BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of	)	DOCKET UE-230805
	)	
PUGET SOUND ENERGY,	)	COMMENTS OF THE ALLIANCE OF
	)	WESTERN ENERGY CONSUMERS
Advice No. 2023-44, Electric Tariff Revision.	)	
	)	**REDACTED**
	)	

1 The Alliance of Western Energy Consumers ("AWEC") appreciates the opportunity to file comments on Puget Sound Energy's ("Puget," "PSE" or "Company") 2024 Power Cost Update filed consistent with the Commission's Final Order 24/10 in Docket Nos. UE-220066/UG-220067. AWEC has reviewed PSE's filing and workpapers and recommends that Puget's power cost forecast be reduced by the amounts indicated in each section below. The bases for AWEC's proposed adjustments are discussed below.

A. *Energy Imbalance Market congestion revenues should be included in 2024 Net Power Costs.*

2 As discussed below, Puget recognized $[redacted] in congestion revenues from the EIM in the 12-months ending June 2023. AWEC recommends that this level of congestion revenues be considered as a reduction to power costs in the calculation of Energy Imbalance Market ("EIM") benefits in Puget's 2024 Power Cost Update.

3 Congestion revenues are not being considered in the calculation of EIM benefits included in the 2024 Power Cost Update, as filed. The calculation of EIM benefits used in the 2024 Power Cost Update was generally described by witness Wetherbee in the 2022 General

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Rate Case ("GRC"). Puget's net power cost forecast includes two categories of EIM benefits.[1] First, PSE forecasts sub-hourly dispatch benefits by running the AURORA model with sub-hourly intervals. Second, PSE models greenhouse gas ("GHG") settlement revenues outside of the AURORA model based on a four-year average.

4 Puget began participating in the EIM in October 2016. As a result of its participation, it has recognized material benefits, which result in reductions to power costs. In actual operations, these savings are generated from the combined effect of settlement receipts or payments from the EIM and the corresponding impacts of the EIM on sub-hourly plant dispatch. There are several different settlement revenues and charges that PSE receives or pays in connection with its participation in the EIM. These settlements include items such as fifteen-minute instructed imbalance, five-minute instructed and uninstructed imbalance, greenhouse gas revenues, congestion revenues, and a variety of other items. The specific settlement revenues and charges that Puget paid over the four-year period ending June 2023 were provided in Puget's response to AWEC Data Request 1, which has been attached as **Confidential Attachment A** to these comments.

5 **Confidential Figure 1,** below, summarizes the various settlement revenues and charges that PSE has received in the EIM:

[1] *See* Docket UE-220066 (Cons.), Exh. PKW-1CT(R) at 28:10-21.

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Confidential Figure 1

PSE EIM Settlement Revenues and Charges July 2019 – June 2023

[redacted]

6 In **Confidential Figure 1**, a negative value represents a settlement revenue to Puget, whereas a positive amount represents a cost. For purposes of these comments, AWEC is focused predominantly on congestion revenues. This is because congestion revenues have not historically been considered in the EIM benefits forecast included in power costs. Notwithstanding, it can be noted from **Confidential Figure 1** that the amount of congestion revenues PSE has received has increased steadily year over year. Given the magnitude of these revenues, AWEC believes it is appropriate to consider them in EIM net benefits as a reduction to power costs in the 2024 Power Cost Update.

7 With respect to the actual EIM settlement data attached in **Confidential Attachment A**, the sub-hourly dispatch benefits, calculated by running the AURORA model

with sub-hourly dispatch, correspond to the settlement revenues and payments associated with imbalances. These include settlements associated with fifteen-minute instructed imbalance, five-minute instructed imbalance and five-minute uninstructed imbalance. Importantly, the imbalance settlement payments themselves are not necessarily net benefits of sub-hourly dispatch viewed in isolation. In addition to the settlement payments, the corresponding cost impacts of plant dispatch instructions—i.e., instruction from the EIM to increase or decrease production—must also be considered when evaluating net benefits. For example, Puget may have received instructed imbalance settlement revenues for increasing the dispatch from a participating resource, and the net benefit of such an instruction is the difference between the settlement revenue and the increased fuel cost. Correspondingly, Puget may have paid instructed imbalance settlement payments for reducing the dispatch from a participating resource, and the net benefit of such instruction is the difference between the fuel cost savings and the settlement payment. Thus, an imbalance settlement may be a cost to Puget, although viewed in conjunction with the fuel cost savings, a net sub-hourly dispatch savings is achieved.

8 Greenhouse gas revenues are a separate EIM charge and are not considered in the imbalance payments and charges made with respect to sub-hourly dispatch. These charges, which occur when a carbon-free resource is dispatched into states with emissions programs, are additive to the sub-hourly dispatch benefits calculated by running the AURORA model with sub-hourly intervals. Accordingly, Puget added greenhouse gas EIM benefits as an additional cost savings outside of the AURORA model. The same is true, however, for congestion revenue settlement payments, even though Puget did not acknowledge those benefits in the 2022 GRC.

9 As noted in **Confidential Attachment A**, there are many different revenues and charges other than imbalance charges and GHG revenues that Puget recognizes with respect to

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the EIM and which are additive to the sub-hourly dispatch savings. These include items such as congestion revenues, flexible ramping rewards, marginal loss offsets, and other charges. Witness Wetherbee discussed some of these items in the 2022 GRC, including greenhouse gas revenues and flexible ramping rewards.[2] Notably missing from this list, however, was congestion revenues. Other charges, such as marginal loss revenues and other uplifts, are generally small and net to around zero. The congestion revenues recognized are significant, however, representing the largest source of EIM settlement revenues received in the 12-months ending June 2023.

10 Congestion revenues arise in the EIM because the locational marginal prices at each node within the EIM are different. The primary reason for the different location prices is congestion—i.e. the effects of limited transmission capability between nodes and transmission areas within the EIM topology. Because the locational marginal prices at each node are different, it results in a total amount of imbalance payments from the EIM that are less than the imbalance payments received from the EIM. This difference represents congestion revenues, and in any given month the total amount of system wide congestion revenues is allocated to participating EIM entities based on the contribution of each Balancing Authority Area in the EIM Area to the Marginal Cost of Congestion consistent with Section 11.5.4.1.1 of the California Independent System Operator Tariff.

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2 Exh. PKW-1CT(R) at 32:19-33:18. Note that while PSE did propose to include greenhouse gas revenues in its power cost forecast, it claimed that the flexible ramping rewards were inconsequential. While not discussed here, flexible ramping rewards are not immaterial and accordingly are appropriate to reconsider in Puget's next general rate case.

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11 Over the four years ending June 2023, the amount of congestion revenues that Puget has recognized as a result of this allocation process has been material. This is detailed in **Confidential Table 1**, below.

Confidential Table 1

PSE EIM Congestion Revenues Charges July 2019 – June 2023 (Whole Dollars)

[redacted]

12 As can be seen, the amount of congestion revenues increased in every year, more than doubling by the 12-months ending June 2023. Considering this magnitude and the fact that the revenues have been increasing, AWEC recommends that EIM congestion revenues in the amount of $[redacted] be considered in the 2024 Power Cost Update. This value is based on the actual experience over the 12-months ending June 2023.

13 The EIM benefits associated with Greenhouse gas revenues are calculated using a 48-month average. Using the 12-month average in the case of congestion revenues is more appropriate than using the 48-month average because the revenue amount has been increasing every year. With higher market prices experienced since 2020, for example, it is expected that congestion revenues will also correspondingly be higher. Accordingly, a 12-month average will more accurately capture the appropriate amount of congestion revenue benefits for ratepayers.

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B. PSE's proposed modeling change for wind integration should be rejected in this case.

14 In its 2024 power cost forecast, PSE has proposed to change how it models wind integration costs. This update increases power costs by $26.2 million.[3] PSE justifies this update by arguing that increasing amounts of wind are driving down market prices at times when wind generation is high.[4] AWEC has two concerns with PSE's methodological change.

15 First, PSE's modeling change is outside of the scope of the updates allowed under the Revenue Requirement Stipulation from the 2022 General Rate Case. Paragraph 28(b) of that stipulation identifies the specific costs and inputs that can be updated for 2024 power costs.[5] None of those costs and inputs include how PSE's renewable resources are modeled. This makes sense, as PSE's methodological change is complex and requires an AURORA license to evaluate its overall reasonableness, which has not been provided to intervenor parties for this limited update process.

16 Second, even without access to the AURORA model, AWEC disputes that PSE's modeling change is reasonable. This change materially reduces the value of PSE's owned and contracted wind resources. AWEC's understanding is that this new modeling method does not reflect how PSE modeled these resources in its IRPs and RFPs that ultimately led to the selection of these resources. In these evaluation processes, had PSE modeled these resources as it now proposes, it may have selected different resources, or it may have paid a different price. PSE's

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3 PSE 2024 Power Cost Update Report at 6 (Sept. 29, 2023).

4 PSE 2024 Power Cost Update Regarding Complex Changes to the PCA Baseline Rate at 4-5.

5 These costs and inputs are: (1) costs associated with Mid-C hydro contracts; (2) costs associated with upstream pipeline capacity; (3) outage schedules; (4) BPA rates; (5) load forecast; (6) variable O&M costs; (7) impacts to dispatch logic related to CCA compliance; (8) hedges and physical supply contracts; (9) natural gas prices; (10) changes to terms of current resources; and (11) any new and updated resources (including transmission contracts).

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modeling change effectively shifts the market and resource procurement risk of these resources to its customers. If PSE is allowed to update its wind integration methodology, it will disincentivize PSE to ensure that it is accurately forecasting the value of future renewable resources.

C. CCA dispatch costs should be excluded from the 2024 PCA, consistent with the Commission's decision in UE-220066/UG-220067 Order 26/12.

17 In its Power Cost Update, PSE proposes to include $22.7 million in costs representing the estimated impact of the Climate Commitment Act ("CCA") on resource dispatch and wholesale sales revenues.[6] PSE notes that this increase "is the net result of (a) a projected decrease in secondary market sales revenue ($66.9 million power cost increase) offset by (b) a decrease in projected natural gas fuel costs ($44.2 million power cost decrease)." PSE also notes that the 2024 power cost forecast does not include any costs of allowance purchases that may be required for compliance and that any such costs would continue to be deferred in accordance with the accounting petition approved in Docket UE-220974.[7]

18 Consistent with the Commission's decision on PSE's compliance filing in its most recent Multi-Year Rate Plan, the Commission should order PSE to remove its proposed $22.7 million increase in 2024 net power costs associated with changes in resource dispatch due to the CCA. In its compliance filing, PSE sought to increase net power costs by $135.8 million due to CCA impacts. The Commission's rationale in that proceeding still holds in relation to this 2024 PCA – namely, that "the Company did not present any detailed testimony regarding the impact of the CCA on its power costs."[8] While the magnitude of impacts was a factor for the

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6 2024 Power Cost Update at 6 (September 29, 2023).
7 *Id.*
8 Dockets UE-220066, UG-220067, and UG-210918, Order 26/12 at ¶ 19 (Jan. 6, 2023).

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Commission in the compliance filing, its underlying concerns about comparable access to information persist. Similar to the compliance filing, the parties in this case do not have access to AURORA for purposes of reviewing and analyzing the Company's modeling methodology and assumptions.

19 Additionally, the Commission is also considering whether and how greenhouse gas costs should be considered in dispatch as part of its CCA Commission-led workshop series in Docket U-230161, which may ultimately result in rules that address this issue directly. The Commission should not prejudge the outcome of the workshop by approving a CCA dispatch adder for PSE in this limited update process.

D. PSE's proposed demand response Power Purchase Agreements should not be subject to cost recovery as part of 2024 Net Power Costs unless offsetting benefits are included.

20 In its filing, PSE proposes to include approximately $11.4 million in costs of demand response contracts that have not previously been included in power costs.[9] PSE's request to recover costs in this proceeding is consistent with the settlement in its most recent general rate case; however, PSE has not included any discussion or evidence that addresses the anticipated benefits associated with demand response contracts in this filing. AWEC would expect that such contracts would lead to a reduction in 2024 net power costs by reducing peak demand.

21 AWEC's understanding is that PSE excluded power cost benefits associated with these demand response projects because it considered those benefits to be speculative at this time. That, however, is not a basis to exclude such benefits altogether – PSE has assigned a

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[9] 2024 Power Cost Update at 3 (September 29, 2023).

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power cost benefit to these projects by giving them a $0 value. As the Commission has stated, "[w]hen fixed costs that reduce variable power costs are included in general rates, the PCAM's baseline power costs must be reset to reflect the benefits in order for ratepayers to realize the net benefits of the fixed costs they are being asked to pay for. Doing so matches the benefits with the burden."[10] The Commission has addressed circumstances where costs are included in rates when benefits are anticipated, but speculative. When PacifiCorp joined the EIM, the Oregon Commission approved a settlement wherein benefits were set equal to costs.[11] The Washington Commission's treatment of EIM benefits was slightly different, but the Commission again relied on the necessity of matching costs with the inclusion of benefits in rates.[12] The matching principle is a longstanding ratemaking principle that should not be abandoned in this case.

22 Given the lack of analysis and quantified benefits associated with these demand response contracts, the prudence of these contracts is unclear. If the costs of the demand response PPAs exceed their reasonably anticipated benefits to ratepayers, the contracts may not be prudent. Because PSE has not quantified the benefits of these PPAs, if the Commission concludes that including the new demand response contract costs in PSE's 2024 net power costs is appropriate, the Commission should set benefits equal to costs in this case. PSE can update these benefits in a future proceeding when it has evidence of the actual value these contracts bring to its system.

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10 Docket No. UE-152253, Order 12 ¶ 222 (Sept. 1, 2016).

11 *In re PacifiCorp*, Oregon PUC Docket Nos. UE 287 and UM 1689, Order No. 14-331, 2014 Ore. PUC LEXIS 322 (Oct. 1, 2014).

12 Docket No. UE-152253, Order 12 ¶ 222 (Sept. 1, 2016).

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E. If the Administrator for the Bonneville Power Administration orders a 2023 distribution dividend for Transmission, those benefits should be reflected in PSE's 2024 net power costs.

23 On November 16, 2023, the Bonneville Power Administration ("BPA") presented its Q4 Quarterly Business Review, during which BPA's financial results for its 2023 fiscal year were reported. As part of this presentation, BPA discussed its Transmission net revenues and the resulting Reserves Distribution Clause ("RDC") calculations. BPA's Financial Reserves Policy establishes the actions that the Administrator may take based on certain reserves levels. When reserves exceed established thresholds, as BPA's FY 2023 Transmissions Reserves have done, then the Administrator considers repurposing those reserves for other high-value business unit-specific purposes. Such purposes can include Dividend Distributions, otherwise known as rate credits. For Transmission, BPA's calculated RDC is $130.4 million. While BPA released its preliminary proposal on how to utilize the Transmission RDC amounts, a final decision has not been made.[13] If the Administrator determines that Transmission RDC amounts should be utilized for Dividend Distributions, those rate credit benefits should accrue to PSE's customers – who bear the costs of BPA's transmission rates – as part of PSE's 2024 net power costs. A decision from BPA is anticipated on or before December 15, 2023; however, if a final determination has not been made prior to the rate-effective date, such benefits should be deferred for the benefit of customers and subject to amortization in a future ratemaking proceeding. BPA rate credits, when approved, are known and measurable changes that should be included in NPC forecasts when the information is known prior to rates becoming effective.

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[13] Comments on BPA's Transmission RDC Preliminary Proposal are due on December 1, 2023, after which the Administrator will review the comments and make a decision on the disposition of RDC amounts.

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Respectfully submitted,

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