrun, but that variance between budget and capital is attributable to work performed due to deficiencies identified during the course of the outage that were not foreseeable in the development of the budget.

Moreover, not one Colstrip owner has made—or likely could make on its own—any commitment regarding potential retirement dates for Colstrip Units 3 & 4. Even if one takes into consideration the enactment of the Clean Energy Transformation Act, which, in part, prohibits PSE, beginning January 1, 2026, from serving load in the state with electricity generated by coal-fired resources, PSE will likely continue to rely on power generated by Colstrip Units 3 & 4 for 2020 and the ensuing five years.

Commonly accepted maintenance cycles for coal facilities dictate major maintenance on a regular cycle. This helps ensure the safety and reliability of the units. Major maintenance for a coal unit is analogous to major maintenance for automobiles. Any owner that has had a car for six years and intends to keep the unit for an additional four years must continue to replace the brakes, change the oil, inspect and/or replace the belts, and other such normal maintenance items. Major maintenance helps ensure the safety and reliability of the both cars and coal units.

The last major maintenance for Colstrip Unit 3 was performed in 2017, and the last major maintenance for Colstrip Unit 4 was in 2016. Each unit is due for major maintenance on its regular maintenance cycle, and these major maintenance events are necessary. As discussed above, the variance between actual and budgeted costs for major maintenance activities for Colstrip Units 3 & 4 has been relatively minimal, with the only significance attributable to deficiencies identified during the course of the outage that were not foreseeable in the development of the budget. Accordingly, the Commission should allow PSE to continue to amortize major maintenance events for Colstrip Units 3 & 4 in rates. If, however, the Commission were to not allow PSE to continue to amortize this major maintenance event in rates, then PSE respectfully requests that the Commission adopt Commission Staff's proposal to defer the costs of the major maintenance the event for recovery in a later proceeding.

IV. THE COMMISSION SHOULD ALLOW PSE TO SHIFT CERTAIN COLSTRIP COMMON COSTS PREVIOUSLY ALLOCATED TO COLSTRIP UNITS 1 & 2 TO COLSTRIP UNITS 3 & 4

Q. Commission Staff recommends exclusion of common costs for the Colstrip Steam Electric Station and charged to Colstrip Units 1 & 2 in the test year from the rate year.[10] Please explain in general terms common costs at Colstrip Steam Electric Station.

A. Common costs at the Colstrip Steam Electric Station cover shared expenses, such as maintenance of the general plant site, water treatment and handling equipment, river pumping station, labor relations work, postage, employee safety equipment and training, information technology services, engineering services, communications equipment and more. Some of these items or tasks can fluctuate depending on work load, while others are basic charges. For instance, how much postage is used will depend on how many pieces of mail are generated as opposed to costs that are more structural charges, like environmental monitoring.

In this proceeding, PSE included a representative amount of common costs that will continue to remain to be paid at the Colstrip Steam Electric Station. PSE based the amount used on test year amounts, which is a common method for determining the amount of production operations and maintenance costs to include in rates. Specifically, PSE shifted a percentage of common costs previously allocated to Colstrip Units 1 & 2 costs to Colstrip Units 3 & 4.

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[10] *See* Jing, Exh. JL-1CT, at 35:1 – 36:4.

Additionally, PSE considered the needs to facilitate the process of plant retirement for Colstrip Units 1 & 2 that will take place over the rate year. For these reasons, PSE shifted common costs in an amount of $1,299,767 that were previously allocated to Colstrip Units 1 & 2 to Colstrip Units 3 & 4. PSE respectfully requests that PSE include these common costs for recovery during the rate year.

Q. Does PSE agree with Commission Staff's recommendation that the operations and maintenance budget for Colstrip Units 3 & 4 not be used to establish rate year operations and maintenance costs for those units, even if the budget was finalized in December 2019?[11]

A. No. PSE continues to believe that the budget prepared by the plant operator (i.e., Talen Montana) for Colstrip Units 3 & 4 is a reasonable estimate of the rate year operation and maintenance costs for those units. As discussed previously in this testimony, Commission Staff's argument of large variances between budget and actual expenses is based upon the budget and actual costs of all four units of the Colstrip Steam Electric Station. Variances between budgeted and actual expenses (excluding major maintenance) for Colstrip Units 3 & 4 have been minimal. For example, the Fourteenth Exhibit to the Prefiled Direct Testimony of Jing Liu, Exh. JL-15, shows that the average variance between budgeted and

[11] *See* Jing, Exh. JL-1CT, at 38:19 – 39:13.

actual expenses (excluding major maintenance) for Colstrip Units 3 & 4 for calendar years 2013 through 2018 was less than one half of one percent (0.42%).

V. PSE DID NOT INCLUDE COSTS ASSOCIATED WITH THE NEW COAL SUPPLY AGREEMENT WITH WESTMORELAND ROSEBUD MINING COMPANY BECAUSE THE PREHEARING CONFERENCE ORDER PROHIBITED PSE FROM UPDATING ALL BUT A LIMITED SUBSET OF POWER COSTS IN THIS PROCEEDING

Q. Did the Colstrip owners enter into a new coal supply agreement with Westmoreland Rosebud Mining Company for Colstrip Units 3 & 4, as referred to in Commission Staff's testimony[12]?

A. Yes. PSE and the other Colstrip owners (other than Talen Montana) entered in to a new coal supply agreement with Westmoreland Rosebud Mining Company LLC ("Westmoreland") on December 5, 2019. Please see the First Exhibit to the Prefiled Rebuttal Testimony of Ronald J. Roberts, Exh. RJR-15C, for a copy of the coal supply agreement with Westmoreland.

Q. Please explain how the new coal supply agreement with Westmoreland will address the possibility of coal purchase from non-Westmoreland sources and Montana state legislation related to alternate fuel sourcing for Colstrip raised in Commission Staff's testimony.[13]

A. With the execution of the new coal supply agreement with Westmoreland for supply of coal to Colstrip Units 3 & 4, any speculation regarding the possibility of

12 *See* Gomez, DCG-1CT, at 20:6 – 31:13.

13 *See id.* at 20:6 – 23:14.

use of coal from a supplier other than Westmoreland is now moot. Additionally, Commission Staff's testimony refers to comments made by Talen Montana in relation to Colstrip fuel sourcing legislation considered by the Montana Legislature in 2019.[14] Those comments were made by a representative of Talen Montana in its role as an owner of interests in Colstrip Units 1, 2, and 3, and were not made in any role as a representative for the Colstrip owners generally or as operator of the Colstrip units. PSE did not make similar comments with regard to the proposed legislation, and the comments of a representative of Talen Montana in its role as but one of several owners of the Colstrip units should not—and cannot—be attributable to PSE. In sum, PSE and all Colstrip owners other than Talen Montana were able to execute a coal supply agreement with Westmoreland to source coal for Colstrip Units 3 & 4 for the period 2020 and beyond.

Q. Are the potential permitting issues in Montana associated with a new Colstrip coal unloading facility[15] relevant to this proceeding?

A. No. The potential permitting issues in Montana associated with a new Colstrip coal unloading facility are irrelevant to this proceeding. A new Colstrip coal unloading facility would only have been necessary if the coal for Colstrip Units 3 & 4 had been sourced by a supplier other than Westmoreland. With the execution of a new coal supply agreement with Westmoreland, PSE's obligation

[14] *See* Gomez, Exh. DCG-1CT, at 22:3-7

[15] *See id.* at 23:8-2:8

for coal supply rests solely with Westmoreland as the supplier, and a new coal unloading facility is neither contemplated nor necessary.

Q. Are the potential permitting issues in Montana associated with a potential mine expansion[16] relevant to this proceeding?

A. No. Westmoreland is a separate company from PSE, and PSE has no ability to affect Westmoreland's current or future business decisions with respect to any potential mine expansion. PSE solely relies upon Westmoreland to supply a commodity, and Westmoreland business decisions and financial, permitting, or environmental obligations are Westmoreland's alone. More importantly, PSE's new coal supply agreement with Westmoreland protects both PSE and its customers from any pricing pressures facing Westmoreland related to any decision to expand the Rosebud Mine. Indeed, the terms and the conditions of the coal supply agreement expressly require PSE to pay the same price, regardless of the area of the Rosebud Mine that Westmoreland uses to supply Colstrip Units 3 & 4.

Q. Why did PSE exclude the costs of the new coal supply agreement[17] from this proceeding?

A. PSE did not incorporate the cost of a new coal contract for Colstrip Units 3 & 4 into its request in this proceeding because, at the time of the direct filing on

[16] *See* Gomez, Exh. DCG-1CT, at 25:12 – 26:14.

[17] *See id.* at 28:10-13.

June 20, 2019, the terms and conditions of the new coal supply agreement were subject to negotiations, and the costs of the coal supply agreement were not known and measurable.

Additionally, the prehearing conference order in this proceeding limited PSE power cost updates in this case to certain enumerated cost categories.[18] The pricing associated with the new coal supply agreement did not fall within any of the categories of power costs that the prehearing conference order permitted PSE to update. Accordingly, PSE has honored the terms of the prehearing order by not including costs associated with the new coal supply agreement in this proceeding. If the Commission were to modify the prehearing conference order to include the costs associated with the new coal supply agreement to be included within the limited power cost updates permitted in this proceeding or to otherwise order PSE to include the costs of the new coal supply agreement in this proceeding, then PSE would be willing to do so.

[18] *See Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-190529 & UG-190530 (consolidated), Order 03 at 9 (July 22, 2019) (limiting PSE's ability to update power costs to (1) forward market data, (2) short-term fixed-price power contracts that are an AURORA input, (3) fixed-price gas for power contracts, (4) index-based power and gas for power contracts, and (5) costs that are themselves dependent on the updated AURORA output).

VI. ISSUES REGARDING THE PSE INTEGRATED RESOURCE PLAN TECHNICAL ADVISORY GROUP ARE BEST ADDRESSED IN THE IRP DOCKET

Q. What relevance does Commission Staff's testimony with respect to the Integrated Resource Plan Technical Advisory Group[19] have on this proceeding?

A. PSE sees no relevance in Commission Staff's testimony regarding Integrated Resource Plan ("IRP") Technical Advisory Group ("TAG") meetings in this proceeding. The Commission has separate dockets and separate rules with respect to general rate cases and IRPs. Each proceeding has different structures, goals, and outcomes. Any IRP issues should be addressed in the IRP proceeding, in accordance with the rules developed by the Commission for those proceedings.

VII. THE COMMISSION SHOULD ADDRESS ANY ISSUE ASSOCIATED WITH THE 2018 OUTAGES FOR COLSTRIP UNITS 3 & 4 IN DOCKET UE-190882

Q. How does PSE response to testimony of Commission Staff regarding the 2018 outage for Colstrip Units 3 & 4?

A. PSE generally agrees with Commission Staff that the that the prudency of capital costs associated with the 2018 outages for Colstrip Units 3 & 4 will be addressed in Docket UE-190882.[20] Commission Staff's testimony, however, states that Commission Staff "is contesting $7.5 million … which is comprised of PSE's

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[19] *See* Gomez, Exh. DCG-1CT, at 27:6 – 28:8.

[20] *See id.* at 12:7-9.

share of capital costs associated with the 2018 Colstrip outage and the installation of SmartBurn for Units 3 and 4."[21]

As mentioned previously, Commission Staff's testimony "recommend[s] that the Commission reject $7.2 million of PSE's test year capital addition for SmartBurn."[22] This suggests that Commission Staff's adjustment for SmartBurn controls, which the Commission should dismiss for the reasons discussed above, account for all but $300,000 of the capital costs "associated with the 2018 Colstrip outage and the installation of SmartBurn for Units 3 and 4."[23] It is unclear from Commission Staff's testimony and supporting exhibits what costs are included in the additional capital costs of $300,000 not attributable to SmartBurn controls or whether these costs relate to the 2018 outages for Colstrip Units 3 & 4. If, and to the extent, that such costs are identifiable and attributable to the 2018 outages for Colstrip Units 3 & 4, PSE respectfully requests that the Commission consider those costs in Docket UE-190882 at the same time that it considers all other costs associated with the 2018 outages for Colstrip Units 3 & 4.

[21] Gomez, Exh. DCG-1CT, at 12:4-7.
[22] *Id.* at 20:3-4.
[23] *Id.* at 12:4-7.

VIII. UPDATES TO PSE'S PRODUCTION OPERATIONS AND MAINTENANCE COSTS

Q. Has PSE made any updates to production operations and maintenance costs since it made its direct filing on June 20, 2019?

A. Yes. PSE has accepted a minor change to update the major maintenance cost for PSE's Fredonia Generating Station. This update increases production operations and maintenance costs by $42,500. Please see the Second Exhibit to the Prefiled Rebuttal Testimony of Ronald J. Roberts, Exh. RJR-16, for the revised production operations and maintenance costs. Please note that this exhibit updates the Sixth Exhibit to the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-7, filed on June 20, 2019.

IX. CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes.