EXH. BDM-23CT
DOCKETS UE-240004/UG-240005 et al.
2024 PSE GENERAL RATE CASE
WITNESS: BRENNAN D. MUELLER

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	Docket UE-240004 Docket UG-240005 (*consolidated*)
In the Matter of the Petition of PUGET SOUND ENERGY For an Accounting Order Authorizing deferred accounting treatment of purchased power agreement expenses pursuant to RCW 80.28.410	Docket UE 230810 (*consolidated*)

PREFILED REBUTTAL TESTIMONY (CONFIDENTIAL) OF

BRENNAN D. MUELLER

ON BEHALF OF PUGET SOUND ENERGY

SHADED INFORMATION IS DESIGNATED AS CONFIDENTIAL PER PROTECTIVE ORDER IN DOCKETS UE-240004/UG-240005 ET AL.

SEPTEMBER 18, 2024

REDACTED VERSION

PUGET SOUND ENERGY

PREFILED REBUTTAL TESTIMONY (CONFIDENTIAL) OF
BRENNAN D. MUELLER

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I. INTRODUCTION

Q. Are you the same Brennan D. Mueller who submitted prefiled direct testimony on February 15, 2024, on behalf of Puget Sound Energy ("PSE") in this proceeding?

A. Yes, on February 15, 2024, I submitted the Prefiled Direct Testimony of Brennan D. Mueller, Exhibit BDM-1T and twenty- one supporting exhibits (BDM-1T through BDM-22C).

Q. What is the purpose of your rebuttal testimony?

A. My testimony responds to various power cost-related issues raised in the prefiled response testimony of Commission Staff ("Staff"), Alliance for Western Energy Consumers ("AWEC"), and Public Counsel. My testimony also presents a revised forecast of PSE's rate period power costs that incorporates certain recommendations from parties and includes updates to several forecast inputs that have changed since PSE's original filing in February 2024.

Q. Please summarize your rebuttal testimony.

A. My testimony first addresses the need for annual updates to PSE's power cost forecast and the associated Power Cost Adjustment ("PCA") variable baseline rate. In Section II I evaluate recommended modifications to PSE's proposal from

Staff witness John D. Wilson and generally agree that these recommendations are reasonable. AWEC witness Bradley G. Mullins and Public Counsel witness Robert L. Earle argue that PSE should not be allowed to update the PCA baseline rate outside of general rate case proceedings. The concerns raised by these witnesses are already addressed in PSE's proposed annual update process and are further mitigated by the modifications proposed by Staff. PSE maintains that routine, annual updates to the power cost baseline rate are essential to establishing fair and accurate rates.

Section III responds to proposed changes to PSE's power cost forecast methodology from Staff and AWEC. Staff witness Wilson recommends changes regarding fuel cost assumptions for dispatch of the Colstrip generation facility, future adjustments to the valuation of PSE's Clay Basin natural gas storage capacity, and the addition of certain Energy Imbalance Market ("EIM") costs and benefits to PSE's forecast. Each of these recommendations is reasonable and has either been incorporated in the power cost forecast update presented in Section IV of this testimony or, with respect to Clay Basin natural gas storage, will be included in future forecasts. AWEC witness Mullins recommends including additional EIM benefits in PSE's power cost forecast. The benefits he identifies, however, are already included in PSE's forecast methodology. AWEC's recommendation would result in a double-counting of these benefits and should be rejected.

In Section IV I present an update to the power cost forecast provided with PSE's initial filing in February 2024. In addition to the proposed methodology changes discussed in Section III, this update incorporates new power purchase agreements that PSE executed since its initial filing as well as updates to various forecast inputs such as natural gas prices and transmission contract rates. These updates align PSE's power cost forecast with current market conditions and the most recent information available regarding the costs PSE actually expects to incur during the rate period.

PSE's updated forecast of 2025 power costs is $1,165 million. This is $183 million (18.5 percent) higher than the 2025 forecast presented in PSE's initial filing and $49 million (4.4 percent) higher than power costs currently included in rates. PSE's updated forecast of 2026 power costs is $1,192 million, approximately $96 million (8.7 percent) higher than the 2026 forecast presented in PSE's initial filing. Most of the increase to PSE's forecast since its initial filing is due to inclusion of new power purchase agreements ("PPA") in the forecast.

Section IV of my testimony concludes with a discussion of additional new PPAs that PSE expects to execute prior to the conclusion of this general rate case but, because they are not finalized, are excluded from the updated power cost forecast presented herein.

Finally, Section V of my testimony responds to recommendations from Staff witness Wilson with respect to Washington's Climate Commitment Act ("CCA"), including how PSE should consider CCA allowance costs in its resource dispatch decisions and how/when CCA allowance costs incurred by PSE's electric utility will be recovered in customer rates.

Q. Have you prepared exhibits in support of this prefiled rebuttal testimony?

A. Yes. My rebuttal testimony is accompanied by 20 exhibits that support the updated power cost forecast presented in Section IV. Each of these exhibits, with the exception of Exh. BDM-40C, is an updated version of an exhibit presented with my Prefiled Direct Testimony submitted in February 2024. Exhibit BDM-40C is a new exhibit showing an outside-the-model adjustment to Colstrip fuel costs related to the modeling change discussed in Section III. I also sponsor another nine exhibits, BDM-44C through BDM-52C, which provide detail regarding new power supply resources PSE has acquired since its initial filing of this case several months ago.

II. ANNUAL POWER COST UPDATES

Q. What is your proposal for annual power cost updates?

A. PSE proposes a process by which the power costs included in its PCA variable baseline rate are updated 90 days prior to the start of each calendar year with the resulting rate change to take effect on January 1 of each year. This schedule would be modified for calendar year 2025, for which PSE requests to update its power cost forecast in a compliance filing at the conclusion of this general rate case proceeding. The proposal is, for the most part, a continuation of the annual update process in place for calendar years 2023 and 2024 according to the settlement agreement and final order in PSE's 2022 general rate case.

On April 30 of each year, concurrent with its existing PCA annual filing, PSE would file a preliminary forecast of power costs for the upcoming calendar year (for example, the April 30, 2025, filing would include a preliminary forecast of 2026 power costs). With this preliminary forecast PSE would also include discussion and details regarding any proposed changes to its power cost forecast methodology. This timeline allows five months for parties to review any changes to PSE's forecast before any such changes would be incorporated in a final forecast to be filed on October 1.

Relative to the preliminary forecast, updates in PSE's final power cost forecast for each year would be limited to a list of straightforward and well documented inputs or assumptions. The inputs and assumptions subject to update are:

- Costs associated with Mid-C hydro contracts,
- Costs associated with upstream pipeline capacity,
- Planned outage schedules and forced outage rates,
- BPA rates,
- PSE's retail electric demand forecast,
- Variable O&M costs,
- The price of emissions allowances for compliance with the Climate Commitment Act,
- Hedges and physical supply contracts,
- Natural gas prices,
- Changes to terms of current resources, and
- Any new and updated resources (including transmission contracts).

To the extent PSE's updated power cost forecast includes any new resources, those resources would undergo a prudency review at the earliest opportunity following approval of PSE's forecast. This earliest opportunity will likely often be PSE's annual PCA compliance filing on April 30 of each year. In the event PSE files a general rate case or power cost only rate case ("PCORC") prior to its PCA compliance filing, PSE would seek a prudence determination for any new resources in that general rate case or PCORC.

If approved, PSE's proposal for annual power cost updates would remove forecasted variable power costs and the PCA variable baseline rate from general rate case or PCORC proceedings – variable power costs would no longer be a component of the general rates that PSE updates in such proceedings.

Q. What does Staff recommend regarding annual updates to PSE's power costs?

A. Staff finds PSE's proposed power cost update process reasonable and supports the proposal. However, Staff recommends that parties should have the option to request that prudency reviews for either new PPAs or proposed forecast methodology changes be deferred to the next general rate case or PCORC filing.[1]

Q. How is PSE accommodating a thorough prudence review of new resources?

A. It is important to complete prudence reviews in a timely manner near the time resource decisions are made, but PSE understands it is also important for parties to have sufficient time to conduct a thorough review. If parties believe they need

[1] Wilson, Exh. JDW-1T at 4:16-5:3.

additional time to review particularly complex resource acquisition decisions, PSE would not oppose deferring that review to a future proceeding.

However, deferral of prudency review for proposed forecast methodology changes appears unnecessary. Forecast methodologies have not historically been subject to a specific prudence review. Parties review prudence of power cost outcomes and the decisions leading to them, but the forecast itself must be established prior to a rate effective period. Parties would have the ability to review any changes to PSE's forecast methodology throughout the five months long annual power cost update process and could continue to propose different methodologies, but deferral of such reviews to a later proceeding would not be feasible.

Q. How does PSE propose to manage the number of regulatory filings related to power costs?

A. PSE's proposal introduces an additional filing each year to update its power cost forecast and establish a new PCA variable baseline rate. However, PSE's proposal also removes power cost forecast and PCA variable baseline rate considerations from both general rate case and PCORC proceedings. The additional time and effort parties would spend reviewing variable power costs in PSE's annual update process would at least nearly, if not fully, be offset by time and effort saved not reviewing those same power costs in other rate case filings. Therefore, Public Counsel's opposition to PSE's power cost proposal because of a perceived increase in regulatory filings and a supposed insufficient opportunity for prudence reviews is unfounded.[2] Dr. Earle ignores an important distinction between variable power costs, which are included in rates based on a forecast with actual variances then shared with customers according to the PCA sharing bands, and fixed power costs, which include operations and maintenance expenses and rate base items that are not included in the PCA. PSE's proposal limits proceedings concerning *variable* power costs to exactly one per year in the already existing annual PCA Annual Review filing that is filed on April 30 of each year.

Regarding prudence reviews, as stated above, PSE would not oppose reasonable requests to defer prudence reviews to a later proceeding. However, Public Counsel's recommendation would move all prudency reviews to only general rate cases and not allow such reviews in PCORC proceedings or annual power cost updates.[3] PSE cannot support that recommendation. PCORCs have historically been used for prudency review of new resources and, given the volume of anticipated additions to PSE's resource portfolio, PCORCS will remain an important venue for PSE to seek prudence determinations. Deferring all prudence reviews to a general rate case could result in a very large number of individual resource decisions for parties to review, especially if general rate cases are filed only once every two or three years. It is unlikely that parties would be able to effectively review perhaps ten or even many more new resources in a single general rate case proceeding. Spreading these prudence requests into PCORCs

[2] Earle, Exh. RLE-1CT at 11:15-18.
[3] Earle, Exh. RLE-1CT at 14:13-15.

and annual power cost update filings provides *more* time and additional opportunities for a meaningful review of each new resource PSE acquires.

Q. How does PSE's power cost forecast and the PCA variable baseline rate maintain PSE's incentives to manage power costs?

A. The power cost forecast used to establish the PCA variable baseline rate includes only reasonably known and measurable costs that PSE actually expects to incur during the forecast period. These costs are necessarily incurred for PSE to provide reliable electric supply to its customers and PSE has relatively little control over most of them. Therefore, PSE is not seeking to simply increase the power costs included in rates by updating its forecast prior to the start of each year – the objective of PSE's proposal is to better align the cost in rates with PSE's forecast of actual expenses. Variable power costs are currently increasing given relatively rapid changes to PSE's power supply portfolio and high power prices, but this likely will not always be the case. An established process for annual power cost updates ensures that customer rates can similarly be reduced when variable power costs decrease. Therefore, AWEC's concern that PSE is not motivated to manage power costs between rate cases[4] is misplaced and unfounded.

In fact, establishing a reasonable baseline rate that reflects the current realities of PSE's power supply portfolio and regional market conditions should actually *increase* any incentive for PSE to manage its power costs. With the current PCA sharing bands, 90 percent of any power cost under- or over-recovery greater than

[4] *See* Mullins, Exh. BGM-1T at 28:14-16.

$40 million is passed back to customers. If the PCA baseline rate is set much too low or much too high (as is often the case absent regular updates), then PSE may begin a year already expecting to, for example, under-recover well over the $40 million 90 percent sharing band. At this point, PSE's incentive to take actions that may reduce power costs is relatively low because only ten percent of savings would benefit PSE. To be clear, PSE seeks to minimize actual power costs regardless of any incentives that may be created by the PCA sharing bands. But to the extent the sharing bands are designed to incentivize cost management, they work best when the variable baseline rate is established as closely as possible to the actual costs that PSE expects to incur under normal conditions.

Q. Why will PCORCs remain necessary if PSE's proposed annual power cost update process is approved?

A. PCORCs will remain an essential tool to ensure that the costs of PSE's production and generation resources are aligned as closely as practical to the costs reflected in customer rates. PSE's proposal for annual power updates addresses only the variable power costs included in the PCA variable baseline rate, which are primarily just the net cost of power supply purchased from others and the fuel consumed by PSE's resources. Annual power cost updates do not address the need to include in rates accurate fixed costs associated with the resources PSE owns and operates. PCORCs will continue to be needed for timely updates to PSE's fixed production costs and to minimize the amount of time new resource costs spend in deferral, as discussed in more detail by PSE witness Susan E. Free in her Prefiled Rebuttal Testimony, Exh. SEF-28T.

III. PROPOSED CHANGES TO PSE'S POWER COST FORECAST

A. Colstrip fuel cost for dispatch decisions

Q. Please explain PSE's current position related to Colstrip fuel cost for dispatch decisions.

A. PSE reviewed Staff witness Wilson's response testimony regarding PSE's dispatch of the Colstrip generation facility, and PSE finds Staff's recommendation reasonable. Specifically, Staff recommends that PSE update its production cost model to utilize a marginal price of fuel equal to the discounted tier price in PSE's coal supply agreement for Colstrip dispatch decisions.[5] PSE's forecast model previously utilized an estimated average price of fuel for Colstrip dispatch decisions. The lower tier price is a better representation of the true marginal cost of fuel than is the average price under most scenarios, including those modeled in this case. It has the additional benefit of ensuring that estimated coal fuel costs in PSE's power cost forecast are tied directly to the coal volumes projected to be consumed in that same forecast (PSE's previous method utilized a preliminary forecast of fuel consumption to determine the average price of coal and that forecast then often differed slightly from fuel consumption in the final forecast).

[5] *See* Wilson, Exh. JDW-1T at 41:14-15.

Q. Has PSE incorporated Staff's proposal in its updated power cost forecast?

A. Yes. The updated power cost forecast presented in Section IV below utilizes the lower marginal coal price recommended by Staff for Colstrip dispatch decisions. As discussed in Staff's Exh. JDW-12 (PSE's Response to Staff Data Request No. 119), this change results in a small increase to Colstrip production (0.2 percent) and a similarly small change to PSE's forecasted power costs (0.1 percent increase to the 2025 forecast).

B. Valuation of Clay Basis natural gas storage

Q. What is PSE's current position regarding its calculation of the power cost benefit of Clay Basin natural gas storage?

A. PSE reviewed Staff 's recommendation that the Commission accept PSE's proposed modeling methods for Clay Basin storage in this case, but only on an interim basis,[6] and PSE finds Staff's recommendation reasonable. As suggested by Wilson,[7] PSE will revisit its Clay Basin storage modeling assumptions once additional actual operational data is available and utilize that data to establish normal operating parameters for the facility.

[6] *See* Wilson, Exh. JDW-1T at 7:6-7.
[7] *See* Wilson, Exh. JDW-1T at 45:2-4.

C. Energy Imbalance Market costs and benefits

Q. How does PSE account for EIM costs and benefits in its power cost forecast?

A. PSE's power cost forecast includes EIM benefits according to a methodology developed collaboratively with representatives from Staff, AWEC, and Public Counsel subsequent to the settlement agreement in PSE's 2020 PCORC. PSE's methodology seeks to capture the full benefit of EIM participation by utilizing power cost results from model runs that reflect optimal resource dispatch assuming the presence of a sub-hourly (EIM proxy) market. In order to determine the EIM benefit embedded in these power cost results, PSE performs alternative model runs that assume a sub-hourly market is not available. The difference between forecasted power costs with the sub-hourly market and the alternative forecast without a sub-hourly market accounts for most of PSE's resulting estimate of EIM benefits to include n rates. The estimated EIM benefit embedded in PSE's Aurora model results was $35.9 million in 2025 as of PSE's initial filing. The 2025 EIM benefit included in Aurora model results from PSE's updated power cost forecast discussed in Section IV is $29.5 million.

Benefits associated with net payments received by PSE for export of low-greenhouse-gas-emitting resources to California via the EIM are not included in the Aurora model results described above. PSE includes an estimate of these benefits in its power cost forecast outside of the Aurora model. This estimate, an additional $2.6 million reduction to power costs in 2025, is based on historical actual greenhouse gas payments received by PSE minus the historical actual offsetting cost of any California emissions allowances PSE has to purchase for EIM exports to California.

Q. What is PSE's current position regarding its forecast of EIM costs and benefits in this rebuttal testimony?

A. PSE reviewed Staff witness Wilson's response testimony regarding PSE's forecast of EIM costs, and he identifies two types of EIM credits and charges that were omitted from PSE's power cost forecast. Wilson recommends that PSE include them, reduce its power cost forecast by $95,000 per year to account for EIM flexible ramping payments, and increase its power cost forecast by $467,000 per year to account for various transaction fees and interest charges paid to the EIM operator.[8] Both of these values are based on PSE's historical actual receipts and charges between January 2021 and December 2023. The net impact of Staff's recommendation is a $372,000 increase to PSE's forecasted power costs in both 2025 and 2026.

PSE finds Wilson's recommendations reasonable. The EIM charges/credits identified by Staff are incremental to the costs and benefits captured in PSE's Aurora model results. Therefore, it is appropriate to add an estimate of these costs and benefits to PSE's forecast outside of the Aurora model, just as PSE does with EIM greenhouse gas payments.

[8] *See,* Wilson, Exh. JDW-1T at 47:17-48:4.

Q. Has PSE updated its power cost forecast to include EIM flexible ramping payments, administrative charges, and transaction fees as proposed by Staff?

A. Yes. PSE's updated power cost forecast presented in Section IV below includes additional net costs of $372 thousand per year to account for EIM flexible ramping payments, administrative charges, and transaction fees.

Q. Is PSE accepting other proposals related to EIM costs and benefits?

A. No. Other proposals, submitted by AWEC, are not reasonable. AWEC argues that PSE's power cost forecast excludes the financial benefit of certain EIM settlement line items and recommends that PSE deduct the four-year average of these actual settlement amounts from its power cost forecast.[9] The EIM settlement line items AWEC recommends deducting from PSE's forecast are congestion offset payments and marginal losses offset payments, or neutrality charges. Deducting the four-year average of these actual payments from PSE's forecast would reduce power costs $6.7 million per year.

PSE also opposes AWEC's proposal to include EIM neutrality payments as a reduction to PSE's power cost forecast.[10] The method used to estimate EIM benefits in PSE's power cost forecast already includes benefits associated with neutrality payments. Such payments arise in actual after-the-fact EIM settlement accounting because the settlement price that is paid to generators in the EIM is not always equal to the price that load or demand pays to the market. This difference

[9] *See* Exh. BGM-1T at 23:9-12.
[10] *See* Exh. BGM-1T at 22:10-11.

occurs primarily because transmission constraints and/or system losses cause locational marginal prices ("LMP") to differ within the market footprint. For EIM settlements, generators are paid a LMP based on the geographic location of the generator while load is charged a LMP based on the geographic location of the load. To the extent generation in one location is used to serve load in a different (higher LMP) location, revenue collected by the market operator from loads will exceed revenue paid out to generators. This surplus revenue is returned to market participants in the form of neutrality payments. The full value of an EIM transfer is the applicable LMP adjusted for any neutrality payments.

The EIM methodology used in PSE's power cost model relies on an EIM price forecast that includes the impact of transmission constraints and losses—it therefore already reflects the full value of EIM transfers. The prices used in PSE's model are an estimate of EIM transfer prices equivalent to LMPs *after* adjustment for congestion and losses – they are not an estimate of the specific LMPs that would be used to calculate after-the-fact EIM settlements. All EIM transfers in PSE's power cost model are executed at the EIM transfer price forecast so there is no difference between the prices paid by load and the prices received by generators. There is no surplus revenue collected by a market operator that must be returned to participants as neutrality payments. Instead, the full revenue or cost of each EIM transaction is captured in the EIM transfer price.[11] AWEC's

[11] This approach is analogous to the California Independent System Operator's method of calculating EIM benefits wherein EIM transactions are valued at a "transfer price" that is equal to LMPs adjusted for congestion revenue. See https://www.westerneim.com/Documents/EIM-BenefitMethodology.pdf.

recommendation to add a separate estimate of EIM neutrality charges to PSE's existing EIM forecast methodology would result in double counting those benefits. The Commission should reject this recommendation.

IV. PSE'S POWER COST FORECAST

A. Updated 2025 and 2026 power cost forecast

Q. Has PSE updated its forecast of 2025 and 2026 power costs since its initial filing in February 2024?

A. Yes. PSE prepared an update to its power cost forecast with inputs and assumptions current as of August 15, 2024. The updated forecast of 2025 power costs is $1.17 billion. This is $183 million (18.5 percent) higher than the 2025 forecast presented in PSE's initial filing and $49 million (4.4 percent) higher than power costs currently included in rates. PSE's updated forecast of 2026 power costs is $1.19 billion, approximately $96 million (8.7 percent) higher than the 2026 forecast presented in PSE's initial filing. Table 1 below provides a summary of PSE's updated power cost forecast for 2025 compared to the approved 2024 forecast currently in rates.[12]

[12] On December 22, 2023, the Commission issued its Final Order 01 in Docket UE-230805 rejecting in part PSE's proposed 2024 power costs and ordering and authorizing a compliance filing. On December 27, 2023, PSE submitted its compliance filing with revised tariff sheets incorporating adjustments to forecasted 2024 power costs consistent with the Commission's Order 01.

Table 1. 2025 power cost forecast versus 2024 forecast currently in rates ($ in thousands)

FERC acct./ category	($ in thousands)	2025 forecast	2024 forecast (in rates)	2025 increase / (decrease)
501	Coal fuel	$53,698	$55,532	($1,834)
547	Natural gas fuel	$468,953	$324,050	$144,902
555WS	Wind and solar purchases	$76,473	$76,718	($245)
555H	Hydro purchases	$447,393	$275,779	$171,614
555	Other contract purchases	$434,590	$421,046	$13,544
555MP	Market purchases	$98,506	$157,150	($58,644)
447	Secondary sales	($516,269)	($249,030)	($267,240)
565	Transmission	$178,866	$153,227	$25,639
456	Other revenues	($116,234)	($126,901)	$10,667
557DR	Demand Response	$16,618	$11,391	$5,227
557	Other power supply expense	$22,547	$17,154	$5,393
	Total Power Costs	**$1,165,140**	**$1,116,116**	**$49,024**

Exhibit BDM-24C includes a summary of PSE's updated forecast of power costs for calendar years 2025 and 2026 compared to the 2025 and 2026 forecast included in PSE's initial filing.

Q. What updates did PSE make to its 2025 and 2026 power cost forecast?

A. In addition to the changes made to incorporate Staff's recommendations discussed in Section III, for this updated power cost forecast PSE:

i. Updated natural gas price inputs to the average of forward prices for the forecast period from the 90-days ending August 15, 2024;

ii. Updated natural gas transportation contract rates with effective tariff rates as of August 15, 2024;

iii. Updated Bonneville Power Administration ("BPA") transmission rates beginning October 1, 2025 to reflect an anticipated rate increase at that time. PSE expects BPA will issue its proposed rate change during the last quarter of 2024, likely in time to include BPA's actual proposal in a compliance filing update to PSE's power cost forecast;

iv. Updated planned outage schedules for PSE's thermal generators with outage plans as of August 15, 2024;

v. Updated the assumed price of CCA allowances to the estimated Tier 1 Auction price for 2025 and 2026. This assumption is discussed in more detail in Section V below;

vi. Updated Colstrip fuel prices with prices reflecting the most recent quarterly inflation adjustment according to PSE's coal supply agreement with Westmoreland Rosebud Mining;

vii. Updated the costs of PSE's Mid-Columbia hydroelectric contracts with the most recent budgets and/or forecasts provided by the project owners, and

viii. Added five new PPAs and one new transmission contract to PSE's power supply portfolio.

Q. What new resources did PSE add to its power supply portfolio for this forecast update, and what is their impact to PSE's power costs?

A. New resources added to PSE's power supply portfolio for this forecast update include only resources for which PSE had executed contracts as of the time this forecast update was prepared on August 15, 2024. These resources were not included in the forecast presented in PSE's initial filing as contracts had not been executed at the time that forecast was prepared. PSE intends to seek a prudence determination for each of these new resources at the next available opportunity according to PSE's proposed annual power cost update process discussed in Section II above. All of these new resources were acquired to meet PSE's resource adequacy and/or clean energy needs. New resources in this forecast update include:

1. An additional [redacted]. Addition of this PPA to PSE's forecast increases 2025 power costs approximately $15.2 million. This contract is provided as Exh. BDM-44C.

2. An approximately four percent share (approximately 84 MW) of output from Grant County Public Utility District's Priest Rapids hydroelectric project from January 1, 2025, through December 31, 2025. Addition of this PPA to PSE's forecast increases 2025 power costs approximately $27.2 million. This contract is provided as Exh. BDM-45C.

3. A contract with [redacted], [redacted]. PSE's share of output under the contract increases from just over nine percent (approximately 57 MW) in 2026 and 2027 to nearly 19 percent (approximately 115 MW) in 2031 and 2032. Addition of this PPA to PSE's forecast increases 2026 power costs approximately $12.2 million. This contract is provided as Exh. BDM-46C.

4. A contract with [redacted], [redacted] This contract increases PSE's 2025 power cost forecast by approximately $13.3 million. This contract is provided as Exh. BDM-47C.

5. A contract with [redacted] This contract increases PSE's forecasted 2025 power costs by approximately $73.2 million and 2026 power costs by $57.6 million. This contract is provided as Exh. BDM-48C.

6. A new transmission contract with Northwestern Energy for transmission capacity needed to deliver output from PSE's Beaver Creek wind facility in Montana. Beaver Creek is expected to begin generating as early as March 2025 with full commercial operations in August 2025. Addition of this transmission contract to PSE's forecast

13 [redacted]

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increases 2025 power costs by $10.8 million and 2026 power costs by $13.0 million. This contract is provided as Exh. BDM-49.

The Board of Directors and EMC decisional materials are provided as Exh. BDM-50HC.

Q. Why do new PPAs increase PSE's forecasted power costs?

A. As discussed in my prefiled direct testimony,[14] adding new PPAs to PSE's power cost forecast increases forecasted costs when the PPA price exceeds the cost of unspecified spot market purchases that the PPA displaces in PSE's power cost model. This is generally the case with PSE's new PPAs, as these power supply agreements provide significant additional benefits relative to unspecified spot market purchases. The power cost forecast model assumes PSE's resource portfolio has sufficient capacity and renewable energy to meet resource adequacy and clean energy requirements during the forecast period, even if that is not the case. Therefore, when PSE adds a new PPA that provides resource adequacy and/or clean energy benefits, those benefits do not show up as an explicit reduction in PSE's power cost forecast. Further, the cost of capacity needed to ensure PSE can provide reliable electric service is increasing amid a tightening regional supply and demand balance. These higher costs increase the power cost impact of new resources that provide resource adequacy benefits. For example, PSE's recent short-term request for proposals and other resources transacted in 2024 indicate that capacity is being priced at or above the [redacted] per kW-year that

[14] *See* Mueller, Exh. BDM-1T at 15:18-17:17.

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PSE identified as the high end of a capacity price range when it filed its initial testimony in this case.

B. New resources not included in PSE's updated power cost forecast

Q. Does PSE expect to acquire additional new resources for 2025 and 2026 that are not included in the updated power cost forecast presented above?

A. Yes. PSE has executed two new PPAs since this power forecast update was prepared. PSE is also in advanced negotiations for additional new power supply resources and expects contracts will be executed prior to the conclusion of this general rate case.

Q. What new PPAs has PSE executed since completing its power cost forecast update?

A. On September 5, 2024, PSE executed a PPA with Brookfield Renewable Trading and Marketing LP for 50 MW of capacity and energy to be supplied primarily from the Powell River hydroelectric project in British Columbia, Canada. At least 80 percent of energy delivered under the PPA will be CETA-compliant clean energy. Deliveries under the contract begin February 1, 2026, and continue through December 31, 2043. PSE expects this new PPA will increase forecasted 2026 power costs by approximately $9.6 million. The Brookfield PPA is provided as Exh. BDM-51C.

On September 11, 2024, PSE executed a PPA with Eugene Water and Electric Board for a 14.46 percent share (approximately 25 MW) of the output of the Stateline Wind facility for the period January 1, 2025, through December 31, 2025. PSE expects this new PPA will increase forecasted 2025 power costs by approximately $845 thousand. An update to PSE’s 2025 power cost forecast at the end of this proceeding would include these new resources. This PPA is provided as Exh. BDM-52C.

Q. What other new PPAs does PSE expect to execute before the end of this year?

A. PSE is close to finalizing agreements to purchase output from 30[15] individual distributed energy resources (“DER”). These resources are all relatively small (less than five MW) solar, battery, or hybrid solar-plus-battery installations located within PSE’s service territory. At least 25 of them are expected to begin generating before the end of 2026 but only five are likely to be available during 2025. PSE estimates these new PPAs will increase forecasted 2025 power costs by about $100 thousand and increase 2026 power costs by about $2.7 million. An update to PSE’s power cost forecast at the end of this proceeding would include these new DER PPAs, assuming they are finalized at that time.

PSE is also in advanced stages of negotiation for a contract to secure [redacted]

REDACTED VERSION

[15] PSE discussed 34 likely DER projects in Exh. BDM-1T at 20:5. Four of those original projects no longer appear feasible.

[redacted] Based on contract terms currently under discussion, PSE estimates this agreement would [redacted] its forecasted power costs [redacted] per year. PSE would include this new resource in an update to its power cost forecast at the end of this proceeding, assuming it is finalized at that time. PSE would then seek a prudence determination at the next available opportunity, likely in its April 2025 PCA annual filing.

V. CLIMATE COMMITMENT ACT ALLOWANCE COSTS

<u>A. CCA allowance costs in PSE resource dispatch decisions</u>

Q. Please summarize PSE's position regarding the inclusion of CCA allowance costs in PSE's resource dispatch decisions.

A. PSE currently only considers CCA allowance costs in the dispatch decisions for resources supplying wholesale sales. This position is based on the guidance to date provided by the Washington State Department of Ecology ("Ecology") regarding its no-cost allowance allocation and adjustment process. PSE expects to ultimately receive no-cost allowances for all emissions associated with serving its retail electric demand. PSE expects it will have to purchase allowances for any emissions associated with its sales of surplus energy to the wholesale market.

Given this understanding, PSE's decision to exclude CCA allowance costs from the dispatch cost of resources used to supply retail electric demand minimizes total electric supply costs for PSE's customers. Because PSE expects to receive no-cost allowances for emissions associated with supplying retail electric demand, there is no direct benefit to offset the cost of reducing any such emissions.

Staff, however, recommends that PSE include the cost of CCA allowances in the cost used to make dispatch decisions for all of its emitting resources, regardless of whether those resources are being dispatched to serve PSE's retail electric demand or being used to support sales of surplus energy in the wholesale market.[16] Staff asserts that PSE's current practice of considering CCA allowance costs only in the dispatch cost of resources supplying wholesale market sales may be inconsistent with Ecology's intentions regarding the no-cost allowance provisions of the CCA.[17]

Q. Is Staff's recommendation to include CCA allowance costs in all PSE resource dispatch decisions reasonable?

A. It depends. Staff's interpretation of Ecology's intent for implementing its no-cost allowance adjustment process is different from PSE's. Generally, Staff's interpretation is that Ecology does not intend the allowance adjustment to be a one-for-one true-up to actual emissions associated with retail load and that PSE will be able to retain and sell any allowances initially allocated but not needed for

[16] *See* Exh. JDW-1T at 5:10-13.
[17] *See* Exh. JDW-1T at 5:5-10.

emissions associated with retail load.[18] If this interpretation is in fact correct, then Staff's recommendation is a reasonable one – and it would minimize costs for PSE's customers. As stated below, however, PSE has no first-hand knowledge of such interpretation from Ecology.

Q. What is the basis for Staff's interpretation of Ecology's intent with respect to its no-cost allowance adjustment process?

A. Staff's interpretation appears to be based largely on an interview with an Ecology staff person earlier this year. PSE was not a party to this interview and Ecology has not subsequently provided to PSE any of the information reported to Staff in the interview. Based on the information and guidance Ecology has provided publicly, PSE maintains that its current understanding of the no-cost allowance adjustment process reflects the likely outcome of this process.

Q. Has PSE evaluated the impact of Staff's recommended approach on forecasted power costs?

A. Yes. Adopting Staff's recommendation significantly increases PSE's power costs while also reducing emissions from PSE's fossil-fueled generators. Whether or not the recommendation increases total projected power supply costs (including both power costs and net emissions allowance costs) depends on interpretation of Ecology's no-cost allowance adjustment process. Table 2 summarizes results of

[18] *See* Exh. JDW-1T at 16:11-14.

PSE's analysis for calendar year 2025 assuming PSE's interpretation is accurate. Table 3 summarizes results assuming Staff's interpretation is accurate.

Table 2. 2025 power cost forecast versus Staff's recommendation to include CCA allowance costs in all PSE resource dispatch: *PSE* interpretation of no-cost allowance adjustment ($ in thousands)

	PSE's updated power cost forecast (a)	Staff's recommendation w/ CCA in all dispatch (b)	Increase / (decrease) (c)
1. Forecasted power costs	$1,165,140	$1,270,656	$105,516
2. PSE emissions (metric tons)	6,827,096	4,160,406	(2,666,690)
3. No-cost allowance allocation (metric tons)	5,788,232	3,966,204	(1,822,027)
4. Cost of allowance purchases	$62,718	$11,724	($50,994)
5. Total cost	**$1,227,858**	**$1,282,380**	**$54,522**

Table 3. 2025 power cost forecast versus Staff's recommendation to include CCA allowance costs in all PSE resource dispatch: *Staff* interpretation of no-cost allowance adjustment ($ in thousands)

	PSE's updated power cost forecast (a)	Staff's recommendation w/ CCA in all dispatch (b)	Increase / (decrease) (c)
1. Forecasted power costs	$1,165,140	$1,270,656	$105,516
2. PSE emissions (metric tons)	6,827,096	4,160,406	(2,666,690)
3. No-cost allowance allocation (metric tons)	5,561,608	5,561,608	0
4. Cost of allowance purchases (*net of sales*)	$76,400	($84,593)	($160,993)
5. Total cost	**$1,241,540**	**$1,186,063**	**($55,477)**

As shown in Tables 2 and 3 above, including CCA allowance costs in PSE's resource dispatch decisions when supplying retail demand as recommended by Staff increases 2025 power costs by approximately $106 million (column (c) 1 in each table). Assuming PSE's understanding of the no-cost allowance allocation process in Table 2, these higher power costs are not offset by lower net emissions costs (as there is no ability to sell excess allowances – see row 4 in each table) and the result is an increase of approximately $55 million to total cost, as shown on line 5 in Table 2. Assuming Staff's interpretation of the no-cost allowance allocation process, higher power costs are more than offset by a net benefit from assumed sales of surplus no-cost allowances and the result is a decrease of approximately $55 million to total cost shown on line 5 of Table 3.

Note that the difference between these two outcomes depends entirely on the no-cost allowance allocation. In Table 2, line 3, that allocation is assumed exactly equal to emissions associated with supplying PSE's retail electric demand, according to PSE's interpretation of Ecology's rules. In Table 3, line 3, that allocation is fixed at the amount of no-cost allowances initially allocated to PSE by Ecology for 2025 and is not adjusted based on actual after-the-fact emissions.

Q. Given the uncertainty regarding how Ecology will ultimately implement its no-cost allowance adjustment, does Staff's recommendation reduce risks relative to PSE's treatment of allowance costs in dispatch decisions?

A. No. PSE's treatment of CCA allowance costs in its dispatch decisions is the lower risk option. The significant increase to power costs that occurs with Staff's recommended approach would occur regardless of how Ecology ultimately implements its allowance adjustment. This certain increase to PSE's power supply cost may or may not be offset by benefits from sales of surplus no-cost allowances.

The lower risk approach is to avoid certain cost increases now until there is more certainty with respect to Ecology's adjustment of no-cost allowances.

Q. When will PSE have a more certain understanding of Ecology's no-cost allowance adjustment?

A. Ecology's adjustment to PSE's no-cost allowance allocation for calendar year 2023 is expected to occur in October 2024. PSE does not know exactly what information will be provided with that process, but it will at least provide an example of how Ecology chooses to implement the adjustment for that first year of the program. Further, Ecology is planning to host a series of "Cap-and-Invest Electricity Forums" beginning in early October 2024. PSE is hopeful that these forums will provide additional clarity regarding Ecology's intentions for the program.

Q. What price did PSE assume for CCA allowances in its power cost forecast and the alternative scenario presented above?

A. PSE assumed a 2025 allowance price of $60.37 per metric ton. This is an estimate of the Tier 1 Auction price for calendar year 2025. In its initial power cost forecast PSE assumed a 2025 allowance price of $57.91 per metric ton. This was the price of CCA allowances trading in the secondary market at the time PSE prepared that forecast.

Q. Why did PSE change the source of its CCA price assumption for this power cost update?

A. At the time of this power cost forecast update, secondary market allowance prices are less than $38 per metric ton, a decrease of more than 34 percent since PSE prepared its initial power cost forecast at the end of 2023. These secondary market prices, however, are heavily influenced by the risk of CCA repeal created by Washington ballot initiative 2117. If that initiative passes, the CCA will be repealed, and allowance prices will effectively go to $0. If that initiative fails, the CCA will remain in place and allowance prices can be expected to return to levels near where they were prior to the initiative. In either case, there is not a realistic scenario wherein allowances could be acquired in 2025 at current secondary market prices. The expected Tier 1 auction price that PSE uses in this power cost update is a reasonable estimate for the price at which PSE can expect to be able to acquire allowances in 2025.

Q. Should any other costs associated with carbon dioxide emissions be considered in PSE's resource dispatch decisions?

A. No. In order to minimize overall cost and most efficiently utilize available resources, dispatch decisions must reflect the actual costs incurred when a generating unit is dispatched. External social costs, like the social cost of greenhouse gases ("SCGHG"), are relevant to longer-term decisions regarding how a resource portfolio will evolve over time, including retirements of existing resources and acquisitions of new ones. The Clean Energy Transformation Act explicitly instructs utilities to consider the external SCGHG when evaluating conservation efforts, developing integrated resource plans, and evaluating resource acquisition options. Estimates of SCGHG may also be useful for policymakers to determine the appropriate level at which to establish, for example, a tax on carbon emissions or expectations for the "right" price in a cap-and-trade program that could then be used to determine the volume of emissions allowances made available to a market. Additionally, the Commission recently issued a Policy Statement Addressing the Issues and Impacts of the Climate Commitment Act in Docket U-230161 ("Policy Statement"), which expressed the Commission's intention to immediately require PSE to include the SCGHG in dispatch decisions.[19] However, absent a program that establishes actual cost obligations on emissions, external costs should not be considered in short-term resource dispatch or utilization decisions. Doing so only results in inefficient use of resources and cost increases with little or no overall reduction to emissions.

Q. Has PSE quantified the impact to power costs if it were to consider the estimated SCGHG in its resource dispatch decisions?

A. Yes. Reflecting both the SCGHG and expected CCA allowance costs in PSE's dispatch decisions would drastically increase cost for PSE's customers. Table 4 below provides a summary of PSE's forecasted 2025 power costs, carbon

[19] *See* Policy Statement Addressing the Issues and Impacts of the Climate Commitment Act, Docket U-230161 at ¶ 18 ("The Commission expects IOUs to include the social cost of greenhouse gases (SCGHG) and CCA costs in both real-time dispatch and long-term IRP modeling.")(Aug. 15, 2024). The Policy Statement was rescinded without explanation on August 19, 2024.

emissions, and emission allowance costs with the SCGHG in dispatch compared to PSE's 2025 forecast.

Table 4. 2025 power cost forecast versus power costs with SCGH in PSE resource dispatch decisions ($ in thousands)

	PSE's 2025 power cost forecast	Scenario with SCGH in dispatch	Increase / (decrease)
Forecasted power costs	$1,165,140	$1,569,502	$404,362
PSE emissions (metric tons)	6,827,096	1,365,241	(5,461,855)
No-cost allowance allocation (metric tons)	5,788,232	1,365,241	(4,422,991)
Cost of allowance purchases	$62,718	$0	($62,718)
Total cost	**$1,227,858**	**$1,569,502**	**$341,644**

As shown in Table 4 above, including the SCGHG in PSE resource dispatch decisions could increase annual power costs by more than $400 million with only a relatively small offsetting benefit from lower CCA allowance purchase costs.

Q. Would including SCGHG in PSE's resource dispatch decisions reduce overall carbon emissions?

A. While including SCGHG in PSE's resource dispatch decisions would certainly reduce emissions from PSE's generators (by perhaps more than four million metric tons, as shown in Table 4), it is unlikely that such a policy would reduce overall emissions in the region, and it could even increase them. If PSE adds the SCGHG to its dispatch costs and the rest of the generators in the interconnected western United States do not, then this policy simply makes PSE's generators appear relatively less efficient and they will dispatch only after actually less efficient (*i.e.* higher emissions) generators are already dispatched. This means that energy from a relatively efficient PSE gas-fueled generator would be replaced with energy from a much less efficient generator, potentially even one burning coal or diesel. Ultimately, a policy for PSE to include SCGHG in its dispatch decisions could cause PSE customers to pay much higher rates for less clean energy supply.

B. Inclusion of CCA allowance purchase costs in customer rates

Q. How does PSE propose to recover direct costs incurred to purchase CCA allowances for its electric utility?

A. PSE proposes that it continue to defer any direct CCA allowance purchase costs pursuant to the accounting petition approved in Docket UE-220974. PSE will request to collect deferred amounts from customers at a time to be determined when PSE has a better understanding of its actual net CCA allowance obligation.

Q. Does PSE agree with Staff's recommendation to include all CCA allowance-related costs in the rates approved for power costs in this proceeding?[20]

A. No. At least not at this time. Including CCA allowance costs in PSE's power cost forecast and PCA variable baseline rate requires a reasonably accurate estimate of what these costs will actually be on a forward-looking basis. Because variances between actual power costs and those in the PCA baseline rate are shared between PSE and customers, an inaccurate forecast can lead to significant un-recovered costs (in the case of allowance costs much higher than forecast) or a windfall for

[20] *See* Wilson, Exh. JDW-1T at 26:3-5.

the company (in the case of allowance costs much lower than forecast). And, as Staff recognizes,[21] there is significant uncertainty regarding Department of Ecology's ultimate allocation of no-cost allowances to electric utilities. This uncertainty makes it currently impossible to forecast PSE's CCA allowance obligation and ultimate allowance costs with a reasonable level of confidence.

VI. CONCLUSION

Q. Does that conclude your prefiled rebuttal testimony?

A. Yes, it does.

[21] *See* Wilson, JDW-1T at 5:15.