Exh. JDW-1TC
Dockets UE-240004/UG-240005
Witness: John D. Wilson
REDACTED VERSION

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent**	**DOCKETS UE-240004 & UG-240005 (Consolidated)**

TESTIMONY OF

JOHN D. WILSON

ON BEHALF OF STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Power Costs; Portfolio Forecast Error; Energy Recovery Mechanism;
Chelan PSA Prudency

August 6, 2024

CONFIDENTIAL PER PROTECTIVE ORDER – REDACTED VERSION

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I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is John D. Wilson. I am Vice President at Grid Strategies, LLC. Grid Strategies is based in the Washington, DC area, although my office is in Lexington, KY.

Q. Please state your qualifications to provide testimony in this proceeding.

A. I received a BA degree from Rice University in 1990, with majors in physics and history, and a Master of Public Policy degree from the Harvard Kennedy School of Government, with an emphasis in energy and environmental policy, and economic and analytic methods.

Since 2019, I have been a consultant, first, at Resource Insight, Inc., and now at Grid Strategies, LLC. Previously, I was deputy director of regulatory policy at the Southern Alliance for Clean Energy (SACE) for more than twelve years, where I was the senior staff member responsible for SACE's utility regulatory research and advocacy, as well as energy resource analysis. I engaged with southeastern utilities through regulatory proceedings, formal workgroups, informal consultations, and research-driven advocacy.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, conservation program design, ratemaking and cost recovery for utility efficiency programs, allocation of costs of service between rate classes and jurisdictions, design of retail rates, and performance-based ratemaking for electric utilities.

My professional qualifications are further summarized in Exhibit JDW-2.

Q. Have you testified previously before the Washington Utilities and Transportation Commission (the Commission)?

A. Yes. I testified concerning power costs on behalf of Commission Staff (Staff) in PacifiCorp's 2023 general rate case, Docket UE-230172, PacifiCorp's 2022 power cost adjustment mechanism annual report, Docket UE-230482 and Avista's 2024 general rate case, Dockets UE-20006 & UG-240007.

Q. Have you testified before other commissions?

A. Yes. I have testified or filed reports more than 60 times before utility regulators in ten U.S. states and Nova Scotia, and I have appeared numerous additional times before various regulatory and legislative bodies.

Q. What is the purpose of your testimony in this proceeding?

A. I am presenting my review of Puget Sound Energy's (PSE) power cost forecast for rate years 2025 and 2026, as presented in the testimony of Brennan D. Mueller in Exhibit BDM-1T, and the prudency of the Chelan Power Sales Agreement, as presented in the testimony of Zacarias C. Yanez in Exhibit ZCY-1CT.

Q. Have you prepared exhibits in support of your testimony?

A. Yes. I sponsor Exh. JDW-2 through Exh. JDW-23:

- Exh. JDW-2 CV John Wilson
- Exh. JDW-3 PSE's Response to Staff DR No. 117
- Exh. JDW-4 PSE's Response to Staff DR No. 118
- Exh. JDW-5C PSE's Response to Staff DR No. 214
- Exh. JDW-6 *In re Petition of Petition of Puget Sound Energy*, Docket UE-220974 et. al, Staff Open Meeting Memorandum (Feb. 2023)
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- Exh. JDW-23 PSE's Response to Staff DR No. 129

The information contained in these exhibits is correct to the best of my knowledge and belief.

II. RECOMMENDATIONS AND SUMMARY

Q. Please summarize your testimony.

A. My testimony reviews PSE's proposed annual power cost update process, its forecast of power costs for 2025 and 2026, and the prudency of the Chelan Power Sales Agreement (PSA). Overall, PSE's proposed power costs are reasonable, but I recommend certain modifications to the process, correction to the power cost forecast, and that the Chelan PSA should only be approved with the addition of a "guardrail" on costs. I also review PSE's proposed treatment of CCA carbon allowances.

Q. Is Staff supportive of PSE's proposed annual power cost update process?

A. Yes. PSE's proposed power cost update process is reasonable and Staff supports it. Note that Staff's support includes PSE's proposal to update its power cost forecast for calendar year 2025 in a compliance filing at the end of this rate case rather than in a filing on October 2, 2024.[1] However, Staff recommends that parties should have the option to request that prudency reviews for either new PPA resource acquisitions

[1] Mueller, Exh. BDM-1T at 42-49; and Exh. JDW-3 (PSE's Response to Staff DR No. 117).

or proposed changes to methods for calculating power costs be deferred to the next general rate case or annual Power Cost Only Rate Case (PCORC) filing, as discussed in Section III.

Q. Please summarize the actions you recommend the Commission take with regard to PSE's compliance strategy for the Climate Commitment Act (CCA).

A. PSE's current practice of including CCA allowance costs for only the portion of its emissions related to wholesale market sales may be inconsistent with the Department of Ecology's (Ecology) intention to implement the no-cost allowance provision of the CCA, as discussed in Section IV and summarized in Section IV.G. In both forecast power costs and in operations, the Commission should direct PSE to include CCA allowance costs in the dispatch of its thermal generation plants, whether to serve customer load or to sell electricity into the wholesale market. PSE should then offset the allowance costs for its retail customer load with no-cost allowances.

However, there is significant uncertainty regarding Ecology's intended policy regarding true-up of no-cost allowances. My testimony discusses how the Commission should manage that uncertainty given that PSE is currently dispatching its plants without including the price of carbon allowances.

I also recommend against approving PSE's proposal to continue deferral of CCA costs, and to instead include all CCA allowance-related costs in the rates approved for power costs in this general rate case (see Section IV.A). As discussed in Section IV.D, PSE's forecasted power costs should be increased by [redacted] million for emissions in calendar year 2025 and [redacted] million for emissions in calendar year 2026.

I also recommend that the Commission review the prudence of allowance costs in PSE's annual PCA proceeding. In addition to the annual prudency reviews, the Commission may reasonably determine that a final, retrospective prudence determination covering each four-year compliance window is appropriate. Variable environmental costs are commonly reviewed in power cost proceedings, and there is no important difference between the carbon allowances and other environmental costs that are subject to review in such proceedings. In Section IV.E, I describe the tradeoffs between an annual prudence review and an alternative prudence review process in which all or some portion of CCA allowance transaction costs are deferred to the end of the four-year compliance period.

Q. Please summarize your recommended changes to 2025 and 2026 forecast power costs.

A. Because two of my recommended changes to PSE's forecast power costs require updates to PSE's model, I am not able to provide a recommended adjustment at this time. After considering other parties' testimony, Staff will file a data request for an updated power cost forecast consistent with adjustments that are supported by Staff.

The largest impact to 2025 and 2026 forecast power costs is likely to result from including CCA allowance costs in the modeled dispatch of PSE's thermal generation plants, as recommended above.

The Commission should require PSE to update its production cost model to correct its 2025 power cost forecast to use a marginal dispatch cost for Colstrip, including CCA compliance cost in the dispatch cost, as discussed in Section V.

I also have two recommended adjustments to PSE's forecast power costs that do not require updates to PSE's model.

First, while the Commission should accept PSE's proposed modeling methods for Clay Basin Storage power costs, it should do so on an interim basis until it is feasible to use a normalized historical cost basis.

Second, the Commission should direct PSE to include $372,000 in additional Western Energy Imbalance Market (WEIM) power costs in its 2025 and 2026 forecasts, reflecting the net effect of the flexible ramping and the various fees and other payments described in Section VII.

Q. Please summarize your recommended conditions on a prudency decision for the Chelan PSA.

A. The Commission should determine that the Chelan PSA is imprudent, or alternatively, subject to a "guardrail" on allowable costs. The "guardrail" should be a requirement that PSE must file a special request to re-evaluate the prudency of the Chelan PSA if production costs exceed the forecast amount by $50 million.[2]

[2] The forecast can be found at: Yanez, Exh. ZCY-3HC at 55.

III. POWER COST REVIEW PROCESS ISSUES

Q. Is Staff supportive of PSE's proposed annual power cost update process?

A. Yes. PSE's proposed power cost update process is reasonable and Staff generally supports it. Note that Staff's support includes PSE's proposal to update its power cost forecast for calendar year 2025 in a compliance filing at the end of this rate case rather than in a filing on October 2, 2024.[3] Staff also recommends that PSE be required to include in its PCA filings the offsetting benefits of changes, any Energy Imbalance Market (EIM) revenues, rate credit dividend distributions, and any other new or additional revenues.[4]

Q. Please summarize PSE's proposal for reviewing the prudence of new resources in PSE's annual power cost update.

A. PSE proposes to use the annual PCA compliance filing to seek prudence determinations for power purchase agreements (PPAs). PSE proposes that power costs for PPA resources can be included in rates, as forecast, before a prudence determination is sought in the annual PCA compliance filing in order to improve the accuracy of the baseline power cost rate.

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[3] Mueller, Exh. BDM-1T at 42-49; and Exh. JDW-3 (PSE's Response to Staff DR No. 117).
[4] *See In re Petition of Puget Sound Energy*, Docket UE-230805, Order 01, 5 ¶16 (Dec. 22, 2023) (noting staff's concerns regarding PSE's inclusion of the costs of Demand Response (DR) Contracts without including the benefits and, based on review of filings and testimony provided at the open meeting, allowing PSE to include the DR contract costs as the value of DR carries an offsetting benefit which will accrue to the benefit of customers).

PSE recommends that the Commission determine the prudence of new PPA resources at the earliest available opportunity so that PSE may minimize the time that new resource costs spend in deferral, better aligning the timing of cost recovery with the benefits of those resources.[5]

Q. Does Staff support PSE's proposal for reviewing the prudence of new resources in PSE's annual power cost update?

A. Generally, yes. However, Staff recommends that parties should have the option to request that prudency reviews for either new PPA resource acquisitions or proposed changes to methods for calculating power costs be deferred to the next general rate case or PCA filing. For any PPA resource acquisitions with atypically complex terms that may require more extensive discovery and analysis or any proposed changes to methods, parties could file initial data requests in the annual PCA compliance filing. Deferring prudency would provide those parties with time to analyze the responses prior to the next general rate case, when additional data requests could be filed, without delaying a decision in the annual PCA compliance filing.

For example, PSE initially requested a prudence determination as part of its 2022 PCA compliance filing in Docket UE-230313. In response to concerns I raised regarding customer exposure to costs under the Chelan PSA contract, PSE did not

[5] Exh. JDW- 4 (PSE's Response to Staff DR No. 118, part (a)).

object to Staff's request for deferral until this general rate case.[6] The Commission found that it was reasonable and appropriate to allow more time before it determined the prudency of the resource.[7] The Chelan PSA contract is a good example of a PPA resource that includes nonstandard terms and conditions that require further review, and it also happens that PSE requested a prudence determination about nine years before relevant costs would be placed in rates. It was an easy decision to defer the issue in 2023, but Staff suggests that even if PSE had negotiated the same contract for power costs beginning in 2023, it probably would have made the same recommendation to defer the issue until now. The delay provided Staff with time to more carefully review the issue and, importantly, file an additional round of data requests to further clarify the issue, as discussed in Section VIII.

In contrast, another PPA resource prudency issue raised in the same proceeding related to the PowerEx Winter PPAs. These PPAs were already in effect and of a relatively short duration. Compared to the Chelan PSA, the PowerEx Winter PPAs had relatively straightforward terms and conditions, presenting no technically unusual issues for analysis. I identified three issues: the short-term capacity need, the evaluation of alternatives, and consistency with PSE hedging policies. I provided an opinion to the Commission describing the evidence available on the PowerEx Winter

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[6] *See Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-230313, Order 01, 4, ¶ 19 (Nov. 22, 2023).
[7] *Id*. at 5, ¶ 22.

PPAs, and the Commission found the evidence sufficient to find the contracts prudent.[8]

PSE does not appear to object to Staff's proposal to allow for deferrals, noting that it "would determine its support [for] or objection" to such deferrals "on a case-by-case basis."[9] Staff agrees that in determining whether a deferral is warranted, parties and the Commission should balance the interest in minimizing the time that new resource costs could spend in deferral with the significance and complexity of the PPA resource proposal.

IV. IMPACT OF CARBON EMISSIONS POLICY ON POWER COSTS

A. Relationship of CCA Allowances to Power Costs

Q. Has PSE included Climate Commitment Act (CCA) allowance costs in its forecast power costs?

A. No. According to PSE, "PSE's power cost forecast does not include any direct costs of allowance purchases that may be required to comply with the CCA. PSE will defer any such costs pursuant to the accounting petition approved in Docket UE-220974."[10]

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[8]. *See Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-230313, Order 01, 4-5, ¶ 17-19, 21 (Nov. 22, 2023).

[9] Exh. JDW- 4 (PSE's Response to Staff DR No. 118, part (b)).

[10] Mueller, Exh. BDM-16 at 26:7-10. See also, Exh. JDW-5 (PSE's Response to Staff DR No. 214, part (a)).

Q. Does Staff agree that the accounting petition approved in Docket UE-220974 should apply to this general rate case?

A. No. Staff's support for deferral of CCA costs in UE-220974 was due to the fact that CCA costs were not included in rates. Staff stated,

> Commission staff (Staff) finds that the basis for these deferred accounting petitions is reasonable because the new legal requirements in the CCA are an extraordinary circumstance and the costs have a material impact. Further, costs associated with the CCA could not have been reasonably included in rates in any of their last general rate cases. Staff finds that deferred accounting treatment is reasonable in these petitions because CCA costs are not currently included in rates, and these costs are likely to be significant.[11]

Instead of deferring these costs, PSE has the opportunity to include CCA allowance costs in this general rate case.

Q. Should PSE continue to use deferral accounting for CCA compliance costs?

A. No. As PSE has noted, it is important to "ensure customers are being charged for the costs of the CCA associated with the power they use in the period closest as possible to when the usage occurs."[12] Including CCA costs in forecast net power costs is the method that associates them with power usage.

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[11] Exh. JDW-6 (*In re Petition of Petition of Puget Sound Energy*, Docket UE-220974, Staff Open Meeting Memorandum, 3 (Feb. 23, 2023)

[12] *In re Petition of Puget Sound Energy*, Docket UE-220974 and UG-220975, Petition of Puget Sound Energy, 5, ¶ 17 (Dec. 29, 2022).

Q. Are CCA allowance costs likely to be significant?

A. Yes. PSE has stated that, "Utilizing conservative estimates, the cost of allowances needed for CCA compliance by the electric utility for purposes of this petition could approach $200 million annually."[13] However, PSE acknowledges that the $200 million estimate "does not include any offsetting benefit of no-cost allowances."[14]

Q. Does PSE assume that it will receive enough no-cost allowances to meet its obligations for emissions related to its retail load?

A. Yes. PSE states that, "PSE will not incur allowance purchase costs for emissions associated with serving retail demand."[15] PSE expects that Ecology will use its "true-up" process to ensure that PSE is allocated approximately the same amount of no-cost allowances as required to meet its CCA obligations associated with retail load.[16]

Q. Does PSE have a reasonable basis for its understanding of how the no-cost allowances should be granted?

A. Yes. PSE states that its position is supported by a July 15, 2024 order issued by the U.S. District Court for the Western District of Washington in the case *PacifiCorp v.*

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[13] *Id*. at 5, ¶ 16.
[14] *Id*. at 5, n.7.
[15] Mueller, Exh. BDM-1T at 29:16-18. Also, "PSE expects to receive no-cost allowances for emissions from PSE generation and market purchases used to serve its retail electric demand but not for emissions associated with wholesale sales." Exh. JDW-7 (PSE's Response to Staff DR No. 213, part (a)).
[16] Exh. JDW-7 (PSE's Response to Staff DR No. 213, part (b)).

Watson, which is Attachment A to Exhibit JDW-7 (Staff DR No. 213). The federal court decision emphasizes the foundational role of the Clean Energy Transformation Act ("CETA"), stating:

> Rather than subject those utilities—including PacifiCorp—to overlapping sets of requirements, and potentially subject Washington's electric customers to unnecessary increased costs beyond what they already face under CETA, the legislature chose to issue no-cost CCA allowances to electric utilities to the extent that their emissions were already covered by CETA's decarbonization schedule.[17]

This and other language in the federal court's decision can be read to support PSE's expectations about how Ecology should run the "true-up" process.

Q. Does the federal court decision clearly resolve the question of whether Ecology will allocate the amount of no-cost allowances that utilities require to meet CCA obligations if dispatch fails to consider the cost of allowances?

A. No, but it raises questions that Ecology should address. There are two reasons that the federal court decision does not appear to me to address the key question of whether utilities should include an emission allowance cost adder in dispatch decisions.

First, the focus of the federal court's decision is not on the dispatch of carbon-emitting units to serve retail load in Washington, but rather on PacifiCorp's belief that it should either be issued no-cost allowances for electricity generated for

[17] Exh. JDW-7 (PSE's Response to Staff DR No. 213, Attachment A: *PacifiCorp* Order at 16:5-9).

export or that it should be exempted from CCA compliance obligations.[18] Thus the court was not asked and its decision does not answer whether it would be reasonable for Ecology to issue allowances based on the assumption that utilities are considering the cost of allowances in dispatch.

Second, the decision is more focused on Ecology's rules governing the initial allocation of no-cost allowances than the true-up process, which is not directly mentioned in the decision. ("In practice, this means that the CCA provides electric utilities with no-cost allowances for the portion of their emissions that they forecast will be used to generate electricity sold to retail customers within Washington state."[19]) The closest the decision comes to PSE's position is its statement that "electric utilities serving Washington customers don't need [the CCA's] market pressure [to reduce emissions] because CETA already requires them to decarbonize, and on a faster schedule."[20] This statement describes a rationale that Ecology may or may not have adopted, as discussed below.

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[18] Exh. JDW-7 (PSE's Response to Staff DR No. 213, Attachment A: *PacifiCorp* Order at 2:14-17.)

[19] Exh. JDW-7 (PSE's Response to Staff DR No. 213, Attachment A: *PacifiCorp* Order at 6:17-19).

[20] Exh. JDW-7 (PSE's Response to Staff DR No. 213, Attachment A: *PacifiCorp* Order at 16:23-17:2).

Q. Is PSE's understanding of how the Department of Ecology intends to run its CCA program correct?

A. It is unclear whether Ecology intends for the "true-up" process to be a one-for-one true-up of emissions with no-cost allowances. In an interview earlier this year, Ecology staff suggested that PSE's understanding of the program is incorrect. However, I later learned of a written comment by Ecology from 2022 that supports PSE's understanding.[21]

Q. Please summarize your understanding of Ecology's position as expressed to you in an interview.

A. Ecology staff explained during an interview that even though the Department will make adjustments to future year allowances based on information about the utility's actual emissions relative to allocated allowances, that true-up will not be one-for-one.

Ecology staff have not begun drafting these methods. Ecology staff explained that future allocation decisions will be based on concepts such as the magnitude of the difference between actual and allocated emissions in the historical year and reasons for the difference (e.g., whether it is a high, normal, or low hydro year).

Furthermore, it is my understanding that the Ecology intends for the no-cost allowances allocated to Washington utilities to be exposed to markets, and that the

[21] See discussion of Ecology's Publication 22-02-046, Concise Explanatory Statement Chapter 173-446 WAC Climate Commitment Act Program, at 18-19 below.

utilities have an opportunity for financial gains or losses that would be either passed through to their customers or reflected on their balance sheets. Ecology's process allows for a significant lag between the allocation of no-cost allowances, the emissions period (year), and the two compliance account dates. Utilities are authorized to buy and sell allowances based on their interests and in bilateral or any structured market but may only sell no-cost allowances through Ecology-administered auctions. Thus, there is a significant period of time in which PSE may hold allowances because of the limited auction opportunities.

Q. Does Ecology's intention to effectively condition the magnitude of the "true-up" based on reasons for the difference between forecast and actual emissions raise any concerns?

A. Yes. It seems highly problematic for Ecology to conduct what amounts to a prudency review of the dispatch decisions of Washington utilities, including PSE. It appears to me that the Department of Ecology lacks the requisite staff and process to conduct such a review. The fact that Ecology has not developed even a draft of the methods it could use in such a review is particularly troubling given that it places immediate cost risk on PSE and its customers.

Q. Have Ecology staff expressed the opinion that the CCA is likely to be a material driver of decarbonization in the electric utility sector?

A. Yes, in my interview with Ecology staff, I understood that Ecology intends to design the carbon allowance program to ensure active allowance trading by Washington's electric utilities. Ecology staff appear to view the active participation of the electric utilities in Washington's carbon allowance market as necessary for it to function smoothly. Ecology views electric utility participation in the market as providing necessary liquidity for other market participants. Ecology intends that further rules and guidance will result in electric utilities buying and selling a significant number of allowances.

Based on these statements, I understood that Ecology views CETA as the primary driver of capacity needs to meet clean energy targets but that Ecology staff also have an expectation that CCA allowance costs will be included in system dispatch.

Q. Please summarize the position expressed by Ecology in 2022.

A. Subsequent to my interview with Ecology staff, I reviewed Ecology's Publication 22-02-046, Concise Explanatory Statement Chapter 173-446 WAC Climate Commitment Act Program. In its response to comments, Ecology states,

> Ecology believes that in the short term the importance of not creating a disincentive to the creation or submission of an accurate emissions forecast outweighs the valid ideal suggested here of creating an economic incentive to reduce more than is required by CETA.[22]

This statement appears at odds with the position expressed by Ecology staff in the interview I conducted earlier this year. It is unclear to me whether Ecology's position has evolved since 2022 or if there was a misunderstanding during my interview with Ecology staff.

I will also note that neither Ecology's written comments in 2022, nor the interview I conducted earlier this year were informed by the federal court decision issued on July 15, 2024. For that matter, PSE appears to have formed its opinion well before the court decision it cites as justifying its position.

B. Reasonableness of PSE's Allowance Tracking

Q. Is PSE tracking its allowances consistent with the CCA?

A. PSE appears to be tracking its CCA allowances and emissions for both its retail load and its wholesale sales.[23] Thus, its tracking system appears to have the capability to support compliance with CCA allowance requirements. However, it is not clear whether PSE anticipates the possibility that its no-cost allowances may be used both

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[22] Exh. JDW-7 (PSE's Response to Staff DR No. 213, Attachment B at 231) (Concise Explanatory Statement *available at* https://apps.ecology.wa.gov/publications/documents/2202046.pdf).

[23] Exh. JDW-8 (PSE's Response to Staff DR No. 22(C), Confidential Attachment A); Exh. JDW-5 (PSE's Response to Staff DR No. 214, part (a) and Attachment A).

for emissions associated with serving retail load and for emissions associated with wholesale sales whose revenues benefit its retail customers.

Q. Do Ecology's rules allow PSE to use no-cost allowances for emissions associated with wholesale sales?

A. Yes. Even though Ecology's <u>allocation</u> of no-cost allowances is based on Washington retail load, that does not restrict PSE or other utilities from <u>using</u> no-cost allowances for other purposes or even to sell them at auction. Thus, PSE is not prohibited from using no-cost allowances to cover emissions associated with wholesale load. Ecology's intent is to allocate sufficient no-cost allowances to avoid a cost burden on retail load, and for those allowances to be used prudently by PSE in a manner that benefits its retail customers. PSE may find opportunities to cost-effectively reduce emissions associated with serving retail load, thus freeing up allowances to reduce the cost of selling power on the wholesale market, with the net revenues accruing to the benefit of its retail customers through net power costs.

C. PSE's CCA Allowance Forecast

Q. Does PSE have sufficient no-cost allowances to comply with the CCA?

A. Yes, PSE currently forecasts that its emissions will be less than the no-cost allowances it has been allocated to comply with the CCA.

As a fundamental point, PSE's allocation of no-cost allowances could exceed or fall short of actual emissions due to external factors, such as a high or low hydro year. This has been anticipated by all involved.

It appears that the Department of Ecology's 2023 allocations (based on PSE's July 2023 forecast) allocate more no-cost allowances than PSE forecasts will be required as of February 2024. Ecology allocated PSE 5,561,608 tons of carbon allowances for 2025, but PSE now forecasts 5,154,837 tons of carbon emissions associated with its retail load; the difference for 2026 is much smaller.[24] While historical variation is to be expected, Ecology's allocation of no-cost allowances exceeds PSE's emissions forecast for 2025 by about 7 percent.

The main reason that the Department of Ecology has issued more no-cost allowances to PSE than will be required for emissions associated with its retail load is that PSE's forecast of renewable and non-emitting resources has increased, as shown in the same materials as referenced above.

Q. Should PSE address the decrease in emissions allowance forecast?

A. Yes. The Commission's Order 01 in Docket UE-220797 requires that "the Company must notify the Commission if there are any substantive changes, as that term may be

[24] Exh. JDW-9 (PSE's Response to Staff DR No. 216, Attach A(C)).

defined by the Commission in a subsequent proceeding."[25] I am not aware that the Commission has defined substantive change at this time.

In my opinion, a 7 percent change in its emissions forecast is a substantive change and merits a notification to the Commission. That said, due to the direction and nature of the change, I do not recommend that the Commission require PSE to also file an update to its supply and demand forecast pursuant to RCW 70A.65.120 in advance of its next regular filing deadline.

However, it should be noted that this creates a significant opportunity for PSE to either use them to meet compliance obligations associated with its wholesale customers or sell them, either of which could create value for customers. I will discuss this further in Section IV.F of my testimony below.

D. PSE's CCA Compliance Forecast

Q. Is PSE including an emissions allowance cost adder in dispatch decisions for natural gas and coal generation resources when serving retail electric demand?

A. No. PSE's position is as follows:

> PSE must purchase allowances for any emissions associated with electricity not sold to retail customers (e.g., electricity sold in the wholesale market or delivered to other utilities). In other words, the CCA provides electric utilities with no-cost allowances for the portion of their emissions that will generate electricity sold to retail customers within Washington State but not for other emissions …

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[25] *In re Petition of Puget Sound Energy*, Docket UE-220797, Order 01, 3, ¶ 10 (Jan. 24, 2023).

> To minimize total electric supply costs to retail customers, PSE has considered only those costs that retail electricity customers would actually incur in making resource dispatch decisions. Accordingly, PSE does not include an emissions allowance cost adder in making dispatch decisions to serve retail electric demand but does include an emissions allowance cost adder in making dispatch decisions whether to make wholesale electric sales.[26]

Q. Has PSE placed too much confidence in the "true-up" process in its compliance forecast?

A. That depends on whether the position expressed by Ecology staff in the interview I conducted is accurate, or whether the position expressed by Ecology in 2022 reflects its position.

In either case, it is reasonable to anticipate that Ecology will make adjustments to reduce or eliminate PSE's current "deficit" position. According to WAC 173-446-230(j):

> The schedule of allowances will be updated by October 1st of each calendar year as necessary to accommodate the requirements of the adjustment processes described in this subsection. In addition, if a revised forecast of supply or demand is approved in a form and manner consistent with the requirements of this section by July 30th of the same calendar year, then ecology may adjust the schedule of allowances to reflect the revised information provided by an updated forecast.

Thus, PSE's revised load forecast will be taken into account during the October 2024 update.

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[26] Exh. JDW-7 (PSE's Response to Staff DR No. 213, part (a)).

If Ecology were planning to operate the “true-up” process as a one-for-one true-up of emissions with no-cost allowances, then it would be reasonable (although perhaps not ideal) for PSE to exclude allowance costs from its least-cost dispatch operation. This approach is consistent with the view expressed by Ecology in 2022.

However, including estimated allowance costs in dispatch decisions is most consistent with the views expressed by Ecology in the interview I conducted earlier this year. As PSE acknowledges,

> If Ecology were not to allocate no-cost allowances for some or all of the emissions associated with serving retail demand, then PSE would likely include estimated allowance costs in dispatch decisions. As described in the Prefiled Direct Testimony of Brennan D. Mueller, Exh. BDM-1T, and in subpart a. above, resource dispatch decisions should reflect costs that retail electric customers will actually incur upon dispatch of a resource.[27]

Based on Ecology’s goals as expressed in the interview, it seems likely that Ecology would increase PSE’s no-cost allowances, but it is uncertain whether it would issue enough additional allowances to fully “true up” PSE’s current emissions forecast. As noted above, Ecology anticipates that future allocation decisions will be based on concepts such as the reasons for the difference between forecast and actual emissions (e.g., whether it is a high, normal, or low hydro year), as well as the expectation that allowance costs will be a factor in dispatch, as discussed further below.

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[27] Exh. JDW-7 (PSE’s Response to Staff DR No. 213, part (d)).

Q. So is there a clear-cut case for prudent dispatch by PSE?

A. No. Given the inconsistency in Ecology's positions, it is important to obtain clarification from Ecology on this point. Proceeding on the assumption that Ecology will fully true-up allowances for PSE puts PSE at risk of having to purchase additional allowances in the future at potentially suboptimal prices. And proceeding on the opposite assumption requires PSE to dispatch based on allowance prices and risk substantial over-compliance with the CCA and CETA, imposing unnecessary costs on its retail customers. While PSE is confident that it has made the correct choice, I cannot advise the Commission that Ecology's position is clear or that the recent federal court decision constrains Ecology from expecting allowance costs to be considered in dispatch decisions.

Q. Has PSE included the cost of CCA allowances for wholesale market sales in its power cost forecast?

A. No. PSE states that while it has included the "forecasted benefit of wholesale market sales," it has not included the forecasted allowance purchase costs that will result from the emitting generation. PSE calculated its margin from wholesale market sales as the revenue from sales less the fuel costs, but did not include the expected cost of allowances.[28]

[28] Exh. JDW-10 (PSE's Response to Staff DR No. 215, part (a) and Attachment A).

As discussed in Section IV.A above, Staff opposes PSE's position that the Company is authorized to defer such costs pursuant to the accounting petition approved in Docket UE-220974. Instead, Staff recommends that such costs be included in rates in order to ensure that the net power costs include all associated costs in the period closest as possible to when the costs are incurred.

Accordingly, PSE's forecasted power costs should be increased by [redacted] million for emissions in calendar year 2025 and [redacted] million for emissions in calendar year 2026.[29]

E. Prudency Review of CCA Compliance Costs

Q. Is a prudence review for CCA costs something that the Commission should anticipate?

A. Yes, for two reasons. First, as discussed above, PSE is currently, and proposes to continue, excluding carbon allowance costs from dispatch of generation to serve its retail load. It has the opportunity to sell those allowances, so using them during periods when the unit would not dispatch if the costs were included results in excess costs for Washington customers. Second, the potential magnitude of CCA costs that could appear in a future power cost true-up is very large.

[29] Exh. JDW-10 (PSE's Response to Staff DR No. 215, part (a)).

Q. When should the Commission review the prudence of PSE's CCA allowance use and transactions?

A. In my opinion, the Commission will find it most efficient to review the prudence of PSE's CCA allowance use and transactions in annual power cost review proceedings. PSE's decisions to buy, sell, hold, or use allowances are intertwined with its unit dispatch and power purchase decisions. The CCA requires PSE to include the relevant carbon allowance price and emissions allowance obligation in all unit dispatch and power purchase decisions. (I will explain this requirement below.) Accordingly, in future power cost proceedings, PSE should demonstrate that throughout the year it has identified an appropriate carbon allowance price and that its unit dispatch and power purchase decisions were prudent, which should include a showing that those decisions were consistent with its current estimate of the carbon allowance price.

In future power cost proceedings, PSE will also need to demonstrate that its purchase or sale of allowances is prudent. This showing will rely on PSE's forecast of carbon allowance prices since it is not required to demonstrate sufficient carbon allowances to meet its obligations until the end of the four-year compliance period. Thus, it would be reasonable for the Commission to review the prudence of PSE's carbon allowance transactions (or lack thereof) in either the annual power costs proceeding or a post-CCA compliance period proceeding, or some combination of the two.

Considering the analysis above suggests five factors that the Commission should weigh when determining how to review the prudence of CCA use and transactions:

- Administrative simplicity;
- Necessity of reviewing the allowance price and other factors that should be considered in unit dispatch and power purchase decisions during the annual power cost proceeding;
- Consideration that decisions to transact (or not transact) in the carbon market and carbon auctions depends on the reasonableness of the carbon price estimate and carbon price forecast as it existed during the year;
- Consideration that it is preferable to account for the costs (or benefits) resulting from decisions to transact (or not transact) in the year in which those transactions affect power costs (using mark-to-market valuations for unused allowances, as discussed above); and
- Consideration that it will be easier to review the reasonableness of a utility's carbon price forecasting method after that method is exposed to a variety of real-world circumstances, which may take several years to manifest.

The first three factors clearly weigh in favor of reviewing all carbon allowance topics during the annual power cost proceeding. The fourth factor is more ambiguous, as PSE may buy or sell allowances in 2024 that are (or could have been) applied to its 2025 obligations, for example. Finally, the fifth factor weighs in favor of reviewing carbon allowance transactions at the end of the four-year compliance period.

Notwithstanding the fourth and fifth factors, in my opinion, the Commission will find it most efficient to review the prudence of PSE's CCA allowance use and transactions in annual power cost review proceedings. This approach is most consistent with how the prudence of expenditures that carry over from year to year, such as fuel supply inventories, are reviewed. An electric utility's decisions to buy, sell, hold, or use allowances are intertwined with its unit dispatch and power purchase decisions in a manner similar to its decisions to purchase fuel or enter into power supply transactions that may span across PSA reporting years.

Q. Do you support a prudency review after the four-year compliance period?

A. Yes, such an approach is reasonable even though it is not my first recommendation. While an additional prudency review after the four-year compliance period would need to be clearly defined as to its scope, the Commission may reasonably determine that in addition to annual prudency examinations, a final, retrospective prudency examination covering each four-year compliance window would be appropriate.

This alternative approach is suggested in the Commission's Order 01 in Docket UE-240141, which states:

> While we agree with Staff that the Schedule 700 charge and credit rates that Cascade proposes in this docket should be authorized, we make no finding regarding the prudence of these charges and credits at this time. Instead, we authorize the proposed rates on a provisional basis, subject to later review and possible refund. The prudency of the rates will be examined in a dedicated proceeding at a later date when CCA

> compliance costs and revenues over the entire four-year compliance period may be reviewed.[30]

Application of the precedent in the Cascade proceeding to an electric utility is complicated by the fact that an electric utility's decisions to buy, sell, hold, or use allowances are intertwined with its unit dispatch and power purchase decisions.

Q. What would be the scope of a CCA allowance prudency review at the end of the four-year compliance period?

A. The scope of a prudency review at the end of the four-year compliance period would need to be clearly defined to avoid duplicative review. The Commission could review the prudence of PSE's CCA allowance use in annual power cost review proceedings but defer review of its net allowance balances to the end of the four-year compliance period. Specifically, in the annual power cost review proceeding, the Commission could review the cost of allowances that are associated with emissions throughout the year, whether the net cost of those allowances was reasonable, and whether those costs were appropriately reflected in unit dispatch or power procurement decisions.

Then, in its final prudence review of the four-year compliance period, the Commission could review PSE's overall allowance-management decisions, including the timing of purchases or sales, decisions to carry a balance or a deficit,

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[30] *In re Petition of Cascade Natural Gas Corporation*, Docket UG-240141, Order 01, 3, ¶ 10 (May 23, 2024).

and the overall net cost of the allowances. Any credit or recovery resulting from the final prudence review could be applied in the next rate case or annual power cost review proceeding.

However the Commission determines to conduct its prudence review, it should find that PSE is obligated to manage its CCA allowances and compliance obligations in a prudent manner. The net cost or benefit of PSE's allowance transactions will have an impact on power costs.

Q. What technical issues should the Commission consider in determining how it will review CCA-related costs for prudency?

A. A key complication is that Ecology's compliance requirements do not occur at the end of each calendar year but require electric utilities to have 30 percent of the allowances required at that time. The remaining 70 percent of allowances are not due until the end of the four-year compliance period.

Under the approach I recommend – full prudency review in each annual power cost filing – PSE should include the actual net cost of CCA allowance transactions in its annual power cost filing *and*, for any surplus or deficit in allowance transactions, PSE would determine an *additional* net cost on a mark-to-market basis. For example, if PSE only holds 30 percent of the required allowances at the end of a year, it would need to add the cost of the remaining 70 percent of required allowances on a mark-to-market price basis.

To implement this option, PSE would need to develop methods for pricing its unsold (or unpurchased) allowances and then carry forward the resulting net value to subsequent years. While requiring somewhat complex calculations, full review of CCA-related costs each year has the advantages of providing the Commission with a clear and comprehensive opportunity to review the prudence of PSE's transactions and pricing decisions concurrent with the intertwined plant dispatch and power purchase decisions.

If, on the other hand, the Commission decides to conduct a final prudence review of the four-year compliance period, then PSE could simply record its actual net transaction costs for the year and defer the valuation of any allowance surplus or deficit to the future. This option would be more easily administered and eliminate the need to develop a mark-to-market pricing method. However, separating the review of allowance surpluses or deficits to the end of the four-year compliance creates a challenge to clearly defining the scope of the annual power cost review and the four-year CCA compliance cost review.

While a final prudence review of the four-year compliance period is a reasonable option, it is not necessary. If the Commission reviews prudence on a calendar year basis, at the end of a calendar year in which the four-year compliance period ends, PSE and other electric utilities would be expected to fully resolve the value of allowances carried forward from prior years and the net allowance cost for the final calendar year of the compliance period. Thus, if the Commission uses a calendar year review process for CCA-related costs, the final year of the compliance period will require consideration of whether the balances were reconciled properly and result in fully accounting for compliance, but otherwise would not differ from the review process conducted in the prior three years.

F. Cost Risk Associated with PSE's CCA Compliance Practices

Q. What is the potential magnitude of CCA costs for PSE?

A. PSE has not estimated CCA costs, other than the $200 million estimate mentioned above, which excluded consideration of no-cost allowances. However, considering the increased 2025 forecast for emissions associated with retail load, priced at PSE's forecast allowance cost per MWh of gas generation, PSE's 2025 power costs could increase by [redacted] million, or about [redacted] percent of PSE's proposed 2025 power costs.

Unless included in 2025 rates, this increase in power costs would be reflected in the 2025 power cost proceeding, assuming it materializes. This forecast adjustment only considers the risk of higher allowance requirements than granted by Ecology. It does not consider the risks associated with trading in allowances. If PSE has an opportunity to purchase low-cost allowances, passes it up, and then later determines that it requires allowances, that will have an impact on power costs.

It is very likely that PSE will be an active participant in Washington's allowance market. Thus, it is reasonable to view CCA cost risk as being substantially more than the amount estimated above.

Q. Are PSE's dispatch practices optimally designed to manage emissions?

A. No, even if its dispatch practices are consistent with the CCA, PSE's decision to consider CCA allowance prices only for dispatch to serve wholesale load could result in peculiar if not uneconomic dispatch. For example, it is illogical for PSE to apply a carbon adder to dispatch of a natural gas combined cycle unit, but not to apply a carbon adder to dispatch of Colstrip units 3 and 4.[31]

Another problem with PSE's dispatch practices is that in order to accommodate this distinction between generation that serves retail load and generation that serves wholesale load, PSE:

> … relies on month-ahead forecasts of resource availability and retail demand to estimate which portion of its total electric supply will be used to supply wholesale sales and then includes a CCA allowance cost adder in the dispatch decision for that portion of the electric supply portfolio.[32]

PSE's "sub-optimal" approach, relying on forecasts of "load, variable resource output, and market prices," is entirely unnecessary.[33] This process could be eliminated by simply including allowance prices in dispatch decisions for all thermal resources.

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[31] See stacking methodology in Exh. JDW-5 (PSE's Response to Staff DR No. 214, part (b)).
[32] Mueller, Exh. BDM-1T at 30:12-15.
[33] *Id*. at 30:8-11.

G. Recommendations for Commission Action on CCA Costs

Q. How do you recommend the Commission address the uncertainty regarding Ecology's position on whether electric utilities should consider CCA allowance costs in dispatch?

A. If the Commission is unable to obtain certainty regarding how Ecology will treat the true up process for no cost allowances by the end of this rate case, then the Commission should proceed under the assumption that Ecology will not guarantee a true up to actuals. This is for two reasons: First, my interview with Ecology Staff is the latest information we have from the agency on this topic and is consistent with the long-term goal expressed by Ecology in 2022. Therefore, the more recent information is more likely to reflect the agency's ultimate decision. Second, there is a greater risk to assuming that the mechanism will guarantee a true up to actuals than assuming the opposite.

Q. Why would assuming that Ecology will provide a true up of allowances to actual emissions present the greater risk?

A. Consider two scenarios in which the wrong assumption is made. (Obviously, getting the assumption correct is the ideal outcome.)

In the first scenario, it is wrongly assumed that Ecology's true-up mechanism assumes that PSE will respond to the economic incentive created by the value of CCA allowances, and that Ecology will ultimately allocate only enough allowances to PSE to cover an economically-efficient dispatch of its plants considering allowance prices. In this scenario, PSE considers CCA costs in dispatch and has lowered emissions by changing dispatch and power purchases. The resulting power costs would be higher than they would have been without considering CCA costs in dispatch.

However, in this scenario, Ecology's policy is to provide allowances without assuming that utilities would adjust dispatch, so PSE could be provided with more no-cost allowances than it needed. PSE would be able to sell those allowances or use them to comply with obligations associated with emissions associated with wholesale market sales, to the benefit of its retail customers. Thus, a mistake in this direction is not as costly as it first seems, although it may result in substantial costs.

In the second scenario, it is wrongly assumed that Ecology's true-up mechanism will allow a true-up to actuals. This is the scenario that considers the risk of approving PSE's proposal. If this scenario occurs, PSE would need to purchase allowances to cover the difference between the no-cost allowances provided and the actual emissions over the 4-year compliance period, assuming that the Company's emissions are above the 4-year compliance obligation.[34] Had it considered CCA compliance in dispatch, it would have been able to choose the more cost-efficient option between switching resources it dispatches and the (estimated) cost of obtaining additional CCA allowances. But without including the CCA costs in

[34] If the emissions are below the company's compliance obligation, then like in Scenario 1 the Company can receive value for the additional allowances it was allocated.

dispatch, the Company resigns itself to paying the entire difference between forecasted and actual emissions through allowances.

Because the first scenario has the potential to result in little or no additional cost, Staff believes the second scenario is the riskier option. It is also worth noting that it currently seems more likely that PSE's emissions will be above its no-cost allowance allocation, which makes the first scenario more likely to occur at this point. Therefore, in the face of uncertainty, requiring PSE to consider CCA costs in dispatch is the safer option.

Q. Is it possible that even if the first scenario occurs, costs passed through to customers could be cost-efficient?

A. Yes, considering the basic economics, even if PSE and other Washington utilities are not *required* to include the cost of CCA allowances in their dispatch decisions, it may be cost-efficient to do so. If PSE can sell a carbon allowance for $50 per ton, and it costs PSE $49 per ton to reduce its emissions, then the net benefit to PSE's customers is $1 per ton.

From a strict economics point of view, the quantity of no-cost carbon allowances provided by Ecology to PSE should be irrelevant to PSE's dispatch decisions. Those dispatch decisions can create value in the form of carbon allowance revenue just as surely as they can also create value in the form of market power revenues. However, this "strict economics" point of view does not consider risks associated with the lack of foresight of carbon allowance supply, demand and prices.

Q. If Ecology's position is that the CCA should not currently be designed to create an economic incentive to reduce emissions more than is required by CETA, what is your recommendation?

A. If the Commission determines that is Ecology's position, then it would be reasonable for the Commission to accept PSE's forecast of CCA-related costs for the immediate future. However, the Commission should encourage PSE to evaluate whether it can develop a dispatch method that does not rely on month-ahead forecasts of its retail and wholesale sales to determine its monthly CCA allowance adder.

However, considering the economic argument I presented above, the Commission should require PSE to evaluate the economics of including carbon allowance costs in its dispatch, considering both a "perfect-foresight" case as is usually considered in power cost forecasts and a risk-based analysis that considers the real-world uncertainty that occurs when future carbon allowance prices and power dispatch needs are uncertain.

Q. If Ecology's position is that CCA costs should be considered in dispatch, what is your recommendation?

A. If the Commission determines that is Ecology's position, then it would be reasonable for the Commission to direct PSE to include CCA allowance costs in the dispatch of its thermal generation plants, whether to serve customer load or to sell electricity into the wholesale market. PSE should then offset the allowance costs for its retail customer load with no-cost allowances. PSE should adopt these practices in both its forecast power costs and in operations.

Then, PSE should sell and buy allowances in a prudent manner to minimize power costs. This will require new risk management policies and practices, and potentially additional staff to manage the carbon allowance portfolio.

Q. What is your recommendation with respect to how CCA-related costs should be reviewed for prudency?

A. As discussed above, in my opinion, it is most appropriate for the prudence of allowance costs to be reviewed in each utility's respective power cost true-up proceeding —in PSE's case, its annual PCA proceeding. Variable environmental costs are commonly reviewed in power cost proceedings, and there is no important difference between the carbon allowances and other environmental costs that are subject to review in such proceedings.

V. COLSTRIP FUEL COST ERROR

Q. Please explain the Colstrip fuel cost error.

A. For 2025, PSE's Colstrip coal contract price per ton is determined using a base price of [redacted], a tier price of [redacted], and a reclamation rate of [redacted].[35] PSE models Colstrip dispatch against an average

[35] Exh. JDW-11 , (BDM workpaper Thermal Resource Inputs, tab Colstrip fuel price (C)).

annual fuel price of [redacted] per ton.[36] However, the marginal fuel price for Colstrip is not the average annual fuel price but rather price that an additional ton of fuel consumption would increase annual fuel costs, or the annual marginal price.

PSE explains that,

> Given that PSE expects to purchase a volume of coal sufficient to reach the second tier price in 2025, an additional ton of fuel consumption would increase annual fuel costs by [redacted] (=[redacted] + [redacted]), irrespective of which month that additional ton of fuel consumption occurs.[37]

PSE argues that even though using a marginal fuel price in model dispatch "may be a reasonable approach," "it adds complexity and is unlikely to have a meaningful impact on PSE's forecasted power costs."[38] By "complexity," appears that PSE is referring to a "simple … outside-the-model fuel cost adjustment" and the possibility that coal consumption will not always be sufficient to reach the tier price."[39]

However, PSE's 2025 forecast indicates that its coal use will exceed the minimum annual volume by [redacted], with the exceedance beginning during [redacted]. As PSE forecasts that its annual dispatch of Colstrip will significantly exceed the minimum annual volume, it is not reasonable to forecast power costs using an average price that is not ever a marginal cost. Accordingly, PSE should update its Aurora model to use the annual marginal price for dispatch throughout 2025 and use

[36] Exh. JDW-12, (PSE's Response to Staff DR No. 119(C), part (a)).
[37] Exh. JDW-12, (PSE's Response to Staff DR No. 119(C), part (b)).
[38] Exh. JDW-12, (PSE's Response to Staff DR No. 119(C), part (c)).
[39] *Id.*

a simple outside-the-model fuel cost adjustment to account for the difference between the base price and the tier price.

PSE's dispatch price should also include CCA compliance costs, as discussed in Section IV.

Q. What is the impact of the Colstrip fuel cost error on forecast power costs?

A. PSE estimated that its total 2025 power cost forecast would increase by $770,000 if it used a marginal dispatch cost.[40] PSE's model inputs did not include CCA compliance costs, which would probably tend to reduce the net effect of the changes to the model inputs.

Q. What is your recommendation to the Commission?

A. The Commission should require PSE to update its 2025 power cost forecast using a marginal dispatch cost for Colstrip, including CCA compliance cost in the dispatch cost. Since the CCA compliance cost will tend to reduce Colstrip fuel costs, the $770,000 power cost increase estimate provided by PSE should not be used, and the updated modeling should be required.

[40] Exh. JDW-12, (PSE's Response to Staff DR No. 119(C), part (c)).

Q. Does the Colstrip fuel cost error have implications for operations?

A. Yes, PSE should ensure that Colstrip is dispatched to annual marginal cost. Instead, PSE dispatches Colstrip using two price benchmarks. Initially, the projected annual average coal price is used for dispatch decisions. Once the tier price is reached, then the annual marginal cost is used for dispatch decisions.[41]

From an economic point of view, PSE's dispatch price benchmarks are not optimized. Instead, PSE should dispatch Colstrip using the annual marginal fuel cost, including the reclamation rate and CCA compliance costs.

PSE describes several potential complicating circumstances that could affect dispatch decisions, but then acknowledges that, "Given very low production cost it is rare for PSE to reduce Colstrip output for economic reasons [and] the difference between the average coal price and the second-tier coal price is small and has a minimal impact on actual dispatch decisions."[42]

If PSE continues to use a suboptimal dispatch price benchmark for Colstrip, then its actual dispatch decisions should be reviewed relative to market prices. Any potential power costs resulting from uneconomic dispatch should be disallowed as imprudent.

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[41] Exh. JDW-12, (PSE's Response to Staff DR No. 119(C), part (d)).
[42] *Id*.

VI. GAS STORAGE COST FORECAST

Q. Please explain why gas storage cost is included in forecast power costs.

A. PSE's portion of the Clay Basin Storage unit provides a seasonal source of gas for some gas-fueled plants. This benefits customers by reducing fuel costs: Gas is injected into storage during low-priced months and withdrawn during higher-priced periods. This also benefits customers by providing gas supply during periods of peak demand, when pipeline capacity may constrain delivery to the region.

It appears that PSE began to use or reserve a portion of Clay Basin Storage for its electric system in May 2023.

Q. Please summarize how PSE includes gas storage cost in forecast power costs.

A. The cost forecast for PSE's Clay Basin Storage is modeled outside of Aurora.[43] PSE's monthly injections and withdrawals are manually entered, "selected to maximize the annual benefit of gas storage utilization subject to constraints on the maximum rate of injection/withdrawal …, maximum and minimum storage volumes …, and the relative monthly price of natural gas at the Rockies hub shown."[44]

Q. Please describe your observations regarding this modeling.

A. First, PSE's assertion that its manually entered injection and withdrawal quantities are "selected to maximize the annual benefit" is not supported by any evidence. If

[43] Mullins, Exh. BDM-8(C).
[44] Exh. JDW-13 (PSE's Response to Staff DR No. 122).

my understanding is correct that PSE has only had committed capacity for its electric utility since 2023, then there are only 12 months of useful operational data. During that year, PSE's modeled withdrawals and injections have differed somewhat from the one year of historical data, as shown in Table 1. This could be reasonable given that PSE was likely filling up its capacity for its electric utility over this time.

Table 1: Clay Basin Storage Withdrawals and Injections, Historical vs Model Assumption (mmBtu)[45]

	2023 – 2024	Model Assumption
Withdrawals	[redacted]	[redacted]
Injections	[redacted]	[redacted]

I also reviewed PSE's assumed starting volume, maximum storage volume, and minimum storage volume to determine if they are based on normalized conditions. PSE states that its, "power cost forecast and the resulting baseline rate assume outcomes for these variables will be "normal" – generally equal to long-term historical averages or expected values given other normalizing assumptions."[46] A reasonable estimate of the impact of "normal" weather, load and generation on the level of gas withdrawals should reference historical annual inventory data.

However, because PSE has such a limited history of data, the variation in the minimum storage value shown in Table 2 from the most recent 12-month minimum is probably immaterial. Currently, PSE bases its modeled maximum annual storage

[45] Exh. BDM-17C; Exh. JDW- (PSE's Response to Staff DR No. 130, Attachment A); and Exh. JDW-15 (PSE's Response to Staff DR No. 219).
[46] Mueller, Exh. BDM-1T at 5:16-19.

based on its contractual maximum storage rights and its minimum storage based on a share of its historical operational target minimum.[47] While these values reasonable for the time being, PSE should switch to a historical normal basis for its modeling assumptions in a few years.

Table 2: Clay Basin Storage Volumes, Historical vs Model Assumption (mmBtu)[48]

	2023 – 2024	Model Assumption
Starting Volume	[redacted]	[redacted]
Maximum Storage	[redacted]	[redacted]
Minimum Storage	[redacted]	[redacted]

Q. Are there indirect impacts of gas storage costs on forecast power costs?

A. Yes. Because Clay Basin Storage costs vary with facility usage, the variable portion of those costs affects dispatch. However, PSE does not model injections to and withdrawals from Clay Basin Storage in Aurora. Since gas storage costs represent much less than 1 percent of total gas fuel burn expense on the PSE system, this is probably a reasonable simplification since it is likely that including Clay Basin Storage model results would have an immaterial impact on unit dispatch, and PSE should be able to reasonably estimate savings associated with Clay Basin Storage outside of Aurora.

[47] Exh. JDW-16 (PSE's Response to Staff DR No. 218, part(b) and Attachment A).
[48] Exh. BDM-17C; JDW-14 (PSE's Response to Staff DR No. 130, Attachment A); and Exh. JDW-15 (PSE's Response to Staff DR No. 219).

Q. What is your recommendation to the Commission?

A. The Commission should accept PSE's modeling methods for Clay Basin Storage on an interim basis until it is feasible to align its modeling method with the PSE's other practices for forecasting on a normalized basis.

VII. WEIM OMISSIONS

Q. Please explain how PSE includes Western Energy Imbalance Market (WEIM) costs and benefits in its forecast power costs.

A. PSE includes two categories of WEIM costs and benefits in its forecast power costs. First, PSE accounts for the WEIM by including it in its regional model, as follows:

> 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.[49]

PSE breaks out the WEIM charges and revenues in its NPE forecast by calculating the "difference between forecasted power costs with the sub-hourly market and the alternative forecast without a sub-hourly market."[50]

Second, PSE forecasts net revenues for export of low-greenhouse-gas-emitting resources to California, based on historical actual net greenhouse gas allowance revenues of $2.6 million.[51]

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[49] Exh. JDW-17 (PSE's Response to Staff DR No. 133, part (c)).
[50] *Id*.
[51] *Id*.

Q. Are PSEs forecasts of WEIM power costs and benefits reasonable?

A. Yes. With respect to the WEIM power costs, it is reasonable for PSE to model its system at a sub-hourly level since it has power markets available that transact on that timescale. I am not convinced that its method of identifying WEIM-specific transactions is particularly accurate, but neither is the breakout material if the overall cost forecast is reasonable.

The use of a differential model is probably a reasonable method of identifying the additional value that the WEIM unlocks. However, whether transactions occur in the WEIM or in some other relatively short-term bilateral market (such as an hourly market) is probably not something that can be determined in PSE's configuration of its production cost model.

With respect to net greenhouse gas emission allowance revenues, a historical baseline is a reasonable forecast method at this time, given the difficulty in forecasting the rapid transition in energy and markets affecting California's emissions allowance market.

Q. Has PSE omitted any WEIM power costs and benefits from its forecast?

A. Yes, PSE has omitted two types of WEIM power costs and benefits from its forecast. First, it has omitted $95,000 in annual net benefits from the WEIM flexible ramping market.[52]

[52] Exh. JDW-17 (PSE's Response to Staff DR No. 133, part (d)).

Second, PSE has omitted $467,000 in annual "transaction fees, penalties for under or over-reported generation or demand volumes, and interest charges or payments associated with timing differences between when charges or credits are incurred and when they are ultimately settled."[53]

Q. What is your recommendation to the Commission?

A. The Commission should direct PSE to include $372,000 in additional WEIM power costs in its forecast, reflecting the net effect of the flexible ramping and the various fees and other payments described above.

VIII. PRUDENCY OF CHELAN POWER SALES AGREEMENT

Q. Please summarize PSE's request for the Chelan Power Sales Agreement (Chelan PSA).

A. PSE requests the Commission find the Chelan PSA prudent. The Chelan PSA is a 20-year contract (2031 to 2051) for a 25% share of two hydroelectric projects. PSE explains that the Chelan PSA will provide capacity, storage and zero-emissions energy.

[53] Exh. JDW-17 (PSE's Response to Staff DR No. 133, part (d)).

Q. Does the Chelan PSA meet the Commission's standard for prudency?

A. No. In my review of the PSA, I confirmed the market data used by PSE in its evaluation. PSE provides several benchmarks that support the levelized pricing as being reasonable.[54] I also agree that PSE has a capacity need for the relevant time period and that the Chelan PSA contributes towards meeting that need.[55] However, while PSE's price forecast for the Chelan PSA is reasonable, the contract terms place customers at risk of large and unreasonable cost increases. Therefore, I recommend that the Commission find the Chelan PSA imprudent[56] unless the Commission imposes limitations on cost recovery under the contract (a "guardrail"), as I discuss below.

Q. Please explain how the Chelan PSA places customers at risk of large and unreasonable cost increases.

A. The Chelan PSA price includes two components. First, there is also a fixed annual charge that [redacted].[57]

Second, there is a cost-indexed charge. PSE customers bear a risk of cost-driven price increases, including capital improvements, without limitation.[58]

[54] Yanez, Exh. ZCY-3HC at 6.
[55] *Id*. at 5.
[56] Note that because the Chelan PSA begins in 2031, a prudency determination in this case does not impact Staff's overall revenue requirement recommendation.
[57] Exh. JDW-18 (PSE's Response to Staff DR No. 27, Docket UE-230313).
[58] Exh. JDW-19 (PSE's Response to Staff DR No. 28, Docket UE-230313).

Q. Can PSE dispute the costs or exit the Chelan PSA if the price becomes unreasonable?

A. No. PSE has no right to dispute the costs or exit the contract.[59]

Q. If PSE doesn't have any say in the Chelan PSA price, is it reasonable to assume that the Chelan PUD will act prudently and not make excessive investments in the Chelan PSA projects?

A. No. The primary restraint on uneconomic investments is the Chelan PUD's exposure of costs for its retail customers. PSE explains that, "Chelan PUD is obligated to … use Commercially Reasonable Efforts consistent with Prudent Utility Practices."[60] It is important to note that the definition of Prudent Utility Practices is entirely from the perspective of Chelan PUD and its responsibility to manage the Chelan PSA projects, and does not consider the commercial interests of its customers, including PSE.

A significant concern is unforeseen relicensing or civil works (dam/earthworks repair) costs.

If both PSE's and Chelan PUD's customers were exposed to the same costs and prices, then it might be reasonable to assume that Chelan PUD would not make

[59] Exh. JDW-20 (PSE's Response to Staff DR No. 29, UE-230313); Exh. JDW- 21 (PSE's Response to Staff DR No. 128, part (a)).
[60] Exh. JDW-21 (PSE's Response to Staff DR No. 128, part (c)).

excessive investment in the Chelan PSA projects.[61] But that is not the case, Chelan PUD might make uneconomic investments in the Chelan PSA projects because the fixed charge component of PSE's negotiated payment is at risk. If Chelan PUD retires units, then the PSE's fixed annual charge is reduced commensurately.[62]

Q. Are power contracts that expose the buyer to potentially unlimited costs without an exit right common?

A. No, I have never seen such a contract. More typically, a buyer that lacks decision-making authority will have negotiated terms on which it may exit the contract, such as a cost increase cap.

For example, in 2021, Oglethorpe Power exercised its right to object to continue with construction of Plant Vogtle in the face of cost increases of over $1 billion.[63] It leveraged that right to obtain concessions from the managing partner, Georgia Power, regarding sharing of cost overruns. By exercising rights as a minority partner in the project, Oglethorpe avoided some of the cost escalation.[64]

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[61] PSE also notes other possible restraints against Chelan PUD making uneconomic investments in the Chelan PSA projects including "securing financing or material for uneconomic investments." Exh. JDW-21 (PSE's Response to Staff DR No. 128, part (d)).
[62] Exh. JDW-22 (PSE's Response to Staff DR No. 30, Docket UE-230313).
[63] Bermel, Colby, "Georgia Power, Oglethorpe Spar Over Vogtle Cost Cap," *S&P Global* (September 25, 2018). *Available at*: https://www.spglobal.com/marketintelligence/en/news-insights/trending/qeom6obml-rkzd3fx07-fw2
[64] Kann, Drew, " Two Plant Vogtle Partners to Settle Cost Dispute as New Issue Arises," *Atlanta Journal-Constitution* (October 6, 2023). *Available at*: https://www.ajc.com/news/georgia-power-oglethorpe-power-agree-to-settle-vogtle-cost-dispute/QY74LTTBYFEYNNKQIYO42HYQBA/.

Q. What might be the maximum cost increase that Chelan PUD might be willing to bear before deciding to retire the Chelan PSA projects?

A. I estimate that Chelan PUD would be willing to bear a cost increase of at least [redacted] in annual production costs. I calculated this estimate as shown in Table 3.

PSE forecasts its 2032 contract cost as $[redacted] million, including a $[redacted] million fixed annual charge and $[redacted] million in production costs, and projects avoided costs of $[redacted] million, using a mark-to-market (MTM) method.[65] Chelan PUD's production costs and benefits are simply 2.6 times those of PSE since it receives 65% of the project and PSE receives 25%.[66]

I assume that Chelan PUD would be willing to invest up to the point at which its costs equal its benefits, and that it would calculate the benefits in the same manner that PSE calculated them. Based on this assumption, I estimate that Chelan PUD has an incentive to keep the Chelan PSA projects in service even if that requires additional costs that are [redacted] percent of its current costs, or nearly a [redacted] of forecast production costs.

[65] Yanez, Exh. ZCY-3HC, at 11, 13.
[66] Exh. JDW-20 (PSE's Response to Staff DR No. 29, Docket UE-230313, part (a)).

Table 3: Estimated Tolerance of Chelan PUD to Production Cost Increases

		PSE Costs[67]	Chelan Costs	Formula
1	Fixed	[redacted]	[redacted]	PSE fixed cost is revenue to Chelan
2	Production	[redacted]	[redacted]	Chelan = 2.6 x PSE
3	Total	[redacted]	[redacted]	1 + 2
4	Benefit (MTM)	[redacted]	[redacted]	Chelan = 2.6 x PSE
5	Cost Increase	[redacted]	[redacted]	PSE = Chelan / 2.6 Chelan = 4 – 3
6	Total Cost	[redacted]	[redacted]	3 + 5
7	Net Benefit	[redacted]	$ -	PSE = 4 – 6; Chelan = 0
8	Cost Increase	[redacted]	[redacted]	6 / 2
9	Net Benefit (Cost)	[redacted]	[redacted]	7 / 4

I also performed similar calculations to determine what level of increased production costs would result in PSE's total costs equaling its total benefits, which is simply row 4 minus row 3. The result is $[redacted] million.

Q. Does the Chlan PSA balance risks appropriately?

A. No. As a matter of first impression, PSE's economic interest is in keeping additional production costs from the Chelan PSA below $[redacted] million, while Chelan PUD's corresponding maximum willingness-to-pay is more than [redacted] that of PSE, and could result in PSE customers bearing as much as $[redacted] million in additional production costs. PSE customers bear far more economic risk than Chelan PUD customers under the negotiated contract terms.

67 Yanez, Exh. ZCY-3HC at 11, 13, 55.

Another way to view the balance of risks is to evaluate the Chelan PSA is as if it were a power market hedge. Of course, it is not a hedge; PSE is unlikely to find a counterparty for a twenty-year forward contract beginning in 2031, and its policies and practices do not contemplate such a transaction. And furthermore, the Chelan PSA is a physical transaction not a financial hedge. However, for purposes of interpreting the risks of the Chelan PSA, I will apply the approach used under PSE's Energy Supply Transaction and Hedging Procedures Manual.[68]

PSE's manual requires PSE's Energy Management Committee (EMC) to approve any credit limits that are both >$50m and >7.5% of PSE's total counterparty exposure.[69] As shown above, PSE's counterparty risk is $[redacted] million, which I anticipate would be more than 7.5% of PSE's total counterparty exposure in 2032. If the Chelan PSA were governed by the Manual, then EMC approval would be required. It appears very unlikely that under the Manual a transaction with unlimited cost exposure for PSE would be approved by its EMC.

Q: What should PSE have negotiated with Chelan PUD?

A: In exchange for the fixed annual charge, PSE should have negotiated a reasonable cap on the cost-based portion of the contract that, at a minimum, results in some reduction in the fixed annual charge for unexpectedly high costs. PSE should also

[68] Haines, Exh. PAH-4(C).
[69] *Id*. at 20.

have negotiated an exit clause for costs that exceed a predefined threshold, accounting for any reduction in the fixed annual charge.

Q. What is your recommendation to the Commission?

A. While I am not familiar with all Washington laws and precedents, I do not expect that the Commission has the authority to amend the language of a contract between PSE and Chelan PUD. Instead, the Commission should impose limitations on cost recovery under the contract (a "guardrail").

The "guardrail" should be a cap on allowable costs: The Commission should require PSE to file a special request to re-evaluate the prudency of the Chelan PSA if production costs exceed the forecast amount by $50 million.[70]

Q. Would it be reasonable for PSE's customers to pay a $50 million increase in production costs for the Chelan PSA?

A. No, it is extremely unlikely that a $50 million increase in production costs would be considered reasonable. The project contingency assigned to a typical project at a maturity of "Class 3" (Baseline Budget) is 20 percent, and such projects are expected to have cost estimates that are accurate within a -20% to +30% range.[71] Allowing for full use of the 20 percent contingency and an additional full 30% cost overrun would be a relatively extreme outcome considering that the Chelan PSA is a

[70] The forecast can be found at: Yanez, Exh. ZCY-3HC, at 55.
[71] Exh. JDW-23 (PSE's Response to Staff DR No. 129, Attachment A).

"[c]ommercially available project with a long operating history and a proven transmission solution."[72] Under those extreme conditions, production costs in 2032 would be $[redacted] million.

In comparison, the $50 million "guardrail" that I recommend would allow total production costs to increase to $[redacted] million and net benefits from the project, using PSE's mark-to-market forecast for 2032, of only $[redacted] million. Once the $50 million guardrail is reached, any additional costs should be disallowed unless PSE is able to demonstrate the prudency of the additional costs.

Q. Does this conclude your testimony?

A. Yes.

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[72] *See* Yanez, Exh. ZCY-3HC at 6.