EXH. PKW-1CT
DOCKET UE-20___
2020 PSE PCORC
WITNESS: PAUL K. WETHERBEE

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-20____**

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF

PAUL K. WETHERBEE

ON BEHALF OF PUGET SOUND ENERGY

REDACTED VERSION

DECEMBER 9, 2020

PUGET SOUND ENERGY

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I. INTRODUCTION

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

A. My name is Paul K. Wetherbee. My business address is 355 110th Avenue NE, Bellevue, Washington, 98004. I am the Director, Energy Supply Merchant 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 Paul K. Wetherbee, Exh. PKW-2, for an exhibit describing my education, relevant employment experience, and other professional qualifications.

Q. What are your duties as Director, Energy Supply Merchant?

A. As Director, Energy Supply Merchant, my responsibilities include the following:

(i) managing the dispatch of PSE's portfolio of generation assets, related transmission, and associated environmental attributes; and

(ii) directing the front office power and gas trading operations and the hedging program functions.

Q. Please summarize the contents of your testimony.

A. This prefiled direct testimony addresses the following issues relevant to power costs for this proceeding's rate year—June 1, 2021 through May 31, 2022 (the "rate year"):

(i) an overview of PSE's power costs and how they are managed;

(ii) new power supply resources included in rate year power costs;

(iii) renewal and addition of transmission contracts with Bonneville Power Administration ("BPA");

(iv) changes to existing generation resources and new resources that impact power costs;

(v) PSE's methodology for estimating rate year power costs;

(vi) PSE's projected rate year power costs for this proceeding; and

(vii) a comparison of PSE's projected rate year power costs for this proceeding to those currently in rates.

II. POWER COSTS OVERVIEW

Q. What is included in PSE's power costs?

A. Power costs include the costs of fuel to run generating units, purchased power, and third-party transmission. Specifically, power costs include costs of coal, gas and oil to run thermal generators, fixed and variable costs of natural gas transportation and storage, long-term power purchase agreements ("PPAs"), other market purchases and sales, costs of purchased transmission capacity, and various other costs incurred directly in connection with the purchase of electricity.

Q. What is the basis for the power cost rates that are in place today?

A. Current rates were established in PSE's last general rate case, Docket UE-190529 (the "2019 GRC"). The Commission's Final Order 08 and Modifying Orders 10 and 12 (collectively, the "Final Order") established power costs in that proceeding, and the rates went into effect on October 15, 2020.

Q. What level of power costs does PSE propose and how do the proposed costs compare with costs currently in rates?

A. The Second Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-3C, provides a summary of PSE's proposed power costs in comparison with power costs in the 2019 GRC Final Order. PSE's projected power costs for the rate year of $760.4 million are 1.2 percent higher than the amount set in rates ($751.7 million) effective October 15, 2020. The primary drivers of these increased costs are:

(i) higher natural gas prices, which have increased more than 30 percent relative to prices in the 2019 GRC;

(ii) increased costs of existing PPAs, including PSE's contracts for output from the Mid-Columbia ("Mid-C") hydroelectric projects;

(iii) new PPAs to serve PSE customer load and meet projected capacity and renewable energy requirements, including

a) a 40 megawatt ("MW") PPA with Energy Keepers, Inc ("Energy Keepers PPA") which began March 1, 2020,

b) a 17 MW PPA with Sierra Pacific Industries ("SPI Biomass PPA") beginning January 1, 2021,

c) a PPA with Morgan Stanley Capital Group for 100 MW during winter heavy load hours beginning January 1, 2022 ("Morgan Stanley PPA"),

d) a PPA with Avangrid Renewables for 150 MW during winter heavy load hours beginning January 1, 2022, to provide needed capacity prior to commercial operation of the 200 MW Golden Hills Wind facility ("Golden Hills Interim Capacity PPA"), and

e) a 100 MW capacity agreement with BPA beginning January 1, 2022 ("BPA Capacity Contract"); and

(iv) higher costs of transmission purchases from BPA.

These costs are partially offset by lower forecasted customer load, including removal of load associated with customers served under PSE's Schedule 139 Green Direct tariff. Green Direct customer load and the cost of resources used to serve that load are not included in the power costs supported in my testimony. Please see the Prefiled Direct Testimony of Susan Free, Exh. SEF-1T, for details regarding the proposed treatment of PSE's Green Direct program.

The Energy Keepers PPA is presented in Section III of my testimony below. The SPI Biomass PPA, Morgan Stanley PPA, Golden Hills Interim Capacity PPA, and BPA Capacity Contract are presented in the Prefiled Direct Testimony of Cindy L. Song, Exh. CLS-1HCT.

Q. What is the nature of PSE's load and resources to serve that load?

A. PSE's electric load is primarily driven by residential and commercial customers, with a portion coming from industrial customers. Forecasted load for the rate year is 2,375 average megawatts ("aMW") with peak demand of 4,909 MW. The difference between average energy and peak demand illustrates the variable nature of PSE's load.

PSE owns a mix of thermal, wind, and hydroelectric resources to serve its load. These resources alone are not sufficient to meet customer demand in all hours of the year. Therefore, PSE relies on contracts with non-utility generators and market purchases to meet its load. PSE holds transmission capacity that enables it to buy and sell power on the market, primarily at the Mid-C trading hub.

Q. What resources does PSE have to meet its customer load and manage its power costs?

A. PSE owns a diverse portfolio of generating assets that includes the following resources (listed at nameplate capacities):

(i) 370 MW of base-load coal-fired capacity;

(ii) 1,308 MW of gas-fired, combined-cycle combustion turbines with moderate heat rates;

(iii) 614 MW of relatively less-efficient, simple-cycle gas and oil-fired combustion turbines;

(iv) 263 MW of hydroelectric capacity; and

(v) 772 MW of wind capacity.

PSE also holds PPAs for 774 MW of hydroelectric capacity at Mid-C and approximately 1,222 MW of other resources, including new PPAs. In addition, PSE utilizes short term wholesale market purchases and sales to balance load with resources in real time, optimize the value of its resources, and manage portfolio risk.

Q. What governance does PSE have over wholesale market transactions and power cost management activities?

A. PSE's Energy Supply Merchant ("ESM") department is composed of energy market analysts, energy traders, and other professionals. The ESM department develops and implements portfolio management strategies and transacts in the markets for power and gas. PSE's Energy Risk Control ("ERC") department is responsible for independently monitoring, measuring, quantifying, and reporting official risk positions and performing credit analysis. The ERC department is directed by the Director of Resource Acquisition and Energy Risk Control.

PSE's Energy Management Committee ("EMC"), composed of five PSE officers, oversees the activities performed by both the ESM and ERC departments. The EMC is responsible for providing oversight and direction on all portfolio risk issues in addition to approving long-term resource contracts and acquisitions. The EMC provides policy-level and strategic direction on a regular basis, reviews position reports, sets risk exposure limits, reviews proposed risk management strategies, and approves procedures for implementation by PSE staff. PSE's Energy Supply Transaction & Hedging Procedures Manual and Energy Risk Policy lay out the policies that govern energy portfolio management activities and define roles and responsibilities of various departments. In addition, PSE's Board of Directors provides executive oversight of these areas through the Audit Committee.

Q. What actions does PSE take to manage power costs within its governance structure?

A. PSE uses a combination of least-cost dispatch, optimization, and portfolio hedging to manage power costs.

Q. Please explain least-cost dispatch.

A. The ESM department plans for sufficient generation capacity to meet the forecasted day-ahead demand for electricity plus a reserve margin. PSE uses a least-cost dispatch approach for all resources, considering transmission and generation constraints. This strategy minimizes portfolio costs by seeking the most economic supply, whether generated or purchased in the wholesale market.

Q. Please explain optimization.

A. Given PSE's resource adequacy planning standard to meet peak-hour loads, there is often excess capacity. To optimize the portfolio, the ESM department sells excess transmission, generation, and natural gas pipeline capacity (not utilized for load) into the regional markets. Portfolio optimization activities align with PSE's Energy Supply Transaction & Hedging Procedures Manual and Energy Risk Policy.

Q. What are the current portfolio hedging strategies approved by the EMC?

A. The purpose of hedging is to reduce the effects of price volatility in power costs prior to delivery. PSE's Energy Supply Transaction & Hedging Procedures

Manual provides guidance and risk management strategies for hedging exposure in two different time periods – 1) the Programmatically Managed Hedge period and 2) the Actively Managed Hedge period. The Programmatically Managed Hedge period begins [redacted] in advance of delivery. The ESM department uses the Programmatically Managed Hedge program to systematically reduce PSE's net power portfolio exposure (including natural gas for power generation) so that, as a month rolls into the Actively Managed Hedge period, exposure for that month will be within the monthly EMC-approved exposure limit. The Actively Managed Hedge program begins [redacted] in advance of delivery. During this period, ESM staff monitor positions on a daily basis and authorized traders execute transactions to manage exposure within monthly and [redacted] authority limits established by the EMC.

Q. What hedges are included in rate year power costs?

A. Rate year power costs include gas-for-power and power contracts that were transacted as of October 21, 2020, for delivery during the rate year (June 1, 2021 through May 31, 2022).

Table 1 below provides a summary of the fixed-price rate year power portfolio hedges included in rate year power costs.

Table 1. PSE's 2020 PCORC Rate Year
Short-Term Fixed Price Power Portfolio Hedges
as of October 21, 2020

	MWh Volume	Rate Year Cost	Avg. $/MWh
Net On-Peak Power Purchases	[redacted]	[redacted]	[redacted]
Net Off-Peak Power Purchases	[redacted]	[redacted]	[redacted]
	Dth Volume	Rate Year Cost	Avg $/Dth
Net Gas for Power Purchases	[redacted]	[redacted]	[redacted]

As discussed below, to determine rate year power costs, PSE (i) marked to model the fixed-price gas-for-power contracts in the "Costs Not in Aurora" calculation and (ii) included the fixed-price power contracts within the Aurora model.[1] In addition, PSE has entered into physical power and gas-for-power contracts for the rate year which are priced at plus or minus index. The premiums and/or discounts for index contracts are also included in the "Costs Not in Aurora" calculation.

Q. Please expand on the types of hedges included in rate year power costs.

A. PSE hedges power or gas-for-power to fix the price of the commodity. PSE utilizes either fixed-for-float swaps[2] to financially hedge power and natural gas or

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1 The Aurora model is discussed in Section V of this prefiled direct testimony.

2 Fixed-for-float swaps fix the price of a commodity relative to the market "index" price of a commodity and settlement is done financially. For example, PSE may enter into a fixed-for-float Mid-C power contract for a future month at a fixed price of $32.00 per MWh for all hours of the day ("flat"). When the future month occurs, the contract is settled by comparing the fixed $32.00 per MWh to the market price of, say $35.00 per MWh. In this example, the counterparty would pay PSE the difference between the fixed price and the market price, or $3.00 per MWh. For a 31-day month with 744 hours, this would be a payment of $2,232 for a 1 MW contract.

fixed-price physical power and gas contracts. The mechanics of a financial fixed-for-float swap, in combination with a physical index purchase, result in a fixed position identical to purchasing fixed price physical supply.

PSE is able to transact with counterparties through standard agreements for financial swaps and fixed price physical power. PSE’s market counterparties may only be able to sell physically, financially, or, in some cases, both. Therefore, liquidity is enhanced by transacting both physically and financially.

III. NEW RESOURCES

Q. Does PSE seek prudence determinations for any new resources that impact power costs in the rate year?

A. Yes. PSE seeks a prudence determination in this proceeding for each of the five new PPAs listed earlier in Section II of this testimony. Details regarding the SPI Biomass PPA, Morgan Stanley PPA, Golden Hills Interim Capacity PPA, and BPA Capacity Contract are provided in the Prefiled Direct Testimony of Cindy L. Song, Exh. CLS-1HCT. The Energy Keepers PPA is addressed in my testimony below.

Q. What is the Energy Keepers PPA?

A. In October 2019, Energy Keepers, Inc. issued a request for offers to purchase up to 40 MW of firm carbon-free energy from its hydroelectric project[3] on the

[3] The project, formerly known as the Kerr Dam, was renamed Seli'š Ksanka Qlispe' Dam in 2015.

Flathead River in western Montana. On January 29, 2020, PSE agreed to purchase 40 average MW of output from the project from March 1, 2020 through July 31, 2035. The contract price is fixed for the term of the agreement at $[redacted]/MWh.

Q. What benefits does the Energy Keepers PPA bring to PSE's portfolio?

A. With the passage of the Clean Energy Transformation Act ("CETA"), PSE's need for renewables, and more generally non-emitting resources, increased significantly beyond the Renewable Portfolio Standards ("RPS") requirement of 15 percent in 2020. Compliance with CETA will require an estimated 13.4 million additional MWh per year of clean energy by 2030. At 40 aMW, the Energy Keepers carbon-free supply represents 350,400 MWh that can be applied towards PSE's interim targets prior to 2030 and PSE's compliance need between 2030 and 2035. In 2021, the first Clean Energy Implementation Plan will outline additional clean resources to meet interim targets leading up to the compliance requirements of carbon neutral by 2030 and carbon free by 2045.

The Energy Keepers PPA also reduces PSE's reliance on short-term market purchases by coupling firm supply from an identified generation resource with existing firm transmission.

Q. How did PSE analyze the benefits of the Energy Keepers PPA?

A. PSE used its Portfolio Screening Model ("PSM") to calculate the portfolio benefit of the Energy Keepers proposal assuming a PPA cost of $[redacted]/MWh. The PSM model was used in PSE's 2019 Integrated Resource Plan ("IRP") process to develop possible scenarios to meet capacity needs and RPS targets over a 20-year horizon. The baseline scenario uses a generic resource build plan to meet those needs. The financial impact of adding a resource to the portfolio is compared against a baseline resource plan that meets the same capacity need. If the new resource reduces the present value of net cost in the portfolio, it provides a portfolio benefit. Consistent with CETA guidance, this analysis incorporated the social cost of carbon.

Q. What were the results of the PSM analysis with the Energy Keepers PPA?

A. The analysis showed a decrease in PSE's portfolio cost when the Energy Keepers PPA is included, indicating a $[redacted] present value portfolio benefit relative to the baseline resource plan. The social cost of carbon is included in this estimate.

Q. Did PSE perform any additional analysis of the Energy Keepers PPA?

A. Yes. As an alternative valuation approach, PSE staff reviewed forward market energy prices, market values for carbon, and modeled capacity values to validate the proposed PPA price. PSE staff used official Mid-C forward price marks from Platts and forward California carbon pricing from the Intercontinental Exchange (ICE). PSE included in this analysis an estimate of the value to reducing its reliance on market purchases.

Q. What were the results of PSE's alternative valuation of the Energy Keepers PPA?

A. PSE's alternative valuation approach indicated a value of $[redacted]/MWh for the Energy Keepers PPA.

Q. What alternatives did PSE consider in its decision to acquire the Energy Keepers PPA?

A. PSE considered proposals selected through its 2018 All Source Request for Proposals ("RFP") process as alternatives to the Energy Keepers PPA for evaluation purposes. Specifically, the SPI Biomass PPA proposal most closely matches the Energy Keepers supply arrangement. Energy Keepers and SPI both provide clean energy for CETA compliance, are of similar duration (15 and 17 years, respectively), provide 40 MW and 17 MW respectively, and both proposals include a fixed price. The levelized cost of energy ("LCOE") for the SPI Biomass PPA is $[redacted] and the Energy Keepers PPA is $[redacted]. LCOE measures the lifetime costs divided by energy production. Where applicable, the costs include capital costs, operating expenses, taxes, and return on investment. The SPI Biomass PPA has a transmission cost advantage of approximately $3 per MWh because BPA transmission is not required for SPI as the facility is located in PSE's Balancing Authority Area.

In addition, PSE considered multi-year proposals submitted through its 2019 Short-Term RFP as pricing points for clean Pacific Northwest hydroelectric supply. [redacted] and [redacted] both submitted three-year hydroelectric energy supply proposals. The associated premiums ranged from $[redacted] to $[redacted] per MWh above forward Mid-C market prices. These premiums, added to the 15-year forward Mid-C market price of approximately $35 per MWh, provided an indicative value range of $[redacted] to $[redacted] per MWh.

Q. Was acquisition of the PPA approved by the EMC?

A. Yes. PSE's EMC approved the PPA with Energy Keepers. The Third Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-4C, is a memo that contains additional details related to PSE's analysis of the Energy Keepers PPA and the negotiation process, and final updates provided to the EMC. The Fourth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-5C, contains the original EMC presentation recommending PSE submit an offer for the Energy Keepers PPA.

Q. What does PSE request from the Commission regarding the Energy Keepers PPA?

A. PSE requests the Commission determine that PSE's acquisition of this new resource is prudent and allow PSE full recovery of its costs in rates.

IV. TRANSMISSION CONTRACT RENEWALS AND ADDITIONS

Q. Please provide an overview of PSE's transmission contracts.

A. PSE uses transmission to wheel power from both its owned and contracted resources to PSE's system to serve load. In addition to relying on its own transmission, PSE relies extensively on BPA transmission contracts to transmit generated or purchased power to PSE's system. A large portion of this BPA transmission is used to wheel short-term market purchases from the Mid-C trading hub to provide energy and meet PSE's capacity need, as explained in PSE's 2019 IRP process.[4] These transmission contracts are an integral part of PSE's electric resource portfolio and are necessary to provide capacity and energy.

Q. Has PSE entered into new transmission contracts or renewed existing contracts since its 2019 GRC?

A. Yes. PSE acquired two new transmission contracts with BPA and renewed several existing contracts. Specifically, my testimony addresses the following contracts that will be in effect during the rate year in this proceeding:

- renewal of one 23 MW BPA transmission contract for delivery from the Mid-C market trading hub;

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4 *See* Exh. CLS-8, Puget Sound Energy, Inc., 2019 Revised Progress Report, Chapter 5 (Develop Options to Mitigate Risk of Market Reliance) (Dec. 2019).

- renewal of ten BPA transmission contracts totaling 475 MW to take delivery from existing generation resources and provide station service to a generation resource;

- one new 50 MW contract and renewal of a 94 MW contract for BPA transmission from Garrison, Montana to PSE's system.

My testimony also addresses one new 75 MW contract which begins in 2024 for delivery from the Lower Snake River ("LSR") Wind Facility.

Q. Has PSE prepared a summary of transmission renewals and additions included in this filing?

A. Yes. Table 2 shows new and renewed BPA transmission contracts that will be in effect during the rate year June 2021 through May 2022.

Table 2. New and Renewed BPA Transmission Contracts

BPA Mid-C Transmission Contract Renewal

Receipt Point	Assigned Reference No.	Renewal Deadline	Start Date	MW Capacity
Vantage	90922767	3/1/2020	3/1/2021	23
Total Mid-C Renewal				**23**

BPA Transmission Renewed for Long-Term Resources

Resource	Assigned Reference No.	Renewal Deadline	Start Date	MW Capacity
Centralia	81687654	10/1/2020	10/1/2021	100
Frederickson 1	88642719	3/1/2019	3/1/2020	137
Goldendale	91991852	9/1/2020	9/1/2021	18
LSR (Central Ferry)	76213396	12/1/2020	12/1/2021	50
LSR (Central Ferry)	76213399	12/1/2020	12/1/2021	50
LSR (Central Ferry)	76213403	12/1/2020	12/1/2021	25
LSR (Central Ferry)	76213405	12/1/2020	12/1/2021	25
LSR (Central Ferry)	76213391	12/1/2020	12/1/2021	50
Mint Farm	89952868	12/1/2019	12/1/2020	12
Mint Farm	91094468	6/1/2020	6/1/2021	8
Total for Resources				**475**

Other New or Renewed BPA Transmission

Receipt Point	Assigned Reference No.	Renewal Deadline	Start Date	MW Capacity
Garrison, MT	92063927	10/1/2020	10/1/2021	94
Garrison, MT	89426103	New	7/1/2020	50
Total from Garrison				**144**

A. BPA 23 MW Mid-C Transmission Renewal

Q. How does PSE determine the appropriateness of renewing firm Mid-C transmission?

A. As Mid-C transmission contracts become eligible for renewal, PSE evaluates the costs and risks of Mid-C resources using a similar approach and the same tools it uses to evaluate generation assets for acquisition. PSE compares the cost of transmission contracts to other resource alternatives to meet resource needs based on models developed in the IRP.

Q. When does PSE evaluate Mid-C transmission renewals?

A. PSE evaluates the costs and benefits of renewing its Mid-C transmission contracts one year and two months prior to their expiration date. Renewing a transmission contract one year prior to expiration enables PSE to execute right of first refusal. The two additional months are required for PSE's internal review process. The analysis is presented to the EMC twice. The first presentation is to explain the analysis and request for decision. Following the second, or final, presentation the EMC members vote to decide if the transmission contract purchase or renewal should be made.

PSE will continue to evaluate Mid-C transmission contracts and will have the opportunity to make adjustments to its total Mid-C transmission capacity available to meet peak capacity need as other Mid-C transmission contracts come up for renewal. At that time, PSE will have the option to reduce its Mid-C transmission capacity if new information results in a different conclusion than analysis of previous renewals.

Q. Please describe PSE's 23 MW Mid-C transmission contract with BPA.

A. PSE's existing Mid-C transmission contract for 23 MW originating at the Vantage Substation in Grant County, Washington, was set to expire at the end of February 2021. PSE renewed this contract for the minimum term of five years to retain renewal rights and to allow flexibility to re-evaluate transmission needs in the future. If PSE did not renew this contract, it may have been difficult to get back the transmission capacity in the future. PSE manages the risk of not getting capacity in the future by renewing contracts at their renewal deadlines.

Q. How did PSE evaluate the decision to renew its 23 MW Mid-C firm transmission contract from the Vantage Substation?

A. PSE used its PSM to compare (i) the incremental portfolio cost of generation resources assuming renewal of the 23 MW transmission contract with (ii) the incremental portfolio cost assuming expiration of the contract. PSE used this comparison to determine whether there was an economic benefit to renewing the transmission contract.

Q. What were the results of the analysis?

A. The analysis showed that renewing the 23 MW Mid-C transmission contract resulted in a lower portfolio cost as compared to allowing the transmission contract to expire. PSE used two scenarios to evaluate this contract, one with and one without an assumed price on carbon dioxide emissions. With carbon pricing, renewing this contract reduced net present value of portfolio costs $210,000 compared to allowing the contract to expire. Without carbon pricing, renewing this contract reduced net present value of portfolio costs $108,000 compared to allowing the contract to expire.

Q. Why is there a portfolio benefit to the transmission contract renewal?

A. The 23 MW Mid-C transmission contract with BPA allows PSE to delay building or acquiring new generation capacity during the planning horizon, which results in a lower net present value of portfolio costs.

Q. Did PSE's EMC approve renewal of the 23 MW Mid-C transmission contract?

A. Yes. The EMC approved renewal of the 23 MW Mid-C transmission contract on February 27, 2020. The Fifth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-6, includes information presented to the EMC supporting this contract renewal.

<u>B. Existing Generation Resource Transmission Renewals</u>

Q. Did PSE renew any BPA transmission contracts used to wheel power from existing resources?

A. Yes. PSE renewed nine transmission contracts to allow continued delivery of power from the Centralia Generating Station, Frederickson 1 Generating Station, Goldendale Generating Station, the LSR Wind Facility and the Mint Farm Generating Station. In addition, PSE renewed a transmission contract for station service *to* Mint Farm. The ten contracts are described below.

<u>1. 100 MW Transmission Renewal for Centralia</u>

Q. Please describe the 100 MW contract serving the Centralia Generating Station.

A. PSE has a PPA with TransAlta for output from the Centralia coal-fired plant. PSE uses these 100 MW of transmission rights to serve load from Centralia until 2025, when the Centralia PPA expires. The transmission contract would have expired at the end of September 2021, and PSE renewed it to allow for continued delivery of power from the facility.

Q. What does PSE intend to do with the 100 MW of BPA transmission associated with Centralia when the resource closes?

A. After 2025, this transmission can be redirected for alternative uses on BPA's transmission system, to deliver energy from a new resource near Centralia, or resold to other entities.

Q. Did PSE's EMC approve renewal of the 100 MW of BPA transmission for Centralia?

A. Yes. The EMC approved the 100 MW BPA Centralia transmission contract on July 23, 2020. The Sixth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-7C, includes information presented to the EMC supporting this contract renewal.

<u>2. 137 MW Transmission Renewal for Frederickson 1</u>

Q. Please describe PSE's 137 MW Frederickson 1 transmission contract with BPA.

A. The Frederickson 1 Generating Station is a jointly-owned, existing facility currently serving PSE load. Power from the facility is wheeled to PSE's system using a 137 MW transmission contract which would have expired at the end of February 2020. PSE renewed the contract for five years (through February 28, 2025) to allow continued delivery of power from the facility.

3. 18 MW Transmission Renewal for Goldendale

Q. Please describe the 18 MW transmission contract for the Goldendale Generating Station.

A. The Goldendale Generating Station is an existing 277 MW facility interconnected to BPA's transmission system. Power from the facility is wheeled to PSE's system in part using an 18 MW transmission contract which would have expired at the end of August 2021. PSE renewed the contract for five years (through August 31, 2026) to allow continued delivery of power from the facility.

4. 200 MW Transmission Renewals for LSR

Q. Please describe the five transmission contracts for a total of 200 MW associated with LSR.

A. LSR is an existing wind generation resource that helps PSE serve load and meet RPS requirements. PSE renewed five transmission contracts for a total of 200 MW which would have expired at the end of November 2021. PSE renewed the contracts for five years (through November 30, 2026) to allow continued delivery of power from the facility.

5. Two Transmission Contract Renewals (20 MW) for Mint Farm

Q. Please describe the transmission contract renewals associated with the Mint Farm facility.

A. The Mint Farm Generating Station is owned and operated by PSE. Power *from* the facility is wheeled to PSE's system using, in part, a 12 MW transmission contract which would have expired at the end of November 2020. PSE renewed this contract for five years (through November 30, 2025) to allow continued delivery of power from the facility. Power is wheeled *to* the facility to provide station service using the 8 MW transmission contract which would have expired at the end of May 2021. PSE renewed this contract for five years (through May 31, 2026) to allow continued delivery of station service power to the facility.

C. Transmission from Garrison, Montana

Q. Did PSE enter or renew any other BPA transmission contracts?

A. Yes. PSE renewed one 94 MW contract and entered one new 50 MW contract for BPA transmission between Garrison, Montana and PSE's system. These two transmission contracts are described below.

1. 94 MW Renewal of Transmission from Garrison, Montana

Q. Please describe PSE's 94 MW contract for BPA transmission from Garrison, Montana.

A. This 94 MW contract provides transmission from Garrison, Montana to the PSE system and would have expired at the end of September 2021. PSE renewed the contract for five years (through September 30, 2026). This transmission capacity provides an alternative path to wheel power from PSE's generation assets in Montana in the event of outages or derates on the main Garrison 500 kV transmission line and provides capacity for PSE to meet its winter peak energy requirements.

Q. How did PSE evaluate renewal of the 94 MW transmission contract?

A. PSE compared the cost of the transmission contract with a call option offered by BPA in PSE's 2018 RFP, adjusted for capacity. That analysis indicated a $25 million benefit of the transmission contract relative to the call option on a net present value basis over the life of the contract.

Q. Did PSE's EMC approve renewal of this 94 MW BPA transmission contract?

A. Yes. The EMC approved renewal of the 94 MW BPA transmission contract from Garrison on July 23, 2020. The Sixth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-7C, includes information presented to the EMC supporting this transmission contract renewal.

2. New 50 MW contract for transmission from Garrison, Montana

Q. Please describe PSE's new 50 MW contract for BPA transmission from Garrison, Montana.

A. In April 2019, Talen Energy issued an RFP in search of purchasers for two 50 MW contracts for long-term point-to-point transmission service with BPA, with rights from January 1, 2020 through June 30, 2025, and point of receipt at Garrison. One contract had a point of delivery at Mid-C, the other had a point of delivery at PSE's system. PSE reviewed the potential uses, benefits and risks of the transmission, the current and future trends in regional transmission, and potential approaches to establish a bid premium. PSE decided to bid on the 50 MW contract with PSE's system as the point of delivery, and PSE was the successful bidder. PSE could use this transmission to take delivery of a seasonal or multi-year PPA, to transmit power from a future Montana wind resource, or could redirect the rights elsewhere in the BPA system for the Energy Imbalance Market ("EIM") or a new renewable resource. The contract includes full contractual rights including rollover rights and requires payment to BPA for the transmission service. The bid to Talen is a one-time payment to secure the transmission rights, and is amortized over 66 months.

Q. Please summarize PSE's analysis related to acquiring the Talen Energy 50 MW BPA transmission contract.

A. PSE estimated the value of the contract by considering the cost of purchasing 50 MW of transmission directly from BPA. PSE analyzed the cost and timing to obtain 50 MW of long-term firm transmission directly from BPA through a Transmission Service Request. The Montana to Washington transmission path is fully subscribed, with 965 MW of transmission requests in the BPA queue. BPA identified $1.2 billion in upgrades to provide transmission service to those requests by 2030. If PSE were to obtain 50 MW of transmission service from Montana to Washington in 2030 by participating in these future upgrades, PSE would be required to post collateral, which could be in the form of a line of credit. PSE estimated the net present value of interest costs on this line of credit to be approximately $[redacted]. This cost provided the basis for a bid premium of $[redacted] to acquire the 50 MW of resold transmission directly from Talen Energy. The Seventh Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-8C, is a memo that details the analysis related to the decision to acquire the transmission contract.

Q. Did PSE's EMC approve acquisition of the 50 MW Garrison BPA transmission contract?

A. Yes. The EMC approved a bid of $[redacted] for acquisition of the 50 MW BPA transmission contract on May 21, 2019. The Eighth Exhibit to the Prefiled Direct

Testimony of Paul K. Wetherbee, Exh. PKW-9C, includes information presented to the EMC supporting this new transmission contract.

D. Summary of Transmission Contract Renewals and Additions Included in the Rate Year

Q. Was PSE's renewal and acquisition of BPA transmission capacity a valuable and reasonable business decision?

A. Yes. As noted above, PSE relies on existing BPA transmission contracts from Mid-C to PSE's system to meet its capacity need. In this regard, these types of transmission contracts are akin to a generation resource for PSE and provide needed capacity. Additionally, firm transmission is required for PSE's generation resources and contracts in order to provide reliable delivery to PSE's system to serve load. In all cases, PSE performed a full and detailed justification for the prudence of the costs of renewing and acquiring these BPA transmission contracts.

Q. What does PSE request from the Commission regarding PSE's new and renewed transmission contracts?

A. PSE respectfully requests the Commission determine that these contracts and expenses were prudently incurred and allow PSE to fully recover these costs in rates. Table 3 presents power costs included in the rate year for each of PSE's new or renewed BPA transmission contracts.

Table 3. PSE Rate Year BPA Transmission Contracts Renewal and Additions Costs

Resource	Rate Year Power Cost ($000)
Mid-C Vantage 23 MW	$520
Centralia 100 MW	$2,259
Frederickson 1 137 MW	$2,653
Goldendale 18 MW	$407
LSR 200 MW	$4,518
Mint Farm 20 MW	$452
Garrison 94 MW	$2,124
Garrison 50 MW	$1,857
Total	**$14,790**

E. New Transmission for LSR beginning in 2024

Q. Did PSE acquire any new BPA transmission contracts to wheel power from existing resources?

A. Yes. PSE acquired one new firm transmission contract for wheeling power from the LSR Wind Facility. The contract is for 75 MW of capacity and begins in 2024.

Q. Please describe the 75 MW LSR transmission contract.

A. In 2016, PSE submitted a request for 154 MW of transmission capacity from BPA at the LSR Wind Facility starting in 2024. This request was a contingency plan for a 154 MW request for new transmission from the Hopkins Ridge wind facility starting in 2024, because transmission from Hopkins Ridge expires in March 2024 without rollover rights. In the event BPA was unable to grant the Hopkins Ridge transmission request, a backup plan was to build a tie line from Hopkins Ridge to LSR. PSE accepted a partial offer of 79 MW in 2018 and presented this contract in its 2019 GRC. In December 2019, after completing necessary reliability upgrades, BPA granted the remaining 75 MW to complete PSE's 154 MW total request for new transmission from LSR.

Q. How did PSE evaluate the 75 MW contract?

A. PSE evaluated the 75 MW LSR contract by first evaluating the risk of having no transmission for Hopkins Ridge after 2024. In March 2018 PSE used the Portfolio Screening Model to evaluate the impact of allowing the BPA transmission required to serve Hopkins Ridge to expire. PSE compared ongoing operations with renewed transmission to a premature shutdown of Hopkins Ridge in 2024. Without the required transmission, output from Hopkins Ridge would be stranded, and PSE would need to acquire a replacement renewable resource. The analysis indicated that acquiring the transmission was a lower cost alternative to acquiring a replacement renewable resource.

In 2018 and 2019, the 75 MW contract from LSR remained a backup plan for the Hopkins Ridge facility since BPA had not yet confirmed award of the requested 154 MW of transmission service after 2024. PSE determined that the BPA transmission had three other potential uses if it was not needed for Hopkins Ridge: (1) a future phase at LSR, (2) redirect elsewhere in BPA's system, or (3) resell to a third party.

Q. Was the 75 MW transmission contract for the LSR Wind Facility approved by PSE's EMC?

A. Yes. The EMC approved the LSR transmission contract on June 21, 2018. The Ninth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-10, includes information presented to the EMC supporting this new transmission contract.

Q. Are costs for the 75 MW LSR transmission contract included in rate year power costs in this proceeding?

A. No. Costs associated with this transmission contract are not included in rate year power costs because the contract does not begin until March 1, 2024. PSE is seeking a prudence determination for this contract at this time rather than waiting for a future proceeding.

Q. What does PSE request from the Commission regarding PSE's new 75 MW transmission contract for LSR?

A. PSE respectfully requests the Commission determine that PSE's decision to enter into this contract was prudent and allow PSE to fully recover associated costs in future rates.

V. PROJECTED RATE YEAR POWER COSTS

A. Overview of Power Costs

Q. Please quantify PSE's power cost projection for this proceeding.

A. As shown in Table 4 below, PSE's projected rate year power costs are $760.4 million.

Table 4. Projected Rate Year Power Costs
($ in millions)

Aurora model costs	$484.9
Costs not in Aurora	$275.4
Projected Rate Year Power Costs	$760.4

Please see the Second Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-3C, for PSE's projected rate year power costs. Please see the Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T, for the adjustment of PSE's projected rate year power costs to test year levels. Please see the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-1CT, for PSE's projected rate year production operations and maintenance costs.

B. Methodology

Q. How did PSE estimate rate year power costs in this proceeding?

A. As in prior cases, PSE used the Aurora hourly dispatch model to project a portion of its power costs for the rate year. PSE calculated the remaining rate year power costs outside of the Aurora model and refers to these power costs as "Costs not in Aurora."

Q. What costs are projected using the Aurora model?

A. The variable costs of fuel for PSE's resources, certain long-term PPAs, and other market purchases and sales are estimated by Aurora and included in rate year power costs. Other power costs, such as transmission costs, fixed gas transportation costs and fixed costs associated with Mid-C hydroelectric projects, are calculated outside of Aurora.

Please see the Tenth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-11C, for a summary of rate year power costs by resource. Please see the Eleventh Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-12C, for monthly detail of costs and energy produced by Aurora in comparison to similar output from the 2019 GRC.[5] Please see the Twelfth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-13C, for a summary of rate year costs calculated outside of Aurora. Please see the Thirteenth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-14C, for input data on the resources used in Aurora.

Q. Were there changes made to the Aurora hourly dispatch model since the 2019 GRC?

A. Yes. Energy Exemplar, the developer of the Aurora hourly dispatch model, provides periodic software and database updates. The software version of Aurora

[5] 2019 GRC data in Exh. PKW-13C and Exh. PKW-14C includes adjustments related to the Final Order in that proceeding.

used in this filing is Version 13.4.1001, which Energy Exemplar released in December 2019. The database used is Aurora WECC Zonal 2020_1.0.1 ("2020 Database"), which Energy Exemplar issued in September 2020. Energy Exemplar updated regional resource, demand, and financial information within the 2020 Database to reflect more recent data and assumptions than those included in the Aurora database used in the 2019 GRC.

C. Power Costs Methodology

Q. Did PSE make changes to its approach to estimating power costs since the 2019 GRC Final Order?

A. No. PSE followed the methodology prescribed in the 2019 GRC Final Order to estimate power costs in this proceeding. PSE does not propose any changes to its approach to power cost modeling in this case. The approach includes:

(i) Use of the Aurora model and database for the costs and characteristics of all resources, fuels, loads and transmission in the Western Interconnection, with updates of natural gas prices, load, and resource characteristics of PSE resources;

(ii) Use of three-month average natural gas prices as an input to Aurora;

(iii) Use of power prices generated by Aurora by modeling the Western Interconnection;

(iv) Calculation of portfolio costs, including the cost of balancing and contingency reserves, using the "Two Zone" Aurora model with prices from the Western Interconnection model as an input;

(v) Use of 80 years of hydroelectric energy, with a separate model run for each hydro year and use of average model results to calculate rate year power costs. This includes 80 separate runs of the Western Interconnection model followed by 80 runs of the Two Zone model; and

(vi) Calculation of major costs not in Aurora, such as transmission costs, gas transportation costs and fixed costs of Mid-C contracts using Excel spreadsheets.

D. Major Assumptions

1. Rate Year Power Supply Resources

Q. Is PSE's rate year power supply portfolio for this proceeding different from the pro forma power cost portfolio approved in the 2019 GRC?

A. Yes. Changes to PSE's power supply portfolio have occurred or will occur by or during the rate year. Specifically, the underlying portfolio used to determine PSE's rate year power costs for this proceeding reflects the following:

(i) the addition of new PPAs described earlier in this testimony, including:

a. Energy Keepers PPA
b. SPI Biomass PPA
c. Morgan Stanley PPA
d. BPA Capacity Contract, and
e. Golden Hills Interim Capacity PPA;

(ii) new transmission contracts discussed earlier in this testimony;

(iii) updates to contracts executed under PSE's Schedule 91 Tariff, "Cogeneration and Small Power Production";

(iv) updates to PSE's share of output from Mid-C hydroelectric projects, including expiration on September 30, 2021 of PSE's contract with Douglas PUD for the Colville Tribe's 5.5 percent share of Wells hydroelectric output and extension of the Meaningful Priority contract with Grant PUD for 4.33 percent of Priest Rapids Project output; and

(v) updates to all other rate year power contracts and resources to reflect current operations, contract terms, and planned maintenance schedules.

2. Operations and Maintenance Costs of Gas-Fired Resources

Q. Are production operations and maintenance costs supported by your testimony?

A. No. Although production operations and maintenance ("O&M") costs are updated in a power cost only rate case, operationally, they are managed separately from power costs, and they are not included in rate year power costs that I present in this testimony. Please see the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-1CT, for a discussion of production O&M costs. However, when ESM department employees make daily economic decisions of how to provide the lowest cost power for customers, they compare the variable cost of running resources with purchasing power on the market. The cost of running a resource includes fuel and variable O&M costs, because those costs will be incurred if the resource is run. Therefore, modeling of those economic dispatch decisions requires including variable O&M in the dispatch logic when considering the choice between running a resource and purchasing power, consistent with operations. PSE used O&M costs in Aurora model dispatch logic in the same way in the 2019 GRC.

Q. Have the variable O&M costs used to model the dispatch of gas-fired resources changed since the 2019 GRC?

A. Yes. Variable O&M costs used to model the dispatch of gas-fired resources were updated to reflect the most recent three-year rolling average of each facility's actual variable O&M costs. Table 5 below compares the variable O&M costs used in the 2019 GRC and the variable O&M costs used in this proceeding.

Q. Does PSE also include major maintenance costs in its dispatch logic when calculating rate year power costs in this proceeding?

A. Yes. PSE also included major maintenance costs in its dispatch logic when calculating rate year power costs in this proceeding. Major maintenance is a production O&M cost supported in this case by Mr. Roberts and is not included in the rate year power costs that I support in my testimony. However, the timing, frequency, and magnitude of major maintenance events are all influenced by the run time of resources, so these costs are considered in the economic dispatch logic used to calculate power costs in this proceeding. Major maintenance costs were similarly included in the dispatch logic in the 2019 GRC.

Major maintenance costs for all simple-cycle combustion turbines except for Fredonia 3&4 were modeled on a cost per start basis. For combined-cycle combustion turbines and Fredonia 3&4, major maintenance costs were developed on a cost per hour of run time basis and modeled in Aurora on a cost per MWh basis.

Q. What major maintenance costs were used to model power costs in this proceeding?

A. Major maintenance costs used in this proceeding are included in Table 5 below. They are the same as those used in the 2019 GRC and were developed by PSE in accordance with The California Independent System Operator's ("CAISO") methodology for EIM participants.

Table 5. Variable O&M and Major Maintenance Costs of Gas-Fired Resources

Resource	2019 GRC Variable O&M ($/MWh)	2020 PCORC Variable O&M ($/MWh)	Major Maintenance 2020 PCORC & 2019 GRC
Combined-Cycle Combustion Turbines			
Encogen	$[redacted]	$[redacted]	$[redacted] / MWh
Sumas	$[redacted]	$[redacted]	$[redacted] / MWh
Ferndale	$[redacted]	$[redacted]	$[redacted] / MWh
Mint Farm	$[redacted]	$[redacted]	$[redacted] / MWh
Goldendale	$[redacted]	$[redacted]	$[redacted] / MWh

Resource	2019 GRC Variable O&M ($/MWh)	2020 PCORC Variable O&M ($/MWh)	Major Maintenance 2020 PCORC & 2019 GRC
Simple-Cycle Combustion Turbines			
Whitehorn 2&3	$[redacted]	$[redacted]	$[redacted] / start
Frederickson 1&2	$[redacted]	$[redacted]	$[redacted] / start
Fredonia 1&2	$[redacted]	$[redacted]	$[redacted] / start
Fredonia 3&4	$[redacted]	$[redacted]	$[redacted] / MWh
Frederickson 1 combined cycle variable O&M of $[redacted]/MWh is based on PSE's contract with the majority owner, Atlantic Power. Major Maintenance inputs for Fredonia 3&4 were expressed on a $/start basis in the 2019 GRC. Change to $/MWh more closely aligns with how costs are actually incurred for these units.			

<u>3. Projected Hydro Availability</u>

Q. What historical streamflow record did PSE use in its net power cost projection in this proceeding?

A. PSE used the average of the 80-year Mid-C streamflow history from 1929 through 2008 to project power costs for the rate year, the same data used in the 2019 GRC. This remains the most recent long-term hydro data available.

PSE used historical streamflow records from the same 80-year period for projections related to PSE's owned hydropower on the west side of the Cascade Mountains.

In accordance with the Final Order in the 2019 GRC, PSE ran the Western Interconnection Aurora model separately for each of the 80 historical hydro years and used the average of the 80 model results for its calculation of rate year power prices. Then PSE ran the Two Zone Aurora model separately for each of the 80 historical hydro years and used the average of the 80 model results for its calculation of rate year power costs.

4. Natural Gas Prices

Q. What natural gas prices did PSE use in running its Aurora hourly dispatch model for the rate year?

A. As the Commission noted in its final order in Dockets UE-060266 and UG-060267 (the "2006 GRC"), the update for gas costs is "well-established" and should be "straightforward, mechanical and non-controversial."[6] Consistent with this order and all rate cases since, PSE used a three-month average of monthly forward market prices for the rate year from each trading day in the three-month period ending October 21, 2020. PSE input these data into the Aurora hourly dispatch model for each month of the rate year.

Q. How were hedges treated in rate year power costs?

A. As in prior rate cases, rate year power costs include all previously executed rate year short-term power and gas-for-power contracts as of the price cut-off date,

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6 *WUTC v. Puget Sound Energy*, Dockets UE-060266 and UG-060267, Order No. 08 ¶ 104 (Jan. 5, 2007).

October 21, 2020. Fixed-price short-term rate year power contracts are included within the Aurora hourly dispatch model. Rate year contracts for natural gas are adjusted outside of the AURORA model in the "Costs Not in Aurora" calculations, because Aurora calculates gas costs based on the three-month average prices, and these costs need to be adjusted to be consistent with prices of contracts already executed. The gas price input to the Aurora hourly dispatch model represents a three-month average of the forward market rate year gas prices at a certain point in time (in this case, October 21, 2020). Given PSE's hedging program, rate year power costs must reflect PSE's actual fixed-price gas-for-power and power rate year contracts as of that date. The adjustment requires calculating the difference between the three-month average monthly price of natural gas at the pricing cut-off date (October 21, 2020 in this proceeding) and the actual price of natural gas hedges transacted for the rate year as of the same cut-off date.

For each month of the rate year, this difference is multiplied by the volume of the gas-for-power hedges transacted for the rate year. The resulting amount represents the "mark-to-model" adjustment that is included in the power cost forecast. "Costs Not in Aurora" also include premiums and discounts associated with any power and gas-for-power contracts priced at plus or minus index. These contracts require updating whenever natural gas prices are changed or updated during a proceeding. Please see the Fourteenth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-15C, for PSE's calculation of fixed-price gas for power mark-to-model adjustments.

Including the fixed-price power contracts within the Aurora model and marking the fixed-price gas-for-power contracts to the three-month average rate year gas price input in the "Costs Not in Aurora" calculation is the same methodology used by PSE in determining rate year power costs in all rate cases since the 2006 GRC. This adjustment ensures that the cost included in rates represents what PSE expects to pay for those contracts PSE has already entered into.

Q. How do projected gas prices for this proceeding compare with those in the 2019 GRC?

A. Use of a single price can be misleading because there are different projected gas prices for each month of the rate year and for the different trading hubs from which PSE purchases gas. Additionally, these prices do not consider the impact of the fixed price gas contracts at the price cut off date, which may significantly change the average gas price. For purposes of comparison, however, the average forward gas price at the Sumas trading hub for the rate year is $2.83 per million British thermal units ("MMBtu") (for the three months ended October 21, 2020), which is $0.66 per MMBtu higher than the average $2.17 per MMBtu price included in the 2019 GRC and used as the basis for rates effective October 15, 2020. As an additional point of comparison, the average gas price reflected in the 2017 GRC Settlement was $2.48 per MMBtu (for the three months ended June 23, 2017). Table 6 below presents average rate-year gas price comparisons.

Table 6. Average Annual Rate Year Gas Prices

Rate Case =>	2020 PCORC	2019 GRC	2017 GRC Settlement
3-Mo Average at =>	10.21.2020	12.05.19	6.23.17
Rate Year	June 2021 – May 2022	May 2020 – Apr 2021	Jan 2018-Dec 2018
Sumas price ($/MMBtu)	$2.83	$2.17	$2.48
Change from Prior	$0.66	$(0.31)	$(0.28)

Please see the Fifteenth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-16C, which presents monthly gas prices used in this analysis along with the Aurora-generated Mid-C power prices.

Q. Please explain the source of the gas price inputs.

A. PSE used forward gas market price data supplied by a third party vendor. In prior cases, this vendor was Kiodex Global Market Data ("Kiodex"). In this case, forward gas market data is supplied by S&P Global Platts. In 2020, PSE replaced its agreement with Kiodex with a contract with Platts for forward market price data for specific gas and power trading points.

Q. Does PSE intend to update its projected power costs with updated gas price projections during this proceeding?

A. Yes.

Q. What is PSE's proposal to update its projected rate year power costs during this proceeding?

A. PSE intends to provide all parties with updated power cost information—including, but not limited to, updated average gas prices—in a manner and at a date that enables all parties adequate time to review the proposed changes. Below is a list of the items PSE intends to update if new or more recent information becomes available during the course of this proceeding:

1. Natural gas prices to a more recent three-month average of forward market prices,
2. power and gas-for-power hedge contracts,
3. BPA transmission contract rates,
4. natural gas pipeline rates,
5. Mid-Columbia hydroelectric contract costs,
6. Colstrip Units 3&4 fuel costs,
7. other rate year contract rates, and
8. resource outage schedules.

Q. Is PSE's proposal to update its projected rate year power costs during this proceeding consistent with Commission precedent?

A. Yes. PSE's proposal to update its projected rate year power costs during this proceeding is consistent with Commission precedent. In Order 06 in Dockets UG-040640, *et al*.,[7] the Commission expressly recognized an agreement among the parties to the proceeding "that more recent data predicts the near and perhaps even intermediate term better than older data."[8] Additionally, the Commission expressly recognized in Order 08 in Dockets UE-111048 & UG-111049[9] that power costs should be determined based on costs that are reasonably expected to be actually incurred during short and intermediate periods following the conclusion of such proceedings:

> We resolve the philosophical question raised by ICNU in favor of the practical conclusion that power costs determined in general rate proceedings and in PCORC proceedings should be set as closely as possible to costs that are reasonably expected to be actually incurred during short and intermediate periods following the conclusion of such proceedings.[10]

Further, in the PCA Settlement, which was approved by the Commission in Order 11 of Docket UE-130617,[11] the parties agreed:

> PSE is limited to filing one power cost update per PCORC, with an additional update allowed as part of the compliance filing if the Commission determines the update is necessary due to increased gas

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[7] *WUTC v. Puget Sound Energy*, Dockets UG-040640, *et al.*, Order 06 (Feb. 18, 2005).

[8] *Id.* ¶ 116.

[9] *WUTC v. Puget Sound Energy*, Dockets UE-111048 & UG-111049, Order 08 (May 7, 2012).

[10] *Id.* at n.303.

[11] *WUTC v. Puget Sound Energy,* Dockets UE-130617 *et al.*, Order 11 (Aug. 7, 2015).

costs and orders that such update be made as part of the compliance filing.[12]

Honoring the language in Commission orders and the PCA Settlement, PSE's proposal to update its projected rate year power costs during this proceeding will result in power costs that are set more closely to power costs that are reasonably expected to be actually incurred during the rate year.

Q. Has PSE updated power cost information during the course of prior rate case proceedings?

A. Yes. In rate cases going back to at least 2004 when the Commission established the precedent, PSE has updated its rate year power cost projections with new information when it became available. In general rate cases, PSE has typically updated power cost information first in a supplemental filing, again upon rebuttal, and, if ordered by the Commission, a third time as part of its compliance filing.[13] In the 2019 GRC, Commission Staff opposed the power cost update at the prehearing conference, and PSE ultimately agreed to provide only one limited update to power costs in its rebuttal filing in that case. In prior PCORCs, PSE updated power cost information once during each proceeding. Power cost updates

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[12] *Id.*, Attachment A to Settlement Stipulation, page 4, ¶ 7.

[13] PSE's 2006 GRC, 2007 GRC, 2009 GRC, 2011 GRC, and 2017 GRC each included power cost updates in both a supplemental filing and in the rebuttal filing. PSE did not provide supplemental testimony in the 2004 GRC but did provide updates to power cost inputs with its rebuttal filing.

were included with PSE's rebuttal filing in the 2013 PCORC and with a supplemental filing in the 2007 and 2014 PCORCs.[14]

5. Natural Gas Resources

Q. Please describe the gas resources held by PSE for power generation.

A. PSE maintains a diverse portfolio of firm pipeline capacity and firm storage capacity to provide reliable fuel supply to the generation fleet. The capacity currently held will meet (i) 100 percent of PSE's combined-cycle combustion turbine requirements on a year-round basis, (ii) approximately one-half of the winter-time requirements of its simple-cycle combustion turbine requirements, and (iii) approximately one-third of the summer-time requirements of its simple-cycle combustion turbine requirements.

PSE also holds firm transportation capacity upstream of the two major pipeline interconnects at Sumas, Washington, and Stanfield, Oregon, to ensure the availability and access to supply at those points and to diversify the pricing of the supply. Such upstream capacity is equivalent to approximately 50 percent of PSE's requirements at those points. For generating facilities situated on the distribution system of Cascade Natural Gas Company ("Cascade Natural Gas"), PSE has reserved the necessary firm distribution service to ensure reliable deliveries of fuel acquired upstream.

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[14] PSE's 2005 PCORC was settled prior to any supplemental or rebuttal filing so did not include updates to power cost information.

PSE has contracted for firm storage service to provide reliability, flexibility, and, in conjunction with special firm storage redelivery service, incremental supply to the generation fleet in the winter months. The storage service provides necessary reliability and flexibility to start or stop generation as needed during the gas day by providing an immediate supply of fuel or a place to store the gas and avoid a pipeline imbalance. The storage also serves as an integral part of the portfolio to allow incremental deliveries in winter months because it is coupled with winter-only pipeline capacity. PSE's storage service capacity can also serve as an alternate supply source to avoid extreme pricing deviations at either of the major supply points.

Tables 7 and 8 below detail the firm natural gas resources held by PSE to serve its generation fleet. There have been no changes to the volumes presented in these tables since the 2019 GRC.

Table 7. Natural Gas Resources for PSE Gas-Fired Generators
Firm Pipeline Capacity

Pipeline	Path	Capacity (Dth/d)		Rate Year Fixed Cost ($000)
Northwest Pipeline	Sumas to plants	108,957		$15,523
Northwest Pipeline	Stanfield or Plymouth to plants	78,928		$11,245
Northwest Pipeline	Plymouth or Stanfield to plants	15,000		$529
Subtotal NWP Annual		202,885	(1)	$27,297
NWP-Winter Only	Jackson Prairie to plants	34,197	(1)	$1,209
Total NWP		237,082		$28,506
Cascade Natural Gas	Sumas to Whitehorn	24,000	(1)	$177
Cascade Natural Gas	Sumas to Ferndale	52,000	(1)	$1,310
Cascade Natural Gas	NWP to Encogen	37,000		$204
Cascade Natural Gas	NWP to Fredonia	94,000		$1,482
Cascade Natural Gas	NWP to Mint Farm	52,000		$1,311
Northwest Pipeline	Goldendale Lateral	50,350		$129
Puget Sound Energy	Sumas Pipeline	26,000	(1)	–
Westcoast Energy	Station 2 to Sumas	88,352		$12,625
Nova Gas Transmission	NIT to A/BC	41,420		$2,023
Foothills Pipeline	A/BC to Kingsgate	40,946		$1,068
Gas Transmission NW	Kingsgate to Stanfield	40,567		$1,939
Total Capacity to plants	Annual	304,885		
	Winter	339,082		
Total Pipeline Fixed Charges				**$50,776**

Notes:

(1) Capacity included in Total Capacity to plants

Table 8. Natural Gas Resources for PSE Gas-Fired Generators
Firm Storage Service Capacity

Project	Withdrawal Capacity (Dth/d)	Storage Capacity (Dth)		Rate Year Fixed Cost ($000)
NWP Plymouth LNG	70,500	241,700		$958
NWP Jackson Prairie	6,704	140,622		$67
Jackson Prairie Storage Project (interbook)	50,000	500,000	(1)	$1,579
Total Storage Service	127,204	882,322		
Total Storage Fixed Charges				$2,604
Total Gas Resource Fixed Charges				**$53,380**

Notes:

(1) Withdrawal capacity is subject to recall

Q. What pipeline rates are reflected in rate year power costs?

A. Rates in effect as of October 2020 are reflected in power costs. If rate adjustments are approved by the appropriate regulatory authorities during the pendency of this case, PSE will include adjustments to the pipeline rates and related gas transportation costs when power costs are updated. Please see the Sixteenth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-17C, for the calculation of rate year costs of PSE's firm pipeline capacity.

6. Colstrip Fuel Prices

Q. What Colstrip fuel costs did PSE use for its power costs projections in this proceeding?

A. Colstrip Units 3 & 4 fuel costs were determined using coal prices from the December 2019 Coal Supply Agreement ("CSA") with Westmoreland Rosebud

Mining. PSE began purchasing coal according to the terms of this agreement in January 2020. Please see the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-1CT, for information regarding the Colstrip Units 3 and 4 CSA.

7. Wind Generation

Q. What wind forecast did PSE use to develop its power costs projections in this proceeding?

A. PSE used 2016 wind forecasts developed by Vaisala Corporation ("Vaisala"), an outside expert on wind generation, for the wind resources owned by PSE (i.e., the Hopkins Ridge Wind Facility, the Wild Horse Wind Facility, the Wild Horse Wind Facility Expansion, and the Lower Snake River Wind Facility).

For the Klondike III power purchase agreement, PSE used the 2016 wind forecast provided by Avangrid Renewables, LLC, the owner of the Klondike III Wind Power Project. These forecasts were approved in the 2019 GRC Final Order.

8. Load Forecast

Q. What load forecast did PSE use in running its Aurora hourly dispatch model for the rate year?

A. PSE used the most current electric load forecast—the F2020 load forecast—adjusted to remove Green Direct customer load as the rate-year demand input to the Aurora model. The electric load forecast, net of demand-side resources (conservation), for the rate year is 20,803,205 MWh, or 2,375 aMW. This is a decrease of 2,349,450 MWh, or 10.1 percent from the 2019 GRC load forecast of 23,152,655 MWhs (2,643 aMW). Removal of load associated with Green Direct customer accounts for 723,147 MWh of this reduction.

Q. How does this lower load forecast affect the power costs supported by your testimony?

A. Lower forecasted load decreases the amount of power that PSE must purchase in the market (or increases the amount of power that PSE is able to sell in the market) and thereby reduces total power costs. However, the reduction to power costs is proportionally smaller than the reduction to forecasted load, so the net result is an increase to power costs per unit. While total rate-year power costs presented in this case are less than 1.2 percent higher than those approved in PSE's 2019 GRC, power costs per MWh have increased 12.6 percent.

Q. Why do total power costs not decrease in proportion to decreases in forecasted load?

A. Reductions to forecasted load do not cause a proportional reduction to power costs because (i) a significant portion of total power costs are fixed costs – they are the same regardless of how much energy PSE delivers to customers – and (ii) the average variable cost of resources in PSE's portfolio is higher than the average price of short-term market purchases determined using the Aurora model in this case.

Q. What fixed costs are included in PSE's rate-year power cost projection?

A. $275.4 million, or 36.2 percent, of total rate-year power costs in this case are fixed costs that do not vary with the amount of PSE customer load. These costs include items such as purchased transmission, demand charges for gas pipeline capacity, and payments for PSE's share of output from Mid-C hydroelectric projects. Fixed costs included in power costs are calculated outside of the Aurora model and summarized in Exhibit PKW-13C.

Q. Why do fixed costs cause power costs per unit to increase when forecasted rate-year load decreases?

A. Since these costs do not change when load decreases, a lower load forecast means there are fewer MWh over which to spread the same fixed costs.

Q. How does the average variable cost of PSE's resources relative to the price of short-term market purchases affect unit power costs?

A. When its portfolio of long-term resources does not provide enough energy to meet forecasted customer load, PSE relies on short-term market purchases to make up the difference. The average price of short-term market purchases may be lower than the variable cost of other resources in PSE's portfolio, or it may be higher. PSE has seen both over the past two decades.

If the average price of those market purchases is lower than the average variable cost of other resources in the portfolio, as is currently the case, then each MWh purchased from the market reduces the average cost of PSE's total power supply. If load increases, so too does the volume of lower-priced market purchases, and power costs per MWh are reduced. Conversely, a reduction to load results in fewer relatively low-priced market purchases and increases average power costs per MWh.

In contrast, if the average price of market purchases is higher than the average variable cost of other resources in PSE's portfolio, as was the case in the early 2000s, then each MWh purchased from the market increases the average cost of PSE's total power supply. In such case, an increased load would increase average power costs per MWh, while a reduced load would decrease average power costs per MWh.

Q. Did removal of Green Direct load and resources cause unit power costs to increase?

A. No. The price of Green Direct resources is higher than the average cost of forecasted market purchases in this case, so the power cost reduction associated with removing the Green Direct resources more than off-sets the unit cost impact associated with removing the Green Direct load.

Q. Why are power costs per unit, as opposed to just total power costs, relevant in this case?

A. While the majority of my testimony focuses on total projected power costs for the rate year, PSE recovers these costs through the variable baseline rate, which is expressed in dollars per MWh. The variable baseline rate established in this case will therefore reflect the impact of both slightly higher total power costs and significantly lower forecasted rate-year load. The impact of these two factors combined is reflected in the baseline rate calculation and pro forma test-year adjustments presented by Susan E. Free in Exh. SEF-4 and Exh. SEF-5.

9. Operating Reserves

Q. What operating reserves are included in rate year power costs?

A. Rate year power costs include estimated (i) costs of contingency reserves, (ii) costs related to balancing load with wind and other resources every hour, and (iii) day ahead wind integration costs. These costs were also included in power costs in the 2019 GRC.

Q. What are contingency reserves and how are they calculated?

A. As a Balancing Authority, PSE is required by North American Electric Reliability Corporation ("NERC") and Western Electric Coordinating Council ("WECC") standards to fulfill a Contingency Reserve Obligation. Contingency reserves are capacity reserves that Balancing Authority operators are required to maintain to help preserve the stability of the bulk power system during system disturbance events such as a generating unit tripping offline or an unexpected transmission line outage. They are incremental reserves, which means the Balancing Authority operator must have the ability to increase generation in the event of a disturbance to maintain its area balance. In the WECC, contingency reserves are defined as three percent of the load in the Balancing Authority plus three percent of online generation located within or dynamically tied to the Balancing Authority. Fifty percent of the Contingency Reserve Obligation must be maintained by generating units that are online (spinning), and up to fifty percent can be provided by units that are offline but can be brought online within ten minutes (non-spinning).

Q. Has PSE's Contingency Reserve Obligation changed since rates were established in the 2019 GRC?

A. No. WECC continues to be in a trial period that allows a Balancing Authority to meet its entire Contingency Reserve Obligation with resources that are not spinning. This is a trial period. NERC is expected to make a decision about whether to make this change permanent. Since that decision has not yet been made and the permanent legal requirement is still to have fifty percent of Contingency Reserve Obligation provided by resources that are spinning, PSE has modeled Contingency Reserve Obligation with fifty percent spinning and fifty percent non-spinning resources for projecting power costs in this proceeding.

Q. What are costs related to balancing load with wind and other resources every hour?

A. PSE must enter each hour with sufficient reserves available to continuously balance its load with resources. These costs represent the cost of reserving that capacity each hour.

Q. What level of capacity does PSE reserve on an hour-ahead basis operationally?

A. Operationally, the amount of reserves varies from hour to hour. It also varies depending on whether reserves are incremental, meaning reserved capacity provides the ability to increase production, or decremental, meaning resources provide the ability to reduce generation. PSE must go into each hour with a balanced base schedule in order to participate in the EIM, and CAISO has requirements for incremental and decremental flexible ramping reserves.

Generally, those reserves are 157 MW of incremental reserves and 244 MW of decremental reserves. PSE includes these reserves plus 35 MW of reserves for regulation in both directions in Aurora to model the cost of hour-ahead reserves needed to balance load with wind and other resources each hour. Reserves costs have been included in PSE's rate year power costs since the 2013 PCORC.

Q. What are day-ahead wind integration costs?

A. Day-ahead wind integration costs have been included in PSE's rate year power costs since the 2013 PCORC. They are the costs and benefits that occur between the day-ahead and real-time markets due to the uncertainty of wind power generation. PSE sets up its position in the day-ahead market based on the day-ahead wind forecast. When the portfolio position is updated on an hour-ahead basis with an updated wind forecast, there are costs and benefits associated with movements in the wind forecast and market prices between the day-ahead and hour-ahead positions.

Since the 2013 PCORC, PSE has calculated these costs and benefits based on historical hourly generation and price data and included the net cost in rate year power costs, adding recent data as time has passed. In this proceeding, PSE used costs through December 2019 to calculate day-ahead costs by resource. Please see the Seventeenth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-18C, for day-ahead wind integration costs for each of PSE's wind resources.

Q. Has PSE changed its methodology for calculating these costs since the 2019 GRC?

A. No.

<u>10. BPA Transmission Rates</u>

Q. Are BPA transmission rates expected to change before or during the rate year?

A. Yes. BPA is in the process of a combined power and transmission rate proceeding to set new rates for BPA's fiscal years 2022-2023 (October 1, 2021 through September 30, 2023) (the "BPA 2022 Rate Case").

Q. Is PSE participating in the BPA 2022 Rate Case?

A. Yes. PSE is an intervener in the BPA 2022 Rate Case to advocate for PSE customers' interests to ensure any rate changes are supported by the facts presented. Consistent with past practice, PSE has worked with other parties to recommend ways to reduce the rate increases, which would be effective October 1, 2021, through September 30, 2023.

Q. How does PSE propose to include BPA transmission rate changes in rate year power costs?

A. PSE included a transmission rate increase of 2.65 percent for BPA's point-to-point transmission rates effective October 1, 2021, in its calculation of rate year BPA transmission costs. This rate change assumption is based on the average of BPA rate increases from 2002 through the most recent effective rates in October 2019. PSE included a 4.95 percent decrease to BPA rates for reserves and resource integration based on preliminary information provided by BPA in August 2020. PSE intends to update these assumptions if new information regarding the outcome of the BPA 2022 Rate Case becomes available during the course of this proceeding. Please see the Eighteenth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-19C, for PSE's calculation of rate year transmission contract costs.

11. Energy Imbalance Market

Q. What is the Energy Imbalance Market?

A. The EIM is a voluntary, within-hour energy market that provides Balancing Authorities another tool to reliably and economically maintain balance between electric demand (load) and supply (generating resources). It is operated by a central market operator who optimizes the generation resources of the Balancing Authorities within the EIM footprint every fifteen and five minutes. CAISO serves as the market operator for the EIM in which PSE operates. Historically, energy has been predominately traded among entities through bilateral transactions of hourly energy products. Within the hour there has been no liquid market for energy, and Balancing Authorities had to rely on their own generating resources to continuously match imbalances in load and non-dispatchable generation. The EIM provides a sub-hourly market that enables Balancing Authorities to transact and utilize lower-cost resources in other Balancing Authorities to balance load and resources.

Q. What costs related to the EIM are included in rate year power costs?

A. There are no explicit EIM related costs included in PSE's proposed rate year power costs. Actual costs for the test year ended June 2020 were $3.9 million in FERC Account 557, Other Power Supply Expenses. PSE will incur costs during the rate year, but no amount is included in proposed rate year power costs. Exclusion of these costs is consistent with rates currently in place, which were established in the 2019 GRC. This treatment of EIM costs was agreed to in PSE's 2017 General Rate Case Settlement and has been followed since that time.

12. Exhibits Presenting Specific Input Data and Calculations for Proposed Rate Year Power Costs

Q. Has PSE provided other exhibits to support proposed rate year power costs in this proceeding?

A. Yes. The following exhibits present specific input data and calculations for proposed rate year power costs:

(i) The Nineteenth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-20C, presents contract costs of Mid-C hydro resources.

(ii) The Twentieth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-21C, presents distillate fuel incremental costs.

(iii) The Twenty-First Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-22C, presents an adjustment to remove non-fuel costs that are included in Aurora's peaker start costs. These are not power costs, but because they are bundled with start fuel costs in Aurora output, they need to be removed.

(iv) The Twenty-Second Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-23C, presents Colstrip fixed fuel costs.

(v) The Twenty-Third Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-24, presents Other Power Costs chargeable to FERC account 557. These are actual costs from the test year ended June 30, 2020.

E. Comparison with Power Costs in Current Rates

Q. How do the power cost projections in this proceeding compare with the power cost projections approved in the 2019 GRC Final Order?

A. Proposed power costs of $760.4 million are 1.2 percent higher than the $751.7 million approved in the 2019 GRC Final Order.

Q. What does PSE request from the Commission regarding rate year power costs?

A. PSE respectfully requests that the Commission approve PSE's proposed rate year power costs of $760.4 million.

VI. CONCLUSION

Q. Does that conclude your prefiled direct testimony?

A. Yes, it does.