BEFORE THE WASHINGTON UTILITIES AND

TRANSPORTATION COMMISSION

U-161024

In the Matter of Rulemaking for Integrated Resource Planning, WAC 480-100-238, WAC 480-90-238, and WAC 480-107	))))))))))	NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION, RENEWABLE ENERGY COALITION, RENEWABLE NORTHWEST, NORTHWEST ENERGY COALITION, AND CLIMATE SOLUTIONS JOINT COMMENTS

I. INTRODUCTION

1. The Northwest and Intermountain Power Producers Coalition ("NIPPC"), the Renewable Energy Coalition ("REC"), Renewable Northwest ("RNW"), the NW Energy Coalition ("Coalition"), and Climate Solutions ("Joint Parties") submit these comments in response to the March 13, 2018 Notice of Comments and Workshop (the "Notice") and the informal draft rules ("Draft Rules") that the Washington Utilities and Transportation Commission (the "Commission" or "WUTC") has proposed to update its implementation of the Public Utility Regulatory Policies Act ("PURPA"). The Joint Parties appreciate this opportunity to comment on the Draft Rules and to respond to the issues highlighted by the Commission. These comments also address additional topics that the Joint Parties consider important to this PURPA rulemaking process.

2. The Joint Parties encourage the Commission to adopt the Joint Recommendation, filed February 26, 2018, which reflects a stakeholder compromise on a number of key issues of this rulemaking. The Joint Recommendation was filed by Puget Sound Energy ("PSE") and outlines areas of common ground between PSE and the Joint Parties. It represents a

compromise supported by parties as a comprehensive package. The Joint Parties may not necessarily support any single aspect of the Joint Recommendation taken in isolation. The Joint Parties' discussions with Puget Sound Energy ("PSE") were fruitful, resulting in a recommendation that appropriately balances the interests of utilities, ratepayers, and independent power producers. The Joint Parties note that both Avista and PacifiCorp have filed responses to the Joint Recommendation. Below, we address these utilities' substantive concerns, and we look forward to working with all parties to finalize the Draft Rules.

3. These comments seek to address the questions raised by the Commission in the March 14, 2018, Notice of Comments and Workshop and include recommendations for the Commission to consider regarding: the timing of power purchase agreement ("PPA") negotiations and avoided cost updates; the formation of a legally enforceable obligation ("LEO"); contract term length; size eligibility; other specific relevant rule changes; and the need to address interconnection rules in a subsequent process. The Joint Parties view each of these additional issues as fundamental/crucial to the Commission's implementation of PURPA.

II. COMMENTS

1. Is the proposed definition of capacity, as described in WAC 480-106-DDD, an appropriate definition for the purpose of this rule?

4. The Joint Parties encourage the Commission to more clearly and consistently define capacity in the Draft Rules. While other terms or definitions may be appropriate, the Joint Parties recommend, and will use throughout these comments, the following three terms:

> Generator nameplate capacity (installed): The maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer. Nameplate capacity is stated in alternating current for solar.

Capacity value: The contribution of a generating resource to meeting system reliability. It can be defined as the percentage of the generator nameplate capacity that could replace a resource with one-hundred percent capacity value while maintaining the same system reliability level. The system reliability metric is usually the loss of load probability.

Capacity costs: Fixed (non-fuel and non-variable) costs that a utility can avoid by purchasing the output of a qualified facility ("QF"), including but not limited to the capital, land, taxes, salaries and insurance costs of a baseload, peaker or renewable generation facility.

5. The term capacity is often used to describe similar but materially different concepts. Three of those concepts are considered in the Draft Rules and have generally accepted meanings: 1) maximum output of a generation facility (or nameplate capacity); 2) contribution of a facility to reliably meeting system demand (or capacity value); and 3) non-energy costs, which generally includes the capital costs of base-load, peaking or renewable generation (or capacity costs). The Joint Parties recommend that the first concept be described in the final rules as "nameplate capacity," the second as "capacity value," and the third as "capacity costs" or "avoided capacity costs."

A. Nameplate Capacity Should Be Used to Determine the Capability of a Generator to Produce Electricity

6. The Draft Rules' first definition of capacity is "the capability to produce […] electricity energy measured in kilowatts (kW)." This definition is somewhat consistent with the concept of nameplate capacity, which describes how much power (measured in Watts) a generator can produce, with power being a measure of the rate at which energy is generated (in Joules per second). The Draft Rules also refer to this concept using the terms "nameplate capacity" and "design capacity." We encourage the Commission to avoid using, in its final rules, multiple terms to refer to the same concept. For reasons of clarity, consistency, and accuracy, the Joint Parties encourage the Commission to use the term

"nameplate capacity" rather than "design capacity" or "capacity."[1] The Joint Parties also recommend that the Draft Rules' definition of "nameplate capacity" specify alternating current, as this relates to power delivered to the grid (rather than the direct current physically generated by solar panels that is then converted to alternating current to be delivered to the grid). Specifying alternating current for solar generation under the definition of nameplate capacity is consistent with the PSE and the Joint Parties' Recommendation, which specifies a, "Nameplate capacity of 5 MW size (AC for solar) threshold for standard contract and rate eligibility."

7. The primary reason for the Joint Parties' recommendation that the Commission use the term "nameplate capacity" in the Final Rules is that this term is widely used in the industry, clear, and accurate.[2] Although there are a number of different ways to measure eligibility, we stand by the use of nameplate capacity in the Joint Recommendation to honor that agreement. The Joint Parties would also like to highlight that some types of generation resources, in particular hydroelectric and biomass, can be designed to operate slightly below or above their nameplate capacity depending on operational circumstances. Using terminology that looks at potential design or operational capacity of the generator may lead to disputes between a QF and a utility about what the correct capacity level is for the

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1 Proposed WAC 480-106-HHH(4) ("Standard rates for purchases by facilities with a nameplate capacity of seven megawatts or less, shall be implemented as follows:") and WAC 480-106-FFF (2)(twice using the term "design capacity of seven megawatts or less").

2 The Oregon Commission has used nameplate capacity since PURPA was passed, while Idaho Public Utilities Commission uses metered energy amounts. See Re Public Utility Commission of Oregon Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities, Docket No. UM 1129, Order No. 05-584 at 39-40 (May 13, 2005). Oregon's approach is more clear, and does not allow a generator to operate its facility lower than its nameplate capacity in order to qualify for standard rates. See id.

eligibility of standard contracts. As a result, adopting more consistent and specific terminology will decrease the likelihood of the Commission having to resolve potential future disputes. For this same reason, we encourage the Commission to specifically identify a single, common threshold for standard rates for solar QFs at the equivalent of nameplate capacity using alternating current. If the Commission does not use nameplate capacity then the Joint Parties recommend that the Commission explicitly adopt FERC's method of calculating the rolling one-hour measure of max energy input to the grid, which is how FERC establishes QF eligibility.[3]

B. The Draft Rules Should Recognize that Capacity Value and Avoided Capacity Costs May Differ

8. The Joint Parties recommend that the Commission explicitly distinguish between capacity value and avoided capacity costs. The Draft Rule's second definition of capacity" includes the, "capability … to avoid the need to produce electric energy."[4] The Joint Parties believe that this definition of capacity describes the capacity value that a generator may provide and/or the contribution of a generating resource to meet system reliability. A reasonable way to define capacity value is as the percentage of the generator nameplate capacity that could replace a resource with one-hundred percent capacity value while

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3 The Federal Power Act establishes a maximum "power production capacity" of 80 MW to establish PURPA eligibility. 16 U.S.C. § 796(17)(A). FERC has approved QF certification for facilities with net generation of 80 MW over a rolling 60-minute basis even where net generation may exceed 80 MW. American Ref-Fuel Co., 54 FERC ¶ 61,287, 61,816 (1991). FERC has also determined that interconnection losses, even over a distant interconnection line, may be deducted from the net power production capacity. Malacha Power, 41 FERC ¶ 61.350, 61,946-947 (1987). FERC Form 556 removes parasitic station load and interconnection losses from the calculation of the maximum net power production capacity, which may not exceed 80 MW. FERC Form 556 at 9, available at https://www.ferc.gov/docs-filing/forms/form-556/form-556.pdf.

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maintaining the same system reliability level. The system reliability metric used is usually the loss of load probability ("LOLP"). Importantly, capacity value can be determined for either the QF or the utility's proxy resource.

9. In contrast, avoided capacity costs in the PURPA context are the capacity costs of the utility, not those of the QF. Indeed, avoided capacity costs should reflect the costs that the utility incurs or would incur to acquire resources to meet system reliability (i.e., the utility's costs associated with the capacity value of its own generation). These utility costs are the utility's costs of capital, land, and other fixed costs that are aggregated into a capacity payment to a QF. It is important to distinguish that a utility does not purchase "capacity" per se from a QF, but instead pays the QF for the capacity costs that the utility would otherwise incur. In addition, as there can be overlap and sometimes a lack of clear distinction between cost categories, the utility's "avoided capacity costs" are a proxy for, and may not perfectly match, the actual costs associated with the "capacity value" of the utility's generation. For example, it can sometimes be difficult to ascertain whether a cost is truly an energy or capacity cost, and a clear definition of what avoided capacity costs are will help minimize disputes.

2. WAC 480-106-GGG strengthens the relationship between a utility's integrated resource plan and the avoided cost rates available to qualifying facilities. Consequently, avoided cost rates calculated at the time a legally enforceable obligation is incurred will reflect the utility's own forecasts and plans for meeting anticipated demand through a combination of supply-side and demand-side resources over a specified future period. Please comment on the merits of strengthening the relationship between a utility's integrated resource plan and its avoided cost.

10. The Joint Parties generally support the concept of strengthening the connection between a utility's integrated resource plan ("IRP") and avoided cost rates. However, we are concerned with this concept in the context of the current IRP rules. Traditionally, the

IRP has been seen as a utility's plan. The Commission reviews and acknowledges a utility's plan, but does not necessarily scrutinize the individual plan elements in the same manner as it would in a rate case.[5] In addition, the Commission does not issue an order approving or disapproving specific elements, as it might in a rate case. From our perspective, additional process is necessary should the Commission wish to adopt the approach in WAC 480-106-GGG to ensure that interested parties have an opportunity to review the inputs that will be used to calculate avoided cost rates.

11. The Joint Parties' experience indicates that the approach taken in the Draft Rules to strengthen the connection between the IRP and avoided cost rates only functions well if: 1) the IRP review process is strengthened so that PURPA specific issues can be resolved within the IRP process itself; 2) the Commission establishes separate processes or proceedings in which it resolves key PURPA issues through an adjudication or rulemaking; and/or 3) the IRP is merely the starting place for a rebuttable presumption of reasonableness, but it is clear that parties can contest or litigate issues when the rates are filed.

12. We encourage the Commission to allow stakeholders the opportunity to review and, when necessary, challenge avoided cost rate changes. A meaningful opportunity for challenge should allow stakeholders to go beyond just double-checking the utility's math and would include the inputs and assumptions relied upon by the utilities. Without an opportunity to challenge, the process would allow utilities to determine their own avoided cost prices and, consequently, determine whether PURPA is viable in their service territories. While IRPs are long processes with stakeholder involvement, they are not

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[5] See WAC 480-100-238.

contested cases and do not include meaningful opportunities to challenge that the Joint Parties believe are necessary.

13. IRPs do not always match the utilities' actions. In those situations, it may be reasonable that avoided cost rates be based on more recent or accurate information. For example, PacifiCorp's 2015 IRP indicated that the Company would not acquire any new renewable resources for more than twenty years.[6] After the OPUC acknowledged the 2015 IRP, Oregon increased its renewable portfolio standard. Given the new law and the decreasing production tax credit, PacifiCorp immediately departed from its 2015 IRP action plan and tested the market to determine if it should acquire new renewable resources. PacifiCorp's actions were a reasonable response to changing circumstances; however, PacifiCorp departed from its 2015 IRP action plan. In this circumstance, it would have been reasonable to base PacifiCorp's avoided cost rates on the utility's plans to procure renewables rather than on its outdated, but acknowledged, 2015 IRP.

14. In summary, strengthening the connection between the utilities' IRPs and avoided cost rates works well if the Commission conducts a more rigorous review of the key avoided cost rate inputs and assumptions from utility IRPs. A more rigorous review could be achieved by: 1) expanding the IRP process to make it more similar to an adjudicatory proceeding with opportunities for stakeholders to challenge the information within the IRP; 2) conducting separate investigations, rulemakings or other proceeding to resolve important issues (e.g., renewable capacity value); or 3) allowing an opportunity to contest the underlying inputs and assumptions in avoided cost rate update filings.

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[6] See PacifiCorp's 2015 IRP, available at https://www.pacificorp.com/es/irp.html.

3. WAC 480-106-GGG(1)(a) requires a utility to file an avoided energy cost based on the utility's forecast of market prices. WAC 480-106-GGG(1)(b) requires the utility to determine the avoided capacity cost using the Proxy Unit method. When using the Proxy Unit method, one option is to set the avoided energy price based on the energy price of the proxy resource. Should the avoided energy price be based on the market forecast or the price of the energy used for the proxy resource?

15. The Joint Parties support the use of the Proxy Method for calculation of capacity costs and a forward market price for wholesale electricity for the calculation of energy costs in long-term contracts. A proxy method bases the capacity cost payment on the fixed costs of a proxy unit. A proxy method could calculate the energy costs, paid as cents per kWh, with either (i) the variable or running costs of the particular proxy unit (e.g., gas price, operation and maintenance, etc.), or (ii) a forward market price for wholesale electricity (e.g., generic energy price forecast for the region). Between the two options for setting the avoided energy price presented in the Commission's question, the Joint Parties recommend that the avoided energy price be based on a market price forecast for wholesale electricity sales. Various methods could potentially produce reasonable results for estimating future energy prices. When deciding between potentially reasonable different options, the Joint Parties encourage the Commission to select the simplest and most transparent process that reduces stakeholder burden as well as the likelihood of litigation and/or disputes.

16. The Joint Parties' primary recommendation is that Washington investor-owned utilities ("IOUs") use a publicly available and independently published third-party forecast, such as that of the U.S. Energy Information Administration ("EIA"), for the energy costs of a proxy unit. The Idaho Public Utilities Commission Staff, not the utilities, calculates the avoided cost rates for each of the three utilities using the EIA forecast for setting the energy

price for the proxy resource.[7] Two of the three Washington IOUs (Avista and PacifiCorp) operate in Idaho and are familiar with the use of EIA forecasts for setting avoided energy prices. Other third-party forecasts might be reasonable if the information can be provided to stakeholders, including QFs and their representatives, on a non-confidential basis or under the terms of a protective order to facilitate review and vetting.

17. The use of proprietary, expensive, and/or complex computer models to estimate avoided energy prices can lead to an opaque process from the Joint Parties' perspective. While computer models could potentially increase the precision of avoided cost rates, vetting those rates can be prohibitively expensive and complicated for stakeholders. Any model has some black box elements, forcing QFs to either accept the results or hire an expert to acquire and run the models in order to assure that the methodologies accurately forecast actual costs, that all inputs are true inputs and not hard-wired into the model runs, that no mistakes were made, etc.

4. WAC 480-106-GGG(1)(a) requires utilities to file an avoided energy cost on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year. Should the Commission also require the avoided energy cost to include hourly or blocks of hourly periods?

18. The Joint Parties see value in avoided energy costs that include hourly or blocks of hourly prices. Under WAC 480-106-GGG(1), utilities would file avoided energy costs differentiated only by seasonal peak and off-peak periods. As a result, WAC 480-106-GGG(1) would lead to avoided energy costs that rely on seasonal averages and that could

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[7] Re Commission's Review of PURPA QF Contract Provisions including the Surrogate Avoided Resource (SAR) and Integrated Resource Planning (IRP) Methodologies for Calculating Avoided Cost Rates, Case No. GNR-E-11-03, Order No. 32697 at 16-17 (Dec. 18, 2012) (use of EIA for forecasting energy prices).

obscure information about hours of high value during which solar may be generating.[8] Such a reliance on seasonal averages could lead to underestimating the costs that a solar QF would help avoid.[9] Indeed, increased granularity in energy values is important for solar compensation,[10] and could result in more accurate avoided cost rates.

19. However, the Joint Parties are concerned about the potential challenges in accurately calculating hourly or blocks of hourly prices and translating them into specific rates. The economic impact of such granularity in avoided energy costs on different resources may be significant if the capacity value that a QF provides on an hourly basis does not flow through to the actual rates. For example, if the hourly prices that attempt to reflect the capacity of value of solar are incorrect, then solar generation will not be paid for their capacity value and undercompensated. In addition, the Joint Parties are not aware of other utilities in the Northwest that calculate avoided cost prices on an hourly basis.

20. Therefore, the Joint Parties recommend that the proposed rules allow and encourage utilities to set rates based on avoided costs of energy that include hourly or blocks of hourly periods, but that they also require that any methodologies used to differentiate rates on this basis be vetted and approved by the Commission. A utility's decision to use any particular method in its IRP would not provide sufficient vetting under current IRP rules because there would be no opportunity for stakeholders to challenge and obtain Commission resolution. The Commission and stakeholders should have an opportunity to review a utility's proposed

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8 C.f. Public Utility Commission of Oregon Investigation to Determine the Resource Value of Solar, Docket No. UM 1716, TASC/400 Gilfenbaum/6 (stating concerns with the use of monthly, weekly or daily averages to estimate the resource value of solar).

9 C.f. Id.

10 Re Public Utility Commission of Oregon Investigation to Determine the Resource Value of Solar, Docket No. UM 1716, Order 17-357 at 4 (Sept. 15, 2017).

methodology prior to the utility filing its avoided cost rates with the Commission to ensure that they properly credit all generators with the capacity value they provide.

5. WAC 480-106-GGG(2)(iii)[11] discusses schedules of estimated avoided cost. Is discounting the capacity payment from the utility's year of need to the present day an appropriate way to represent the avoided costs of a resource the utility has identified a need for in the future? In balance, does it provide the required price signal for capacity? Does this subsection require additional rule language and specificity?

21. The Joint Parties understand that this question is directed at the hypothetical situation in which a utility does not have a capacity need in the near term, and only has a capacity need in the long-term.[12] In such a circumstance, the Draft Rules appear to contemplate that there could be no capacity payment in the early years, but that there could only be a capacity payment starting on the date upon which the utility has identified a capacity need in the future. Consequently, the Notice asks whether that capacity payment should be discounted to the present day, or otherwise levelized, so that some payment to the QF for the utility's avoided cost capacity payments are made during all years.

22. The Joint Parties first recommend that the Commission's Rules assume that QFs can always avoid some proportion of a utility's capacity costs. FERC's regulations require utilities to purchase "any energy and *capacity* which is made available" from QFs.[13] For example, FERC's "[u]se of the term 'legally enforceable obligation' is intended to prevent a utility from circumventing the requirement that provides capacity credit for an eligible

11 This citation should be to Draft Rule WAC 480-106-GGG(1)(b)(iii).

12 This is in contrast to the situation in which the utility has a need for capacity resources for its system reliability needs, but those are not identified in its IRP, then the capacity payment will be based on a proxy peaker plant.

13 18 CFR 292.303(a) (emphasis added).

qualifying facility merely by refusing to enter into a contract with the qualifying facility."[14] The Ninth Circuit also agrees that avoided costs include both energy and capacity costs.[15] It is only in the extreme case that a utility would have no foreseeable need for any capacity and may thus be relieved of the obligation to pay QFs for the capacity costs that the utility cannot avoid.[16]

23. However, if the Commission determines that a utility truly has no demand or need for capacity in the near term, the Joint Parties agree that the distant capacity payment should be levelized so that QFs are paid for capacity in all years. Levelization may be necessary to smooth out low avoided cost rates, especially for new QFs that need to obtain financing and for existing QFs that need to make significant capital investments. Levelization may also be necessary if there are long periods with low avoided cost rates. Levelization is especially important for existing QFs because they have specific contract expiration dates, few if any potential buyers for their power, and no ability to time their online date with higher resource deficiency avoided cost prices. However, levelization for QFs may not be necessary in most circumstances if the Commission adopts 15-year fixed-price contracts and ensures that all QFs receive value for capacity during all contract years. However, the option should be available for QFs to make that determination based on their specific circumstances.

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[14] 45 Fed. Reg. at 12,224; see also id. at 12,225-26 (providing background to support the capacity-payment requirement).

[15] Independent Energy Producers v. California Public Util. Comm'n, 36 F.3d 848, 851 n.5 (Ninth Cir. 1994).

[16] See Hydrodynamics, 146 FERC ¶ 61,193 at P 35 (Mar. 20, 2014).

6. WAC 480-106-GGG(c) is intended to permit utilities to offer standard rates that take into account the differing qualities of various generation types, such as variations in capacity factors. Currently, the informal PURPA Draft Rules do not specify how a utility might identify these qualities and use them to calculate avoided capacity costs. Does this subsection provide enough specificity or is additional rule language needed?

a. No resource, including thermal generation, has a one hundred percent capacity factor. Should the rules require applying a calculation that compares the qualifying facility to the highest capacity factor resource? For example, if the highest capacity factor plant has a capacity factor of 90 percent, and the qualifying facility has a capacity factor of 30 percent, then the capacity credit to the qualifying facility is 30% ÷ 90% = 33%.

24. The Joint Parties do not oppose accounting for the different qualities of various generation types, including variations in the capacity value. However, this accounting should be carefully implemented so that the full capacity value of renewable resources is reflected in utility avoided cost rates. Variable renewable QFs are currently assumed to have the same capacity value as the proxy plant and receive a full capacity cost payment.[17] Any changes to how the capacity payment is determined should be based on a well-supported methodology that is approved by the Commission.

[17] These comments discuss the capacity value of variable wind and solar generation, which have been and are being studied. The capacity value of biomass, geothermal and hydro have not been separately analyzed, and the Joint Parties recommend that these resources should simply be assumed to have the same capacity value as the baseload or peaking proxy resource. The Oregon Public Utility Commission recently completed an investigation into the capacity value of renewable resources, and the Oregon Commission approved an all party stipulation that approved the use of either an Effective Load Carrying Capability or Capacity Factor approximation for estimating the capacity contributions for wind and solar generators for integrated resource planning. Re Public Utility Commission or Oregon, Investigation to Explore Issues Related to a Renewable Generator's Contribution to Capacity, Docket No. UM 1719, Order No. 16-326 at Appendix A at 3 (Aug. 26, 2016). No methodology was used for other renewable resources, and the Oregon utilities' avoided cost rates differentiate between wind, solar and other renewables, which are assumed to have the same capacity value as the thermal proxy resource. E.g., Pacific Power's Oregon Standard Avoided Cost Rates Avoided Cost Purchases from Eligible QFs at 5-8.

25. The utilities' currently approved methodologies include a capacity payment that reflects the capacity costs that utilities avoid as a result of the QFs, but capacity cost payments are not adjusted based on the supply characteristics of different QF technologies. The Draft Rules proposed that the standard rate "may differentiate among qualifying facilities based on the supply characteristics of different technologies for purposes of calculating the avoided capacity cost."[18] The Joint Parties understand that the Draft Rules would adjust the capacity cost payment to the QF based on the capacity value that a QF may provide to the utility. On a practical basis, this will result in a reduction in the capacity cost payment to the QF.

26. The Joint Parties encourage the Commission to adopt a method that fully and accurately captures the full capacity value that variable generation provides to utilities so that QFs are not undercompensated for the capacity costs that they would cause the utilities to avoid.

27. The Notice questions whether a generic resource capacity factor, (a generally accepted measure of how much energy is produced by a resource compared to its maximum output), should be used to estimate capacity payments, which we consider should be determined based on a resource type's capacity value, or the contribution of a resource to reliably meeting demand. The Joint Parties recommend that the Commission not reduce the capacity payment for variable resources until the utility has a fully vetted and approved methodology for calculating the capacity value of variable resources.

28. The Joint Parties encourage the Commission to direct utilities to use a robust methodology for calculating the capacity value of variable resources. Specifically, we

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[18] Proposed 480-106-GGG(1)(c).

recommend the Effective Load Carrying Capability ("ELCC") or a suitable alternative estimation method that, like the capacity factor approximation method, considers loss of load probability reduction in all hours of the year. The Commission has not yet offered direction to utilities on acceptable methodologies to calculate the capacity value of variable resources. As a result, utilities can use methodologies to estimate capacity value that may undervalue the contribution of renewable resources to system capacity by estimating capacity value on a subset of hours. A QF has capacity value outside of only the peak hours because capacity is needed (to a lesser extent) during shoulder peak hours, and because the QF may be displacing a generating unit that operates (and has capacity costs) during non-peak periods.

29. Comparing PSE and PacifiCorp's solar capacity value is illustrative. For example, PacifiCorp performed a Peak Capacity Contribution Study as part of their 2017 IRP, which includes capacity values for solar in its western Balancing Area Authority of 53.9% for fixed file solar PV and 64.8% for single axis tracking solar PV.[19] In contrast, PSE has concluded that solar provides no peak capacity value because it is a winter peaking utility.[20] In the absence of a Commission approved methodology, an average capacity factor may be a suitable interim placeholder for the QF's capacity value.

30. Undervaluing the capacity contribution of variable resources is not in the public interest and may lead to inaccurate projections of future needs in a utility's IRP. First, a utility that undervalues renewable generators' capacity contributions, may over procure

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19 PacifiCorp 2017 IRP, Volume II at 316, available at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeII_2017_IRP_Final.pdf.

20 PSE 2017 IRP, at 2-8, available at https://pse.com/aboutpse/EnergySupply/Pages/Resource-Planning.aspx.

capacity resources at ratepayer expense. Second, if the utility's analysis relies on inaccurate assumptions on variable resources' contribution to capacity, it is not possible to know whether its IRP "describ[es] the mix of energy supply resources and conservation that will meet current and future needs at the lowest reasonable cost to the utility and its ratepayers," as required by WAC 480-100-238(2)(a).

31. Best utility practice is to calculate a resource's contribution to capacity by considering all hours in a year. The ELCC is defined as the amount by which the utility's load can increase when the specific technology resource (for example, solar or wind) is added to the system while maintaining the same system reliability, as measured by a system adequacy metric such as LOLP.[21] The percentage of the ELCC (in MW) to the nameplate capacity of the resource added (in MW) is the capacity value (in percent) of the added generator. Therefore, a generator has some level of ELCC and capacity value if it reduces the LOLP in some or all hours or days.

32. The ELCC is recognized as a common and robust approach to determining capacity value. The North American Electric Reliability Corporation ("NERC") recommended "the use of LOLP [loss of load probability] ... or related metrics for resource adequacy calculations and for determining the capacity contribution of VG [variable generation]."[22] Furthermore, NREL states that the ELCC method is "...well recognized and widely used due

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21 National Renewable Energy Laboratory, Comparison of Capacity Value Methods for Photovoltaics in the Western United States, July 2012, at 4, available at https://www.nrel.gov/docs/fy12osti/54704.pdf.

22 NERC, Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning, March 2011, available at https://www.nerc.com/files/ivgtf1-2.pdf.

to [its] robustness."[23] However, the data requirements for a robust ELCC can be non-trivial, so alternative approximations have been developed. NREL found that some approximation techniques could yield similar results to an ELCC, finding "the CF (capacity factor approximation method) to be the most dependable technique."[24]

7. Joint Recommendations – The discussion Draft Rules do not include any option or the requirement to transfer any renewable energy credits (RECs) generated by qualifying facilities. The Joint Recommendations propose that RECs should be included in the sale when the avoided costs used to determine a utility's offered standard rate are based on a resource that would also generate RECs. Would this arrangement be satisfactory for all parties? In the instance where standard rates are based on a resource that does not generate RECs, is there reason to permit, or to require, the utility to offer a tariff schedule to qualifying facilities, which include the avoided cost of RECs? This arrangement would enable smaller developers to sell RECs at a set price and avoid the challenge of navigating a complex market, mirroring the rationale that PURPA uses in compelling utilities to purchase of capacity and energy.

The Joint Parties strongly support the adoption of renewable avoided cost rates. As long as this option is provided to QFs, the Joint Parties do not see a need to establish a tariff that separately requires the utilities to purchase renewable energy certificates when the avoided cost resource is based on a non-renewable resource.

A. We encourage the Commission to Adopt Renewable Avoided Cost Rates Consistent with the Joint Recommendation

33. The Joint Parties encourage the Commission to adopt rules that allow QFs the option of transferring RECs associated with their net output and that compensate QFs based on the renewable resource costs avoided by the utility. The proposed creation of a renewable rate, as outlined in the Joint Recommendation, would be satisfactory to the Joint Parties as it

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23 National Renewable Energy Laboratory, Comparison of Capacity Value Methods for Photovoltaics in the Western United States, July 2012, at 27, available at https://www.nrel.gov/docs/fy12osti/54704.pdf.

24 Id.

would allow the QF to commit to transfer its RECs to the utility for years when the rate is set based on the costs of the next deferrable major renewable resource.[25]

34. The Commission has the authority to adopt rules with additional avoided cost rate options that reflects the costs of renewable energy by focusing on the *utility's* avoided costs to comply with state law. FERC has confirmed that the "'full avoided cost' need not be the lowest possible avoided cost and can properly take into account real limitations on 'alternate' sources of energy imposed by state law."[26] Thus, FERC approved the California Public Utility Commission's proposal to calculate avoided costs based on the costs of certain highly efficient cogeneration facilities because California law mandated utilities to acquire energy from such facilities.[27] Likewise, the Oregon Public Utility Commission provides a renewable avoided cost rate that reflects the costs of the next renewable plant the utility must acquire under Oregon's renewable portfolio standard law, such as a wind farm.[28]

35. Although the Joint Parties recommend that the Commission allow QFs the option of selecting between a renewable and nonrenewable avoided cost rate, we do not recommend that those rates be restricted by facility type. For example, PacifiCorp has proposed in other states to limit the availability of renewable avoided cost rates based on facility type.[29] This would mean that a solar QF would defer PacifiCorp's next planned solar facility but would

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25 Joint Recommendation at 2.

26 Cal. Pub. Util. Comm'n, 133 FERC ¶ 61,059, at P.7 (Oct. 21, 2010).

27 Id. at PP. 21-26.

28 In the Matter of Public Utility Commission of Oregon: Investigation Into Resource Sufficiency Pursuant to Order No. 06-538, Order No. 11-505 (Dec. 13, 2011).

29 Rocky Mountain Power (PacifiCorp) Schedule 37 and Schedule 38 Updates, UPSC Consolidated Docket Nos. 17-035-T07 and 17-035-37, available at https://psc.utah.gov/electric/dockets/electric-2017/; OPUC Docket No. UM 1802, PacifiCorp Opening Testimony of Daniel MacNeil at PAC/100, MacNeil (Jan. 27, 2017).

not be allowed to defer the next planned wind facility. Under PacifiCorp's limitation, only a wind QF could defer PacifiCorp's next planned wind facility and no other renewable resources would be allowed to defer any of PacifiCorp's planned wind facilities. This limitation ignores that QF deferrals should be considered in the aggregate and that a solar facility can defer the energy, capacity, and renewable attributes that the utility would obtain if it constructed, for example, a wind facility. Practically speaking, such a limitation would lead to rates that undervalue all renewable types that are not the next planned resource type. All renewable QFs, regardless of facility type, should therefore defer the next planned renewable resource. This Commission, like the Oregon Public Utility Commission, should adopt renewable rates that allow any Washington Renewable Portfolio Standard eligible renewable resource to defer a utility's next planned renewable resource.

B. Under the Joint Recommendation, a Utility Should Be Permitted to, but It Is Not Necessary to Require a Utility to Provide QFs the Option of Selling their RECs to the Utility When Standard Rates Are Based on a Non-Renewable Resource

36. The Joint Parties recommend that the Commission not require utilities to purchase QF RECs when the avoided cost rate is based on the costs of a non-renewable resource. A renewable rate, as outlined in the Joint Recommendation, is preferable to a mechanism in which standard rates are based on a non-renewable resource with a separate tariff schedule for the utility to separately purchase the RECs. In addition, utilities can implement renewable avoided cost rates as indicated by the Joint Recommendation, which aligns with the methodology PacifiCorp and Portland General Electric use in Oregon.

37. The Joint Parties' experience with various utility IRPs in the region indicate that renewable resources are increasingly being selected as part of the "mix of energy supply resources and conservation that will meet current and future needs at the lowest reasonable

cost to the utility and its ratepayers."[30] As a result, an avoided cost rate structure that would only look at thermal, non-renewable generation as the proxy resource (but that allow the QF to sell their RECs to the utility) could underestimate a utility's avoided costs by failing to recognize situations where the next avoidable resource is a renewable resource. Thus, a standard rate based on a thermal resource, plus the option for the QF to sell its RECs to the utility at a set price, would likely provide less benefit to ratepayers, the utility, and the QF, than a renewable rate based on the costs of the utility's next renewable resource acquisition.

38. The Joint Parties recommend that the Commission allow utilities to decide whether to file a tariff schedule that includes the avoided cost of the RECs when standard rates are based on a resource that does not generate RECs. This position is based on the assumption that the Commission adopts a renewable avoided cost rate that includes a mechanism for the transfer of, and compensation for, RECs, like that one in the Joint Recommendation.

8. Joint Recommendations – If the Commission adopts the recommendation to require the inclusion of limited contract provisions to qualifying facilities of all sizes, should the rule specify contract provisions that utilities must offer?

39. We encourage the Commission to allow the parties to maintain flexibility in larger QF contract negotiations, but to encourage utilities to publish their large QF contract information. NIPPC and REC's original comments and recommendation in this proceeding was that large QFs above the standard rate eligibility cap should have the unilateral option to select standard contract provisions.[31] However, the Joint Recommendation does not include any required contract provisions for QFs above the size-eligibility threshold. Rather than requiring certain provisions, we recommend that the Commission require utilities to post large QF contract term sheets. These term sheets can be updated along with the

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30 WAC 480-100-238(2)(a).

31 NIPPC and REC Comments at P. 62.

utilities' standard contracts. Non-confidential versions of executed contracts with large QFs should also be made available to provide better transparency into the market. This level of transparency would aid QFs and utilities alike in their negotiations.

40. The Joint Parties recognize that large QFs have unique provisions and a one-size-fits-all approach does not work. Some of the approaches the Joint Parties considered during conversations leading to the Joint Recommendation to address the difficulty in setting contract provisions for larger QFs include: 1) requiring approval of different contracts for different types of QFs; 2) a core set of contract provisions that can be expanded upon; and 3) allowing each utility to post term sheets for large QF contract negotiations. The Joint Parties believe the last approach is a reasonable resolution and a step forward in meeting the needs for both utilities and QFs because it is tied to the requirement that utilities meet timelines negotiating with large QFs and that the Commission approve a methodology for calculating the rates for large QFs.

41. While the Joint Parties recommend that large QFs not be entitled to pre-approved minimum contract provisions, QFs should still be entitled to contracts that are consistent with the other rules. For example, large QFs should have the right to 15-year contracts. Thus, we encourage the Commission to confirm that the rules established for smaller QFs provide the starting point for larger QF contracts.

9. Joint Recommendations – Does the recommendation that each utility file and obtain Commission approval of its avoided cost rate methodology for qualifying facilities above the size threshold for standard rate eligibility impose an unnecessary burden on utilities, stakeholders, and the Commission? Should the avoided cost rate for larger qualifying facilities depend on facts and circumstances that cannot be easily accounted for by rule?

42. Requiring Commission approval of each utility's avoided cost rate methodology for non-standard avoided cost rates does not impose an unnecessary burden on utilities,

stakeholders, and the Commission. The Joint Parties recognize that an approval process would require engagement by the Commission, utilities, and stakeholders. However, that approval process is necessary to ensure that utility non-standard avoided cost rate methodologies reasonably account for the utilities' avoided costs. The Joint Parties note that all other Northwest states (Idaho, Oregon, Utah and Wyoming) have approved specific methodologies for the calculation of large QF avoided cost rates.

43. The Joint Parties encourage the Commission to adopt rules that require such an approval process to ensure that utility methodologies lead to non-standard rates that provide accurate market signals to QF developers. While avoided cost rates that are higher than an IOU's avoided costs do not meet PURPA's customer indifference standard, avoided cost rates that are artificially low also fail to advance the interests of utility customers and the energy policy of Washington state by inhibiting QF development. Therefore, we encourage the Commission to ensure the accuracy of non-standard avoided-cost rates by adopting final rules that require a final approval process of utility methodologies to set those non-standard avoided cost rates.

10. Timing for PPA Negotiations

44. The Joint Recommendation includes language that underscores the importance of negotiation timelines for QFs seeking PPAs. Specifically, PSE and the Join Parties recommended that: "Tariffs shall specify the information required for a QF to obtain draft and executable contracts, and the timelines and requirements for both QFs and utilities to follow in the contract negotiation process."

45. Due to the natural imbalance of bargaining power between a utility and a QF, and to informational advantages, QFs must be able to rely upon the utility providing information

and processing their PPA request in a timely manner and the utility not requesting or demanding unreasonable information. Placing limits on the maximum amount of time for a utility to provide drafts and specifying the required information for a QF to provide can ensure that the PPA negotiation process runs smoothly.

46. The Joint Parties' goal of having a structured process is not to simply require a QF to go through a certain number of steps to create a legally enforceable obligation ("LEO") or to lock-in rates, but instead to provide both parties a fair process to guide the negotiations. The primary benefit of the Commission adopting a structured process is to require the utility to proceed upon a path with deadlines and clarity regarding what information they should provide and how quickly they should expect the negotiations to proceed under normal conditions. Current rules do not contemplate consequences when utilities may ignore QF PPA requests. Requiring QFs to provide certain information by certain times benefits utilities and QFs alike, as long as utilities cannot use timing process to delay the formation of a legally enforceable obligation.

47. The process should allow both the utility and the QF to request and provide information to each other. While most of the informational requests will be the QF providing information to the utility, the QF should also be able to request information from the utility. For example, a QF should be able make reasonable requests of a utility for backup data and cost models associated the Commission approved methodology used in the formation of its avoided cost rates.

11. Timing for Avoided Cost Rate Filings

48. The Joint Recommendation suggests that avoided cost updates be filed in November and December of each year, or after a 60-day notice. The Joint Recommendation states

"[s]tandard contract avoided cost prices will be filed in November or December of each year to establish standard contract avoided cost prices the following calendar year. Utilities may file avoided cost prices at times other than November or December, after providing minimum notice of 60 calendar days to the Commission and QFs negotiating contracts."

49. As explained in the introduction, we encourage the Commission to consider in their totality, and not just separate and distinct elements, the Joint Recommendation and any rules that it ultimately adopts. The recommendation in Section 10, above, that there be specific processes in the utility's tariffs for both the QF and utility to follow can be used to slow rather than to facilitate the contract negotiation process if there can be surprise avoided cost rate filings. These two sections (negotiation timelines and routine avoided cost updates) highlight how important reliability is for QFs trying to bring new projects online, and how the Commission's resolution of issues need to consider how all the pieces of the PURPA puzzle fit together.

50. A QF needs to know how long QF contract negotiations are likely to last and when to expect a rate change so that it can determine the viability of a proposed project and when to start the negotiation process. QFs should therefore also be aware when a rate change is not filed at the regular time, so they can be on notice that the current rates may be on borrowed time. Ultimately, QFs should know, before they begin their negotiations if they will be able to execute a PPA, or at least form a LEO, before a utility's avoided cost rates change.

51. Draft Rule 480-106-GGG requires utilities to update their filings by November of each year, or before under certain circumstances.[32] The Draft Rules are reasonable and

[32] See Draft WAC 480-106-GGG (2).

effectively achieve similar results as the Joint Recommendation with respect to timing of avoided cost updates. However, we encourage the Commission to adopt the Joint Recommendation's approach because it includes the 60-day notice provision and it allows the utilities greater flexibility to determine when they want to make an avoided cost update filing. This approach should allow QFs to form LEOs prior to the unexpected rate change. Overall, this recommendation represents as an industry compromise that balances the interests of, and is equitable to, both utilities and QFs.

12. Formation of a Legally Enforceable Obligation

52. The Joint Parties recommend that the Commission's final rules address the formation of a LEO. The Commission's Draft Rules do not do so. The Joint Parties acknowledge that reasonable minds can differ as to the best way to ensure that a state's LEO policy is fair and consistent with FERC rules and guidance. At a bare minimum, however, we recommend that the Commission acknowledge that it is the QF, rather than the utility, that controls the establishment of a LEO, and that no state or utility process can legitimately prevent a QF from creating one.

53. The primary and most fundamental purpose of a LEO is to prevent a utility from delaying the signing of a contract, so that a later and lower avoided cost rate is applicable. States have the initial power to determine the specific parameters of when a LEO is formed;[33] however, any state requirement that is inconsistent with federal law and regulations is invalid.[34] For example, a state rule or policy requiring, per se, that one or both parties execute a PPA in order to form a LEO is invalid because it is inconsistent with

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[33] West Penn Power Co., 71 FERC ¶ 61,153 at 61,495 (1995).
[34] See Cedar Creek Wind, LLC, 137 FERC ¶ 61,006 at P.35 (2011).

PURPA and FERC's regulations.[35] Similarly, a state cannot impose a requirement like obtaining an interconnection agreement prior to the formation of a LEO.[36]

54. In the end, any Commission or utility process that ultimately keeps a QF from reasonably committing itself to sell its net output to a utility with the practical result of preventing a QF from obtaining an earlier and higher avoided cost price violates PURPA. Within this context, any guidance this Commission provides to update its current LEO standard will be an improvement. However, we recommend that the Commission, explicitly conclude that the formation of a LEO is based on when the QF makes its commitment, and that the policies, rules and tariffs regarding processing and negotiating PPAs and the timing of avoided cost rate updates are designed to facilitate and not impede the formation of a LEO.

13. Contract Term

55. The Joint Recommendation endorsed a 15-year contract term from the date of commercial operation, provided the QF is able to satisfy commercially reasonable milestones. Avista's Response questions whether this contract term should apply only to QFs below the size cap or to all QFs regardless of size.[37] To be clear, the Joint Recommendation's intention was to allow 15-year contract terms for all QFs regardless of size. While contract length could ultimately be a negotiated term, we encourage the Commission to clarify that all QFs have the right to obtain 15-year contracts.

56. The Joint Parties recommend a 15-year contract term in large part because that is the minimum time period historically needed to allow most projects to obtain financing. This

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35 See id.; see also Grouse Creek, LLC, 142 FERC ¶ 61,187 at PP. 37-38 (2013).
36 FLS Energy, Inc., 157 FERC ¶ 61,211 at P.23 (2016).
37 Avista's Response at 2 (Mar. 9, 2018).

was the basis for Oregon's policy of allowing 20-year contracts with the initial 15 years at fixed prices and the last 5 years at market prices.[38] In 2013, Oregon's regulated utilities revisited this financing issue. Portland General Electric Company ("PGE") supported continuing Oregon's policy, specifically noting it "provides a way for the QF to recover their investment with adequate financing while limiting divergence from estimated avoided costs."[39] The Oregon Department of Energy ("ODOE") agreed, noting, "[s]horter contract terms would require shorter loan terms, resulting in either higher load payments or a smaller loan amount, both of which would likely cause the project to be financially unviable … because a QF's monthly loan payments are typically maxed out—there isn't any more additional underlying generation revenue."[40] We recommend that this Commission likewise establish minimum contract terms that allow most QF projects to obtain adequate financing.

57. This financing requirement is also why it is imperative to allow QFs the ability to begin their contracts upon commercial operation rather than upon contract execution. Avista is correct that allowing up to three years to achieve commercial operation means that

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38 OPUC Docket No. UM 1129, Order No. 05-584 at 19 (May 13, 2005) ("the contract term length minimally necessary to ensure that most QF projects can be financed should be the maximum term for standard contracts").

39 OPUC Docket No. UM 1610, Portland General Electric Direct Testimony at PGE/100, Macfarlane-Moton/23 (Feb. 4, 2013) ("The current practice balances the interests of utility customers and fosters new QF development."); see also PacifiCorp Direct Testimony at PAC/101, Dickman/4 (Feb. 4, 2013) ("The current term length of up to twenty years with a fixed price period of the initial ten years is appropriate."); Idaho Power Company Direct Testimony at Idaho Power/100, Grow/18 (Feb. 4, 2013) (proposing "contracts for up to 20 years … [with the] 15-year fixed price portion … reduced to 10 years.").

40 OPUC Docket No. UM 1610, ODOE Post-Hearing Memorandum at 16-17 (June 17, 2013) ("A smaller loan amount would be detrimental because QF developers typically either lack capital to increase their equity share … or they would be unwilling to do so because their return on the invested capital would not be worth the risks.") (quotation and citations omitted).

the rates could be effectively locked in for 18 years.[41] But, the inverse is also true. This means that if the contract term begins upon execution rather than upon commercial operation, the QF only has 12-years of fixed pricing. Just last month, the Oregon Commission recently affirmed its 15-year-fixed-price policy starting at commercial operations rather than contract execution, explaining:

> Prices paid to a QF are only meaningful when a QF is operational and delivering power to a utility. Therefore, we believe that, to provide a QF the full benefit of the fixed price requirement, the 15-year term must commence on the date of power delivery.[42]

Thus, because 15 years of payments are needed to establish adequate financing, the contract term must begin upon commercial operation.

58. The Joint Recommendation chose a period of up to three years to achieve commercial operations in large part because the interconnection process may take that long. Because the interconnection process is ultimately controlled by the utility, it is not fair to penalize a QF for the utility's inability to move interconnection along.[43] In cases where the interconnection process runs smoothly, three years should be sufficient to bring a QF project online. Additionally, QFs typically need an executed PPA to obtain their project financing. The QF brings its estimated revenue stream (e.g., the PPA) and its estimate costs of

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41 The three-year period would be the maximum amount of time that a QF can choose between contract execution and power deliveries. Absent the potential for interconnection delays, most QFs would choose a more expedited timeline that would be based on the time to lock down adequate financing and construct the facility plus a reasonable amount of time to address unanticipated delays.

42 Re NIPPC, CREA, and REC vs. PGE, Docket No. UM 1805, Order No. 18-079 at 3 (Mar. 05, 2018).

43 The Joint Parties are not intending to insinuate that the utilities interconnection delays are designed or intended to hinder QF development. The interconnection process can be slow with unexpected delays and cost increases even under the best of circumstances. This is even more true with increased distributed generation and improved economics of small scale renewables.

construction to its financer or lender, which only decides to provide the funds after doing a thorough due diligence of both the PPA and the project economics. This means that QFs cannot *begin* addressing many of the various hurdles they must overcome to bring their projects online until *after* contract execution.

59. We recommend that the Commission not allow current market trends to undermine the overall purpose, or potential, of PURPA. While Avista points out that the energy market has changed drastically "over just the past few years" it concedes that "it is impossible to predict how that market will continue to change."[44] The Commission's PURPA rules have largely been in place since they were adopted in 1989. Technology prices are currently driving down costs, but in today's global economy any number of reasons could cause prices to rise again. Long-term contracts provide stability in uncertain times, and this Commission should not elevate the significance of falling technology prices above all else. This is especially true given that utility-built-or-owned generation last for over 30 or 40-year periods.

60. Including commercially reasonable milestones alleviates some of Avista's concerns about the overall contract period. The Joint Parties intention of including these milestones is to balance the up to three year period to become operational with specific requirement that the QF proceed in a timely and deliberate manner to obtain commercial operation. The Joint Recommendation suggested milestones such as: 1) providing any necessary credit support, governmental permits and authorization, evidence of construction financing, and as-build supplements; 2) completing interconnection facilities and start-up testing, and 3) achieving mechanical operation. Milestones should take into account the difference between events

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[44] Avista's Response at 2.

that can affect a QF's ability to achieve a timely commercial operation date and those that will not. Importantly, however, the Joint Recommendation also includes reasonable cure periods, especially for factors under the utilities control—like completion of interconnection facilities. Commercially reasonable milestones ensure that both the QF and the utility move forward with their processes, which provides certainty that only legitimate QFs are able to achieve commercial operation.

61. Some of Avista's concerns are even easier to alleviate. For example, Avista suggests that if avoided cost go up significantly, QFs will likely just dissolve their entity and re-emerge as a newly formed LLC to secure new PPAs under higher prices.[45] The Joint Parties are not aware of this being a legitimate issue in this region or others, and understand that many utilities have added provisions to their PPAs to protect themselves.[46] For example, PacifiCorp, PGE, and Idaho Power's Oregon PPAs include a limitation on post-termination PPA pricing that caps the new PPA price at the original PPA price Thus, Avista's concerns should not deter the Commission from adopting a 15-year minimum contract term.

62. Finally, the Joint Parties' recommend that existing QFs be provided an option for 15-year contracts rather than the ten-year follow-on contracts proposed in the Draft Rules.[47] Existing QFs often need long-term contracts, similar to new QFs. Existing projects also face unique challenges, including that they must often re-negotiate interconnection agreements, update their power purchase agreements, and they have no ability to time their construction to when avoided cost rates may be higher. Existing QFs also may have a need

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45 Avista's Response at 3.

46 See e.g., PGE's Schedule 201, PacifiCorp's Schedule 37.

47 Proposed WAC 480-106-HHH(4)(a).

for major replacement and/or upgrading of their equipment, conveyance structures, interconnections, and other facilities, which can require significant capital investments and financing.

63. We encourage the Commission to clarify that the contract term for existing QFs replacement contracts starts at the time of power deliveries, and that they can enter into replacement contracts well in advance of the expiration of their current contract. No existing project will wait until the last date of contract expiration to negotiate a replacement contract. QFs entering into replacement contracts may need a contractual commitment years in advance to able to obtain financing and price certainty to be able to construct or upgrade generation facilities and interconnections. Therefore, at least some existing QFs have similar needs to new QFs, especially when they need to modernize generation or interconnection facilities or otherwise improve project performance and operations.

14. Size Threshold

64. The Joint Recommendation suggested a 5 MW size threshold for standard rates and contracts while the Draft Rules includes a 7 MW size threshold. Just like with the legally enforceable obligation provision, the Joint Parties believe that reasonable minds can differ on the best implementation path here, meaning there are a number of reasonable options for varies size thresholds. That said, representatives from PSE and independent power producers alike agreed to the 5 MW size, with the Joint Parties believing that this is the low end of what is reasonable. Because this reflects a compromise that is part of a total package, the Joint Parties stand by the Joint Recommendation. We recommend that the Commission adopt the 5 MW size threshold rather than 7 MW because it aligns with the totality of the

Joint Recommendation, including 15-year contracts, both renewable and non-renewable pricing options, etc.

15. Conflict with Federal Law

65. Draft Rule 480-106-AAA states that if there is a conflict between the rules and PURPA or FERC's rules, then PURPA and FERC's rules control. FERC's rules primarily date to the early 1980s and there have been numerous FERC orders interpreting and implementing its rules. This Commission's orders and rules implementing PURPA may conflict with both FERC's regulations and orders.[48] Therefore, the Joint Parties recommend the following addition in underline be added: "If there is any conflict between these rules and PURPA, or the related rules promulgated by FERC in 18 C.F.R. Part 292 or orders issued by FERC, PURPA and those related rules <u>and FERC orders</u> control."

16. Off-System QFs

66. FERC's regulations under PURPA allow a utility to transmit a QF's power to another utility, under certain situations.[49] In this case, the mandatory purchase obligation passes along to the new utility, which is then obligated to purchase the QF power as if the QF were supplying energy and capacity directly to the utility. The Joint Parties recommend that the final rules specifically incorporate and reflect that off-system QFs have the right to sell power. In addition, issues related to purchases from off-system QFs can be controversial and difficult,[50] and the Joint Parties recommend that the Commission attempt to minimize and reduce these disputes by requiring the utilities to file standard contract provisions that detail the QFs rights and obligations.

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48 <u>See</u> <u>Indep. Energy Producers</u>, 36 F.3d at 853, 857-59 (applying conflict preemption).

49 18 CFR 292.303(d).

50 <u>E.g.,</u> <u>PáTu Wind Farm, LLC</u>, 150 FERC ¶ 61,032 (2015); <u>PáTu Wind Farm, LLC</u>, 151 FERC ¶ 61,223 at n.52 (2015).

17. Line Losses

67. The Draft Rules allow line losses to be considered in the calculation of avoided cost rates. The Joint Parties are aware that appropriately determining line losses can be controversial and difficult, and recommend that the avoided cost rates initially presume that there are no positive or negative line losses. The utilities should then be allowed to propose methodologies to calculate line losses, which would preferably be initially reviewed in their integrated resource plans and then in a process that would allow Commission resolution if the stakeholders cannot reach agreement.

18. Interconnection Cost Rule

68. Draft Rule 480-106-KKK (formerly WAC 480-107-125) does not make any substantive changes to the Commission's interconnection PURPA rules. Unfortunately, however, interconnection issues are rapidly emerging as an impediment to PURPA development. The Joint Parties therefore recommend the Commission commence an interconnection rulemaking either as an additional phase of the instant rulemaking process or as a separate investigation. Several stakeholders have discussed the need for more specificity in the interconnection rules, but the Joint Parties recommend that the e Commission does not adopt any substantive changes until the issues have been thoroughly addressed. However, such a review is timely and time sensitive, and should be well in place to provide certainty and protection to both QFs and utilities prior to the modest increases in QF development that will hopefully occur after the Commission adopts final rules in this proceeding. Therefore, the Joint Parties recommend that the Commission promptly open another phase of this proceeding to update its interconnection rules.

III. CONCLUSION

69. The Joint Parties appreciate the Commission staff's thoughtful Draft Rules and the opportunity to submit these recommendations. We ask the Commission incorporate these changes to improve upon the good work done in this rulemaking thus far.

Dated this 13th day of April 2018.

Respectfully submitted,

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