EXH. PKW-1CT
DOCKETS UE-22___/UG-22___
2022 PSE GENERAL RATE CASE
WITNESS: PAUL K. WETHERBEE

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	Docket UE-22____ Docket UG-22____

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF

PAUL K. WETHERBEE

ON BEHALF OF PUGET SOUND ENERGY

REDACTED VERSION

JANUARY 31, 2022

PUGET SOUND ENERGY

**PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF
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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, and my business address is Puget Sound Energy, Inc., P.O. Box 97034, Bellevue, Washington 98009-9734. I am employed by Puget Sound Energy ("PSE") as Director, Energy Supply Management.

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

A. Yes, I have. It is Exh. PKW-2.

Q. What are your duties as Director, Energy Supply Management for PSE?

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

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

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

(iii) managing work groups that address resource adequacy conformance, regional market design, merchant transmission optimization, and the integration of generation assets.

Q. What topics are you covering in your testimony?

A. My prefiled direct testimony addresses the following issues relevant to power costs in this proceeding:

(i) an overview of PSE's power costs and how they are managed, including a report on the power and gas-for-power hedging collaborative;

(ii) PSE's projected power costs for the multiyear rate period in this proceeding, including the limitations of a multiyear forecast and the need for annual updates;

(iii) new resources included in the rate period power cost projection;

(iv) PSE's methodology for estimating rate year power costs including changes to incorporate the net benefit of Energy Imbalance Market ("EIM") participation, which was the subject of collaborative discussions as agreed to in PSE's 2020 Power Cost Only Rate Case ("2020 PCORC")[1] Settlement; and

(v) new and renewed transmission contracts.

II. POWER COSTS OVERVIEW

A. 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 ("PPA");

[1] *WUTC v. Puget Sound Energy*, Docket UE-200980.

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 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 2,437 average megawatts ("aMW") with peak hourly demand of 4,612 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-Columbia ("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):

- 370 MW of base-load coal-fired capacity;
- 1,308 MW of gas-fired, combined-cycle combustion turbines with moderate heat rates;

- 614 MW of relatively less-efficient, simple-cycle gas- and oil-fired combustion turbines;
- 263 MW of hydroelectric capacity, and
- 772 MW of wind capacity.

PSE also holds power purchase agreements for 936 MW of hydroelectric capacity at Mid-C and approximately 1,464 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.

B. Governance and Power Cost Management

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 Enterprise Risk Management.

PSE's Energy Management Committee ("EMC") is composed of five PSE officers and 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 Risk Policy ("Policy") and Energy Supply Transaction & Hedging Procedures Manual ("Procedures") 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. Please see the testimony of Kyle Stewart, Exh. KCS-1CT, for additional discussion of PSE's Policy and Procedures, including recent updates to those documents. PSE's current Policy and Procedures are provided as Exh. KCS-7 and Exh. KCS-8C, respectively.

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 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. The variable nature of PSE's load combined with variability in output from its resources creates capacity in excess of requirements during many periods of the year. To optimize the portfolio, the ESM department sells excess generation, transmission, and natural gas pipeline capacity into the regional markets. These portfolio optimization activities align with PSE's Policy and Procedures.

1. Power and Gas-for Power Hedges

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 ESM department does not enter into risk positions for the purpose of earning trading profits. The Policy and Procedures provide guidance and risk management strategies for hedging market price 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. During the Programmatically Managed Hedge period PSE's ESM department executes hedges to systematically reduce 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 daily and authorized traders execute transactions to manage exposure within monthly and [redacted] authority limits established by the EMC.

Q. Please expand on the types of hedges included in 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 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.

Q. Has PSE changed its hedging practices since the 2020 PCORC?

A. No. PSE's power cost hedging program and practices are the same as those in effect and presented in the 2020 PCORC and prior rate cases. In the 2020 PCORC

[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.

Commission Staff expressed a desire to better understand PSE's hedging practices as well as intra-company natural gas transactions between PSE's electric portfolio and its natural gas distribution company portfolio.[3] The Settlement Agreement adopted by the Commission in that case directs PSE to host collaborative discussions on these topics.

Q. Did PSE and parties to the 2020 PCORC engage in discussions of PSE's hedging program and intra-company natural gas transactions?

A. Yes. On November 16, 2021 PSE hosted a collaborative discussion and presented information about its hedging program and intra-company natural gas transactions. See Exh. PKW-3C for the material PSE presented in this collaborative.

Q. What was the outcome of the hedging and intra-company transactions collaborative?

A. As of the time of this writing there has been no formal conclusion to the collaborative. Because the purpose of the collaborative was informational only,[4] PSE does not anticipate any specific actions or changes to its practices as a result of the collaborative. Upon completion, PSE will file a report with the Commission to document this collaborative and summarize its contents.

[3] Docket UE-200980, Testimony of Jing Liu, Exh. JL-1T at 25:12-26:5.
[4] *See id.*

C. Power Costs in This Proceeding

1. Projected Rate Period Power Costs

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

A. Current rates were established in PSE's 2020 PCORC, Docket UE-200980. The Commission's Final Order 05 Approving and Adopting Settlement Agreement ("Final Order") established power costs in that proceeding, and the applicable rates went into effect July 1, 2021.

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

A. See Exh. PKW-4C for a summary of PSE's projected power costs for the 2023 rate year. PSE's projected power costs are $902.4 million, or 18.1 percent higher than the amount set in rates ($764.0 million) effective July 1, 2021. The primary drivers of this increase are:

- higher natural gas prices, which have increased approximately nine percent relative to prices in the 2020 PCORC;
- inclusion for the full year of new resources that were approved in the 2020 PCORC but were not operational during the rate year or were operational for only part of the rate year in that proceeding, including the Golden Hills Interim Capacity PPA, Golden Hills Shaped Wind PPA, BPA Capacity Contract, and Morgan Stanley PPA;
- new power purchase agreements to serve PSE customer load and meet projected capacity and renewable energy requirements, including:
    - a 5 percent share (approximately 95MW) of the output from the Rocky Reach and Rock Island Hydroelectric

- Projects (“Chelan Slice Agreement”) which began January 1, 2022,
- a 5.5 percent share (approximately 43MW) of the output from the Wells Hydroelectric Project (“Colville Slice Agreement Extension”), which began September 1, 2021,
- a 350 MW PPA with Avangrid Renewables, Inc for output from the Clearwater Wind project in eastern Montana (“Clearwater Wind PPA”) which begins December 1, 2022, and
- a 250 MW contract with Powerex for deliveries during heavy load hours in June through September (“Powerex Summer Peak PPA”) which begins June 1, 2022.

The 5 percent Chelan Slice Agreement and Colville Slice Agreement Extension are presented in the testimony of Zacarias Yanez, Exh. ZCY-1CT, and the Clearwater Wind PPA is presented in the testimony of Colin Crowley, Exh. CPC-1HCT. The Powerex Summer Peak PPA is presented in Section III of my testimony below.

Q. Has PSE also prepared power cost projections for the final two years of the multiyear period in this proceeding (calendar years 2024 and 2025)?

A. Yes. Projected power costs are $913.4 million in 2024 and $850.8 million in 2025. Lower projected costs in 2025 are driven by expiration of the Powerex Summer Peak PPA, reduced volumes under the Centralia PPA, and forecasted load that is 2.1 percent below the forecast for 2024. See Exh. PKW-5C for more detail of these projections.

Q. How did PSE calculate projected power costs for 2024 and 2025?

A. PSE's power cost projections for calendar years 2024 and 2025 were prepared in the same manner as the 2023 power cost projection, which is consistent with Commission precedents and, but for changes described in Section IV of this testimony, the methods approved in PSE's 2019 general rate case and 2020 PCORC. Importantly, the power supply portfolio reflected in PSE's 2024 and 2025 power cost projection includes only existing resources and contracts that have been executed as of this filing – projections presented herein do not include anticipated costs and additional new resources that will be required for PSE to continue to reliably serve load and comply with renewable energy requirements in Washington state's Clean Energy Transformation Act ("CETA").

Q. Are PSE's projected power costs for 2024 and 2025 an accurate representation of the costs PSE actually expects to incur in those years?

A. Like PSE's projected rate year 2023 power costs presented herein, projected 2024 and 2025 power costs incorporate the most recent information available regarding market conditions and the PSE power supply portfolio in place as of December 1, 2021. While current market conditions and the existing PSE portfolio provide a reasonable basis for projecting power costs in the near term, this forecast for the 2023 rate year is for a period between thirteen and twenty-five months into the future. Volatile fuel and power prices combined with anticipated changes to PSE's resource portfolio make it very unlikely that the forecast presented in this filing will remain the most accurate possible forecast by the time rates go into effect in January 2023. Later in this section of my testimony I describe PSE’s proposal to update its rate year power cost forecast during the course of this proceeding. Similarly, power costs presented for years two and three of the multiyear period (2024 and 2025) must be updated closer to the rate effective dates to reflect costs that are as close as possible to costs that are actually expected to occur during those periods. Janet Phelps presents a proposal for annual updates to PSE’s variable power costs and the effective baseline rate in her testimony, Exh. JKP-1T. This proposal would guaranty that the power costs included in customer rates reflect the most accurate, up-to-date information about market fuel and power prices and PSE’s resource portfolio.

Q. Why does PSE expect changes to its resource portfolio?

A. Changes to PSE’s resource portfolio over the next several years will be driven by the need to acquire additional renewable energy for compliance with CETA and by structural changes to the regional resource mix, which are reducing PSE’s ability to rely on the short-term bilateral market for energy needed to serve load. Janet Phelps discusses the magnitude of new resource additions that are likely over the next several years in Exh. JKP-1T, and Kyle C. Stewart discusses recent market conditions and PSE’s need to reduce reliance on the bilateral market for firm capacity in Exh. KCS-1CT.

Q. Has PSE acquired new firm capacity resources to reduce market reliance?

A. Yes. In December 2021 PSE acquired 250 MW of firm energy during summer heavy load hours via a new contract, the Powerex Summer Peak PPA. Section III of my testimony presents details of this contract.

Q. Have entities in the Pacific Northwest jointly taken any action to address the region's firm capacity needs?

A. Yes. In response to the recent trend in decommissioning of baseload fossil fuel generation and increasing renewables integration, utilities in the western United States and Canada have been working to coordinate a comprehensive review and response to resource adequacy in the region through development of a Western Resource Adequacy Program ("WRAP").

2. Western Resource Adequacy Program

Q. What is the WRAP?

A. The WRAP will provide a common resource adequacy planning standard for entities throughout the Pacific Northwest region. The program, which is hosted by the Northwest Power Pool ("NWPP") seeks to increase coordination and visibility with respect to adequacy in the region and is a step toward enhancing regional reliability[5] A key feature of the program is a requirement for participants to demonstrate resource adequacy through a "forward showing" of projected load

[5] Additional information and progress updates regarding development of the WRAP are available on the NWPP website at https://www.nwpp.org/wrap/.

and available capacity resources. Participants lacking adequate capacity according to the program's planning standard will be required to procure additional capacity resources or face penalties.

Q. Has PSE participated in development of the WRAP?

A. Yes. PSE has been an active participant in development of the WRAP and continues to closely monitor progress as the program moves toward its implementation phase.

Q. What is the current status of the program?

A. The primary design phase of program development is complete, and entities are preparing to implement the first stage of the program in which participants will commit to meeting a common resource adequacy planning standard. This first stage will be "non-binding," meaning there will be no penalties if participants do not meet their adequacy obligations.

Q. What are PSE's plans once the WRAP program is operational?

A. PSE will continue to participate in development of the WRAP and evaluate the costs and benefits of participation. PSE is participating in the current phase of WRAP and will begin by submitting a non-binding forward showing of its capacity position by March 31, 2022 for the 2022/2023 winter period. If a cost-benefit analysis demonstrates that continued participation in the program would benefit PSE customers, PSE will include a forward showing with binding resource adequacy obligations for the winter of 2023/2024.

Q. Does PSE anticipate a need to acquire new capacity resources to comply with the WRAP's resource adequacy standard?

A. Yes. It is not clear at this point exactly how much additional capacity PSE will need to meet the WRAP's adequacy standard, but PSE's current firm capacity resources alone are unlikely to be sufficient.

Q. Does the WRAP create an organized market for participants to acquire firm capacity resources?

A. No. While the WRAP is an important first step toward enhancing resource adequacy in the region, current plans do not include an organized structure through which capacity products would be priced and exchanged. There are plans for a component of the program which would allow participants to pool and share resources in the short term during tight grid operating conditions, but participants will have first needed to demonstrate resource adequacy to participate. As currently proposed, the program does not address how or where participants would acquire any capacity needed to demonstrate resource adequacy.

3. Anticipated New Resources Not Included in Power Cost Projection

Q. Does PSE expect to acquire new resources that are not included in the power cost projections presented in your testimony?

A. Yes. PSE anticipates the addition of new resources to its portfolio during the 2023 through 2025 multiyear period in this case and for several years beyond that period. These new resources will be necessary to meet capacity needs identified in PSE's 2021 Integrated Resource Plan ("IRP") (including but not limited to reductions to current reliance on market purchases), comply with the resource planning standards of the WRAP, and comply with the clean energy requirements of CETA. These anticipated new resources are incremental to the power supply portfolio used to project power costs for the multiyear period in this case – the cost of these resources is therefore not reflected in the 2023 through 2025 power cost projections provided earlier in this section of my testimony.

4. Power Costs Need to be Updated Regularly

Q. Does PSE have existing regulatory processes to implement timely updates to the power costs included in rates?

A. PSE can file a PCORC to adjust the power costs included in rates on an expedited timeline relative to a general rate case filing. The PCORC process requires six months from filing until new rates can go into effect, a significant improvement in both time and administrative effort compared to a general rate case, which takes eleven months to complete. Nonetheless, the PCORC process in recent years has not been sufficient to keep the power costs in PSE's rates up to date with the power costs PSE is actually incurring.

Q. How have actual power costs compared to power costs recovered in PSE's rates in recent years?

A. PSE's actual power costs have exceeded the power costs recovered in rates in seven of the last eight years for a total under-recovery of $264.7 million during this period. These under-recoveries have been driven in large part by an inability for PSE's power cost baseline rate to keep up with the pace of change in PSE's power supply portfolio and broader market conditions. Absent more frequent updates to the baseline rate, there will continue to be a mismatch between actual power costs and those recovered in rates as PSE's portfolio expands to meet reliability and clean energy requirements. A formal process by which PSE implements routine annual updates to the baseline rate is needed to make sure power costs included in rates reflect the most up-to-date information about market conditions and the costs and benefits of resources in PSE's power supply portfolio. Janet Phelps presents a detailed proposal and justification for establishing annual updates to PSE's power cost baseline rate in Exh. JKP-1T.

Q. Does PSE intend to update its projected power costs 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 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 in its supplemental and rebuttal filings and, if allowed by the Commission, a compliance filing as 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 and index-priced physical supply contracts.
3. BPA transmission contract rates.
4. Natural gas pipeline rates.
5. Mid-Columbia hydroelectric contract costs.
6. Other rate year contract rates.
7. Input assumptions used in dispatch logic, specifically variable operations and maintenance costs.
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 the Final Order in PSE's 2004 general rate case, 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."[6] Additionally, in its Final Order in PSE's 2011 general rate case, the Commission expressly recognized 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.[7]

Further, in PSE's PCA Settlement, which was approved by the Commission in Order 11 of Docket UE-130617, 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 costs and orders that such update be made as part of the compliance filing.[8]

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 than is possible with the current system.

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[6] *WUTC v. Puget Sound Energy*, Dockets UG-040640/UE-040641, Order 06 at ¶ 116 (Feb. 18, 2005).
[7] *WUTC v. Puget Sound Energy*, Dockets UE-111048/UG-111049, Order 08 at n.303 (May 7, 2012).
[8] *WUTC v. Puget Sound Energy*, Docket UE-130617, Attachment A to Settlement Stipulation at 4 (August 7, 2015).

Q. Has PSE updated power cost information during 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.[9] In the 2019 general rate case prehearing conference, Commission staff opposed power cost updates during that proceeding, 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 were included with PSE's rebuttal filing in the 2013 PCORC and with a supplemental filing in the 2007, 2014, and 2020 PCORCs.[10] Please see the testimony of Janet K. Phelps, Exh. JKP-1T, for discussion of the history of mid-proceeding updates to power costs.

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

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

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

A. PSE respectfully requests that the Commission approve PSE's proposed power costs of $902.4 million for the 2023 rate year, subject to updates during this proceeding as discussed above. Further, PSE requests that the Commission order power cost updates prior to the start of calendar years 2024 and 2025 according to the annual power cost update proposal presented in Janet Phelps's testimony, Exh. JKP-1T.

III. NEW RESOURCES

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

A. Yes. PSE seeks a prudence determination in this proceeding for each of the four new PPAs listed earlier in Section II of this testimony. Details regarding the Chelan Slice Agreement and Colville Slice Agreement Extension are provided in the testimony of Zacarias Yanez, Exh. ZCY-1CT, and details of the Clearwater Wind PPA are provided in the testimony of Colin Crowley, Exh. CPC-1HCT. The Powerex Summer Peak PPA is addressed in my testimony below.

PSE also seeks a prudence determination for two new five megawatt transmission contracts and the renewal of four existing Mid-C transmission contracts totaling 400 MW. These are presented later in section V of this testimony.

A. Powerex Summer Peak PPA

Q. What is the Powerex Summer Peak PPA?

A. In October 2021 Powerex issued a request for proposals ("RFP") for the purchase of firm hydroelectric capacity and energy during summer peak hours beginning in 2022 for a term of up to seven years. PSE submitted [redacted] bids to purchase [redacted]C. Powerex ultimately accepted PSE's fixed-price bid for 250 MW delivered at the British Columbia-United States border for a three-year term. PSE executed the Powerex Summer Peak PPA on December 7, 2021. The agreement provides PSE with 250 MW of firm carbon-free energy during the sixteen heavy load hours of each day, seven days per week from June 1 through September 30, 2022 through 2024. PSE will pay a fixed price of [redacted] per MWh.

Q. What benefits does the Powerex Summer Peak PPA bring to PSE's portfolio?

A. The Powerex Summer Peak PPA addresses PSE's need to reduce reliance on the bilateral Mid-C market for its peak capacity requirements. Kyle Stewart, in Exh. KCS-1CT, discusses the risks of continued market reliance and PSE's need to acquire firm capacity resources to continue to reliably serve customer load. The Powerex Summer Peak PPA delivers reliable energy supply during summer peak hours to meet these requirements in the near term. With deliveries beginning in the summer of 2022, the PPA serves as a bridge until additional capacity can be acquired via PSE's longer-term planning and acquisition time horizon. Through its fixed-price structure, the PPA also reduces PSE's exposure to increasingly volatile market prices during summer months.

Q. Will the Powerex Summer Peak PPA contribute to PSE's resource adequacy needs as defined by the WRAP?

A. Yes. Powerex and PSE both intend to continue participation in the WRAP, and capacity provided under the Powerex Summer Peak PPA will be an eligible resource for the WRAP's adequacy standard.

Q. Does energy delivered under the Powerex Summer Peak PPA contribute to PSE's clean energy objectives?

A. Yes. Energy delivered to PSE under the Powerex Summer Peak PPA will be 100 percent carbon free energy.

Q. How did PSE determine the price it offered for the Powerex Summer Peak PPA?

A. There is no organized or active market for products comparable to those offered in the Powerex RFP, so it was not possible to rely on a single market price reference in determining its value. PSE's bid amount was determined by valuing various components of the product separately and summing these values to determine the total value of the product to PSE's portfolio. PSE first valued the wholesale fixed-price power associated with the Powerex product. This was determined using the current forward price of financial energy contracts at Mid-C for the delivery period, an adder based on current market premiums for firm physical energy, [redacted]. See Exh. PKW-6C for additional details regarding analysis of the Powerex Summer Peak product and PSE's determination of the price offered.

Q. How did PSE determine the value of the [redacted] attributes of the Powerex Summer Peak PPA?

A. [redacted]

Q. How did PSE value the [redacted] component of the Powerex Summer Peak PPA?

A. [redacted]

Q. Were alternatives to the Powerex Summer Peak PPA available to meet PSE's firm capacity need?

A. PSE evaluates the costs and benefits of participating in offerings such as the Powerex RFP as they become available and will continue to do so in conjunction with its near-term market reliance reduction strategy, which is discussed in the testimony of Kyle C. Stewart, Exh. KCS-1CT. Such offers are often not bid into PSE's active RFP process, which includes longer lead time resources selected to meet PSE's long-term capacity needs. Opportunities to acquire firm capacity products to meet PSE's immediate needs are very limited. Absent an organized market for capacity in the Pacific Northwest, the Powerex RFP offered the most transparent mechanism available for acquiring such capacity. PSE's bid strategy ensured that the price of the Powerex Summer Peak PPA reflects the best information available regarding the market value of the product.

Q. Did the EMC authorize PSE to submit its bid for the Powerex Summer Peak PPA?

A. Yes. On October 28, 2021 the EMC authorized PSE's participation in the Powerex RFP as part of a broader market reliance risk reduction strategy. On November 24, 2021, the EMC authorized PSE to submit bids for specific products. PSE's October 28, 2021 presentation to the EMC is included as Exh. KCS-6C. Please see Exh. PKW-7C for the November 24, 2021 EMC presentation.[11]

Q. What does PSE request from the Commission regarding the Powerex Summer Peak 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.

[11] Note that bid pricing shown in the November 24th EMC presentation was indicative and based on Mid-C forward prices as of November 19, 2021. PSE's final bids were based on prices updated as of November 30, 2021, the date of bid submittal.

IV. POWER COSTS METHODOLOGY

A. Overview of Power Costs Methodology

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

A. As in prior cases, PSE used the Aurora dispatch model to project a portion of its power costs for the rate year. PSE calculated the remaining rate period 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 power purchase agreements, and market purchases and sales are estimated by Aurora and included in power costs. Other power costs, such as transmission costs, fixed gas transportation costs, fixed costs associated with Mid-C hydroelectric contracts, and the value of previously executed gas-for-power contracts are calculated outside of Aurora.

Please see Exh. PKW-8C for a summary of rate year power costs by resource. Please see Exh. PKW-9C for monthly detail of costs and energy produced by Aurora in comparison to similar output from PSE's 2020 PCORC. Please see Exh. PKW-10C for a summary of rate period costs calculated outside of Aurora. Please see PKW-11C for input data on the PSE resources and contracts used in Aurora.

Q. Were there changes made to the Aurora dispatch model since the 2020 PCORC?

A. Yes. Energy Exemplar, the developer of the Aurora model, provides periodic software and database updates. The software version of Aurora used in this filing is Version 14.0.1001, which Energy Exemplar released in March 2021. The database used is Aurora WECC Zonal 2020_1.0.1 ("2020 Database"), which Energy Exemplar issued in September 2020. This is the same database used in PSE's 2020 PCORC and remains the most recent database release from Energy Exemplar.

Q. Did PSE make changes to its approach to estimating power costs since the 2020 PCORC?

A. Yes. Projected power costs in this proceeding incorporate the costs and benefits associated with PSE's participation in the CAISO Energy Imbalance Market ("EIM"). Including EIM benefits in its power cost projection required PSE to modify its approach to estimating power costs in this proceeding. Modifications include running the Aurora model on sub-hourly dispatch intervals, adding estimated net EIM greenhouse gas ("GHG") benefits outside of the Aurora model, including the labor and administrative costs of EIM participation in FERC account 557 "Other Power Supply Costs," and using long-term median energy volumes as a model input for PSE's hydroelectric resources. The following sections of this testimony discuss these changes in more detail.

B. 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 for reliably and economically maintaining 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 had been predominately traded among entities through bilateral transactions of hourly energy products. Within the hour there was 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. PSE's participation in the EIM began at the end of 2016.

Q. Has PSE included the costs and benefits of EIM participation in power cost projections for prior rate cases?

A. Prior to its 2020 PCORC, PSE had not included explicit EIM costs or benefits in its rate year power cost projections. The Settlement in PSE's 2017 general rate case adopted a proposal from Commission staff that removed the capital costs associated with EIM participation from PSE's rate base and excluded EIM-related operating costs from PSE's rate year power costs. These costs were instead added to PSE's actual allowed costs in its annual Power Cost Adjustment ("PCA") filing. Because any EIM benefits are implicit in PSE's actual allowed PCA costs, this treatment meant that the net cost or benefit of EIM participation has been included in PSE's annual PCA over or under-recoveries but not reflected in the baseline power cost rate. This same treatment was adopted in PSE's 2019 general rate case.

Q. How did the 2020 PCORC Settlement address treatment of EIM costs and benefits?

A. Parties to PSE's 2020 PCORC argued that the treatment of EIM benefits agreed to in PSE's 2017 general rate case was no longer appropriate and that PSE's rate year power cost projection should include an explicit adjustment for the net benefits of EIM participation. Settling Parties ultimately agreed to reduce the cost of market purchases in variable power costs by an agreed-to amount of $8 million and to include $3.9 million for EIM costs in fixed production costs. The 2020 PCORC Settlement did not include agreement on how or if EIM costs and benefits should be addressed in future rate proceedings. Instead, "the Settling Parties agree[d] to participate in a collaborative workshop on the estimation and treatment of EIM costs and benefits for rate making purposes."[12]

[12] Docket UE-200980, Settlement Stipulation and Agreement at 6.

Q. Did PSE and parties to the 2020 PCORC participate in a collaborative workshop regarding EIM costs and benefits?

A. Yes. PSE hosted a series of five workshops beginning in the middle of June 2021. Representatives from Commission staff, Public Counsel, and the Alliance for Western Energy Consumers ("AWEC") participated in these workshops along with PSE. On November 22, 2021 PSE filed with the Commission a report summarizing the contents of these workshops and their conclusion.[13] Please see Exh. PKW-12C for a copy of the EIM collaborative report, including presentation materials from the workshops.

Q. What topics did PSE and parties discuss in the first EIM collaborative workshop?

A. The first EIM collaborative workshop covered an overview of the EIM including differences in PSE operations before and after EIM participation, and a discussion of principles that should guide parties' collaborative effort to quantify and account for the net impact of EIM participation in PSE's rate year power cost forecasts. Parties also reviewed the 2020 PCORC Settlement Agreement and agreed that the final product of the collaborative should be a filing with the Commission that outlines the content covered in the collaborative and describes an agreed-upon treatment of EIM in PSE's power cost forecasts.

[13] Docket UE-200980, Energy Imbalance Market Collaborative Summary Report.

Q. How are PSE's operations different with EIM participation than they were before the EIM?

A. PSE must constantly balance the output of its resources with load in its balancing authority area ("BAA"). Access to markets for power purchases and sales is a critical tool for maintaining this load/resource balance. PSE utilizes term, day-ahead, and hour-ahead bilateral markets to sell surplus resource generation or to purchase needed energy in excess of what its resources can economically produce. Prior to participation in the EIM, PSE did not have access to a sub-hourly market and had to rely only on its own dispatchable resources to maintain balance within each hour as load and variable resource output changed. With the EIM PSE can use sub-hourly energy purchases and sales to balance load and resource output at a lower cost than using only its own dispatchable resources.

Q. What topics were covered in the second EIM collaborative workshop?

A. In the second workshop PSE presented details regarding CAISO's estimates of EIM benefits, provided an overview of how other Pacific Northwest entities have treated the EIM in power cost forecasts, reviewed PSE's existing power cost forecast methodology, and introduced a proposal for incorporating EIM costs and benefits into PSE's forecast.

Q. How does CAISO calculate its estimates of EIM benefits?

A. The EIM benefits estimates provided by CAISO rely on a counterfactual calculation of what a participating entity's sub-hourly balancing costs would have been without participation in the EIM. The difference between this counterfactual cost estimate and the entity's actual net EIM participation cost is the estimated benefit of EIM participation. Actual net EIM participation cost consists of four components: 1) the actual cost of dispatching an entity's resources up or down in the EIM relative to hourly base-scheduled output, 2) net transfer cost, which is the difference between payments made to the EIM for energy imports and payments received from the EIM for energy exports, 3) net greenhouse gas ("GHG") cost, which is the difference between the cost of carbon allowances associated with fossil fuel exports to California and EIM GHG revenue received for exports to California, and 4) net flex ramp cost, which is the net of payments made for imports and received for exports of flexible ramping capability. The majority of EIM benefits for PSE are attributable to a combination of the first two components of actual net participation costs—the cost of dispatching PSE's resources in the EIM is typically lower than the counterfactual dispatch cost and, even when that is not the case, net payments received from the EIM more than offset any incremental EIM dispatch costs. Net GHG revenue makes up a relatively small portion of CAISO-estimated benefits for PSE and net flex ramp benefits are inconsequential.

Q. What have the CAISO EIM benefits estimates been for PSE?

A. Between 2017 (PSE's first full year of EIM participation) and 2020, CAISO estimated average annual PSE EIM benefits of $13.3 million with a range of between $9.7 million (2017) and $16.2 million (2019). On average, the CAISO benefits estimates indicate that PSE's actual power costs were about one percent lower during these four years than they would have been without EIM participation.

Q. Should the CAISO benefits estimates be interpreted as a direct reduction to PSE's power costs?

A. No. The CAISO benefits estimate methodology relies on assumptions that do not directly align with the definition of power costs used in PSE's regulatory filings. The estimates are better interpreted as an indication of total benefit to PSE's BAA than as specific power cost savings.

First, since the CAISO benefits estimate applies to the entire PSE BAA, a portion of the estimated benefit is attributable to third party (non-utility) loads and resources, which are not included in PSE's power costs. Loads associated with transmission wheeling customers (e.g. Microsoft), third party generation (e.g. Vantage Wind), and loads or resources intentionally excluded from PSE's power costs (e.g. Green Direct) are all included in the CAISO benefits estimate but not in PSE's actual or forecasted power costs.

Second, the CAISO benefits estimates assume that PSE's EIM bids for each resource are equal to the actual incremental cost of output from that resource. While PSE's bids do generally reflect the best estimate of actual resource costs, costs used to establish bids for thermal resources include the cost of fuel as well as variable operations and maintenance ("O&M") costs. EIM costs or savings related to O&M are therefore included in the CAISO benefits estimate but are not included in PSE's actual or forecasted power costs. Any changes to O&M costs resulting from EIM participation would be reflected in PSE's actual production O&M expense. Further, PSE's EIM bids for hydroelectric resources are used to communicate operational constraints and opportunity costs; they do not represent actual costs. There is no incremental power cost associated with a change in hydroelectric output, but the CAISO benefits estimates include costs or savings related to such changes based on the bids PSE submits for these resources.

Q. How have other Pacific Northwest utilities treated EIM benefits in the power cost forecasts they use to establish rates?

A. PacifiCorp, Portland General Electric, and Idaho Power are EIM participants, and all have included an estimate of EIM benefits in rate proceedings. Each of these entities forecasts power costs in rate cases differently and each has chosen to reflect the benefits of EIM using different methods. But none of them have used the published CAISO benefits estimates as a reduction to power costs. PacifiCorp performs an independent calculation of historical EIM benefits and uses those estimates to develop a regression model for projecting future benefits. Portland General Electric adjusts the results of its hourly production cost model to estimate EIM transfer and re-dispatch benefits based on the historical relationship between Mid-C market prices and EIM prices. Idaho Power calculates historical benefits by replicating the CAISO benefits calculation, but replaces the hydroelectric generation bids used by CAISO with an hourly index market price.

Q. Can you please describe PSE's existing power cost forecast methodology as it relates to EIM costs and benefits?

A. PSE uses the Aurora model to estimate rate year power costs. PSE first models the entire Western Interconnect on an hourly basis to forecast hourly market prices in the Mid-C region. These prices are then used as an input for a second Aurora model run, the "two zone model", in which PSE's resources are dispatched on an hourly basis to calculate PSE's portfolio cost. The two zone model reserves capacity in each hour that is needed to balance within-hour load and resource changes, but since the model is run in hourly dispatch intervals it does not ever "see" any within-hour imbalances, and that capacity is never actually deployed to respond to them. PSE's existing hourly forecast methodology therefore does not capture the cost of balancing load and resources on a sub-hourly basis. Since the primary benefit of EIM participation is lower sub-hourly balancing costs, power costs calculated using PSE's existing hourly model do not include the costs against which EIM benefits are measured.

Q. What are the costs of sub-hourly balancing that are not captured in PSE's existing hourly model?

A. Actual load and resource output change constantly and are not flat for an entire hour at a time as assumed in the existing hourly model. Without the EIM, these variations must be balanced using only PSE's own resources and doing so results in a less optimal resource dispatch relative to the dispatch against flat, average hourly values. Following changes in PSE's load/resource balance within the hour requires varying the output of dispatchable thermal resources, which often means generating outside of the most efficient operating range. Peak loads within an hour will always be higher than average load for an hour, and meeting these sub-hourly peaks may require additional, more expensive resources to be dispatched. Once running, operating constraints can prevent these resources from turning off as soon as they are no longer needed, so they may continue to run un-economically for several hours. Balancing the additional generation from these now-running, un-economical resources may then require curtailing output from variable resources like wind or hydro.

Q. What is PSE's proposal for incorporating the costs and benefits of EIM participation into its power cost forecast?

A. PSE's proposal continues to rely on the Aurora model to forecast rate year power costs but utilizes sub-hourly Aurora model dispatch intervals to capture the cost of within-hour balancing both with and without access to a sub-hourly market, or EIM. Sub-hourly model results without the EIM include the cost of within-hour balancing using only PSE's resources. The difference between these results and the lower portfolio cost results modeled with a sub-hourly market is the EIM benefit in PSE's proposed Aurora model power costs. This benefit includes changes in sub-hourly dispatch costs for PSE's resources and forecasted net transfer revenue from sub-hourly market transactions. PSE proposes including additional EIM benefits in the form of CAISO GHG revenue as an adjustment outside of the Aurora model.

Q. What was the subject of the third EIM collaborative workshop?

A. During the third EIM workshop PSE presented details about its proposed approach to incorporating EIM benefits into its power cost forecast, reviewed sample results with participants, and explained the net impact to power costs using the proposed sub-hourly modeling approach compared to using the existing hourly model.

Q. How does PSE propose using the Aurora model to reflect EIM benefits in its power cost forecast?

A. PSE's proposal involves three stages of Aurora model runs. The first stage is nearly identical to PSE's current hourly forecast method: PSE models the entire Western Interconnect on an hourly basis to forecast hourly market prices and these prices are then used as an input to a second, two zone Aurora model run in which PSE's resources are dispatched on an hourly basis. But now, instead of calculating rate year Aurora power costs based on this hourly two zone model, only the optimized hourly market purchases and sales from this run are carried forward to the next stage. These transactions represent the actual day-ahead and hour-ahead transactions that are included in PSE's actual EIM hourly base schedules.

The second stage again begins with modeling the entire Western Interconnect, but this time on a sub-hourly basis, to generate a forecast of sub-hourly market prices. These prices represent EIM prices and, along with the hourly market transactions from the first stage, are used as inputs to a sub-hourly two zone model. This sub-hourly, two zone model is nearly the same as the hourly two zone model, except: 1) it includes sub-hourly inputs for PSE load and wind resource generation, 2) PSE load and resources are already balanced on an average hourly basis via the input of hourly market transactions from the first stage, and 3) transmission capacity between PSE and the sub-hourly market is limited to reflect the actual transmission capacity PSE has available for EIM participation. The results of this sub-hourly two zone model are PSE's rate year Aurora power costs including the benefits of EIM participation.

The third Aurora modeling stage is used to determine what PSE's rate year portfolio costs would be without access to an EIM market. To do this, PSE uses the same sub-hourly two zone model as in the second stage but removes all transmission capacity between PSE and the sub-hourly market. Without access to the market, the model must use only PSE's resources to balance within-hour differences between load and variable resource output. The difference between the higher power cost results from this model run and the results of the sub-hourly two zone model with a sub-hourly market from stage two is the EIM benefit included in PSE's rate year Aurora power costs.

Q. What inputs and assumptions does PSE use in its proposed sub-hourly Aurora model approach?

A. Assumptions used for the hourly Aurora models (first stage of the approach) are nearly the same as those used in the hourly models from PSE's 2019 general rate case and 2020 PCORC. The one exception is that in its proposed approach PSE uses median hydroelectric energy volumes as a model input rather than running the models separately for each year in the 80-year hydro record. This change is discussed in more detail below.

Additional inputs and assumptions are needed for the sub-hourly Aurora model runs. Model inputs for load and wind resource generation needed to be added for sub-hourly intervals. These sub-hourly inputs are interpolated from the same normal assumptions used in the hourly models so that on average sub-hourly inputs are identical to hourly inputs, but they don't remain constant within each hour. This interpolation is performed automatically by the Aurora model for load inputs, but PSE needed to manually calculate the interpolated sub-hourly wind inputs. PSE's proposed approach models the entire Western Interconnect on a sub-hourly basis to create a forecast of EIM prices. This method includes an implicit assumption that all loads and resources in the Western Interconnect are participating in the EIM. While that has not actually been the case in prior years, given recent and planned new participants, the vast majority of loads and resources in the west will be in the EIM by 2023.

Q. Does PSE's proposal for incorporating EIM participation in its power cost forecast include costs or benefits that are not reflected in Aurora model results?

A. Yes. A relatively small portion of the benefits of PSE's EIM participation is the result of net revenue from CAISO GHG payments. For PSE, these revenues are generally the result of energy from PSE's hydroelectric or wind resources being exported to California. The methodology by which CAISO determines where energy exports flow for purposes of these payments is complex and cannot be replicated within PSE's proposed sub-hourly Aurora model approach. PSE therefore proposes using average historical actual net GHG revenue as a proxy for future revenue and deducting this value from power costs outside of the Aurora model. In addition, PSE incurs ongoing operations and maintenance expenses associated with its participation in the EIM. These costs are charged to FERC account 557, Other Power Supply Expenses, which are included in PSE's power cost forecast. Prior to the 2020 PCORC Settlement, PSE adjusted these costs to remove any EIM-related costs. If the benefits of EIM participation are included in the rate year power cost forecast, it is also appropriate to include the costs of such participation. PSE's proposed approach no longer removes EIM-related costs from the Other Power Supply Expenses included in rate year power costs.[14]

Q. Did PSE share sample results of its proposed EIM benefits method with participants in the EIM collaborative?

A. Yes. PSE applied its proposed method to power costs calculated for the 2020 PCORC rate year to illustrate the proposed EIM benefits methodology. The results showed a $13.5 million EIM benefit with $11.4 million of this included in

[14] While power costs charged to FERC account 557 are included in PSE's rate year power cost forecast, these costs are not included in the variable portion of the baseline rate like other power costs discussed herein. They are instead included in the fixed portion of the baseline rate.

sub-hourly Aurora model results and the remaining $2.1 million from net GHG revenue.

Q. What is the net impact of the sample EIM benefits estimate relative to power costs calculated using PSE's existing hourly Aurora methodology?

A. The $13.5 million EIM benefit is measured against power costs calculated on a sub-hourly basis assuming no access to the EIM. This baseline estimate is higher than costs calculated using the hourly model because it includes sub-hourly balancing costs which are not present in the hourly model and have not been included in prior PSE power cost forecasts. Therefore, including EIM benefits does not reduce PSE's power cost forecast by the full amount of estimated benefits relative to the prior hourly modeling approach. Including sub-hourly balancing costs without the EIM increased power costs $5.9 million, so the net impact to variable power costs of PSE's proposed approach was a $7.6 million reduction. After adding $3.9 million of EIM-related Other Power Supply Expense, the net impact to PSE's total power cost forecast was a $3.6 million reduction.

Q. What was the purpose of the fourth and fifth EIM collaborative workshops?

A. The purpose of the fourth EIM workshop was to provide analysts in the collaborative an opportunity to explore the proposed sub-hourly model in more detail than had been provided in the third workshop. PSE opened the Aurora model and walked through the sections of the model that were altered in order to calculate sub-hourly EIM impacts. Participants suggested that the use of interpolation to estimate sub-hourly wind shapes might not adequately represent wind variability and might not lead to an accurate representation of EIM benefits. Participants recommended exploring the use of historical wind data to develop sub-hourly wind shapes. PSE subsequently prepared an alternative estimate of EIM benefits using sub-hourly wind shapes based on historical actual wind output from PSE's wind facilities. The results of this analysis were shared and discussed in the fifth EIM collaborative workshop. Using alternative sub-hourly wind shapes based on historical data did not have a material impact on model results compared to using interpolated sub-hourly wind inputs. PSE suggested that the difference in benefits did not warrant the added complexity of using historical data and continued to recommend its proposed interpolation approach.

Q. What was the outcome of the EIM collaborative?

A. Collaborative parties agreed that the sub-hourly modeling approach proposed by PSE for incorporating EIM impacts in rate year power costs is a reasonable method to quantify and account for the net impact of EIM participation in PSE's rate year power cost forecasts and recommended use of this approach in PSE's 2022 general rate case.

Q. Please summarize PSE's proposed approach to estimating the net benefits of EIM participation.

A. The approach combines new sub-hourly runs of the Aurora model with PSE's existing hourly model to calculate portfolio costs at the sub-hourly level, including the re-dispatch and transfer revenue benefits of EIM participation. The sub-hourly results are the Aurora model costs used for PSE's power cost forecasts. An additional sub-hourly model run can then be used to calculate portfolio costs without the EIM. This additional model run is used exclusively for identifying the EIM benefits that are included in the sub-hourly model with the EIM. Average actual GHG benefits based on recent available data are then deducted from power costs outside of Aurora. Forecasted EIM-related costs charged to FERC account 557 are included in fixed power costs.

Q. Has PSE continued to evaluate its proposed EIM modeling approach since the conclusion of collaborative discussions?

A. Yes. In December 2021, prior to filing this 2022 general rate case, PSE engaged Energy and Environmental Economics, Inc. ("E3"), to review its proposed approach to incorporating EIM costs and benefits in its power cost forecast. The E3 review confirmed that the proposed approach is reasonable and provides an accurate representation of the net benefits of PSE's EIM participation. A copy of E3's report is included as Exh. PKW-13.

Q. Is the approach used in this proceeding the same as presented in collaborative discussions with parties to PSE's 2020 PCORC?

A. Yes.

Q. What EIM benefits are included in PSE's rate year power cost forecast in this proceeding?

A. PSE's power cost forecast for the 2023 rate year includes $15.6 million of EIM benefits. Table 1 below summarizes these benefits.

Table 1. Estimated EIM Benefits Included in Rate Year Power Costs ($ in millions)

Sub-hourly Aurora results with EIM	$561.4
Sub-hourly Aurora results w/o EIM	$574.9
EIM benefit included in Aurora results	$13.5
Not-in-model GHG benefit	$2.1
Total EIM benefit in rate year	$15.6

Please see Exh. PKW-14 for the calculation of EIM net GHG revenues included in PSE's rate year power cost forecast.

Q. What is the net impact of PSE's proposed approach to including EIM costs and benefits in rate year power costs relative to power costs calculated using the prior hourly Aurora model methodology?

A. Relative to power costs calculated using PSE's prior hourly Aurora model and excluding all EIM costs and benefits from forecasted power costs, the approach proposed in this case reduces rate year power costs $2.8 million. This result is the net impact of the $15.6 million estimated EIM benefit offset by $7.9 million of sub-hourly balancing costs not included in hourly Aurora model results and $4.9 million of EIM fixed costs.

C. Hydroelectric Energy Volumes

Q. Did PSE make other changes to its power cost methodology?

A. Yes. PSE used median hydroelectric energy volumes from the 80-year hydro record as an input to the Aurora model instead of separately modeling each of the 80 years and then averaging the results.

Q. Why did PSE change its approach for applying the long-term hydro record in the Aurora model?

A. Modeling each year of the hydro record separately is not feasible in combination with PSE's proposed method for projecting EIM costs and benefits. In prior rate cases PSE ran the Aurora model in hourly dispatch intervals twice for each year in the record – one run of the Western Interconnect model to determine power prices and a second run of the "two-zone" model to calculate PSE portfolio costs using those prices as an input. Modeling each of the 80 hydro years separately, therefore, required 160 individual Aurora model runs.

This is a time-consuming process that requires significant computational power and generates a large volume of output data. Incorporating EIM costs and benefits into PSE's power cost projection requires running the Aurora dispatch model five separate times, with three of these five runs done in sub-hourly (fifteen minute) dispatch intervals. Modeling each of the 80 hydro years separately in this case, therefore, would require two and a half times as many (400) individual model runs as in prior cases and generate proportionally even more output data due to the use of sub-hourly dispatch intervals. Modeling each of the 80 hydro years in PSE's 2020 PCORC generated an already unwieldy volume of model outputs from over 1.4 million dispatch intervals. Modeling each of the 80 hydro years with PSE's proposed method for EIM benefits in this case would increase that number to over 8.4 million dispatch intervals.

Q. Did PSE propose a similar approach for hydroelectric energy inputs to the Aurora model in the 2019 general rate case?

A. Yes. In its 2019 general rate case PSE proposed using average energy volumes from the 80-year hydro record as Aurora model inputs instead of modeling each of the 80 years separately and averaging the results. The proposal in this case is nearly the same except that here PSE proposes using median hydro energy volumes from the 80-year record as opposed to average volumes.

Q. Why is PSE proposing to use median hydro energy volumes instead of average volumes?

A. There is very little difference between average hydro and median hydro in the 80-year record and either option would result in a reasonable estimate of expected hydroelectric energy under normal conditions. During discussions in connection with the EIM collaborative described above, Commission staff expressed a preference for using median hydro volumes over average. This preference was, at least in part, due to a recent change in Avista Corporation's power cost forecast methodology, which now relies upon median hydro volumes as a model input in lieu of separate model runs for each of the 80 hydro years.[15] Avista's decision to use median hydro was the result of a recommendation from an independent consultant and an extensive collaborative process to evaluate its power cost forecast methodologies.

Q. What was the outcome of PSE's proposal to use average hydro energy as a model input in its 2019 general rate case?

A. Commission staff opposed PSE's proposal to use average hydro as a model input in the 2019 general rate case. The Commission ultimately agreed with Commission staff's recommendation to continue separately modeling each of the years in the hydro record. The Commission's final order required PSE to "restore

[15] *See WUTC v. Avista Corporation*, Dockets UE-200900/UG-200901/UE/200894, Exh. CGK-1T and Exh. CGK-8

its practice of separately modeling 80 hydro years in AURORA and then averaging the power costs rather than using a single model run as proposed."[16]

Q. Why is PSE again proposing not to separately model 80 hydro years in this case?

A. The most important reason for PSE's proposal to use median hydroelectric energy volumes as a model input in this case is that, as described above, modeling each of the hydro years individually is not feasible in combination with the proposed approach to incorporating EIM benefits. One of Commission staff's arguments for maintaining 80 separate model runs in the 2019 general rate case was that "model forecast accuracy should not be sacrificed for the sake of simplicity."[17] In this case, by enabling an approach for including the costs and benefits of EIM participation, the proposal to use median hydro as an input increases the accuracy and completeness of PSE's power cost model.

Q. Did PSE make any other changes to its approach to estimating power costs since the 2020 PCORC?

A. No. Other than the modifications to incorporate EIM net benefits described above, PSE followed the same methodology as in its 2020 PCORC to estimate power costs in this proceeding. The approach includes:

1. Use of the Aurora model and database for the costs and characteristics of all resources, fuels, loads and transmission in the

[16] Dockets UE-190529/UG-190530, Order 08 at ¶ 279.
[17] Dockets UE-190529/UG-190530, Exh. JL-1CT at 49:6-7.

Western Interconnection, with updates to natural gas prices, PSE load, and the characteristics of PSE resources.

2. Use of three-month average natural gas prices as an input to Aurora.

3. Use of power prices (now both hourly and sub-hourly) generated in Aurora by modeling the Western Interconnection.

4. 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.

5. Calculation of costs not in Aurora, such as transmission costs, gas transportation costs, fixed costs of Mid-C contracts, and the value of gas-for-power hedges using Excel spreadsheets.

Q. Did PSE also calculate its power costs for this case using the same methodology approved in its 2019 general rate case and presented in its 2020 PCORC?

A. Yes. For comparison purposes, PSE prepared an alternative calculation of power costs for the 2023 rate year which excludes the methodology changes described above. Projected power costs calculated using hourly Aurora model dispatch (no sub-hourly balancing costs or EIM transactions), the average of 80 separate hydro scenarios, and excluding EIM fixed costs would be $903.3 million, or approximately $0.9 million higher than power costs proposed in this case. Results of this alternative projection are presented in Exh. PKW-15C.

D. Major Assumptions

1. Power Supply Resources

Q. Is PSE's power supply portfolio for this proceeding different from the pro forma power cost portfolio in the 2020 PCORC?

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

(i) the addition of new power purchase agreements described earlier in this testimony, including:

a. Chelan Slice Agreement,
b. Colville Slice Agreement Extension,
c. Clearwater Wind PPA, and
d. Powerex Summer Peak PPA;

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

(iii) updates to PSE's share of output from Mid-C hydroelectric projects, including adjustments to PSE's share of Wells output in accordance with the terms of PSE's long-term PPA with Douglas County PUD and an adjustment to PSE's Meaningful Priority share of Priest Rapids Project output from 4.33 percent to 4.29 percent according to the terms of PSE's PPA with Grant County PUD;

(iv) termination of the Electron Hydro PPA;

(v) power and gas-for-power contracts, including hedges and index-price physical supply contracts, executed prior to December 1, 2021 with delivery or settlement during the rate year, and

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

Q. What hedges and index-price physical supply contracts are included in power costs?

A. PSE's power cost projection includes all gas-for-power and power contracts that were transacted as of December 1, 2021 for delivery during the rate year January 1, 2023 through December 31, 2023. Such contracts include hedges in the form of fixed-price power or gas-for-power contracts as well as power and gas-for-power physical supply contracts which are priced relative to index prices.

Q. How did PSE include hedges and index-price physical supply contracts in its power cost projection?

A. As in prior rate cases, PSE's power cost projection includes all previously executed power and gas-for-power contracts as of the price cut-off date, December 1, 2021. Fixed-price power contracts are included within the Aurora dispatch model. Contracts for natural gas are accounted for outside of the Aurora model in the "Costs Not in Aurora" calculations. Aurora calculates gas fuel costs based on the three-month average prices, so these costs need to be adjusted outside of the model to be consistent with prices of contracts already executed. For fixed-price gas-for-power contracts the adjustment requires calculating the difference between the three-month-average monthly price of natural gas at the pricing cut-off date and the actual price of natural gas hedges transacted for the rate period 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.

The resulting amount represents the "mark-to-model" adjustment that is included in the power cost forecast.

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 general rate case. This adjustment ensures that the cost included in rates represents what PSE will actually pay for those contracts PSE has already entered into. Please see Exh. PKW-16C for PSE's calculation of fixed-price gas for power mark-to-model adjustments.

"Costs Not in Aurora" also include premiums and discounts associated with any physical power and gas-for-power supply contracts priced relative to index prices. These contracts, like the fixed-price contracts described above, require updating whenever natural gas prices are changed or updated during a proceeding. Please see Exh. PKW-17C for the index-priced physical power supply contract costs included in the rate year.

Q. Does the energy supply portfolio used to estimate power costs in this case include resources used to serve customers under the Schedule 139 Green Direct Tariff?

A. No. Consistent with the agreed-upon treatment in PSE's 2020 PCORC, modeled PSE loads and resources in this case exclude loads associated with customers served under PSE's Schedule 139 Green Direct tariff and the cost of resources used to serve that load. 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 testimony of Susan Free, Exh. SEF-1T, for information regarding the treatment of PSE's Green Direct program in this proceeding.

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 this filing, operationally they are managed separately from power costs at PSE, and they are not included in rate year power costs that I support in this testimony. PSE witness Mark Carlson addresses production O&M costs in his testimony, Exh. MAC-1CT.

However, when Energy Supply Merchant 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 from 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 2020 PCORC and prior rate cases.

Q. Have the variable O&M costs used to model the dispatch of gas-fired resources changed since the 2020 PCORC?

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. In my prefiled direct testimony in Docket UE-190529, I described PSE's process for calculating these costs on a quarterly basis. In this proceeding PSE uses the same underlying data to calculate variable O&M costs, but those costs are expressed differently as a result of changes made by the CAISO for EIM participants.

Between 2019 and 2021 CAISO hosted a stakeholder process for establishing a method for calculating O&M costs for EIM-participating resources. PSE actively participated in that process by reviewing CAISO's draft proposals and providing verbal and written comments regarding CAISO's various proposals. CAISO was responsive to PSE's input during the process. Through this stakeholder process CAISO created a method for establishing the O&M costs of participating resources for use in the EIM. Those changes became effective in January 2022.

As a result of this change, PSE revisited its O&M calculations and created estimates that are consistent with the CAISO method. The underlying data is the same data PSE has used in its quarterly update process, but the costs are now expressed differently. Previously, variable O&M costs were expressed on a dollars per MWh ($/MWh) basis, and major maintenance costs were expressed on a dollars per start basis for simple-cycle combustion turbines and a dollars per

MWh basis for combined-cycle resources. The new CAISO framework separates variable operations costs from variable maintenance costs and expresses variable operations on a dollars per MWh basis and variable maintenance on a dollars per run-hour basis for combined-cycle resources and a dollars per start basis for simple-cycle resources.[18] Aurora allows inputs only on a dollars per MWh or dollars per start basis, so PSE converts variable maintenance for combined-cycle plants to a dollars per MWh basis for use in Aurora. Variable maintenance costs now include costs that PSE previously included separately as major maintenance costs in its dispatch logic in Aurora. Effective in January 2022 PSE uses the variable O&M costs that PSE calculated to conform with the CAISO method in its dispatch logic for day-to-day operations. Therefore, the new estimates are also used in the dispatch logic for estimating power costs in this proceeding.

Table 2 below compares the variable O&M costs used in the 2020 PCORC and the variable O&M costs used in this proceeding.

[18] Variable maintenance for Fredonia 3&4 simple cycle resources is expressed on a dollars per run-hour basis.

Table 2. Variable O&M Costs of Gas-Fired Resources*

Resource	2022 general rate case Variable O&M ($/MWh)	2020 PCORC Variable O&M ($/MWh)	2022 general rate case Start-up Costs ($/MW/Start)	2020 PCORC Start-up Costs ($/MW/Start)
Ferndale	[redacted]	[redacted]	n/a	n/a
Goldendale	[redacted]	[redacted]	n/a	n/a
Mint Farm	[redacted]	[redacted]	n/a	n/a
Sumas	[redacted]	[redacted]	n/a	n/a
Freddy1**	[redacted]	[redacted]	n/a	n/a
Encogen	[redacted]	[redacted]	n/a	n/a
Fredonia 1&2	[redacted]	[redacted]	$74.64	$59.16
Fredonia 3&4	[redacted]	[redacted]	n/a	n/a
Frederickson	[redacted]	[redacted]	$73.12	$67.84
Whitehorn	[redacted]	[redacted]	$73.12	$67.84

*Nominal dollars.

**Freddy 1 combined cycle variable O&M is based on PSE's contract with the majority owner, Atlantic Power.

3. Projected Hydro Availability

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

A. PSE used the median of the 80-year Mid-C streamflow history from 1929 through 2008 to project power costs in this proceeding, the same data used in the 2020 PCORC. 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.

As discussed above, while PSE relied upon the same hydro generation data for this case as in prior rate cases, PSE used this data differently in the Aurora model.

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The 80-year median hydro energy volumes for each resource were used as inputs to the Aurora model rather than conducting separate model runs for each year in the 80-year record.

4. Natural Gas Prices

Q. What natural gas prices did PSE use in running its Aurora dispatch model and power cost calculations?

A. As the Commission noted in its Final Order in PSE's 2006 general rate case, the update for gas costs is "well-established" and should be "straightforward, mechanical and non-controversial."[19] Consistent with this order and all rate cases since, PSE used a three-month average of monthly forward market prices for the multiyear period from each trading day in the three-months ending December 1, 2021. PSE input these data into the Aurora dispatch model for each month of the 2023 rate year and each month of 2024 and 2025.

Q. How do projected gas prices for this proceeding compare with those in the 2020 PCORC?

A. Use of a single price can be misleading because there are different forward 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

[19] *WUTC v. Puget Sound Energy* Dockets UE-060266/UG-060267, Order 08 at ¶ 104 (Jan. 5, 2007).

forward gas price at the Sumas trading hub for the 2023 rate year is $3.49 per million British thermal units ("MMBtu") (as of the three months ended December 1, 2021), which is $0.29 per MMBtu higher than the average $3.20 per MMBtu price included in the 2020 PCORC and used as the basis for rates effective July 1, 2021. As of the same date, the average Sumas gas price in 2024 is $3.18 per MMBtu and $3.09 per MMBtu in 2025. As an additional point of comparison, the average gas price reflected in the 2019 general rate case was $2.17 per MMBtu (for the three months ended December 5, 2019). Table 3 below presents average rate-year gas price comparisons.

Table 3. Average Annual Rate Year Gas Prices

Rate Case =>	**2022 general rate case**	**2020 PCORC**	**2019 general rate case**
3-Mo Average at =>	12.1.2021	5.28.21	12.05.19
Rate Year	Jan 2023 – Dec 2023	June 2021 – May 2022	May 2020 – Apr 2021
Sumas price ($/MMBtu)	$3.49	$3.20	$2.17
Change from Prior	$0.29	$1.03	$(0.31)

Please see Exh. PKW-18C for monthly gas prices used in this analysis, along with the Aurora-generated Mid-C power prices.

Q. What is the source of gas price inputs used in PSE's power cost projection?

A. PSE uses forward gas market price data supplied by a third-party vendor, S&P Global Platts.

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% 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 Corporation ("Cascade Natural Gas"), PSE has reserved the necessary firm distribution service to ensure reliable deliveries of fuel acquired upstream.

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 4 and 5 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 2020 PCORC.

Table 4. 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)	$182
Cascade Natural Gas	Sumas to Ferndale	52,000	(1)	$1,311
Cascade Natural Gas	NWP to Encogen	37,000		$206
Cascade Natural Gas	NWP to Fredonia	94,000		$1,524
Cascade Natural Gas	NWP to Mint Farm	52,000		$1,312
Northwest Pipeline	Goldendale Lateral	50,350		$129
Puget Sound Energy	Sumas Pipeline	26,000	(1)	–
Westcoast Energy	Station 2 to Sumas	88,352		$17,375
Nova Gas Transmission	NIT to A/BC	41,420		$2,275
Foothills Pipeline	A/BC to Kingsgate	40,946		$797
Gas Transmission NW	Kingsgate to Stanfield	40,567		$1,910
Total Capacity to plants	Annual	304,885		
	Winter	339,082		
Total Pipeline Fixed Charges				**$55,528**

Notes:

(1) Capacity included in Total Capacity to plants

Table 5. 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)	$1,913
Total Storage Service	127,204	882,322		
Total Storage Fixed Charges				**$2,938**
Total Gas Resources Fixed Charges				**$58,467**

Notes:

(1) Withdrawal capacity is subject to recall

Q. What pipeline rates are reflected in power costs?

A. Rates in effect as of December 2021 are used in PSE's projected 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 Exh. PKW-19C for the calculation of rate period costs of PSE's firm pipeline capacity.

Q. Does PSE anticipate any pipeline rate adjustments during this case?

A. Yes. PSE expects new tariff rates for Westcoast Pipeline to be established during the first quarter of 2022. PSE will include the new Westcoast Pipeline rates when it updates power costs later in this proceeding. Also, Northwest Pipeline is expected to file new rates by July 2022. PSE intends to update its cost forecast with these new rates when they become available. Finally, PSE's contract with

Cascade Natural Gas for fuel supply to the Fredonia plant expired in July 2021. PSE continues to receive service under the terms of that contract while a new agreement is under negotiation. PSE intends to update the cost of gas transportation to Fredonia if a new contract is executed before the end of this proceeding.

6. Colstrip fuel prices

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

A. Colstrip Units 3 and 4 fuel costs were determined using coal prices from the December 2019 Coal Supply Agreement with Westmoreland Rosebud Mining. PSE began purchasing coal according to the terms of this agreement in January 2020. The testimony of Ronald J. Roberts, Exh. RJR-1CT, includes information about Colstrip Units 3 and 4 and the Coal Supply Agreement.

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 PSE's 2019 general rate case.

In PSE's 2019 general rate case the Commission ordered PSE to hold collaborative discussions with the Commission staff regarding production from PSE's wind generation resources. PSE hosted a series of four collaborative workshops with Commission staff in the first quarter of 2021 to discuss wind forecasts and changes in PSE wind production.

Q. What was the result of the wind production collaborative?

A. A report summarizing the workshops was filed with the Commission in April 2021. Please see Exh. PKW-20C for a copy of this report. The collaborative report documents several conclusions, including the following:

1. PSE's Vaisala wind forecasts provide reasonable estimates of the normalized generation from PSE's wind facilities, and their use in power cost projections in future general rate cases and power cost only rate cases is appropriate.
2. PSE's wind production did not meet pre-construction energy estimates due to several factors not considered in the original pre-construction wind energy assessment.
3. Energy generation at PSE's wind resources does not show a declining trend. It has varied from year to year and the long-term average is slightly below the 2016 Vaisala forecast.

Q. Did the collaborative specifically address Commission staff's concerns expressed in the 2019 general rate case?

A. Yes. On May 5, 2021 Commission staff filed a statement indicating their conclusion that PSE had complied with the Commission's expectations regarding the wind collaborative.[20]

Q. What wind energy forecast did PSE use for the Golden Hills PPA and Clearwater Wind PPA?

A. PSE used pre-construction energy forecasts provided by the developers of the Golden Hills and Clearwater Wind facilities as inputs in the Aurora model.

8. Load Forecast

Q. What load forecast did PSE use to calculate its projected power costs?

A. PSE used the most current electric load forecast—the F2021 load forecast—adjusted to remove Green Direct customer load as the demand input to the Aurora model in this case. The electric load forecast, net of demand-side resources (conservation), for the 2023 rate year is 21,350,790 MWh, or 2,437 aMW. This is an increase of 547,585 MWh, or 2.6 percent from the 2020 PCORC load forecast of 20,803,205 MWhs (2,375 aMW). The load forecasts for 2024 and 2025 are 2,455 aMW and 2,410 aMW, respectively.

[20] Docket UE-190529/UG-190530 – Compliance Acknowledgment re Wind Capacity Collaborative – PSE.

9. Operating Reserves

Q. What operating reserves are included in PSE's power cost calculation?

A. PSE's power cost projection includes estimated (i) costs of contingency reserves, (ii) costs of holding reserves for 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 PSE's 2020 PCORC.

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. In the past, fifty percent of the Contingency Reserve Obligation had to be maintained by generating units that were online (spinning), and up to fifty percent could be provided by units that were offline but could be brought online within ten minutes (non-spinning). Effective in June 2021 NERC formally approved a change to the contingency reserve requirements in the WECC and no longer requires that half of the obligation be maintained as spinning reserve. PSE can now carry up to 100 percent of its Contingency Reserve Obligation with units that are offline but capable of being brought online within ten minutes.

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 232 MW of incremental reserves and 245 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 power costs since the 2013 PCORC.

Q. Did PSE use current actual flexible ramping reserve requirements in the Aurora model?

A. No. The current actual flexible ramping reserve requirements are determined by CAISO based on historical actual variability in its load and resource output relative to forecasted amounts. These current actual requirements, therefore, do not account for additional variability associated with new resources that are included in PSE's rate year power supply portfolio but have not yet reached commercial operation. In the Aurora model for this case PSE used the current CAISO flexible ramping requirement plus an additional estimated amount of incremental and decremental capability to account for addition of the Clearwater Wind facility, which is not expected to be operational until the end of 2022.

Q. How did PSE estimate the additional flexible ramping capability associated with Clearwater Wind?

A. PSE engaged a consultant, E3, to evaluate the impact of new wind resources on PSE's CAISO flexible ramping requirements. Their study concluded that the Clearwater Wind facility would increase PSE's incremental flex ramp requirement by 40 MW and its decremental flex ramp requirement by 45 MW.

Please see Exh. PKW-21 for a report from E3 documenting the estimated impact of Clearwater Wind on PSE's flex ramp requirements.

Q. What are day-ahead wind integration costs?

A. Day-ahead wind integration costs have been included in PSE's 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 from operational wind facilities and price data and included the net cost in power costs, adding recent data as time has passed. In this proceeding, PSE used costs through December 2020 to calculate day-ahead wind integration costs by resource. Historical actual generation data is not available for the Golden Hills and Clearwater Wind facilities, so PSE estimated day-ahead wind integration costs by applying the average day-ahead wind integration cost per MWh from its existing wind resources to estimated generation from these facilities. Please see Exh. PKW-22C for day-ahead wind integration costs for each of PSE's wind resources.

10. BPA Transmission Rates

Q. What BPA transmission rates did PSE use in its calculation of power costs?

A. For the first nine months of the rate year PSE used current BPA transmission rates, which went into effect October 1, 2021 and will remain in effect through September 30, 2023. These most recent BPA rates are 7.5 percent higher than those in effect prior to October 1, 2021.[21] BPA transmission rates are expected to change before the end of the rate year on October 1, 2023 and change again during the multiyear period in this proceeding on October 1, 2025.

Q. How does PSE propose to include BPA transmission rate changes in its power cost projection?

A. PSE included a transmission rate increase of 5.02 percent for BPA rates effective October 1, 2023 and assumed the same increase again effective October 1, 2025 in its calculation of BPA transmission costs. This rate change assumption is based on the average of BPA rate increases in the five most recent BPA rate cases from 2014 through the most recent effective rate change in October 2021. Please see Exh. PKW-23C for PSE's calculation of rate year transmission contract costs.

[21] The 2020 PCORC Settlement assumed a 2.65 percent BPA transmission rate increase effective October 1, 2021, so current rates do not include the full cost of PSE's BPA transmission contracts.

11. Exhibits Presenting Specific Input Data and Calculations for Proposed Rate Period Power Costs

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

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

(i) Exh. PKW-24C presents contract costs of Mid-C hydro resources.

(ii) Exh. PKW-25C presents distillate fuel incremental costs.

(iii) Exh. PKW-26C 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) Exh. PKW-27C presents Colstrip fixed fuel costs.

(v) Exh. PKW-28 presents Other Power Costs chargeable to FERC account 557.

V. NEW TRANSMISSION CONTRACTS AND TRANSMISSION CONTRACT RENEWALS

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. 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 2020 PCORC?

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

- renewal of four BPA transmission contracts totaling 400 MW for delivery from the Mid-C market trading hub;
- two new five megawatt BPA transmission contracts to wheel output from two new solar Qualifying Facilities from PSE's Clymer substation in Kittitas County, and
- renewal of four BPA transmission contracts totaling 155 MW to take delivery from existing generation resources including 140 MW for the Lower Snake River wind facility ("LSR") and 15 MW for the Mint Farm Generating Station.

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

A. Yes. Table 6 below shows new and renewed BPA transmission contracts that will be in effect during the calendar 2023 rate year.

Table 6. New and Renewed BPA Transmission Contracts

BPA Mid-C Transmission Contract Renewal

Receipt Point	Assigned Reference No.	Renewal Deadline	Start Date	MW Capacity
Midway	94955519	11/1/2021	11/1/2022	100
Rocky Reach	94955524	11/1/2021	11/1/2022	100
Rocky Reach	94955527	11/1/2021	11/1/2022	100
Vantage	94955530	11/1/2021	11/1/2022	100
Total Mid-C Renewal				**400**

New BPA Transmission

Receipt Point	Assigned Reference No.	Start Date	End Date	MW Capacity
Clymer (Kittitas)	93187120	8/1/2021	8/1/2026	5
Clymer (Kittitas)	93187117	8/1/2021	8/1/2026	5
Total New BPA Transmission				**10**

BPA Transmission Renewed for Long-Term Resources

Resource	Assigned Reference No.	Start Date	End Date	MW Capacity
LSR	93508819	6/1/2022	6/1/2027	50
LSR	95313275	12/1/2022	12/1/2027	50
LSR Mint Farm	95313276 93508223	12/1/2022 5/1/2022	12/1/2027 5/1/2027	40 15
Total Renewals for Resources				**155**

A. 400 MW Mid-C BPA Transmission Renewals

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 assumptions developed in its 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, including presentation to and approval by the EMC.

PSE will continue to evaluate Mid-C transmission contracts and will have the opportunity to adjust its total Mid-C transmission capacity 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 400 MW Mid-C transmission contracts with BPA.

A. PSE's existing Mid-C transmission contracts for 400 MW originating at the Rocky Reach (200 MW), Midway (100 MW), and Vantage (100 MW) substations were set to expire at the end of October 2022. PSE renewed each of these contracts 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 these contracts, it may have been difficult to get the transmission capacity back 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 400 MW of Mid-C firm transmission contracts?

A. PSE compared the cost of continuing its 400 MW Mid-C transmission contracts with the incremental portfolio cost of obtaining equivalent capacity from alternate resources based on cost assumptions developed in its 2021 IRP. PSE used this comparison to determine whether there was an economic benefit to renewing the transmission contracts.

Q. What were the results of the analysis?

A. The analysis showed that renewing the 400 MW Mid-C transmission contracts resulted in a lower portfolio cost as compared to allowing the transmission contracts to expire. Renewing these contracts resulted in net present value savings of over $300 million compared to the cost of equivalent capacity from a natural gas-fired peaking plant.

Q. Did PSE's EMC approve renewal of the 400 MW of Mid-C transmission contracts?

A. Yes. The EMC approved renewal of the 400 MW of Mid-C transmission contracts on August 26, 2021. See Exh. PKW-29 for information presented to the EMC supporting this contract renewal.

B. Two New 5 MW Contracts for Qualifying Resources

Q. Please describe PSE's two new 5 MW BPA transmission contracts.

A. PSE acquired two new BPA transmission contracts totaling 10 MW to wheel the output of two new solar Qualifying Facilities ("QF") from its service territory in Kittitas County to load in the Puget Sound region. The new QFs interconnect to PSE's Clymer substation, a facility that is isolated from the rest of PSE's system but connects directly to BPA's transmission system. Use of BPA transmission is therefore required to deliver energy from the new QFs to load after PSE takes possession at Clymer. PSE agreed to acquire these transmission contracts as part of a settlement agreement with the QF project developer.

Q. Why did PSE enter a settlement with the developer of the new solar QFs?

A. The project developer originally proposed four QF projects that would interconnect with PSE's system in the area. A utility is obligated to purchase the output of QFs interconnected to its system, but incremental transmission capacity is typically not required to take delivery from these resources as they can be integrated directly into a utility's distribution system. In this case, however, the isolated nature of this portion of PSE's system makes a wheel over third-party transmission necessary for PSE to take delivery of output from the projects. Regulatory requirements regarding the interconnection of QFs to isolated portions of a utility system were ambiguous as to who is responsible for transmission. In order to avoid potentially lengthy and costly litigation, PSE agreed to facilitate delivery of output from two of the four planned projects by acquiring the new BPA transmission contracts. In return, the developer agreed to terminate PPAs with PSE for output from the remaining two projects.

Q. Did PSE's EMC approve the two new 5 MW BPA transmission contracts?

A. Yes. The EMC approved these new transmission contracts on January 28, 2021. See Exh. PKW-30 for information presented to the EMC supporting PSE's decision to enter the contracts.

C. Existing Generation Resource Transmission Renewals

Q. Please describe PSE's 140 MW LSR transmission contracts with BPA.

A. LSR is an existing wind generation resource that helps PSE serve load and meet renewable energy requirements. PSE renewed three transmission contracts for a total of 140 MW. Two of these contracts totaling 90 MW would have expired at the end of November 2022 and the other contract (50 MW) would have expired at the end of May 2022. PSE renewed each of the contracts for five years to allow continued delivery of power from the facility.

Q. Please describe the 15 MW transmission contract with BPA that PSE renewed for Mint Farm.

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 15 MW transmission contract which would have expired at the end of April 2022. PSE renewed this contract for five years (through April 30, 2027) to allow continued delivery of power from the facility.

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 associated expenses were prudently incurred and allow PSE to fully recover the costs in rates. Table 7 below presents power costs included in the rate year for each of PSE's new or renewed BPA transmission contracts.

Table 7. PSE Rate Year BPA Transmission Contract Renewals and Additions Costs

Resource	2023 Rate Year Power Cost ($000)
Mid-C Midway 100 MW	$2,386
Mid-C Rocky Reach 200 MW	$4,773
Mid-C Vantage 100 MW	$2,386
Clymer (Kittitas) for QFs 10 MW	$239
LSR 140 MW	$3,341
Mint Farm 15 MW	$358
Total	**$13,483**

VI. CONCLUSION

Q. Does that conclude your prefiled direct testimony?

A. Yes, it does.