BEFORE THE WASHINGTON UTILITIES AND

TRANSPORTATION COMMISSION

UE-161024

In the Matter of Rulemaking for Integrated Resource Planning, WAC 480-100-238, WAC 480-90-238, and WAC 480-107	)))))))	RENEWABLE ENERGY COALITION COMMENTS

I. INTRODUCTION

1. The Renewable Energy Coalition (the Coalition or REC) files these comments regarding the Washington Utilities and Transportation Commission (the Commission or WUTC) investigation into current integrated resource plan (IRP) procedures and practices and the adequacy of existing IRP rules. REC is a group of over 30 non-intermittent qualifying facilities (QFs) in Washington, Oregon, Idaho, Utah, and Wyoming selling power to Northwest utilities at avoided cost prices under the Public Utility Regulatory Policies Act (PURPA). Therefore, the IRP is of significant interest to REC because of its key role in the calculation of avoided costs.

2. The Commission has asked for comments on two potential types of changes: 1) changes related to administration of the IRP process, and 2) changes related to the existence of new types of resources. The notice then divided this into seven areas: other issues and schedule, energy storage, request for proposals (RFPs), avoided costs, transmission and distribution planning, flexible resource modeling, and general procedural improvements.

3. The Coalition's primary goal is to ensure fair and reasonable contract terms, conditions, processes, and avoided cost rates for all projects and ratepayers. The Coalition recognizes that PURPA must work to benefit all interested parties, including the utilities, ratepayers, and new and existing QFs of various sizes.

II. COMMENTS

Washington is an inhospitable state for the development of new independent power producers, and small QFs in particular. The Commission's policies will play a key role in whether new generation in this state is built and owned by only the investor owned utilities, or whether small scale community projects also have an opportunity to be part of the resource mix serving end use consumers. The Coalition urges the Commission to make its decisions in this proceeding keeping in mind the practical impact of any decisions, and the historic difficulties that small renewable projects have in this state.

To date, Washington's regulated electric utilities have avoided their PURPA obligations. PacifiCorp has been particularly effective, with PacifiCorp currently purchasing power from only three projects in Washington with about 4 MWs, which represents less than 0.3% of all PacifiCorp's MWs of QF contracts. While not quite as successful in keeping its competitors from selling power, Puget Sound Energy ("PSE") has also been able to protect itself from competition and limit its purchases from QFs. PSE has only seventeen QF contracts, nine of which are under 1 MW, none of which are larger than 5 megawatts, and a total QF nameplate capacity of around 25 MW.[1]

In contrast, other Northwest utilities have modest amounts of PURPA development. For example, PacifiCorp's overall company wide operations have a small

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1 Puget Sound Energy 2013 Integrated Resource Plan, Dockets UE-120767 & UG-120768, Appendix D at D-9 to D-11, available at:

but important amount of QFs, including 141 existing QFs representing 1,732 MW of installed capacity.[2][3] Idaho Power has a peak demand of 3,407 MW and an average load of 1,739 aMW in 2014.[4] In contrast, PSE has a peak demand of 4,837 MW in 2012 and 2,437 aMW in 2012.[5] Despite being a smaller utility than PSE, Idaho Power has 781 MWs of PURPA capacity on its system.[6]

While some of the differences are based on the different service territories of the utilities, the role of state regulation is starkly illustrated by PacifiCorp, which has similar Washington and Oregon service territories in terms of renewable resource availability. PacifiCorp's rates, contract terms, and negotiation practices make it so difficult that cost effective independently owned renewable projects are simply not built in Washington or sell their power to entities outside of the company's Washington service territory.

1. The Wholesale Market and Reliance Upon the Short-Term Market

4. In the category of requests for proposals, the Commission notice mentions wholesale market purchases as a preferred approach by PacifiCorp and Avista. The Staff is correct that, if the IRP model relies on market purchases for capacity needs, then the utility is short on capacity. However, reliance on the market should not be viewed as meeting that capacity need. The Coalition is concerned that reliance on the short term market has significantly altered the IRP process, such that although the utility is resource deficient, sometimes immediately, PacifiCorp and Avista claim that they are not resource

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2 WUTC v. Pacific Power & Light Co., Docket UE-144160, John Lowe Declaration at ¶ 6.

3 Id. at ¶ 7.

4 Re Idaho Power Co., 2015 IRP, Docket No. LC 63, IRP at 23.

5 Puget Sound Energy 2013 Integrated Resource Plan, Dockets UE-120767 & UG-120768, Appendix H at H-19 to H-21, available at: https://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_AppH.pdf.

6 Idaho Power Application at 5; Coalition/200, Lowe/4.

deficient because they plan on using the wholesale market. However, the wholesale market will be used on an ad hoc basis with day-ahead or week-ahead planning as the years go by. The IRP does not identify a signed contract for power, so we do not know that the short term market will in fact be available, or available at a reasonable price, when planned for.

5. PSE's IRP illustrates some of the risks associated with reliance upon the short-term market. PSE states that:

> Now that the region is forecast to move from a capacity surplus to a deficit in the next decade, it is time to re-evaluate this strategy. Currently, PSE relies on up to 1,666 MW of wholesale market purchases to meet its winter peak load obligations, but continuing this degree of reliance on wholesale market purchases will expose PSE and its customers to increasing financial and physical supply risks under regional deficit conditions.[7]

PacifiCorp, however, is taking exactly the opposite approach and doubling down on its alleged plans to rely upon the short-term market to meet its energy and capacity needs.[8]

6. The Coalition posits that the short-term Northwest wholesale market is not significantly different for PSE, Avista, and PacifiCorp. Instead, the motivations of the utilities are different. PSE is planning to make significant capital investments and wants to build new generation to replace its coal fired resources, and is making the case that the short-term market is unreliable. PacifiCorp in contrast, is focusing on transmission planning and investment as well as trying to justify additional capital investments in its existing coal fleet. Thus, PacifiCorp is making the case that the short-term market is reliable and cost effective because that story suits its current investment plans.

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7 PSE 2015 IRP, Appendix G-1.

8 PacifiCorp 2015 IRP Update at 5 (increasing reliance on short term firm sales by an average of 215 MW over the next ten years up to a total of 1,440 MW by 2025).

7. An additional consideration is market risk. WAC 480-100-238(2)(b) states that lowest reasonable cost includes market-volatility risks. We do not think a utility is adequately allowing for market volatility risk in its reliance on short term transactions. Risks may come from areas such as inadequate transmission, increasing power cost prices, and environmental regulations that may greatly reduce the amount of power available on the wholesale market. More analysis and discussion of front office transactions (FOT) market risk in utility IRPs should be required. For example, this could be through additional model runs that assume altered levels of price and availability of FOTs.

2. Capacity Valuation

8. The Commission should require utilities to fully compensate QFs for both the energy and capacity they cause the utilities to no longer incur. PURPA requires electric utilities to purchase power from QFs at their avoided costs, which must also be just and reasonable for both QFs and ratepayers.[9] The Federal Energy Regulatory Commission's (FERC) policy also requires utilities to purchase electricity from QFs based on the utilities' full avoided costs.[10] Avoided costs should be based on a utility's incremental costs that, but for the purchase from the QF, the utility would generate or purchase from another source.[11] State utility commissions are required to set avoided costs in order to "'reasonably account for the utility's avoided costs' as FERC's rules require."[12]

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9 16 U.S.C. § 824a-3(b)(1).

10 Amer. Paper Institute, Inc. v. American Elec. Power Serv. Ass'n, 461 U.S. 402, 406, 412-17 (1983).

11 16 U.S.C. § 824a-3(d).

12 WUTC v. Pacific Power & Light Co., Docket No. UE-144160, Order No. 04 at ¶ 20 (Nov. 12, 2015) citing Small Power Production and Cogeneration Facilities;

9. Federal law requires that avoided cost rates must compensate QFs for both the energy and capacity that the utility would have generated or purchased for itself.[13] Washington's rules also require the utilities to compensate QFs for the capacity they cause the utility to avoid.[14] FERC recently explained that, when a utility has a demand for capacity, then the avoided cost rates must include the capacity costs.[15] In other words, "when the demand for capacity is zero, the cost for capacity may also be zero[;]" but when the demand for capacity is not zero, the cost for capacity may not be zero.[16] A limitation on capacity payments that does not have a "clear relationship" to the utility's actual demand for capacity will fail to implement FERC's "regulations requiring an electric utility to purchase any capacity which is made available from a QF."[17] Avoided cost rates should include the actual and planned costs that will be incurred by the utility.[18] This includes environmental upgrades and the risks associated with potential environmental costs.

10. There are numerous ways in which to compensate QFs for capacity, with the Commission recently considering use of a market risk premium adjustment, forward market prices, a gas peaking plant, a baseload gas plant, and the renewable portfolio

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Regulations Implementing Section 210 of the Public Utility Regulatory Policy Act of 1978, Order No. 69, 45 Fed. Reg. 12,214, 12,226 (Feb. 25, 1980).

13 18 C.F.R. §§ 292.101(b)(6), 292.304; Amer. Paper Institute, Inc., 461 U.S. at 406.

14 WAC § 480-107-095.

15 Hydrodynamics Inc., 146 FERC ¶ 61,193 at P. 35 (March 20, 2014).

16 Id.

17 Id.

18 California Public Util. Comm'n, 133 FERC ¶ 61,059, PP. 15, 26 (Oct. 21, 2010), reh'g denied 134 FERC ¶ 61,044 (Jan. 20, 2011); (quoting and distinguishing Southern California Edison, 71 FERC ¶ 61,269 (June 2, 1995), where FERC determined avoided costs may not include "environmental adders or subcontractors that are not based on real costs that would be incurred by utilities").

standard reporting methodology for calculating incremental cost.[19] The Commission concluded that a capacity payment was appropriate during the sufficiency period and required Pacific to include a separate payment for capacity based on one-fourth of the cost of a simple cycle combustion turbine.[20] There are other potential methods to set the capacity portion of avoided cost rates.[21]

11. The Coalition does not make a recommendation at this time regarding the specific methodology that should be used to set avoided cost rates, but identifies the following guiding principles. First, the Commission should attempt to ensure consistency regarding how avoided costs are used, and the included elements of avoided costs should be as similar as possible for different applications. The costs avoided when a utility purchases from a QF, invests in conservation, or builds a renewable resource rather than a thermal resource are generally the same, and, absent compelling reason, should be the same.

12. Second, QFs need to be paid for the long-term capacity that they cause the utility to avoid. FERC regulations provide a QF with the legal right to sell energy or capacity pursuant a legally enforceable obligation "over a specified term" with rates that are

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19 WUTC v. Pacific Power & Light Co., Docket UE-144160, Order No. 04 at ¶ 20-31 (Nov. 12, 2015).

20 Id. at ¶ 31.

21 Idaho ensure that existing and operating QFs are paid for capacity in renewing contracts. Re the Commission's Review of PURPA QF Contract Provisions, IPUC Case No. GNR-E-11-03, Order No. 32697 at 21-22 (emphasis added) (Dec. 18, 2012) clarified in Order No. 32871 (Aug. 9, 2013); Re Idaho Power Company's Petition to Modify Terms and Conditions of PURPA Purchase Agreements, IPUC Case Nos. IPC-E-15-01, AVU-E-15-01, PAC-E-15-03, Order No. 33357 at 25-26 (Aug. 20, 2015). and Oregon allows renewable QFs to sell power under a separate and generally higher avoided cost rate to reflect the fact that they can allow the utility to meet its RPS obligations. Re OPUC Investigation Into Resource Sufficiency Pursuant to Order No. 06-538., Docket No. UM 1396, Order No. 11-505 (Dec. 13, 2011).

calculated at the time the obligation is incurred.[22] FERC has explained that this specified term includes the right to obtain long-term avoided cost rates.[23] This generally means that QFs are entitled to a fixed contract so that a utility cannot circumvent the requirement that a QF be paid for capacity.[24]

13. Washington, however, generally has short contract terms, even though QFs typically sell power to their interconnected utility for their entire operational life. For example, PacifiCorp is purchasing power from three QFs in Washington, one of which began operations in 2006 and the other two in 1986. While all three need to enter into five year contracts, they all have been selling power to PacifiCorp for between ten and forty years and deferring capacity needs for decades. Utility resources, which are the avoided resource, are placed in rates for their entire economic life, and QF generation should be treated the same. This can be accomplished by requiring capacity payments during the entire economic life of the QF, which would mean that they receive capacity payments as long as they continuously sell power to their interconnected utility.

3. Request for Proposals (RFP)

14. Waivers by the utilities to not use the RFP process greatly disadvantage independent power producers and small power producers, who could provide low-cost power but too often do not have the opportunity. A fair and healthy competitive generation market benefits everyone because there are additional options to sell power. A competitive generation market can ensure that customer rates are kept low through the

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22 18 C.F.R. § 292.304(d)(2)(ii); New York State Elec. & Gas Corp., 71 FERC ¶ 61,027, 14 (1995).

23 Hydrodynamics Inc., 146 FERC ¶ 61,193 at P. 4, 8, 33.

24 Id. at P 33; see also FERC Order No. 69, 45 Fed. Reg. 12,214, 12,224 (Feb. 25, 1980).

acquisition of generation resources with the least cost and risk. We believe the utilities have biased the competitive bidding process in favor of utility ownership. The Commission should insist that the utilities use a competitive bidding process to ensure that the utilities acquire the lowest cost and least risk resources for ratepayers. Simply relying on the prudence review process in rate cases is insufficient. Under no circumstances, however, should QF projects be required to participate in utility RFPs to sell their net output.

4. Time and Process for Avoided Cost Calculations

15. The Coalition believes it would be very useful if avoided costs were calculated and filed when the IRP is filed, resulting in a concurrent review of both the IRP and avoided cost prices. Concurrent filings would allow for immediate, fair, and timely evaluation of the impact of assumptions, inputs, and resource decisions in the IRP on avoided costs. It would also increase administrative efficiencies, reduce inconsistencies between the IRP and avoided cost, and could lead to a more expeditious review of future avoided cost filings. In the off-years of an IRP filing, the same procedure could be followed for the IRP update.

16. The main problems now are that the IRP: 1) does not discuss or focus on QF or avoided cost issues, 2) has long sufficiency periods that are not critically evaluated, 3) allows for stakeholder influence that can be ignored by the utility, and 4) does not provide an opportunity for stakeholders to challenge inputs or assumptions and recommend Commission decisions on issues that will directly affect avoided cost prices.

17. First, there is little focus in the IRP process on avoided cost issues. Although the IRP is key for inputs that are used to calculate avoided costs, the key components and

issues in the IRP that will have a direct impact on avoided cost rates are typically not addressed by the utility or the Commission during the development or review of the IRP. During the planning process, QFs are generally only mentioned in terms of the utility's existing resource portfolio. There is no consideration or evaluation of the impact that an acknowledgment decision for the IRP will have on QFs and avoided cost rates.

18. Secondly, IRPs currently have very long sufficiency periods that are not critically evaluated because they do not affect the short-term action plan. By the use of planned as-needed wholesale market purchases and aggressive demand side management targets, PacifiCorp's resource sufficiency periods extend until 2028. Accurately identifying the resource sufficiency and deficiency demarcation has a huge impact on avoided cost rates. When resource sufficiency periods were short, the impact of inaccurate resource sufficiency and deficiency demarcations was less important. While the difference between a 2024 and 2028 resource sufficiency and deficiency demarcation can be almost irrelevant for planning purposes, there is a huge impact on QFs and this difference in year of deficiency can make the difference between an economic and uneconomic project. We are in a very uncertain time with the future of carbon regulation. For example, it is questionable that PacifiCorp will be able to maintain its existing coal fleet. While it is appropriate for PacifiCorp to retain flexibility in its long term planning given the uncertainties of carbon regulation, it is inappropriate to set avoided cost rates based on resource sufficiency periods that are very likely to be erroneous. PacifiCorp's actual resource acquisitions could significantly change if its IRP assumptions prove inaccurate, including but not limited to: 1) changes in Washington's or Oregon's renewable portfolio standard (RPS); 2) PacifiCorp joining the California Independent System Operator; 3) the

adoption of a federal RPS; 4) adoption of a state or federal carbon tax; 5) the adoption of EPA's Section 111(d) rules; 6) closure of part or all of coal generation facilities; 7) the inability to capture the high levels of demand side management; and 8) the lack of available power at a reasonable price in the wholesale market.

19. Thirdly, the current IRP process allows for stakeholder input, which the utility can ignore. We are aware of the suggestion that because the IRP is subject to stakeholder review, the results of the planning effort can be extended to avoided costs without additional significant review. However, the utilities control the entire process of developing inputs and assumptions for each planning cycle. Stakeholders are provided some opportunity to comment and make suggestions, but regardless of the ability to submit comments, the utilities make the ultimate decision on what the IRP's assumptions and inputs are. Simply put, the utilities can ignore stakeholder comments. Therefore, review of IRP inputs, assumptions, and decisions deserve significant additional review if they are to be used for avoided costs.

20. Fourthly, the current IRP process does not provide an opportunity to challenge inputs and assumptions that will affect avoided cost prices. The Commission does not acknowledge most of the key inputs and assumptions used to set avoided cost rates. Staff, QFs and other interested parties cannot conduct discovery, submit testimony, challenge the evidence used in the IRP, or obtain a Commission resolution on any of these inputs and assumptions. Thus, the current process is meaningless for avoided costs without the ability to have a neutral decision maker like the Commission resolve any disagreements. Any party should be allowed to challenge any input or assumption on the grounds that they would not produce just and reasonable avoided cost rates, regardless of

whether they are consistent with an acknowledged IRP. Reliance upon the IRP for non-controversial inputs and assumptions may be reasonable, but the current process does not provide parties an opportunity to submit testimony or obtain resolution of key issues. Therefore, by the time an avoided cost filing is made, key assumptions and inputs from the IRP are unchangeable. With concurrent filings, the Commission could allow interested parties to review, formally challenge, and obtain Commission resolution of avoided cost rate inputs and assumptions that come directly from the latest IRP.

5. Procedural Improvements

21. Generally, there is a need for more transparency in utility modeling within the IRP. The models used are quite complex, very expensive, and require significant staff time to run and evaluate. Few stakeholders have the in-house expertise, detailed knowledge of utility operations, or resources to acquire and run the same model(s). Commission Staff and stakeholders should have access to the model(s) at no cost and be able to do their own runs to verify the utility's reported results.

22. The existing public review process appears to be functioning. However, it is always well to remember that this is the utility's plan, and although members of the public process may make suggestions or requests, they can easily be ignored by the utility.

III. CONCLUSION

23. Thank you for the opportunity to provide comments on this proceeding. The Coalition urges the Commission to adopt IRP, RFP, and avoided cost rate policies that provide non-utility generations an opportunity to sell power so that end use consumers

are not solely served with utility owned generation. The Coalition looks forward to participating in the public workshop on December 7.

Respectfully submitted this 2nd day of November 2016.

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