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November 14, 2019

Via Electronic Filing

Chair David Danner
Commissioner Ann Rendahl
Commissioner Jay Balasbas
Washington Utilities and Transportation Commission
621 Woodland Square Loop SE
Lacey, WA 98503

Re: Utility PURPA Compliance Filings –
Comments on Utility Avoided Cost Prices for Consideration in Advance of the November 22, 2019 Open Meeting

Docket Nos. UE-190663 – Avista
UE-190665 – Puget Sound Energy
UE-190666 – PacifiCorp

Dear Commissioners:

The Northwest and Intermountain Power Producers Coalition ("NIPPC") and the Renewable Energy Coalition ("REC") submits these comments on the avoided cost prices contained in Avista's, Puget Sound Energy's ("PSE"), and PacifiCorp's (collectively the "Utilities") Public Utility Regulatory Policies Act ("PURPA") Compliance Filings submitted in Docket Nos. UE-190663, UE-190665, and UE-190666 respectively.

The Utilities initially filed these Compliance Filings on August 9, 2019. NIPPC and REC submitted Initial Comments on September 9th, identifying possible issues with each of the Utilities' filings including issues regarding how the avoided cost prices were calculated. These comments provide further detail regarding Avista's and PSE's avoided cost price calculations. NIPPC and REC also intend to submit additional comments regarding Avista's and PSE's contracting procedures in advance of the November 22, 2019 public meeting and in response to expected revisions from the Utilities regarding those procedures.

Per PacifiCorp's letter and revised compliance filing in Docket No. UE-190666 dated October 24, 2019, PacifiCorp's effective date is revised to January 24, 2020, and NIPPC and REC plan to submit comments on PacifiCorp's energy and capacity prices and contracting processes on December 6, 2019.[1] These comments are being submitted later because

1 Pursuant to discussions with Staff and PacifiCorp, PacifiCorp will make a revised filing by November 18, 2019, NIPPC/REC and other stakeholders will submit comment by

PacifiCorp's energy and capacity prices and contracting are more controversial and require additional process.

Finally, NIPPC and REC intend to participate in further proceedings regarding any remaining issues, which include the large qualifying facility pricing methodologies and standard contracts. Specifically, NIPPC and REC intend to submit comments on these topics at a later not-yet-determined date.

Avoided Cost Prices Generally

Under PURPA, each electric utility is obligated to purchase any energy and capacity made available from a qualifying facility, whether that energy and capacity is provided directly or indirectly to the utility.[2] The Washington Utilities and Transportation Commission ("WUTC" or "Commission") requires the Utilities to file a tariff for purchases from qualifying facilities ("QFs") including a schedule of avoided costs that a QF with a design capacity of five megawatts or less may choose to receive.[3] The schedule of avoided costs must include an estimated avoided cost of energy, and an estimated avoided cost of capacity, including levelized avoided cost pricing.[4]

- The avoided cost of **energy** must be based on the utility's "current forecast of market prices" for the current calendar year and next twenty years.[5] The avoided cost of energy may incorporate "the daily and seasonal peak and off-peak period prices, by year."[6]

- The avoided cost of **capacity** must be based on the "projected fixed cost of the next planned capacity addition identified in the succeeding twenty years in the utility's most recently acknowledged integrated resource plan."[7] The cost for that planned capacity addition must be based on either the estimate included in the most recently acknowledged IRP or the most recent project proposals received pursuant to a request for proposal ("RFP").[8] However, if the most recently acknowledged IRP identifies the need for capacity in the form of market purchases, then the capacity cost must be based on the projected fixed cost for a simple-cycle combustion turbine identified in the most recently acknowledged IRP.[9] The avoided cost of capacity must account for the difference in the in-service date of the QF and the next planned resource by levelizing the lump sum

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December 6, 2019, PacifiCorp will file response comments on December 20, 2019, and Staff will review and prepare a memorandum for the January 23, 2020 open meeting.

2 18 CFR 292.303(a).
3 WAC 480-106-030.
4 WAC 480-106-040.
5 WAC 480-106-040(1)(a).
6 *Id.*
7 WAC 480-106-040(1)(b).
8 WAC 480-106-040(1)(b)(i).
9 WAC 480-106-040(1)(b)(ii).

present value of the avoided cost of capacity discounted by the utility's commission-approved weighted average cost of capital.

In Washington, the Commission confirmed that even though many of the avoided cost inputs are sourced from the utilities' IRPs or other internal documents, "any party may raise concerns with any utility's inputs and assumptions when the utility files its tariff for purchases from qualifying facilities," rather than being required to raise any issues related to avoided cost inputs in the underlying IRP or other proceeding.[10] Inherent in this ability to challenge inputs and assumptions, is the expectation that such inputs and assumptions will be fully disclosed within the avoided cost process so that stakeholders have a meaningful opportunity to review, understand, and raise concerns.

This process is important because the utility IRP processes rarely provide stakeholders a meaningful opportunity to influence utility decisions. The IRP pre-filing process involves numerous meetings and issues unrelated to avoided costs. Once filed, the IRP is often near its final form, and the IRP is not a contested process. Further, even after acknowledgement, the utilities are free to depart from their IRP when making actual resource decisions. Thus, the IRP does not provide QFs an opportunity to examine and potentially challenge the various input assumptions and methodologies used by utilities, including those that have a material impact on avoided cost prices. Therefore, it is not reasonable to expect that a QF be involved in that process in order to challenge an avoided cost input and it is not appropriate to assume that any IRP input is fully vetted or to presume its accuracy. Rather, it is appropriate to review the reasonableness of such inputs in the avoided cost filing.

Mid-C Energy Market Forecasts

PSE's and Avista's Mid-C energy market forecasts inappropriately and without explanation underestimate market prices relative to their prior market forecasts, the forecasts of other entities, and actual recorded Mid-C prices.[11] The Commission should direct PSE and Avista to use their market forecasts from their most recently acknowledged IRPs or their market forecast used in their initial estimate of avoided costs in their most recent request for proposal ("RFP"). Such forecasts should be used in these avoided cost filings unless and/or until PSE and Avista present a well-supported market forecast including a reasonable explanation of the forecast assumptions and model and a reasonable justification for why their forecasts differ from those previously used. Historically, market prices and market price forecasts illustrate rising prices over time, yet PSE and Avista present to the Commission new forecasts that remain essentially flat over the planning horizon with no explanation.

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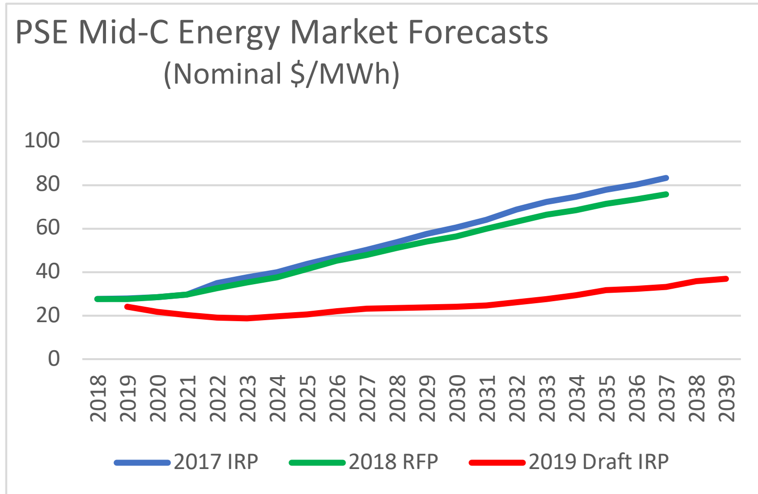
10 *In re Amending, Adopting, and Repealing Sections of WAC 480-106 and 480-107 Relating to the Pub. Util. Regulatory Policies Act*, Docket No. U-161024, General Order No. R-597 at 7 (June 12, 2019).

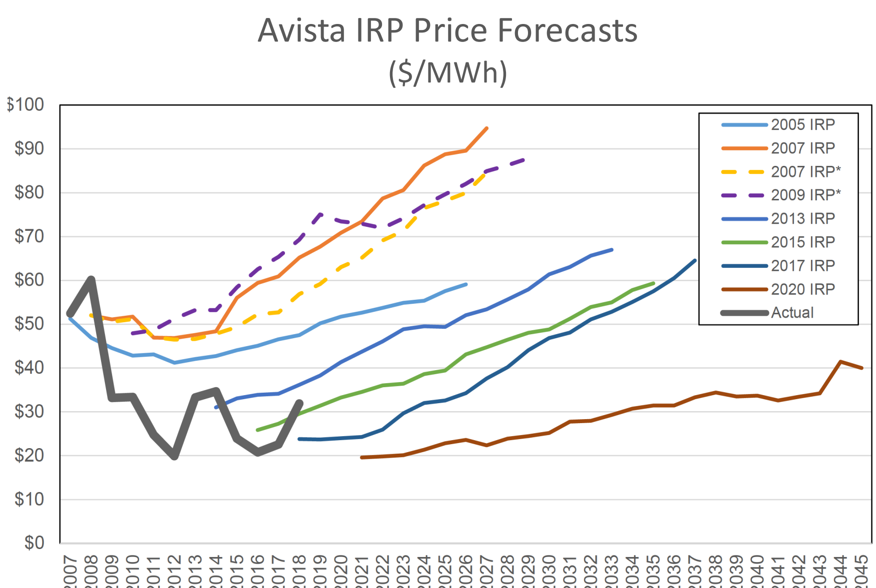
11 Mid-C prices for the period January 1, 2019 through November 16, 2019 have averaged $37.00 per MWH. By comparison PSE's forecast does not ever attain that level.

Figure 1



PSE's Mid-C market forecast departs dramatically from its current draft 2019 IRP forecast. This forecast is far lower than either PSE's 2017 IRP market forecast or even the forecast used to estimate avoided costs for its 2018 all source RFP. *See* Figure 1.[12] While PSE incorporates recent developments in the market, such as the expected social cost of carbon and implementation of Washington's Clean Energy Transformation Act ("CETA"), the stark difference in this forecast from its prior forecasts and even from current Mid-C market prices, warrants a well-reasoned explanation for the departure. PSE asserts that the Commission's rules, by allowing utilities to use their current market forecasts, "do not require that estimated avoided costs of energy come from a source where the forecast accuracy must be vetted."[13] While the most up-to-date forecast may appear on its face to be beneficial to ratepayers, it is not beneficial where it is not accurate. Accuracy should be a primary goal of setting PURPA avoided cost prices because inaccurate pricing will harm ratepayers, whether over- or under-estimated. An overly high forecast may harm ratepayers by sending price signals to QFs that are too

Figure 2



12 *Compare* PSE 2017 IRP, Appendix N at N-71, Figure N-40, *with* PSE 2018 All Resources RFP, Exhibit G at G-2, *and* PSE Workpapers at tab "Energy Prices" (Aug. 9, 2019).

13 PSE's Responses to Stakeholder Comments, Attachment at Issue #14 (Sept. 27, 2019).

high. And, conversely, inaccurately low forecasts harm ratepayers by quashing the utility's otherwise viable PURPA competitive supply.

Avista's Mid-C market forecast from its current draft 2020 IRP is similarly questionable. This forecast is far lower than any of Avista's recent forecasts. *See* Figure 2.[14] Even the actual prices in 2013, 2014 and 2018 appear to be higher than the 2020 IRP forecast through 2043.

In reviewing the underlying assumptions of PSE's and Avista's market forecasts, nothing stands out as the obvious explanation for this dramatic shift in pricing. PSE and Avista's filings lack any discussion for why such a substantive departure exists. The main suspect of a lower price forecast is natural gas prices, but those have generally remained consistent in recent years,[15] and without the opportunity to dive into the modeling, there is little ability to vet these inputs. It is unclear, for example, the extent to which each utility considered supply resource adequacy such as the effect on market prices of the expected retirement of 3,600 MW of coal generation.[16]

Further, PacifiCorp produced a significantly higher price forecast in its avoided cost filing, and even in its recently released IRP. *See* Figure 3.[17] Notably, PacifiCorp's avoided cost filing uses a forecast that projects a minimum of a $61.56/MWh price in 2038[18] and its recent IRP simulation projects that 2038 Mid-C prices will range somewhere between $65.00/MWh at the first percentile to $80.00/MWh at the 99th percentile.[19] In contrast, PSE projects a price of $35.93 in 2038 and Avista projects $38.60/MWh in 2038. Avista and PSE's earlier market price forecasts are more in line with PacifiCorp's price forecasts than their current forecasts.

The Commission's recent decision to delay the utilities' obligations to file their IRPs pending implementation of the Clean Energy Transformation Act raises additional concerns about the accuracy of the market forecasts. The further in time the forecast is from the actual IRP filing, the less we should trust the forecast. This is so because not only are we unable to review the forecasts in depth including the methodology and all underlying assumptions, but also because the utility has space to produce an artificially low forecast now which will only be used

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14 Avista 2020 IRP Electric Market Price Forecast Presentation at 22 (Aug. 6, 2019) available at https://www.myavista.com/about-us/our-company/integrated-resource-planning.

15 *See* U.S. Energy Information Administration, Henry Hub Natural Gas Spot Price (last accessed Oct. 23, 2019) available at https://www.eia.gov/dnav/ng/hist/rngwhhdA.htm.

16 Pacific Northwest Utilities Conference Committee, 2019 Northwest Regional Forecast at 2 (April 2019), available at: http://pnucc.org/system-planning/northwest-regional-forecast.

17 PacifiCorp 2019 IRP at 186 (Figure 7.5 Simulated Annual Mid-C Electricity Market Prices).

18 *See* Staff Memorandum at 3 (Sept. 12, 2019) (referring to PacifiCorp's fixed tilt solar prices, the lowest avoided energy price forecast in the Company's tariff).

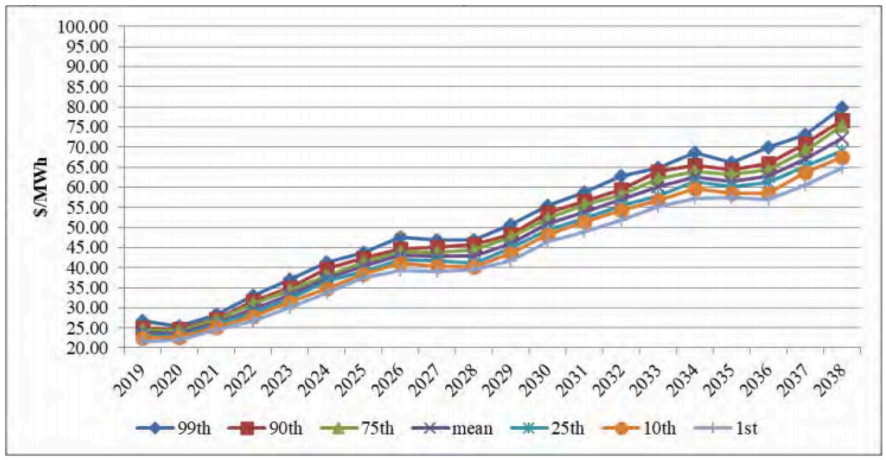
19 See Figure 3.

for the purpose of setting PURPA avoided cost prices and to later produce a more accurate forecast that will be used in the actual IRP filing. As such, it is even more important to fully review and vet the methodologies and assumptions.

Therefore, in light of both current forecasts from other entities and their own historical market forecasts, as well as current supply options and current market prices, both PSE and Avista's Mid-C market forecasts lack credibility absent a compelling justification. Unless and until these market forecasts can be fully vetted, they should not be embedded into these utilities' respective avoided cost filings. To do so would send inappropriate and inaccurate price signals to PSE's and Avista's PURPA competitors, both harming the market and the utilities' respective ratepayers. As such, the Commission should require PSE and Avista to each revise their compliance filings using appropriate market forecasts, either from their most recently acknowledged IRP or recent RFP schedule of avoided cost.

Figure 3

Simulated Annual Mid-C Electricity Market Prices



Finally, the Commission should evaluate whether it is appropriate to define market prices based solely on the Mid-C. The products provided by different generators are not homogeneous. Solar generation provides a different product than wind, both of which provide a different product than that provided by geothermal or biomass. Therefore, Mid-C may not reasonably define "the market" and to use single index to evaluate all these altogether can lead to incorrect conclusions.

Avista Capacity

Avista has not provided sufficient justification for its zero percent wind and solar capacity contribution values. Avista notes that the 7x24 capacity value assumes that the resource provides its maximum delivery rate during on-peak period and asserts that wind and solar should receive a 0% on-peak capacity contribution.[20]

First, Avista should be required to calculate a variable generation resource's contribution to capacity in terms of that resource's contribution to resource adequacy and that resource's ability to reduce the loss of load probability in some or all hours or days utilizing the Effective

[20] *E.g.*, Avista's Workpapers at tab "Filed Schedule – 2020 Start."

Load Carrying Capability ("ELCC") methodology or another appropriate approximation.[21] Other utilities in the Northwest use the ELCC methodology and arrive at values for capacity that are greater than zero. Portland General Electric Company calculated ELCC values for wind that ranged from 12 to 37 percent, depending on the location, and ELCC values for solar of 9%.[22] Montana wind, for example, received the highest, a 37% ELCC,[23] which is notable because Avista's draft action plan anticipates acquiring a 100 MW Montana wind power purchase agreement and another 200 MW of Montana wind in 2027.[24] While there are other issues related to PSE's capacity methodology described below, PSE also uses an ELCC methodology.[25] Even NorthWestern Energy in Montana, which is also a winter-peaking utility, arrived at a 6.1% solar capacity contribution in 2017 and wind capacity contribution of 5%.[26] The calculations should be fairly comparable for Oregon and Washington, given the similar resource locations and similar climates.

Second, Avista provides no sufficient justification for its assumption that wind and solar do not contribute at all to meeting Avista's capacity requirements, or that Avista should be only focusing on a winter peak. Avista's 0% capacity contribution factors do not reflect Avista's own prior study results and those of other utilities that show that wind and, to an even greater extent, solar can provide meaningful capacity contributions, even in the winter. While Avista's winter peak has typically been higher, Avista plans for peaks in both summer and winter,[27] and notes

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21 Avista committed to perform such analysis in its Hydro One merger settlement which was not approved.

22 Portland General Electric Company 2019 IRP at 167-168, Table 6-6.

23 *Id.*

24 Technical Advisory Committee #5, 2020 Electric Integrated Resource Plan DRAFT "Preferred" Resource Strategy presentation at slides 12-13 (Oct. 15, 2019) available at https://www.myavista.com/about-us/our-company/integrated-resource-planning.

25 Puget Sound Energy 2017 IRP at 6-9, Figure 6-4.

26 *In re NorthWestern Energy's Application for Interim and Final Approval of Revised Tariff No. QF-1, Qualifying Facility Power Purchase*, Docket No. D2016.5.39, Final Order No. 7500c at ¶¶ 67-70 (July 21, 2017). This solar capacity contribution was appealed to the district court, which found that the Commission's determination was arbitrary and that based on record evidence NorthWestern's high-demand hours in the summer and winter months resulted in an average capacity contribution for solar of 36%. *Vote Solar v. Mont. Pub. Serv. Comm'n*, BDV-17-0776 at ¶ 22 (MT 8th Jud. Dist. Apr. 2, 2019), *appeal pending*, No. DA 19-0223 (Mont.).

27 Avista's 2017 IRP at 3-19 ("Avista must build generation capacity to meet winter and summer peak periods. Looking forward, the highest peak loads are most likely to occur in the winter months, although in some years a mild winter followed by a hot summer could find the annual maximum peak load occurring in a summer hour. On a planning basis where extreme weather is expected to occur in the winter, peak loads occur in the winter throughout the IRP timeframe.")

that "Avista is also short in summer and on an annual average basis beginning in 2027."[28] Its loss of load probability analyzed in its 2017 IRP was higher in the summer in all but one of the study results.[29] Further, Avista has had four summer peaks in the last 20 years.[30] And its forecasted summer and winter peaks are not all that different. Notably, Avista's 2017 IRP forecasted summer peak of only 74 MW less than its winter peak at the beginning of the planning period, narrowing to 68 MW over the planning horizon.[31] The Seventh Northwest Conservation and Electric Power Plan finds that summer and winter peaks converge at a much faster rate and predicted that summer-peak demand may equal winter-peak demand near the end of the 20-year plan.[32] Avista provides no assessment of wind and solar resources in its capacity contribution. Therefore, by simply focusing on a few peak demand days in winter, Avista overlooks the significant and growing peaks that occur in the summertime. Summer peak loads provide a greater opportunity for solar power plant projects to effectively and meaningfully contribute to peak load requirements.

Additionally, Avista appears to propose to adjust its standard published pricing for individual QFs (not solar and wind) based on the capacity contribution of a similar resource from Avista's IRP.[33] Specifically, Avista states that:

> The capacity contribution for new resources, or for resources without a full thirty-six (36)-month operating history, shall be based on the capacity contribution from a similar resource in the Company's latest IRP. 7x24 assumes resource provides its maximum delivery rate during the winter on-peak period.

This approach in inappropriate for two reasons. First, all non-wind and non-solar resources should be assumed to be baseload resources and have a 100% capacity contribution. All other Northwest utilities assume so in their avoided cost schedules.[34] Second, QFs may choose to receive a standard published price.[35] Avista's course of action will deprive small non-wind and

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28 Technical Advisory Committee #5 Slides at 2020 Electric Integrated Resource Plan DRAFT "Preferred" Resource Strategy presentation at slide 2 (Oct. 15, 2019) available at https://www.myavista.com/about-us/our-company/integrated-resource-planning.

29 Avista's 2017 IRP, Appendix A at 50.

30 Technical Advisory Committee #4, Peak Load Forecasts at slide 11 (Aug. 6, 2019).

31 Avista's 2017 IRP at 3-23.

32 Available at https://www.nwcouncil.org/sites/default/files/7thplanfinal_chap07_demandforecast_1.pdf.

33 *See* Avista's Proposed Schedule 62 at Section I(1)(c) (Nov. 12, 2019).

34 *See* PacifiCorp proposed Schedule QF (Issued Aug. 9, 2019); PSE proposed Schedule 91 (Aug. 9, 2019); Portland General Electric Schedule 201 (effective Apr. 24, 2019); PacifiCorp Oregon Standard Avoided Cost Rates (effective Apr, 24, 2019); Idaho Power Company Oregon Schedule 85 (effective April 24, 2019).

35 WAC 480-106-030(3) ("[QF] developers proposing projects with a design capacity of five megawatts or less may choose to receive a purchase price for power that is set forth in such standard tariff.").

non-solar QFs of transparency into the published price because the ultimate price paid is not published. Rather, under Avista's tariff, the QF will receive some price other than the published price because it will be adjusted by a capacity contribution that is not even stated in the tariff. Avista's approach is therefore inconsistent with the Commission's rules to require published standard pricing for all QFs. As such, the Commission should require that Avista revise its filing to specifically state the capacity payment for each resource type and assume that all non-wind and non-solar resources contribute 100%.

Finally, Avista's monthly energy shaping factors create an unnecessary variance over the course of the year. Rather than paying 100% of the annual energy price in each month, Avista proposes to pay different percentages according to that month's share of the average. For example, in May, Avista would apply a negative four percent energy shaping factor because over the twenty-five year Mid-C price forecast, the average prices in May are equal to -4% of the average price in all months.

The rules allow for daily and seasonal peak and off-peak prices, by year, but do not explicitly allow for monthly prices.[36] While this type of adjustment is generally acceptable, this energy shaping factor is confusing for smaller unsophisticated QFs and simply creates a variance in monthly prices that is not needed. The average annual price already accounts for the variance in prices over the course of the entire year. NIPPC and REC are not opposed to discussing monthly prices with Avista, but it should not be adopted at this time given the counter-intuitive and unsupported justification for negative monthly factors. However, if the Commission is going to adopt Avista's negative monthly factors, then QFs should be provided the option to either not deliver during these months or sell their power to another third party (most QFs do not have the option to sell to other parties, but it is possible for some projects).

Puget Sound Energy Capacity

PSE's implementation of the capacity price is inconsistent with the Commission's rules. First, PSE did not base its avoided costs on the cost of a simple-cycle combustion turbine in the years its IRP identified the need for capacity in the form of market purchases. Staff also identified this as an issue in its initial comments but indicated that "staff understands that the company intends to rectify this with replacement tariff pages and workpapers before the . . . effective date." As of the date of drafting these Comments, NIPPC and REC have not yet seen this revised filing. Because PSE's implementation of this provision is in direct contradiction with WAC 480-106-040(1)(b)(ii), PSE should submit such revised workpapers, and if it does not, the Commission should reject PSE's compliance filing. Staff and stakeholders should have an opportunity to review these costs.

Second, PSE did not base its remaining capacity price on its *next* planned capacity addition but rather on *all* future planned capacity additions. The rules require the capacity price

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36 WAC 480-106-040(a) ("[T]he utility may incorporate the daily and seasonal peak and off-peak period prices, by year.")

to be "based on the projected fixed cost of the *next* planned capacity addition identified in the succeeding twenty years."[37] PSE interprets the language "succeeding twenty years" as requiring or allowing PSE to base its capacity costs on all future planned capacity additions rather than just the next addition.[38] PSE implements this interpretation by including the cost of a four-hour flow battery in 2023 and 2024, then a frame peaker beginning in 2025.[39] Over time and with each different capacity addition, the projected fixed costs vary.

PSE's interpretation is inconsistent with the Commission's rules because the rule clearly states that the capacity price must be based on the projected fixed cost of the next planned addition. This language contemplates only a single capacity addition upon which to base avoided costs. As a matter of policy, this makes sense because PURPA projects help avoid the next most expensive resource addition. Here, PSE's next resource addition, the four-hour flow battery is also its most expensive resource addition. Contrary to PSE's assertions, this interpretation still gives effect to the "succeeding twenty years" language because that is the time period to which the utility should look to determine which capacity addition is next. Therefore, PSE should be required to submit a revised compliance filing consistent with the Commission's rules, or otherwise the Commission should reject PSE's filing.

Additionally, PSE's 2% solar capacity contribution and 11% wind contribution factors undervalue the contribution of those resources. As noted above, other northwest utilities have reached significantly different numbers for their capacity contributions. PSE notes in its own 2017 IRP, that the Wild Horse solar facility produces at 5 to 10% of its peak output even on a dark overcast day, which supports a higher capacity contribution than 2%.[40] In addition, the National Renewable Energy Laboratory demonstrated that solar resources can provide up to 50 to 80% of their AC rating as capacity contribution to peak.[41] As for wind, the U.S. Department of Energy's 2018 Wind Technologies Market Report highlights that wind turbine design is improving to allow energy production from various wind speeds (especially lower wind speeds) increasing effective capacity factor.[42]

Even if PSE's proposed ELCC is accepted, PSE incorrectly calculates the capacity component of the proposed rate. PSE spreads the annual capacity value over 8760 hours of generation, which will result in paying QFs only a fraction of the acknowledged capacity value. PSE should therefore spread the capacity value over the expected annual production of the QF.

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37 WAC 480-106-040(b) (emphasis added).

38 *See* PSE's Responses to Stakeholder Comments, Attachment at Issue #42 (Sept. 27, 2019).

39 PSE Workpapers at tab "Capacity Delivered" (Aug. 9, 2019); *See also* PSE Proposed Schedule 91, Sheet 91-I (Aug. 9, 2019).

40 PSE 2017 IRP, Appendix D at 11.

41 National Renewable Energy Laboratory, Solar Energy and Capacity Value at 1, available at https://www.nrel.gov/docs/fy13osti/57582.pdf.

42 U.S. Dept. of Energy, 2018 Wind Technologies Market Report at 27, available at https://www.energy.gov/eere/wind/downloads/2018-wind-technologies-market-report.

Staff noted that PSE had not yet filed replacement pages implementing this concept, but that the company has been receptive to the revision.[43] Should PSE make such a revision, NIPPC and REC's concerns on this point may be sufficiently addressed.

Finally, PSE does not appropriately account for the starting year of the facility, and assumes the facility starts operating January 1, 2019. As a result, a facility that starts in December 2022 would receive four years of zero capacity value, while it should only receive one month of zero capacity value. This is a problem because the years over which the avoided cost prices are levelized do not match up with the years the QF will be providing energy and capacity. To remedy this issue, PSE should provide different 'first delivery' dates, as Avista does in its tariff.

Conclusion

NIPPC and REC recommend that the Commission make the changes discussed above, or in the alternative, suspend Avista and PSE's avoided cost filings so that the inputs can be appropriately vetted.

Sincerely,

Marie Barlow

Marie Barlow

cc: John Lowe, Executive Director REC
Carol Opatrny, Interim Executive Director NIPPPC

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43 *See* Staff Memorandum at 4 (Sept. 12, 2019).