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Puget Sound Energy
355 110th Ave NE
Bellevue, WA 98004

RE: Comments of Swan Lake and Goldendale
Puget Sound Energy – Final Integrated Resource Plan
UTC Docket UE-200304

The companies working to develop the Swan Lake and Goldendale pumped hydro storage projects ("Swan Lake and Goldendale") appreciate Puget Sound Energy's ("PSE") work that went into preparing its final Integrated Resource Plan ("Final IRP"), which was filed in the above-referenced proceeding on April 1, 2021. The Washington Utilities and Transportation Commission ("Commission") subsequently issued a notice, on April 6, 2021, indicating it would accept comments on PSE's Final IRP until May 6, 2021.[1] In response to that notice, Swan Lake and Goldendale are filing these comments.

While Swan Lake and Goldendale understand that PSE was under immense time pressure to meet the April 1, 2021 deadline to file the Final IRP, because the Final IRP contains several erroneous calculations and assumptions, the Commission should not acknowledge the Final IRP without further revision by PSE. As further explained below, the Final IRP contains several flawed assumptions that significantly affect the portfolio analysis. Because of these flawed assumptions, the Final IRP does not satisfy the Commission's standards.[2]

Swan Lake and Goldendale respectfully request that the Commission abstain from acknowledging the Final IRP and, instead, direct PSE to re-perform several aspects of its analysis to ensure the Final IRP is consistent with the applicable rules and Commission standards.

I. Summary of Comments

As further laid out below, these comments articulate Swan Lake and Goldendale's significant concerns with the Final IRP. These concerns include identification of errors made by PSE in preparing the Final IRP and erroneous assumptions for certain types of resources, which are particularly problematic for the fair and full consideration of pumped storage resources in PSE's Final IRP.

Specifically, these comments address the following topics: (1) PSE's low storage effective load carrying contribution (ELCC) values and the assumptions regarding the charging of storage

[1] *Addendum to Notice of Opportunity to File Written Comments*, Docket UE-200304, April 6, 2021, available at: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=1746&year=2020&docketNumber=200304.

[2] *See* WAC 480-100-620.

resources, particularly related to pumped storage resources; (2) PSE's extremely high net levelized cost attributed to storage resources, particularly pumped storage resources; (3) concerns regarding assumptions used by PSE to demonstrate and meet its capacity need; and 4) Swan Lake and Goldendale's concerns about PSE's Final IRP development process and timing of releasing key information.

II. The Final IRP Uses a Number of Assumptions with Respect to Storage Resources that Artificially Deflate their Capacity Values, Thereby Negatively Impacting The Economic Competitiveness Of Storage

In PSE's Final IRP, there are several assumptions about storage resources and their capacity contribution to PSE's system which materially impact the preferred portfolio results. In particular, PSE's assumptions dramatically limit the capability of stand-alone energy storage to charge, thereby limiting the ability of stand-alone storage resources to provide capacity services in high loss of load periods during the winter. As shown in the Final IRP, low effective load carrying contribution ("ELCC") values for storage result in high net levelized capacity costs, and thus little storage (450 MW) is procured in PSE's preferred portfolio by 2045.[3]

In the Final PSE IRP, the ELCC value of energy storage is significantly lower than estimates performed by PSE's peers in the Pacific Northwest. Swan Lake and Goldendale recognize that the ELCC value of storage, and all other resources, is system dependent and can be affected by numerous factors such as generator forced outage rate assumptions, import assumptions, renewable penetration, thermal retirements, load forecasts, and forecast year. Because of these system-specific factors, Swan Lake and Goldendale do not expect PSE's ELCC values for storage to exactly match the ELCC value estimates of its peers. However, the size of the ELCC value gap between PSE and other entities (such as Portland General Electric ("PGE"), Northwestern Energy, and PacifiCorp) suggests that PSE's ELCC values are being artificially deflated by incorrect assumptions.

Specifically, the ELCC value of an eight-hour duration pumped hydro facility (100 MW) in PSE's service territory is 37.2%, as shown in Figure 1 below.[4] The ELCC values for 100 MW of pumped hydro (8 hour) in PGE, Northwestern, and PacifiCorp systems are 94%,[5] 100% and 99%,[6] respectively.[7]

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[3] Final IRP at 1-13, Fig. 1-14.

[4] Final IRP at 7-31, Fig. 7-20.

[5] *See* page 63, 2019 Portland General IRP Update, available at https://assets.ctfassets.net/416ywc1laqmd/1PO8IYJsHee3RCPYsjbuaL/b80c9d6277e678a845451eb89f4ade2e/2019-IRP-update.pdf.

[6] See page 20, Northwestern Energy Incremental ELCC Study, available at https://www.northwesternenergy.com/docs/default-source/documents/defaultsupply/appendix-2-e3-report-on-elccs.pdf.

[7] See page 404, PacifiCorp 2019 IRP Appendix N. available at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_II_Appendices_M-R.pdf.

Figure 1: Effective Load Carrying Contribution of Energy Storage Devices

BATTERY STORAGE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Lithium-ion, 2-hr, 82% RT efficiency	100	12.4%	15.8%
Lithium-ion, 4-hr, 87% RT efficiency	100	24.8%	29.8%
Flow, 4-hr, 73% RT efficiency	100	22.2%	27.4%
Flow, 6-hr, 73% RT efficiency	100	29.8%	35.6%
Pumped Storage, 8-hr, 80% RT efficiency	100	37.2%	43.8%

Based on data that was not made available until the Final IRP, Swan Lake and Goldendale believe that PSE's significantly depressed storage ELCC values are being driven by three key, inaccurate assumptions: 1) Loss-of-Load Events are consistently 24-hours in key winter months by 2027; 2) there is 1,000 MW (or less) of Mid-C capacity (wholesale purchases) assumed to be available in key winter months by 2027; and 3) only existing supply and any available Mid-C import capacity will be available for the energy storage to charge from, thereby excluding the possibility of storage charging from another market such as the California Independent System Operator ("CAISO").

The first problematic assumption for storage resources' ELCC values is PSE"s assumption that Loss-of-Load Events are 24-hours in winter months in 2027. For energy limited resources, such as energy storage, the availability of surplus energy and capacity in off-peak periods is key for enabling capacity service during on-peak periods. As is shown in Figure 2 below, by 2027, PSE's base case forecasts that there will be 24-hour loss of load events in January and February (hours in which there is insufficient supply or wholesale market purchases available to meet load). The 24-hour loss of load assumption in January and February dramatically hinders the capacity capabilities that storage can provide to PSE since these energy limited resources are not allowed to charge in any hour of the day during these 24-hour Loss-of-Load Events and, as a result, the facilities are rendered unavailable because they have no modeled capacity available (*i.e.*, no charge). PSE has historically been a winter peaking system; however, peak needs have typically been during a few key hours (6AM-8AM/6PM-10PM) as opposed to the entire 24-hour time period.

Driving PSE's first problematic assumption is the second assumption that negatively impacts storage resources—namely, assumptions around the availability of Mid-C wholesale purchases during the 24-hour loss-of-load period in January and February described above. In the Final IRP, PSE notes that they can only rely on 1,000 MW of wholesale purchases in January and February, contrary to the rest of the year where the assumed import capacity is closer to 1,400 MW.[8] This

[8] Final IRP at 7-9, Fig. 7-3.

explains why December (an "on peak" month) does not show the same 24-hour loss of load profile that the January and February month does. It is unclear if the 1,000 MW wholesale purchase limit in January and February is constant across all hours of the day (peak and off peak), but it is clear that allowing additional market purchases in the off-peak night period would result in less 24-hour loss-of-load events and ultimately enable storage to provide more capacity services. It should be noted that, historically, there has not been market supply issues during off-peak periods, meaning PSE's assumption about zero capacity being available in the wholesale markets (including from Mid-C) at night to charge storage resources does not align with historical data.

Figure 2: PSE Base Case Loss-of-Load Hours for 2027[9]

The impact of market charging assumptions can be further illustrated by the base case and climate change impacted temperature profiles that PSE uses in its Final IRP analysis. In the base case scenario, PSE shows that the ELCC of the pumped storage resource (100 MW) is 37.2%.[10] In the base case scenario, all hours in January and February are assumed to be energy constrained (*i.e.*, no energy is available to import from Mid-C or can be supplied from PSE's generation assets), meaning there is no opportunity for storage resources to charge (even at low demand periods in the night) and therefore, the technology cannot provide capacity service.

[9] Final IRP at 7-46, Fig. 7-33.

[10] Final IRP at 7-31, Fig. 7-20.

However, PSE also performed a temperature sensitivity study based on a climate change-impacted temperature profile provided by the Northwest Power and Conservation Council ("NWPCC").[11] In this sensitivity, the ELCC value of pumped storage (and other storage resources) dramatically increases—from 37.2% to 89.2% for a general pumped storage resource.[12] The ELCC improvement for pumped hydro (and all other storage technologies) stems from the fact that the climate change temperature profile did not consider all hours of the winter (January and February) to be energy constrained as the base case did. This significant change in ELCC values prompts significant concerns related to the frequency of Loss-of-Load Hours in the base case winter temperature profile used by PSE in the Final IRP and supports Swan Lake and Goldendale's argument that PSE is using charging and import assumptions that would negatively affect the ELCC of pumped storage projects like Swan Lake.

A third, major analytical concern in PSE's Final IRP that negatively impacts pumped storage resources' ELLC values specifically is that PSE assumes that all pumped storage resources are similarly situated, regardless of their location on the system, and that all such similarly situated pumped storage resources must be charged from either Mid-C or PSE's generating supply. In the example of Swan Lake, PSE's RAM model assumes that Swan Lake cannot charge during key winter months (January and February) due to limited Mid-C market energy availability and low generation from PSE's supply due to forced outages or bad weather conditions. However, given Swan Lake's location on the California-Oregon intertie at Malin substation, Swan Lake's presumed charging market is California (CAISO), rather than either Mid-C or PSE's system. Furthermore, ample transmission is available in the South-to-North direction on the California-Oregon intertie during the critical winter months, when PSE badly needs flexible capacity. As a result, PSE's failure to allow storage resources to charge from other markets (such as CAISO), results in storage resources' ELCC values being artificially depressed. Furthermore, this assumption does not take into account the unique operational circumstances of each resource, thereby resulting in Swan Lake being lumped into the generic pumped storage resource bucket, with its low ELCC value, even though the assumptions that result in low ELCC values for storage resources are inapplicable to a resource like Swan Lake.

In addition to the three inaccurate assumptions noted above, which negatively impact the ELCC values of storage resources, PSE makes other, incorrect assumptions about pumped storage, which further impact these resources' ability to fairly compete in the Final IRP. For example, another inaccurate assumption used by PSE in its Final IRP for pumped storage is that PSE limits pumped storage resources' operating range (or "state of charge") to 70% of the resource's storage capacity.[13] The effect of this assumption is that pumped storage resources are unable to take advantage of almost 1/3 of their available capacity due to PSE's model arbitrarily limiting these resources to only being able to discharge until they reach 30% remaining pond capacity (minimum

[11] Final IRP at 7-46, Fig. 7-33.

[12] Final IRP at 7-47, Fig. 7-34.

[13] *See* Final IRP, Appendix D at D-67, Fig. D-31, available at: https://oohpseirp.blob.core.windows.net/media/Default/Reports/2021/Final/Appendix/15.%20IRP21_AppD_031821B.pdf.

constraint). This limiting assumption does not reflect the operational reality of how pumped storage resources operate. Instead, this assumption has the effect of further deflating the ELCC value of pumped storage resources, thereby resulting in these resources appearing uneconomic in PSE's Final IRP.

As evidenced by other regional utilities' modeling efforts, if the above-listed incorrect assumptions are corrected, and pumped storage resources are attributed a fair and accurate ELCC value, the cost of capacity to acquire these resources is competitive with other dispatchable technologies. Combined, the assumptions used by PSE in its Final IRP, particularly with respect to pumped storage resources, have the effect of artificially skewing the IRP analysis to attribute storage resources, and particularly pumped storage resources, an arbitrarily low ELCC value, thereby causing these resources to appear uneconomic, in favor of locally located demand response and biodiesel peakers. This skewing of the IRP analysis calls into question whether PSE's preferred portfolio contains the least-cost set of resources, as required by the Commission's rules.[14] As a result, the Commission should not acknowledge PSE's Final IRP until these inaccurate assumptions are revisited, corrected, and the model is re-run to produce a preferred portfolio that actually represents the least-cost set of resources.

III. PSE's Final IRP Analysis Attributes Storage Resources an Extremely High Levelized Cost in Comparison to Similar Analyses Conducted by PSE's Peers and Third Parties.

PSE's Final IRP also attributes storage resources, particularly pumped storage, an extremely high levelized cost, especially when compared with analyses conducted by PSE's peers and third-party, independent analysis firms. For example, the Final IRP indicates pumped storage has the highest net levelized cost of all storage technologies, and the least revenue attributed to it, when compared to other storage devices as shown in Figure 3 below.[15] The revenue stack in Figure 3 is composed of energy services, flexibility, and transmission and distribution deferral benefits. The gap in revenue is puzzling, especially given that pumped storage has a higher roundtrip efficiency and duration than other storage technologies, such as flow batteries.

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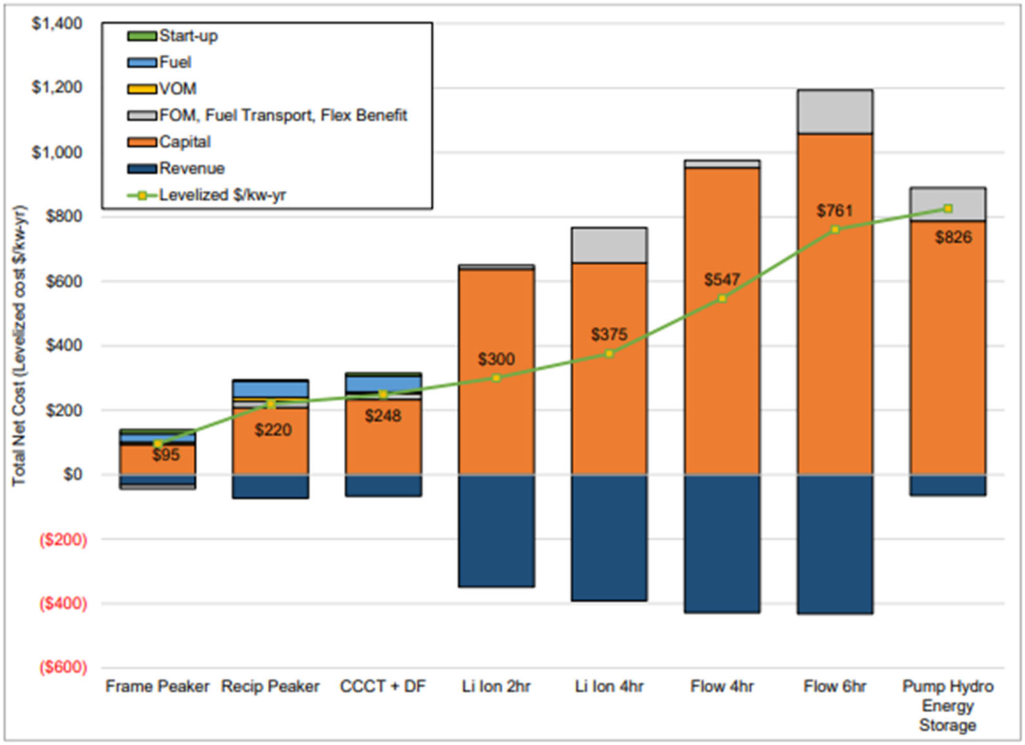
[14] WAC 480-100-610(1) ("[E]ach electric utility has the responsibility to identify and meet its resource needs with the lowest reasonable cost mix of conservation and efficiency, generation, distributed energy resources, and delivery system investments to ensure the utility provides energy to its customers that is clean, affordable, reliable, and equitably distributed. At a minimum, integrated resource plans must include the components listed in this rule. Unless otherwise stated, the assessments, evaluations, and forecasts should be over an appropriate planning horizon.) (emphasis added); see also WAC 480-100-620(7) ("The IRP must include a comparative evaluation of all identified resources and potential changes to existing resources for achieving the clean energy transformation standards in WAC 480-100-610 at the lowest reasonable cost.") (emphasis added).

[15] Final IRP at 8-39, Fig. 8-18.

Figure 3: PSE Net Levelized Cost of Storage



From a transmission and distribution ("T&D") deferral perspective, PSE provides additional value to lithium-ion and flow batteries for flexibility in siting as opposed to pumped storage, which tends to be more geographically constrained. For the Final IRP, PSE utilized a T&D benefit value of $12.61/kW-year for demand response and energy storage resources.[16] Despite the supplemental benefit, the size of the T&D revenues is not sufficiently large to explain the revenue discrepancy seen in Figure 3 above.

Flexibility benefits of the various energy storage devices are also similar in size ($/kw-year), but PSE's results are non-intuitive and once again do not explain the storage revenue gap demonstrated in Figure 3. In PSE's flexibility analysis, a 4-hr flow battery had a higher flexibility value ($23.03/kW-year) than both a 4-hr lithium-ion battery ($18.45/kW-year) and an 8-hr pumped storage device ($18.41/kW-year), despite flow batteries having a lower round trip charging efficiency than both lithium-ion and pumped storage, and further despite the flow battery having less duration than the 8-hr pumped storage. Both pumped storage and lithium-ion batteries have sufficient ramping capabilities to optimize sub-hourly dispatch and, therefore, ramping constraints should not be causing this discrepancy in flexibility benefits, either. It is also worth noting that demand response—a resource typically limited to 4 hours of duration and 10 calls per year—is

[16] *See, e.g.* PSE 2021 IRP Webinar #4 Demand Side Resource, Jul. 14, 2020, available at: https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/July_14_webinar/Webinar_4_Demand-Side-Resources_Presentation.pdf.

estimated to have a $35.24/kw-year flexibility, approximately 90% higher than the flexibility value of both an 8-hr pumped storage and a 4-hr lithium-ion battery, despite storage resources being available year-round (8760 hours) and the demand response resources being available only for 40 hours of the year. Overall, Swan Lake and Goldendale see the flexibility results presented by PSE in the Final IRP as non-intuitive and inconsistent, and therefore, the flexibility benefits require further revision and evaluation to ensure that each resource is being fairly evaluated for their system benefit and to ensure PSE is actually presenting the least-cost set of resources, as required by the Commission's rules.

Given that the discussion above eliminates T&D benefits and the flexibility benefits as potential reasons for the significant cost discrepancy shown in Figure 3, energy services is the only revenue stream that could potentially explain the puzzling gap in revenue between pumped storage, flow batteries, and lithium-ion batteries. Like the flexibility benefit discussion, it is not intuitive that flow batteries would outperform pumped hydro from an energy shifting perspective since flow batteries operate with lower storage duration (4hr-6hr) and worse round trip charging efficiency (73%).[17] The 30% minimum pond constraint that is applied to pumped hydro in the PSE Final IRP, which is further explained above, could influence the energy value, but it is unclear whether this incorrect operating assumption alone is driving the large revenue gap that PSE is presenting in Figure 3.

Based on the explanation above, PSE's levelized cost analysis suffers from several deficiencies that must be further investigated before the Final IRP may be acknowledged. Those deficiencies include very low revenue attributed to pumped storage resources for flexibility and energy services, which is likely the result of a 30% minimum storage capacity assumption and limited charging opportunities during the winter due to PSE's base case assumptions. These deficiencies result in PSE's attributing pumped storage a staggering $826/kW-year net levelized cost. This figure is astounding in how far it deviates from virtually every other analysis of pumped storage performed by PSE's peers or third-party, independent analysis firms. Because these figures for pumped storage are so astoundingly high in comparison to most other analyses of pumped storage resources, Swan Lake and Goldendale have significant concerns about the validity of PSE's analysis.

Thus, before acknowledging the Final IRP, Swan Lake and Goldendale specifically ask that the Commission direct PSE to work with stakeholders developing storage projects to refine PSE's modeling assumptions in order to produce a more accurate result, thereby ensuring PSE's ratepayers are not over-paying for the wrong set of resources.

IV. The Final IRP Understates PSE's Likely Future Capacity Needs

In addition to the specific concerns raised above about the accuracy of PSE's modeling for storage resources, particularly pumped storage, Swan Lake and Goldendale also have concerns about

[17] *See* Final IRP, Appendix D at D-74, Fig. D-32, available at: https://oohpseirp.blob.core.windows.net/media/Default/Reports/2021/Final/Appendix/15.%20IRP21_AppD_031821B.pdf.

PSE's project capacity needs in the Final IRP. The Final IRP makes questionable assumptions that produce an understated, future capacity need that should not be acknowledged by the Commission. In particular, PSE's analysis makes assumptions about: (1) treatment of imports from California used to reduce PSE's capacity needs, while simultaneously limiting third-party's resources from relying on that same transmission to deliver their output to PSE's system; and (2) availability and feasibility of biodiesel combustion turbines ("CTs") to meet a significant portion of PSE's capacity needs. The combined effect of these two assumptions is that the Final IRP significantly understates PSE's looming capacity needs.

a. The Final IRP Treats California Imports Inconsistently to Reduce PSE's Projected Capacity Need While Also Hampering the Ability of Third-Party Resources to Deliver Output to PSE's System.

Another significant concern in PSE's analysis is that it presumes 3,400 MW of transmission is available from California to reduce both PNW regional and PSE capacity needs.[18] While it is unclear how much winter capacity a California import assumption provides to the PNW and PSE, such an assumption creates three major problems for the accuracy of PSE's capacity needs analysis. First, the 3,400 MW South-to-North on the California Oregon Intertie ("COI") comes from the historical available transmission limit on that path in the South-to-North direction. It does not describe the actual generation available for export from California during winter months. To that end, regional reliability planners, under the guidance of the NWPCC, have historically used 2,500 MW of assumed winter imports from California.

Second, in light of pending winter capacity shortages in the Northwest and current reliability problems in California, the Northwest Power Pool ("NWPP"), of which PSE is a member, is developing an RA program specifically for its members. While that program is still in its design stages, one of its key initial decisions has been to avoid relying on annual, seasonal, or even monthly averages of available RA capacity, imported or otherwise, and instead focus on establishing RA capacity for each critical hour during the day in grid stressed periods. This intended NWPP RA approach is in stark contrast to the monthly capacity averages, whether 3400 MW from California or some other monthly average from Mid C, that PSE is apparently using in its capacity modelling.

Third, given California's well-advertised problems with reliability and blackouts, it is appropriate to assume RA imports for hours 1:00AM to 4:00PM on a winter day, but it is clearly not appropriate to assume any available RA imports for hours 4:00PM-9:00PM on a winter day, given California's evening ramp and need for capacity to support its evening peak.

Considering the above, three factors together, PSE's assumptions that it can receive its "share" of the 3,400 MW South-to-North transmission capability during winter early evening hours, and that any capacity will be available from California to import during those early evening hours, are

[18] Id. at 7-6, 7-7 ("GENESYS also attempts to maximize the region's purchase of energy and capacity from California (subject to transmission import limits of 3,400 MW) utilizing both forward and short-term purchases.").

simply not prudent assumptions to make. Instead, PSE should assume 0 imports for hours 4:00PM-9:00PM and procure needed capacity resources from within the Northwest.

Using a more appropriate figure for California imports, based on historical data and assumptions by the NWPCC, would reduce PNW and PSE's assumed imports of California resources by nearly 1,000 MW. While it is unclear whether this number directly correlates to a 1-for-1 increase in capacity need for PSE, even a portion of the nearly 1,000 MW being added to PSE's future capacity needs would dramatically alter PSE's entire, Final IRP analysis. For this reason alone, the Commission should require PSE to re-run its analysis and update the California import assumptions to reflect actual, historical data.

Finally, while PSE should assume something close to 0 MW of California winter imports from 4:00PM to 9:00PM, California import capacity of 2,000-2,500 MW probably is consistently available from 1:00AM to 4:00PM most winter days, and certainly from 9:00AM to 4:00PM when 20+ GW of California solar is present. This multi-hour availability of 2,000-2,500 MW of California capacity should, somewhat ironically, be more than sufficient to charge Swan Lake as described in Section II above. Nevertheless, the capacity shortfall during California's post solar evening ramp remains, which presumably **should increase PSE's overall winter capacity need** by even more than the 1,000 MW suggested above.

These assumptions alter the Final IRP results and call into question the veracity of PSE's analysis. As such, the Commission should not acknowledge the Final IRP and instead, should require PSE to revisit its analysis and correct these faulty assumptions.

b. The Final IRP Wrongly Assumes PSE Will be able to Acquire a Significant Amount of Additional, Clean Capacity from Speculative Technologies.

The Final IRP indicates that PSE intends to acquire nearly 1,000 MW of firm Resource Adequacy ("RA")-qualifying capacity contracts by 2030 for the principal purpose of compensating for a 1,000 MW reduction of PSE's spot market purchases from Mid-C.[19] This nearly-1,000 MW is part of the recently issued All-Source RFP, and PSE's Final IRP assumes a portion of this capacity need will be met by biodiesel CTs, which is both unrealistic and an extremely speculative assumption to make.[20]

Given the "no new gas" sentiment in the Pacific Northwest, constructing CTs of any type will be difficult. This dynamic was illustrated in the Commission's hearing on PSE's Draft IRP (which proposed CTs fueled by renewable natural gas) where virtually all the 60+ commentors opposed construction of any CT infrastructure, assuming such a facility would ultimately use conventional

[19] Fina IRP at 1-13 ("To reduce exposure to the increasingly supply challenged and volatile wholesale energy market, this IRP recommends that up to 1,000 MW of PSE's Mid-C transmission should be filled with firm resource adequacy qualifying capacity contracts that meet PSE's reliability requirements for resource adequacy.").

[20] *See* Final IRP at 1-13, Fig. 1-4 (showing nearly 1,000 MW of biodiesel capacity to be added by 2045, with approximately 255 MW before 2031).

natural gas as its primary fuel. Thus, relying on constructing any type of CT resource, in a political climate that is drastically opposed to such resources, is simply imprudent.

Furthermore, biodiesel technology comes with other, significant limitations that undermine the validity of PSE's assumptions in the Final IRP. For example, to operate in cold weather, biodiesel needs special additives to prevent the fuel from gelling. Additionally, biodiesel peakers face fuel challenges related to fuel cost, carbon intensity, and CETA compliance. PSE does not account for any of these factors in its assumption that biodiesel peakers will be the least cost resource to meet PSE's future capacity needs. As a result, PSE's Final IRP does not perform sufficient due diligence on the biodiesel technology and, instead, assumes over 250 MW of biodiesel CTs can be built at an artificially deflated price, all by 2030.

Another flaw in PSE's biodiesel analysis is that, by PSE's own math, the maximum dispatch of its biodiesel peakers equates to 205 hours of run time, or roughly ~2.35% of the potential annual hours of run time. This translates to approximately 10% of Washington State's 2020 annual production being required by the single plant, in certain scenarios. If that need were to occur in a specific month, there would not have been enough fuel supply for the plant. As a result, PSE's analysis offers a solution (biodiesel CT) that is impractical, higher cost than is being projected, unrealistic, and highly speculative. Again, these significant flaws in PSE's Final IRP call into question whether biodiesel CTs are the least cost resources and, as a result, whether PSE's Final IRP meets the Commission's requirements.[21]

V. PSE's Process in Preparing the Final IRP Was Inadequate and Did Not Provide Stakeholders Meaningful Opportunity to Comment in Advance of the Final IRP's Filing with the Commission.

While Swan Lake and Goldendale appreciate PSE's effort to produce the Final IRP on such a short timeline, the rush to get the Final IRP filed by the April 1 deadline resulted in several procedural failures and missed deadlines that resulted in stakeholders not having an adequate ability to provide input on some of the material aspects of the Final IRP. In particular, many of the supporting files and appendices containing detail around the assumptions used in the Final IRP and PSE's modeling process were not shared until the Final IRP filing was made. As a result, these comments are the first (and only) opportunity for stakeholders to question PSE's modeling assumptions and analysis. Given this significant procedural deficiency, it is incumber upon the Commission to direct PSE to revise its analysis, after public input from various stakeholders, to ensure that the Final IRP is accurate, represents the actual least cost set of resources, and thereby, meets the Commission's rules.[22]

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[21] WAC 480-100-610(1) ("[E]ach electric utility has the responsibility to identify and meet its resource needs with the <u>lowest reasonable cost mix of conservation and efficiency, generation, distributed energy resources, and delivery system investments to ensure the utility provides energy to its customers that is clean, affordable, reliable, and equitably distributed</u>. At a minimum, integrated resource plans must include the components listed in this rule. Unless otherwise stated, the assessments, evaluations, and forecasts should be over an appropriate planning horizon.) (emphasis added); see also WAC 480-100-620(7) ("The IRP must include a comparative evaluation of all identified resources and potential changes to existing resources for achieving the clean energy transformation standards in WAC 480-100-610 <u>at the lowest reasonable cost</u>.") (emphasis added).

[22] *Id*.

VI. Conclusion

Swan Lake and Goldendale appreciate that PSE was put in a difficult situation by needing to prepare and file the Final IRP by April 1st. However, despite the time crunch, the Commission's rules require the Final IRP to fairly analyze the portfolio of resources to determine the "lowest reasonable cost mix of conservation and efficiency, generation, distributed energy resources, and delivery system investments to ensure the utility provides energy to its customers that is clean, affordable, reliable, and equitably distributed."[23] Because of the flawed assumptions used by PSE to prepare the Final IRP, Swan Lake and Goldendale suggest that PSE's Final IRP does not meet this standard, and, as a result, the Commission should not acknowledge the Final IRP, as written. Some of the flaws in PSE's analysis are likely due to the failure to timely provide some of the supporting files and appendices prior to the filing of the Final IRP, which resulted in stakeholders not being able to provide meaningful input on these modeling assumptions.

Without correcting some of the numerous assumptions identified in these comments, Swan Lake and Goldendale have significant concerns that PSE's ratepayers may overpay for the wrong set of resources—a set of resources which Swan Lake and Goldendale suggest may not even meet PSE's real, future capacity needs. In that scenario, not only would PSE's customers overpay, but PSE's future IRPs will identify an even greater capacity need than is currently shown, thereby resulting in an even greater need for capacity resources, at an extremely high cost to PSE ratepayers. The Commission can avoid these results by requiring PSE to revisit its Final IRP analysis and correct some of the inaccuracies contained therein, particularly with respect to pumped storage. As a result, Swan Lake and Goldendale respectfully request that the Commission instead require PSE to re-run its IRP model and analysis using updated information and assumptions based on stakeholder feedback to address some of the issues raised in these comments.

Swan Lake and Goldendale are concerned if the Final IRP is not revised now to reflect accurate inputs and assumptions, given that PSE's recently-issued All-Source RFP relies on the Final IRP for evaluating the RFP responses, the RFP results will also be flawed and cause PSE to enter into contracts with resources that are not truly least-cost, to the detriment of PSE's ratepayers.

Sincerely,

/s/ Nathan Sandvig

Nathan Sandvig
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[23] *Id*.