Appendix 2:
Questions and Comments Directed to Puget Sound Energy

Commission staff (Staff) compiled questions and comments related to Puget Sound Energy's 2021 Draft IRP. Some of these questions are to increase Staff's understanding or to clarify possible ambiguity, while others investigate PSE's IRP analysis and are related to Staff's recommendations in the primary Staff Comments document. Staff hopes that PSE can address these questions and comments in its Final IRP, as appropriate.

Overall IRP content and format

Staff offers comments regarding the usability of the Draft IRP. These suggestions are for the company's consideration, but we acknowledge that these may not fit in with other priorities balanced by PSE:

- Integrate referential hyperlinks into the table of contents for IRP, the contents page included for each chapter, and the appendices. An example of this is in the table of contents and list of tables in the Cadmus CPA, Appendix E.
- <u>Add appendix page numbers</u> to the documents compiled in each appendix.

Chapter 1

Page 1-9: In comparing Figure 1-1 with Figure 1 in PSE's 2019 IRP Progress Report, the 2021 graph appears to show an increase in capacity of existing natural gas, existing wind and solar, and contract resources. Staff assumes that these adjustments reflect contract additions such as those described in PSE's recently filed power cost only rate case under Docket UE-200980. However, that proceeding does not present the acquisition of expanded natural gas resources. Please provide a list of resource modifications that PSE made between the 2019 graph and the 2021 Draft IRP, with a focus on any changes in the company's natural gas resource portfolio.

Page 1-14: Staff appreciates that DERs include numerous resources, including conservation. However, the term "Demand Side Resources" is functioning as an umbrella term for energy efficiency, codes and standards, distribution efficiency and customer-owned solar. This term could be easily misunderstood in the context of other DER resources; one could consider DR and customer-sited energy storage to be a type of demand side resource. Staff suggests using a different term, perhaps conservation or energy efficiency. Customer-owned distributed generation could get its own category.

Page 1-16: "Transmission within PSE service territory will be needed but was assumed unconstrained due to delivery system planning processes and specific identified projects." Will the projects described in Appendix M effectively remove all constraints within PSE's balancing authority area?

Chapter 2

Page 2-10: Why does WA West rooftop solar have a higher ELCC than utility-scale solar?

Staff does not necessarily dispute this but would have assumed that the values to be roughly the same.

Page 2-11: Similar saturation curves for energy storage would be illuminating and useful context next to Figure 2-5 and 2-6. Staff is also curious about whether hybrid renewable-plus-storage resources share the trajectory of standalone wind and solar when more projects of that type proliferate on PSE's system.

Page 2-21: Why is California's carbon price the appropriate proxy price for modeling alternative compliance option costs? Did PSE consider other proxy carbon prices?

Chapter 3

Page 3-27: To clarify, the 200 MW of distributed solar is included as a must-take resource, and PSE has included it because the company identifies transmission to other, less expensive renewable resources will be unavailable. Is this correct? Is it possible to use the IRP's modeling tools to identify a threshold cost for new transmission such that building transmission is a cheaper solution than distributed solar? Or, given that solar costs are likely more fungible than transmission costs, perhaps the other approach would make more sense – how cheap does rooftop Western WA solar need to be for it to beat new transmission to access utility-scale Eastern WA resources, plus the resources themselves? Staff understands the logic and does not disagree with the reasonableness of the result but would appreciate more narrative and alternatives analysis around the must-take resources included in the preferred portfolio modeling.

Chapter 4

Page 4-5: Staff believes the Dept. of Ecology has concluded its rulemaking described on Draft IRP pages 4-5 and 4-6. Will PSE consider this in its Final IRP?

Page 4-16: The August 2020 supply event occurred in summer and was not precipitated or specifically exacerbated by an unplanned outage. PSE's modeling forecasts that most weather-based reliability issues would occur in winter. Please describe any other energy emergency alerts declared by the reliability coordinator for PSE since 2000. When did these events occur? What caused these events – generation failure, transmission failure, severe weather events?

Chapter 5

Page 5-8: "Figure 5-3 and Figure 5-4 below show the electric peak demand and annual energy demand forecasts without including the effects of conservation. The forecasts include sales (delivered load) plus system losses."

Are the system loss assumptions used in the load forecast the same as used in the DER potential assessments? Do these loss rates vary with system loading – that is, are losses for the peak load forecast higher than for the annual energy forecast)? Also, does the loss rate vary across time in AURORA as different resources are "on the margin"? For example, transmission losses when MT or WY wind are "on the margin" are significantly higher than when Eastern WA wind or solar (4.6% vs. 1.9%) are "on the margin."

Page 5-11: Staff understands that that the NWPCC forecast of regional demand in Figure 5-5 includes the impact of PSE meeting the Council's conservation targets for the 7th Power Plan (which is why loads decline or stay flat through 2030). PSE's load forecasts shown in Figure 5-3 and 5-4 do not include conservation, which makes PSE's load appear to be a larger share of regional load than if these load forecasts included EE. This nuance may not be significant, but please confirm whether the load forecast in Figure 5.5 includes PSE's share of meeting the Council's EE targets, since the utility represents a significant share of EE in the 7th Power Plan. Please also explain whether and how using the Council's forecast of regional loads impacts the utility's assessment of market resource availability or prices.

What was the basis of using the "rest of WECC" load for purposes of determining RPS compliance? NPCC makes this assessment when it develops the market price forecast PSE indicates they rely on, so I suspect that is where it gets its RPS estimate as well. But it would be good to confirm that, since that would make these two forecasts — RPS development and forecast market prices — internally consistent.

Page 5-38: "Known controllable devices are included (most current solar and battery systems are not controllable to manage peak reliably to date)"

Please explain why current solar and battery systems are not controllable. Could PSE retrofit or otherwise address this problem through its programs – incentives, net metering requirements, etc. – so that distributed solar systems, especially those with storage, could provide grid benefits?

Page 5-41: Figure 5-24 appears to represent average annual losses. Marginal losses during winter peak and summer peak periods for those areas shown in Table 5-24 should be used to mark-up peak kW savings from DERs to generation (same for distribution system losses). Are those available and able to be included in the modeling? Staff also believes it is better to use the marginal losses associated with the marginal resource being dispatched in AURORA to value DERs. For example, when MT or WY wind is the marginal resource being dispatched, then the marginal loss factor for MT or WY wind should be applied (which is presumably higher than the average 4.6% loss factor shown in Figure 5-24).

Page 5-42: Which of the costs shown in Figure 5-25 were used as the value of deferred transmission for EE, DR and other DERs?

Page 5-49 and following pages: For the natural gas and dual-fuel turbines in sensitivities N, O, V & W, please report both the GHG emissions from those plants as well as the difference in NPV portfolio cost. Staff believes this portfolio cost/ton of GHG emissions reduction for removing (or converting to renewable fuels) these gas-fired resources should be compared to the CETA emissions penalty to better understand the lowest-cost route to compliance. Staff also hopes to see the cost differential between the currently lowest cost means of "firming" renewables used in the valuation of flexible demand resources or other resources that provide comparable grid services. It also would provide a useful basis for comparing the results of scenarios V & W.

Page 5-50: "… PSE has smoothed out the fluctuations in temperature *increased* the heating degree days (HDDs) and cooling degree days (CDDs) over time at 0.9 degrees per decade, which is the rate of temperature increase found in the Council's climate model." Staff presumes that this is a typo, unless we misunderstand the impact of global warming on the Pacific Northwest. Should this read, "*decreased* the heating degree days (HDDs) and increased the cooling degree days (CDDs)"?

Page 5-51: Under Sensitivity V (Balanced Portfolio), are the type and amount of DERs "cost-effective" but simply being ramped in early, or are some DERs that were not cost-effective in the Base portfolio included in this sensitivity case? If relevant, please identify the type and amount of DER resources that were not cost-effective.

Page 5-52: What is the capacity factor of the biodiesel generation in Sensitivity V? What is the average annual fuel use required to provide this generation capacity? Assuming PSE will be testing this portfolio in its risk analysis, it would be useful to know the range of annual dispatch of the biodiesel generation under conditions (such as low water) that might result in much higher utilization to assess risk of adequate bio-fuel availability.

Chapter 6

Page 6-31: "The 310 electric stochastic scenarios are run in the AURORA portfolio model to test the robustness of the portfolio under various conditions."
Is it an accurate interpretation of this statement that each optimized portfolio will be run against 310 different "futures" with stochastically selected inputs such as load growth, market price and gas price, and not that 310 different "futures" will be run to develop 310 "optimized" portfolios?

Page 6-31: Provide more explanation for the company's selected electric vehicle (EV) load profile (or profiles) the company used in its load forecast, possibly linking that decision to any lessons learned and data gathered from the company's pilots.

Page 6-46: "Since this 14 MW is so small compared to PSE's peak demand, and PSE has not typically curtailed customers on these interruptible schedules during a normal peak event, it was included in the firm demand forecast."
Staff is puzzled by why this decision was made. 10 MW of DR is in the preferred portfolio for 2022-2025 (Figure 1-4). If customers are on an interruptible rate, why would the loads associated with those customers be modeled as firm demand? Relatedly, is the 14 MW included in DR potential?

Chapter 7

Page 7-7: The bullet points describing the adjustments made to the BPA study are a bit hard to track. In the second bullet, why is it appropriate to adjust the 2023 winter capacity forecast to include 3400 MW of potentially available short-term imports? If this reflects possible short-term imports from California, has PSE studied whether such capacity imports are available when the Pacific Northwest region is stressed?

Page 7-15: Based on a quick review of the Draft IRP and public meeting materials, the analysis performed by E3 did not appear to be mentioned prior to this Draft IRP. Is this the case? Is the assessment performed by E3 provided in the Draft IRP, or will it be provided in the Final IRP? How does this assessment fit with PSE's own flexibility analysis? Did the 2030 Case explored by E3 include any other system resources beyond wind and solar, such as DR or storage?

Chapter 8

Page 8-17: "Sensitivity C selects distributed solar resources located within PSE's service territory. The model pairs these distributed solar resources with battery storage projects to better serve load when the sun is not shining. These more expensive resources drive up portfolio cost in the later years of the modeling horizon."
It appears to Staff that AURORA selects solar-plus-battery resource options in this sensitivity, rather than just deeming "must build" resources. Is this correct?

Page 8-19: "There is a significant increase in the annual portfolio costs between 2044 and 2045 due to penalties related to violation of CETA constraints in the model. This sensitivity requires further work for the final 2021 IRP."
Rather than assume that all gas-fired units are retired in a single year, which appears to be the case in Sensitivity O, Staff suggests that PSE assume these units are phased out over time. That way, AURORA can test whether developing DERs, rather than additional utility-scale wind and solar, is a lower cost option for replacing some of the lost capacity and flexibility. Did PSE consider the phase-out approach? Please explain.

Page 8-19: "R. Temperature Sensitivity: This sensitivity will be evaluated for the final IRP."
Does PSE intend to adjust the conservation savings inputs to the supply curve that are weather-sensitive to reflect changes in HDD/CDD? That is, will PSE reduce space heating savings per measure and increase space cooling savings per measure for Sensitivity R?

Page 8-25: In Figure 8-12: Net Cost of Capacity in the Portfolio Model, Staff would appreciate the inclusion of DR and EE appear to be missing resources, as these resources also provide capacity. The capacity cost for EE and DR resources may need to be represented as a range and average. Please explain.

Page 8-26: In Figure 8-13: Wind and Solar Cost Components, resource types and geographies are separately identified, which should allow for the inclusion of transmission cost. PSE discusses transmission cost as a determinant in resource selection, so its inclusion in this graph would help understand the impact of transmission as a determinant.

Page 8-35: "Sensitivity C selects distributed solar resources located within PSE's service territory. The model pairs these distributed solar resources with battery storage projects to

better serve load when the sun is not shining. These more expensive resources drive up portfolio cost in the later years of the modeling horizon."
To clarify, in Sensitivity C, are distributed solar-plus-storage resources selected in lieu of resources that require transmission by AURORA because they have lower cost? Or is it that solar-plus-storage resources are selected in this sensitivity because the model is constrained to select these options?

Page 8-40: "Distributed energy resources (DERs) *can meet* a significant portion of load as shown in Figure 8-28. DERs contribute approximately 14 percent of total energy load in 2045. However, DERs are a poor resource for providing peak capacity need, with an effective load carrying capability (ELCC) of less than 2 percent."
Staff understands this statement to refer to *all* DERs, but the conclusion regarding ELCC is specific to distributed PV. The narrative should make it clear that other DERs (EE, DR, and battery storage) have higher ELCCs than 2%.

Page 8-57: "In this sensitivity (Sensitivity O), all existing gas-fired generation resources are retired by 2045 regardless of economic viability. Generic peaking capacity resources are available as a new resource but are expected to retire by 2045."
This states that all existing gas plants are retired *by* 2045, but page 5-49 specifies that *in* 2045, all carbon-emitting resources are retired regardless of their economic viability. Staff suggests tweaking this scenario such that existing gas plants could be retired in phases, with least efficient, most fully amortized plants retired first rather than all at once (and no new gas could be built). Under the mid-scenario, gas dispatch drops to 5%, so these plants are not being heavily relied upon in 2045 even in the base case.

Also, to better understand the need for flexible capacity and assess whether biofuel is a feasible solution for non-fossil capacity in the key CETA compliance years, Staff encourages PSE to run the RAM model for 2030 and 2045 on its final IRP preferred portfolio to test if it meets the company's RA standards. Doing so would reveal the <u>maximum capacity factor of gas plant use</u>, not just average capacity factor, which would provide insight into the maximum biofuel capacity needed under poor water/extreme weather conditions. This also would serve as a check on whether the assumed translation of ELCC/EUE to LOLP to planning reserve margins is completely accurate. Please provide additional detail regarding this analysis.

Page 8-65: As stated in Staff's Comments "IRP Modeling Recommendations," more information is needed regarding reporting of GHG emissions for <u>sensitivities</u> since a primary objective of both the EIA's RPS requirements and CETA is to reduce these emissions. Moreover, the change in emissions is reported for other sensitivities, so why not S and T? Please explain.

Chapter 9

Pages 9-4 and 9-53: Staff offer questions regarding natural gas demand, even before conservation. Can this be satisfied without the Tacoma LNG facility for perhaps the first two winters in the planning horizon? With respect to Figure 9-29 and very similar colors depicted in the key and graph, is system reliance on the facility not starting until around the 2025-2026 winter season? The footnote states it is shown as existing resource, but when does the company estimate it will *begin operations*?

Appendix D – Electric Resources and Alternatives

Page D-65: Staff understands that off-shore wind has a shorter and less-congested transmission route to reach PSE's system. Given that transmission is expensive enough to prompt increased adoption of DERs within PSE's system in the preferred portfolio, and given that off-shore wind costs are decreasing, has PSE estimated a cost-competitiveness price threshold for off-shore wind that could guide PSE's planning?

Appendix E – Conservation Potential Assessment and Demand Response Assessment

Cadmus CPA page 19: Please provide more background and explanation for the administrative adder. Please describe how that is applied to the evaluation of each energy efficiency measure, or each conservation resource bundle.

Cadmus CPA page 62: Please provide more background and explanation for the decision to adjust the program participation rate for grid-enabled water heaters "down by half."