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April 17, 2017

Via E-filing

Mr. Steven V. King
Executive Director
Washington Utilities & Transportation Commission
1300 S. Evergreen Pk. Dr. S.W.
P. O. Box 47250
Olympia, WA 98504-7250

Attn: Filing Center

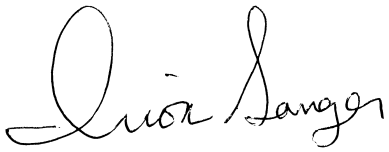
RE: In the Matter of Public Utilities Regulatory Policies Act, Obligations of the Utility to Qualifying Facilities, WAC 480-107-105
Docket No. U-161024

Dear Mr. King:

Please find the Comments of the Northwest and Intermountain Power Producers Coalition and the Renewable Energy Coalition in the above-referenced docket.

Thank you for your assistance. Please do not hesitate to contact me with any questions.

Sincerely,



Irion A. Sanger

BEFORE THE WASHINGTON UTILITIES AND

TRANSPORTATION COMMISSION

U-161024

In the Matter of Public Utilities Regulatory Policies Act, Obligations of the Utility to Qualifying Facilities, WAC 480-107-105	)))))))	THE NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION AND THE RENEWABLE ENERGY COALITION COMMENTS

I. INTRODUCTION

1. The Northwest and Intermountain Power Producers Coalition ("NIPPC") and the Renewable Energy Coalition ("REC") submit these comments regarding the Washington Utilities and Transportation Commission's (the "Commission" or "WUTC") rulemaking to examine the Commission's rules and policies relating to utility obligations under Public Utility Regulatory Policies Act ("PURPA"). With specific and narrow improvements, NIPPC and REC are generally supportive of the overall framework used for setting avoided cost prices paid to qualifying facilities ("QFs") in Washington. However, many other changes to the process for setting rates and entering into contracts, as well as appropriate contract provisions and conditions will be necessary to allow for even a modest amount of QF development. Above all, NIPPC and REC urge the Commission to adopt simple and unambiguous QF policies that can be implemented consistently between all three utilities, reduce the possibility of litigation, and provide new QF developers and the few existing QFs the ability to sell their net output with as much long-term certainty as possible.

2. PURPA was enacted to encourage QF development and each state has implemented PURPA with widely different approaches to determining what the costs of resources that are avoided when a QF sells its net output to the utility. Ideally, avoided cost prices should be set high enough to permit QF development, but without exceeding a utility's actual incremental costs. This achieves true customer indifference, because while setting avoided cost prices too high forces customers to pay too much, setting them incorrectly below actual avoided cost harms customers by preventing lower cost QFs from selling power to the utilities. Failure to properly implement PURPA results in customer rates being higher than necessary as the utilities build and rate base more expensive projects, and customers are exposed to sizeable risks from construction overruns, plant operation, and fuel-cost volatility.

3. The Pacific Northwest and Rocky Mountain states have experienced a "PURPA" war in which PacifiCorp and Idaho Power have sought to administratively repeal PURPA in their California, Idaho, Oregon, Utah and Wyoming service territories. To a lesser degree, PacifiCorp and PSE have also sought to undermine and prevent even a modest degree of QF development in Washington.

4. Until recently, the Commission has avoided addressing the myriad of PURPA-related regional disputes. This may be because the Commission's own PURPA polices have already prevented the development of cost effective QFs that ultimately lower costs and risks for ratepayers. Recent avoided cost filings before the Commission and comments from stakeholders in this integrated resource planning ("IRP") rulemaking proceeding have made it clear that Washington finally needs to set modern PURPA policies that allow low cost QFs to meet the utilities' energy and capacity needs. NIPPC

and REC appreciate the Commission's willingness to re-consider its existing policies are ensuring customer rates are just and reasonable while achieving the goals of PURPA.

5. While there remain some PURPA disputes ongoing in some other states, the overwhelming number of regional administrative proceedings has slowed and provide illustrative examples for the WUTC to review when setting policy. Idaho and Oregon provide examples of what not do to, unless this Commission wants to prevent new QF development. The Idaho Public Utilities Commission ("IPUC" or "Idaho Commission") resolved its PURPA disputes by adopting policies that effectively prevent the development of nearly all new projects, and allow only currently operating cost effective projects an opportunity to continue to sell power through an appropriate valuing of capacity. While PURPA policies continue to unfold in Oregon, PacifiCorp has been the most aggressive private utility succeeding in putting a near complete halt on new projects in that state and is causing significant risk that operating projects will not be able to continue when their current power purchase agreements ("PPAs") expire.

6. While the Idaho Commission and the Oregon Public Utility Commission ("OPUC" or "Oregon Commission") have "over corrected" and offer examples of what not to do, PURPA is complex and all the regional states have at least some positive elements that Washington should consider when adopting a more balanced approach. The Commission should take advantage of the lessons learned to adopt comprehensive policies that allow PURPA to be a tool for the development of lower cost and less risky non-utility generation to help meet Washington's ambitious energy policy goals and near term energy and capacity needs.

7. These comments focus mainly on the issues raised by the Commission in its Notice of Workshop and Opportunity to File Written Comments, dated March 16, 2017, with minimal additions. NIPPC and REC have several specific suggestions to revamp, rather than overhaul, Washington's PURPA rules. The Commission should:

- Ensure that QFs are fully compensated for energy and capacity during both "short-run" and "long-run" periods.
- Establish a new avoided cost price stream to compensate renewable QFs for their renewable attributes when they are willing to transfer their renewable energy certificates purchasing utility.
- Set the maximum size for standard rates at 10 MWs for all generation types.
- Adopt FERC's "one-mile" rule to determine the minimum distance between QFs with the same owner.
- Allow the QF to select a standard contract term up to 20 years.
- Clarify at what point a legally enforceable obligation ("LEO") has occurred, and allow for prompt alternative dispute resolution during contract negotiations.
- Continuing the current approach of annual rate updates, but minimizes the utilities from filing unexpected avoided cost rate changes absent extraordinary circumstances and a sufficient notice period.
- Ensure that QFs have an opportunity to review and challenge the calculation, inputs, assumptions and methodologies to calculate avoided cost updates.

II. BACKGROUND

8. FERC regulations require utilities to purchase QF energy and capacity at the utility's full avoided cost, but have largely left it to state commissions to decide how to

implement PURPA.[1] The utility's avoided cost is the incremental cost that, but for the purchase from the QF, the utility would generate itself or purchase from another source.[2] FERC provided comprehensive policy guidance soon after the passage of PURPA, stating that when a QF demonstrates that it "would permit the utility to defer or avoid construction of a generation unit or the purchase of firm power from another utility, then the rate from such a purchase should be based on the avoidance of both energy and capacity costs."[3] FERC has subsequently addressed various policy issues on a case-by-case basis—mainly when reviewing state utility commission decisions implementing policies deemed to be contrary to PURPA.[4]

9. The historic context of PURPA remains relevant today. PURPA was established to counter the natural bias of regulated utilities for resource ownership, and their reluctance to purchase power from independent power producers. PURPA created market opportunities for new QF power that reduce our dependence on foreign oil, promote alternative power generation, and ensure a diversified electric power industry. PURPA also birthed a new industry of small and independent power producers.

10. Nearly 40 years later, PURPA's purpose in many ways is more vital than ever in the Pacific Northwest. Decreasing technology costs have given rise to new PURPA

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1 16 U.S.C. § 824a; FERC v. Mississippi, 456 U.S. 742, 750, 102 S. Ct. 2126 (1982); Am. Paper Inst., Inc. v. Am. Elec. Power Serv. Ass'n, 461 U.S. 402, 406, 412-17 (1983).

2 18 C.F.R. § 292.101(b)(6).

3 Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policy Act of 1978, FERC Order No. 69, 45 Fed. Reg. 12,214, 12225 (Feb. 25, 1980).

4 See e.g., JD Wind 1, LLC, 129 FERC ¶ 61,148 at P 25 (2009); Cedar Creek Wind, LLC, 137 FERC ¶ 61,038 at P 25 (2011); Grouse Creek Wind Park, LLC, 142 FERC ¶ 61,187 at P 36 (2012); Hydrodynamics Inc., 146 FERC ¶ 61,192 at P 31 (2014).

development, but the utility model and regulatory environment, in large part, have remained utterly unchanged. The region remains dominated by incumbent monopoly utilities, does not have a regional transmission organization, and is marked by the absence of organized markets that are available to all generators. Thus, the same market barriers continue to thwart QF developers.[5]

11. FERC has long expressed concerns over the utilities' general inclination to avoid PURPA's mandatory purchase requirement.[6] And despite consistent FERC oversight, this Commission's authority to review its regulated utilities' avoided costs and set standard contract provisions is far more likely to determine whether there will be any QF development in Washington. NIPPC and REC are not advocating for the Commission to incentivize a boom in new QF development, or otherwise establish policies that could subject ratepayers to unjust rates. Instead, NIPPC and REC are asking the Commission to ensure its QF rules and policies are fair, do not hinder the broader purpose of PURPA, and allow non-utility generation a reasonable opportunity to sell their net output to the state's investor owned utilities. The policy choices at issue in this proceeding—more than any federal regulations or orders—will play a key role in whether PURPA will ever achieve its intended benefits for ratepayers in Washington.

12. Washington's vertically integrated utilities dominate the electricity market, as they do in the Pacific Northwest and Rocky Mountain states. This is true despite Washington's constitutional ban on monopolies and the absence of any laws explicitly favoring service territories. Since the passage of PURPA, Oregon and Idaho have been

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5 QFs are limited to 80 MWs for renewable energy projects and no limitations for cogeneration resources. 18 C.F.R. §§ 292.204, 292.205.

6 American Paper, 461 U.S. at 404; Mississippi, 456 U.S. at 750-51.

able to achieve a modest amount of QF development, which underscores the relatively bleak picture in Washington for non-utility owned developers.

13. Still, Washington has an ambitious renewable portfolio standard ("RPS") and other renewable energy policies. As recently explained by the Commission:

> Collectively, the energy policies that Washington has enacted in the last 20 years have driven energy diversity and greenhouse gas emission reductions through three general approaches: discouraging the use of fossil-fueled generation resources, encouraging the use of renewable generation resources, and facilitating customer adoption of distributed technologies such as solar photovoltaics and electric vehicles.[7]

These goals could be more cost effectively achieved if a greater portion of the utilities resource mix included purchases from independent power producers, including QFs. As this Commission has recognized, these "clear directives to electric utilities to diversify and decarbonize the state's energy resource mix" must be done "in a manner that promotes the public interest while minimizing cost and risk."[8] Without the Commission's effective implementation of PURPA and the competitive bidding rules, customer rates will be higher because the vast majority of the investor owned utilities' renewable energy resources that serve the customers will be owned by those same utilities and not subject to competition from the market.

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7 Re WUTC's Investigation into Energy Storage Technologies, Docket Nos. UE-151069 and U-161024, Draft Report and Policy Statement on Treatment of Energy Storage Technologies in Integrated Resource Planning and Resource Acquisition P. 21 (March 6, 2017).

8 Id. at P. 41.

II. COMMENTS

A. ISSUE A. AVOIDED COST METHODOLOGIES

14. Avoided cost rates must include a reasonable payment for both energy and capacity whenever a QF reduces a utility's need for those resources. FERC has repeatedly confirmed that PURPA established a legal requirement to purchase QF capacity, if the utility has a capacity need.[9] FERC rules also require, to the extent practical, that the Commission consider the aggregate capacity value of QFs.[10] FERC has explained that even though small amounts of capacity provided from QFs might not enable a utility to avoid scheduled capacity additions, the aggregate capacity of such purchases allows deferral or avoidance of such a capacity addition.[11]

15. A fundamental question at issue in this proceeding should not be whether utilities must pay for capacity, but really how they should do so.[12] Absent the unusual situation in which a utility no longer has a capacity need, QFs are always providing a capacity benefit and the utilities' capacity payment to QFs should account for the full value of the

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9 Hydrodynamics, 146 FERC ¶ 61,193 at P 31 ("The [Federal Energy Regulatory] Commission's regulations require that a utility purchase any energy and capacity made available by a QF.").

10 18 C.F.R. § 292.304(e)(2)(vi).

11 FERC Order No. 69 at 12,227.

12 It is possible that the utilities may propose to eliminate capacity payments. In PacifiCorp's last litigated PURPA case, PacifiCorp essentially proposed a new avoided cost rate proposal that would have had the practical impact of eliminating capacity payments. The WUTC rejected PacifiCorp's proposal for failure to be "fair, just, reasonable, and sufficient." WUTC v. Pacific Power & Light Co., Docket No. UE-144160, Order 04 at 37-38, 42 (Nov. 12, 2015). PacifiCorp's approach would have effectively removed capacity payments during the first five to ten years of a power purchase agreement, but restrict a QF to a five-year contract term, making it impossible to be paid for capacity. Id. at PP. 8-9.

capacity provided. Stated another way, a QF should receive a full capacity payment in all years (and months) of its contract. The most appropriate avoided cost methodology and standard contract provisions must work together to this end, because some combinations will undermine the value of QF energy and capacity contributions. For example, short or even moderate contract periods with market capacity rates in a utility's short-run period will effectively value capacity at zero. Thus, whatever new policies the Commission adopts in this proceeding need to carefully consider their total net effect or risk putting an end to the even very small amount of Washington QF development.

16. NIPPC and REC propose one major avoided cost rate change and recommend that the Commission establish a separate renewable avoided cost price stream to more fully compensate for the value provided by QFs that are willing to transfer their renewable energy certificates to the utility. Renewable QFs allow utilities to achieve their state mandated RPS requirements, and help defer incremental renewable resource acquisition. This is important because the utilities are likely to acquire significant amounts of renewables in the future, which will be the next avoidable resource.[13] Thus, a separate renewable avoided cost rate should be expeditiously implemented.

[13] PacifiCorp hopes to add 1,100 MW of new Wyoming wind resources by the end of 2020. PacifiCorp 2017 Integrated Resource Plan (hereinafter PacifiCorp 2017 IRP) at 2 (Apr. 4, 2017).

Issue A. 1. What is the appropriate avoided cost methodology for calculating QF energy and capacity rates? A brief review of commonly cited literature identifies five methodologies: Proxy Unit, Peaker Method, Differences in Revenue Requirement, Market-Based Pricing, and Competitive Bidding. Issue A. 3. Is it appropriate for a utility to calculate separate avoided capacity rates based on short-run and long-run resource requirements?

17. With respect to different avoided cost methodologies for fixed price QFs, the Commission should consider how each of these different methods balance PURPA's goal of setting accurate avoided cost rates. Both of these goals are served by simplicity. Overly complex methodologies obscure the utilities' true avoided costs and are subject to manipulation, as well as lengthy and costly litigation. Thus, the Commission should strive to adopt simple methodologies that generally apply to all three utilities and are consistent with other resource planning and decisions.

18. For capacity payments, the Commission should require the utilities to use the highest cost incremental capacity resources in their IRP or actual resource acquisition plans. The highest cost capacity resources should be used to value capacity because those is the most likely to be avoided. For example, PSE's previous approach of basing the short-run capacity value on demand response measures was an appropriate methodology because it has been proven to set reasonable avoided cost rates, deferred actual capacity investments, and treated conservation, demand side management and QFs equally.

19. If the Commission does not use the capacity value of demand response, then the Commission should maintain the status quo by allowing the utilities to base capacity value on the next peaking resource identified in the utilities' IRP. The Commission, however, should not use PacifiCorp's practice of dividing its short-run capital costs by

four to account for only its peak season. PacifiCorp, like the other utilities, should make full capacity payments to QFs for the entire term of their PPAs with QFs. After all, if PacifiCorp built the peaker its ratepayers would be paying rates based on rate base, and that peaker would be in the rate base all year long.

20. Finally, market approaches to valuing capacity, which have recently been suggested by both PacifiCorp and PSE, are not appropriate and should be rejected outright because they essentially provide zero capacity value to the QF.[14] The Commission has rejected these proposals in the past and should continue to do so, because the utilities' version of a market avoided cost capacity rate essentially pays zero or near zero for valuable capacity. The Commission has specifically asked for comments regarding various proposed methods to calculate capacity, and NIPPC and REC's comments address each in turn below.

i. The Proxy Unit

21. The Proxy Unit Methodology is a simple and transparent method, but heavily dependent upon selecting an appropriate proxy. This method uses the next planned generation—often a gas powered combined cycle combustion turbine ("CCCT"), but could also be the next planned renewable resource. The proxy resource is identified in the utility's most recent IRP or actual operational plans. This is a simple method because

[14] WUTC v. Pacific Power & Light Co., Docket No. UE-144160, Order 04 at P. 21 (Nov. 12, 2015); PSE Advice No. 2016-31 – Schedule 91 – Cogeneration and Small Power Production, Docket No. UE-161240, Substitute Tariff Filing at 2 (Dec. 19, 2016) (the second of four sequential changes included "an estimate of the costs PSE will avoid when Schedule 91 customers reduce the need for PSE to secure firm supply in the market prior to 2022. This element of avoided capacity cost is determined to be $0.08/kW-year, which is an increase from $0/kW-year in the initial filing.").

the avoided costs are simply the fixed and variable costs of the deferred plant. In the case of a fueled plant, avoided fuel costs are derived from a gas forecast and a plant heat rate.

22. Although the Proxy is a workable methodology for the Commission, diligent review of the utilities' IRP and avoided cost filings may be required to correctly implement this method. For example, PacifiCorp uses this method for the time period in which it has identified a major thermal resource need (which the Commission calls the "long-run" period), using a CCCT from its IRP as a proxy to estimate the avoided energy and capacity costs from QFs. PacifiCorp, however, combined this approach with attempting to pay only market prices for its short-run capacity costs. Given that PacifiCorp claims that it is not planning on a new baseload project until 2029,[15] this would result in eliminating capacity payments for the first twelve years of a PPA (assuming that the QF was able to overcome PacifiCorp's refusal to enter into Washington contracts for more than five years).

ii. Peaker Method

23. The Peaker Method recognizes that capacity provided by QFs can defer a peaking unit (often a SCCT) instead of a base load plant (most often a CCCT), which is most likely the next planned resource acquisition. The avoided capacity costs are therefore costs of a SCCT while the avoided energy costs are derived from other production model simulations.

iii. Difference in Revenue Requirement

24. The Difference in Revenue Requirement Methodology theoretically could produce the most accurate results, but is generally overly complex, lacking in

[15] PacifiCorp 2017 IRP at 2.

transparency, and therefore does not present a workable solution. This method derives the present value cost differential between a planned portfolio of resources (generally from the utility's IRP) with and without QFs.

25. The Difference in Revenue Requirement Methodology is opaque, costly, requires sophisticated power cost and financial modeling, and can be manipulated to result in overly low price estimates. It essentially allows the utility, which has an economic incentive to set rates low, too much discretion when calculating avoided cost prices. In Washington's regulatory situation in which there are already too many hurdles to overcome, this kind of modeling is a solution in search of a problem. While it is unclear whether this approach is ever appropriate, there is not enough QF activity in Washington to necessitate this level of computation or invite constant litigation over avoided cost rates.

26. PacifiCorp was recently allowed to use a similar method in Oregon, which it calls its Partial Displacement Differential Revenue Requirement ("PDDRR") method for QFs above the size threshold for standard rates. This methodology has already resulted in multiple areas of litigation in Oregon and other states.[16] PacifiCorp has even admitted in

[16] See e.g., Cypress Creek Renewables, LLC v. PacifiCorp, OPUC Docket No. UM 1799, Order No. 16-429 (Nov. 09, 2016); Re Amended Joint Complaint Filing by Everpower Wind Holdings, Inc.; Pryor Caves Wind Project, LLC; Mud Springs Wind Project, LLC; and Horse Thief Wind Project, LLC against Rocky Mountain Power and PacifiCorp Re the Avoided Cost Pricing for the Bowler Flats Wind QF PPAs, WPSC Docket No. 45008-2-IC-16, Record No. 14579, Complaint (Nov. 2, 2016); Re Application of Rocky Mountain Power for Modification of the Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities, Docket No. 20000-481-EA-15, Record No. 14220, Memorandum Opinion, Findings of Fact, Decision and Order at 12-21 (June 23, 2016) (WPSC rejected PacifiCorp's proposed modification of PDDRR methodology and directed additional process); Re Investigation Into QF Contracting and Pricing, OPUC Docket No. UM 1610,

other state commission proceedings that its computer modeling consistently under forecasted net power costs, which can under-estimate avoided cost as well.[17] This kind of modeling provides too much discretion to unilaterally manipulate or lower rates, and will subject the Commission to significant litigation related costs.

iv. Market-Based Pricing

27. The Market-Based Pricing Methodology is also a simple option, but it returns prices that do not accurately reflect the utility's avoided costs, especially given the current effect very low gas prices are having on the energy market. For example, when PSE proposed this approach in its most recent avoided cost update, it resulted in a proposed "payment" of $0.08 per kilowatt year.[18] This kind of methodology ascribes little to no value to capacity and will prevent otherwise low cost QFs from becoming economic.

28. Market pricing fails to reflect that utilities' IRP show that they are always in need of additional capacity, even though utilities do not purchase their next major resource until the need for energy and capacity has grown to be significant to purchase a gas plant. For example, PacifiCorp's West Control Area's capacity deficit is growing, but it is

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Order No. 16-174 (May 13, 2016); Re Investigation to Examine PacifiCorp's Non-Standard Avoided Cost Pricing, OPUC Docket No. UM 1802, Order No. 16-429 (Nov. 09, 2016).

17 Re Investigation Into QF Contracting and Pricing, OPUC Docket No. UM 1610, Renewable Energy Coalition Prehearing Brief at 13 (Sept. 2, 2015) (citing Re PacifiCorp, dba Pacific Power 2016 Transition Adjustment Mechanism, OPUC Docket No. UE 296, PAC/100, Dickman/21 (Apr. 1, 2015)).

18 PSE Advice No. 2016-31 – Schedule 91 – Cogeneration and Small Power Production, Docket No. UE-161240, Substitute Tariff Filing at 2 (Dec. 19, 2016).

allegedly not planning on a new gas plant for a decade.[19] The reason that PURPA projects should be paid for this capacity is that this capacity need can be delayed and the cost of the new gas plant deferred. For example, PacifiCorp's IRP includes over 1,000 MW of non-owned hydro, solar, and wind capacity that would cause a significant and immediate capacity need if it did not exist.[20] The aggregate effect of existing and planned QF projects helps utilities avoid (and delay) the next planned major resource. Thus, QFs should be paid in the near term for capacity benefits based on the concept that they will help avoid both the short and long-term capacity needs that they help defer.

v. Competitive Bidding

29. The Competitive Bidding Methodology is similarly unworkable, and especially in Washington's current market and irregular utility requests for proposals. This method allows states to utilize open bidding processes to determine the avoided cost rates;[21] however, a state cannot require a QF to win a competitive solicitation as a condition to selling its net output to a utility.[22] The winning bids are regarded as equivalent to the utility's avoided cost. This approach is a poor fit for Washington because, while the

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19 Pacific Power & Light Co. Advice 16-06—Schedule 37—Avoided Cost Purchases from Cogeneration and Small Power Purchases, UE-161312, Advice Filing Attachment A at 1 ("The winter peak has a capacity deficit of 48 MW in 2017 increasing to a deficit of 698 MW in 2026. The summer peak has a capacity deficit of 192 MW in 2017 increasing to 583 in 2026."); PacifiCorp 2017 IRP at 2 (planning to acquire 200 MW gas plant in 2029).

20 PacifiCorp 2017 IRP at 78-81 (indicating that for PPAs, which include QFs, PacifiCorp's L&R Balance Capacity at System Summer Peak is 191 MW for wind, 690 for solar, and 127 for hydro). In addition, PacifiCorp has contracts with over 100 MW of biomass and 4 MWs of geothermal, which has a high capacity value. Id. at 80.

21 Winding Creek Solar, LLC, 151 FERC ¶ 61,103 at P 6 (2015), reconsid. denied, 153 FERC ¶ 61,027 (2015).

22 Windham Solar LLC and Allco Finance Limited, 156 FERC ¶ 61,042 at P 5 (2016) (citing Hydrodynamics, 146 FERC ¶ 61,193 at P 32).

Commission's own rules require utilities to undergo an RFP as part of their IRP process, the requirement is often waived and does not occur. This could make it difficult to obtain accurate and current prices given the infrequent Washington competitive bids.

vi. Energy Efficiency Method

30. Up until recently, PSE used another avoided cost methodology, which could also be a workable option. PSE has valued its small renewable projects based on demand response costs. It used the same levelized cost effectiveness of energy and capacity of 15 years of demand side response measures to evaluate the costs avoided by QFs. PSE switched to using the avoided costs of a peaking resource in its last avoided cost update, which resulted a significant reduction in its avoided cost rates.[23] When it is the marginal cost resource, the use of energy efficiency and demand response may be more accurate and produce consistent methodologies across all utility programs.

vii. NIPPC and REC Recommendations

31. In short, there are a number of methodologies that can be used to derive avoided cost prices and the different methods vary greatly in levels of complexity and transparency. The Commission should require the utilities to use simple, transparent, and predictable methods for calculating avoided cost prices. The Energy Efficiency Method is appropriate when QF projects will defer high cost demand response resources, but the Proxy and Peaker Methods also provide workable options.

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[23] Specifically, PSE lowered its levelized long-run capacity costs from $190/kw year, which was based on its planned IRP demand side response measures found to be cost effective, to $120/kw year, which is the current avoided cost of a peaker plant.

32. With respect to at least PSE, the utility should revert to its historic approach of using demand side response measures, i.e., the Energy Efficiency Method, as a proxy for the short run capacity costs. In the alternative, the Commission should require the utilities to use the Peaker Method to value capacity during its short-run period before the next planned major baseload capacity addition.[24] The utilities should then continue the current Proxy Method during its long-run period in which the utilities' avoided costs are based on the full costs of a CCCT (or renewable plant from its most recent IRP).

33. Should the Commission maintain the status quo, the utilities should not be permitted to continue basing their capacity value on only one quarter of the capital costs of a SCCT. Specifically, PacifiCorp should modify its method to provide full capacity payments that represent each month rather than focusing only on its winter peak. The Commission currently allows PacifiCorp (but not PSE) to modify the Peaker Method during its period of short-term resource need to estimate avoided energy costs, by only allowing one forth the capital costs of a SCCT. PacifiCorp has not proposed that only one quarter of its peaking plans be included for recovery in rate base. Peaking plants and QF resources are available for more than just the few hours of the year that capacity may be needed.

34. In a recent proceeding, PacifiCorp attempted to set capacity costs at zero, but in the alternative argued that one fourth of the capital costs of a SCCT was appropriate

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[24] The terms "short-run" and "long-run" can be variable. For example, historically, PacifiCorp's short-run period before its next major thermal baseload acquisition was just a few years, but now PacifiCorp claims that it will not acquire a new CCCT for more than a decade (2029). PacifiCorp 2017 IRP at 2. While PacifiCorp's plans are questionable, the fact is that these time periods can vary significantly.

based on the claim that it represented the capacity contribution during its winter peaking months.[25] The Commission expressed concerns about PacifiCorp's one-fourth method, but ultimately allowed PacifiCorp to use the calculation on an interim basis pending resolution of this broader PURPA proceeding. Thus, PacifiCorp has never adequately justified whether using only one fourth of the costs of a SCCT accurately represent its capacity needs and costs. Only a fourth of the capital costs do not accurately represent the value of capacity provided by QFs.

viii. Washington Utilities Should Be Required to Pay a Renewable Avoided Cost Rate to Renewable QFs that Are Willing to Sell Both Net Electrical Output and Renewable Energy Certificates

35. State regulatory commissions can require utilities to offer a separate avoided cost prices stream for renewable QFs under a similar methodology for non-renewable rates.[26] Renewable QFs that transfer their renewable energy certificates allow utilities to achieve their state mandated RPS requirements, and help defer renewable resource acquisition, which is why separate prices are warranted. This is important because the utilities are likely to acquire significant amounts of renewables in the future, which could be the next avoidable resource.[27]

36. The heart of this issue is the distinction that renewable resources not only meet a utility's load requirements, but also other state required mandates. In 2010, FERC reversed a long-standing precedent that severely restricted states' ability to set rates that

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

26 California Public Utilities Commission, 133 FERC ¶ 61,059 (hereinafter SoCal Edison Clarification Order) at P 27 (2010)(citing SoCal Edison, 70 FERC ¶ 61,215 at 61,677 (1995)).

27 See e.g., PacifiCorp 2017 IRP at 2 (planning to acquire 1,100 MW of wind in 2021).

that reflected the unique value of renewables.[28] FERC explained that states may take into account procurement requirements, and resulting costs, when setting avoided cost prices, and to determine the avoided costs associated with utility purchases of energy "from generators with certain characteristics"[29] As such, states have broad discretion to use their PURPA policies to help utilities achieve their RPS requirements, as well as other procurement mandates, by creating separate avoided costs price streams.

37. The Commission's current rules do not distinguish between renewable and non-renewable avoided cost pricing, and only compensate QFs based on the avoided capacity costs of the utility's next thermal generation resources. Washington utilities need new renewable resources to comply with Washington's RPS requirements and meet their future energy needs. Therefore, the Commission should adopt properly designed renewable avoided cost rates for renewable QFs that sell both their power and renewable energy certificates.

38. Here, the Commission could benefit from the experience of its neighbor directly to the south. In 2011, the Oregon Commission established separate avoided cost price streams for renewable and non-renewable QFs to account for the value of the renewable attributes of renewable energy.[30] The Oregon Commission explained that when QFs are willing to sell power and cede their renewable energy certificates, they should be

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28 SoCal Edison Clarification Order, 133 FERC ¶ 61,059 at P 26.

29 Id. at P 27.

30 Re Investigation Into Resource Sufficiency Pursuant to Order No. 06-538, OPUC Docket No. UM 1396, Order No. 11-505 at 9 (Dec. 13, 2011).

compensated for the value of green power.[31] Put simply, when renewable QFs help the utilities meet their RPS requirements, they should be compensated accordingly.

39. More specifically, Oregon QFs sell their power and keep their RECs until the date upon which the utility needs new renewable resources, which is established during that utility's IRP or actual resource plans. QFs sell their power at the renewable rate and cede their renewable energy certificates to the utility starting with the date that the utility plans to acquire new physical renewable resources. Thus, the utility's date of next resource acquisition effectively determines whether utilities purchase green power (energy plus renewable energy certificates) or brown power (just energy) under the renewable avoided cost rate stream.

40. Similar to Oregon, Washington should allow renewable QFs the option between renewable and non-renewable avoided cost rates. A QF should be able to elect to keep their renewable energy certificates during all years, but then only be paid the non-renewable avoided cost rate that defers the utilities non-renewable energy and capacity needs. This is important to account for different types of renewable generation and QF business models, including the fact that some QFs may have already sold their renewable energy certificates, or need to keep them to obtain financing. Allowing these QFs to retain their renewable energy certificates is also consistent with FERC's requirement that a QF which has previously sold its renewable energy certificates under a separate contract still has the right to sell its net output under PURPA.[32]

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31 Id.

32 Windham Solar, 156 FERC ¶ 61,042 at P 4.

ix. Existing and Operating QFs Provide Unique Capacity Value

41. Existing QFs should be paid for capacity during all years when they renew their or enter into new contracts, even if the Commission determines that new QFs should be paid otherwise. Paying existing QFs for capacity is consistent with how utilities plan their operations and more equitably recognizes the unique long-term benefits that existing QFs provide to the utilities. QFs already operating and under contract allow utilities to defer their new resource acquisitions, which generally lowers avoided cost rates for QF projects by pushing off the need for both short and long-run capacity. Therefore, while NIPPC and REC support paying all QFs full capacity payments in all contract years, if the Commission adopts a policy that provides no or a minimal capacity payment for new QFs, then at least existing QFs should be paid a full capacity payment in all years.

42. When utilities engage in long-term resource planning they compare their load forecasts to their existing resources, and typically include their existing and expected QF contracts. PacifiCorp, for example, has historically assumed that all of its small QF contracts will renew in its resource modeling, which naturally defers a certain amount of capacity need. This assumption exemplifies the concept that QFs in the aggregate defer new resources, even where they do not fully replace the need for a new resource.

43. Paying existing QFs that chose to renew their contracts is especially important when considering the potential for shorter contract terms. For example, the Idaho Commission recently decreased the contract length a QF can select to two years for wind

and solar QFs.[33] PacifiCorp unsuccessfully advocated for similar term lengths in other states as well.[34] Reducing contract terms to such a short period could theoretically create a regulatory environment where QFs are never paid for long-run capacity contributions.

44. While NIPPC and REC disagree with the Idaho Commission's adoption of two year contract terms, the Idaho Commission at least softened the blow for operating projects because it required currently existing QFs to be paid for capacity during the full term of any contract renewals.[35] If the Commission adopts policies that prevent new QF development through either short contract terms or not paying the full value of capacity, the Commission should at least allow existing QFs to renew contracts with full capacity payments to reflect their unique capacity contributions.

Issue A. 2. Are there multiple methodologies that may be appropriate for calculating the energy and capacity payments, depending on its circumstances? If so, what criteria should the Commission use to identify the most appropriate methodology for a specific utility, at a specific point in time?

45. The Commission should require all three utilities to use consistent methodologies when determining their energy and capacity payments under published, standard rates. These utilities' different operational characteristics can be reflected in the dates of their next major resources, as well as the types and costs of resources, but the underlying

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33 Re Idaho Power Company's Petition to Modify Terms and Conditions of PURPA Power Purchase Agreements, IPUC Case Nos. IPC-E-15-01, AVU-E-15-01, PAC-E-15-03, Order No. 33357 at 32 (Aug. 20, 2015).

34 PacifiCorp formally proposed PURPA changes in five of its six states, but California uses Oregon policies, so any changes in Oregon's PURPA implementation will carry over to California as well.

35 Re Idaho Power Company's Petition to Modify Terms and Conditions of PURPA Power Purchase Agreements, IPUC Case Nos. IPC-E-15-01, AVU-E-15-01, PAC-E-15-03, Order No. 33357 at 1, 4, 21 (Aug. 20, 2015); Re the Commission's Review of PURPA QF Contract Provisions, IPUC Case No. GNR-E-11-03, Order No. 32697 at 21-22 (Dec. 18, 2012) (clarified in Order No. 32871 (Aug. 9, 2013)).

policies should be the same. The other regional states that have multiple investor owned utilities (Oregon and Idaho) all require their utilities to use the same underlying methodology for setting published avoided cost rates. The only partial exception is that Oregon requires PacifiCorp and PGE to offer both renewable and non-renewable avoided cost rates to accurately reflect that utilities, subject to renewable portfolio standards, have different needs for renewable and thermal resources. Idaho Power is not required to offer renewable avoided cost rates, but only because it is exempt from Oregon's renewable portfolio standard. Absent other similar unique circumstances, there is no reason to allow any of the three Washington utilities to utilize different methodologies.

Issue A. 4. Should avoided costs be separated to reflect each type of resource capacity value through a peak credit, Effective Load Carrying Capability, or some other calculation?

46. Capacity contributions from renewable QFs are complicated, because there are different ways to estimate the amount of capacity a renewable resource can actually deliver during a particular utility's peak or when the grid is otherwise stressed. The contribution from renewable generation to its capacity need is often determined in a utility's long-term resource planning, and historically been contested. The Commission's approach here should balance the need for accuracy against the need for transparency. Because the different methodologies that separate capacity value based on resource type, and including the Effective Load Carrying Capability ("ELCC"), can have drastic differences on the value of capacity, the Commission should consider these

methodologies not just academically, but to also understand their real-world implications to the avoided cost rates in Washington.[36]

47. Specifically, NIPPC and REC support use of more granular methodologies like the ELCC in the IRP process, but recommend that published standard avoided cost rates not distinguish between different types of QF technologies. Standard avoided cost rates should be simple to calculate and can reflect the aggregate capacity value provided by all QFs that will sell power to the utility. Oregon is the only regional state that includes full capacity adjustments based on resource type, and the process has been subject to considerable litigation.[37] There is no need to set resource specific standard rates given the amount of PURPA development and the potential for litigation that would be brought about by incorporating this additional complexity.

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[36] In PGE's 2013 IRP it estimated a 5% contribution to capacity, but in its 2016 IRP after implementing an ELCC methodology, that estimate jumped to 14%. This three fold did not represent an actual increase in the capacity contribution, but only a modeling change. Re Investigation to Explore Issues Related to a Renewable Generator's Contribution to Capacity, OPUC Docket No. UM 1719, Order No. 16-326 at 3 (Aug. 26, 2016).

[37] For PURPA alone, the issue was addressed in three orders over the course of a four-year administrative process in Oregon, including an (ultimately unsuccessful) application for reconsideration by Idaho Power Company. Re Investigation Into QF Contracting and Pricing, OPUC Docket No. UM 1610, Order No. 14-058 at 2, 15 (Feb. 24, 2014); Re Investigation Into QF Contracting and Pricing, OPUC Docket No. UM 1610, Order No. 16-174 at 2, 12 (May 13, 2016); Re Investigation Into QF Contracting and Pricing, OPUC Docket No. UM 1610, Order No. 16-337 at 3 (Sept. 8, 2016) (rejecting Idaho Power reconsideration). Although not PURPA specific, the issue was also addressed in an entirely separate proceeding regarding the capacity payments. Re Investigation to Explore Issues Related to a Renewable Generator's Contribution to Capacity, OPUC Docket No. UM 1719, Order No. 16-326 (Aug. 26, 2016). These cases do not include the utility IRPs, which look at resource types, but do not focus on PURPA projects.

48. Theoretically, a more robust calculation that takes into account all hours in a year should return a more equitable result than one that takes into account smaller windows of time, but this topic misses the forest from the trees. Simply put, there is not enough QF activity in Washington to bother allocating capacity values by resource type. Unless and until it becomes worth the trouble, avoided cost rates should ignore resource type, which is consistent with the general principle that QFs should be considered in the aggregate rather than individually, and provides a much simpler method.

49. Introducing complex modeling will create opportunities to manipulate the data, so that the application of the model may need some kind of third-party auditing or verification. Increasing complexity on this front also increases the likelihood that some utilities may not be able to participate, if they do not have the level of load and generation data required to do the more complex calculations with.[38] And these different modeling systems may ultimately result in capacity rates that undervalue certain resource types despite their actual contribution to the utility's capacity need.

50. In theory, capacity estimates could be based on all hours in a year, but this is modeling that requires expensive consultants to understand or verify, and is outside of the ability of the vast majority of QFs to access. For example, ELCC more accurately estimates the capacity value provided by renewables in peak and non-peak hours, but this generality assumes that extremely detailed data crunching, and necessarily involves a cumbersome multi-step process to be done correctly. To hedge against the challenges of

[38] See e.g., Re Investigation to Explore Issues Related to a Renewable Generator's Contribution to Capacity, OPUC Docket No. UM 1719, Order No. 16-326 at 6 (Aug. 26, 2016) (allowing Idaho Power to opt out of ELCC calculations for IRP calculations).

using a "black box" to calculate capacity value, a separate benchmark or approximation method may even be necessary.

51. In the end, this type of complex modeling is appropriate for the time intensive and critically important resource planning process, but QFs and their representatives simply do not have the resources to participate to verify that the results are appropriate for setting PURPA rates. Therefore, for the purposes of setting avoided cost rates, the Commission should adopt a simple, transparent capacity calculation that values capacity equally for all QFs.

B. ISSUE B. STANDARD PRACTICES

52. Policies on standard contract size, term length, site disaggregation, and establishing a legally enforceable obligation ("LEO") often determine whether a QF project is economic. Unsurprisingly, these topics also tend to be heavily litigated. NIPPC and REC relied upon ample experience litigating these issues throughout the region when preparing these comments. With respect to standard published rates, the Commission should establish a 10 MW size threshold, adopt FERC's "one-mile" rule, allow the QF an opportunity to select a contract term length up to a maximum of 20 years from the date of power deliveries, and set out clear milestones for triggering a LEO as well as alternative dispute resolution. For larger QFs, which exceed the Commission's eligibility requirements, the NIPPC and REC also strongly urge the Commission to establish guidelines and protections to ensure that all cost-effective QFs have a fair opportunity to sell their net output. All parties should be required to follow Commission-approved timelines and information requirements that will provide specific guidance to completing the PPA process.

53. It is crucial that the Commission adopt simple policies that can be implemented consistently by Washington's regulated utilities. When weighing the different avoided cost methodologies, and different standard contract options, the benefits of being able to rely on a simple and straightforward policy often outweigh the potential up or downside between the particular options.

Issue B. 1. What should be the maximum design capacity of a facility to qualify for the standard offer? Should the Commission differentiate between types of resources for determining the maximum design capacity of a facility to qualify for a standard contract?

54. All QFs face obstacles that warrant the protections afforded by standard contracts. FERC requires standard contracts for QFs under 100 kW, but permits states to set standard contracts for larger QFs as well. The Commission should establish a size threshold for standard contract rates to include QFs with a design capacity of 10 MW or less, but allow all QFs the ability to select standard contract terms and published prices. This recommendation is based in part on the Oregon Commission's moderately successful 10 MW size threshold for standard contracts. The Oregon Commission has repeatedly confirmed its 10 MW size threshold for QF standard contract eligibility, with the exception that it recently lowered that threshold for solar QFs to 3 MW selling to PacifiCorp and Idaho Power.[39] The Commission should reject Oregon's approach of

[39] Re Investigation Related to Electric Utility Purchases from QFs, OPUC Docket No. UM 1129, Order No. 05-584 at 17 (May 13, 2005) (establishing a 10 MW size threshold); Re Investigation Into QF Contracting and Pricing, OPUC Docket No. UM 1610, Order No. 14-058 at 7 (Feb. 24, 2014) (upholding the 10 MW size threshold); Re PacifiCorp, dba Pacific Power, Application to Reduce the QF Contract Term and Lower the QF Standard Contract Eligibility Cap, OPUC Docket No. UM 1734, Order No. 16-130 at 4-5 (Mar. 29, 2016) (reducing the size threshold for solar projects); Re Idaho Power Application to Lower Standard

adopting a lower size threshold for solar generation because it had the practical effect of stopping new solar QF development for PacifiCorp.[40]

55. Larger QFs, which may not qualify for published rates, are also at a disadvantage when negotiating with utilities and face significant barriers, and will benefit greatly from Commission guidelines and additional protections, including access to standard contract provisions and specific timelines for the utilities to provide information and complete the negotiation process. Regardless of size, all QFs should be eligible for at least 15 year contracts.

56. Standard contracts provide the kind of regulatory certainty that can make or break both new and existing QF projects because of the difficulty negotiating with the utilities. Currently, the Washington utilities all have small size thresholds.[41] The Commission should opt for a higher size threshold to streamline PPA negotiations. The current approach subjects smaller QFs to burdensome, complex, and one-sided negotiations with monopsony utilities that do not want to buy QF power. A larger size threshold for

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Contract Eligibility Cap and to Reduce the Standard Contract Term, for Approval of Solar Integration Charge, and for Change in Resource Sufficiency Determination, Docket No. UM 1725, Order No. 16-129 at 4-6 (Mar. 29, 2016) (reducing the size threshold for solar projects).

[40] After entering into a number of solar PPAs in 2014 and most of 2015, PacifiCorp has not entered into an Oregon solar QF PPA since December 2015, which was soon after the Oregon Commission adopted an interim 3 MW solar size threshold on August 14, 2015. Re PacifiCorp, dba Pacific Power, Application to Reduce the QF Contract Term and Lower the QF Standard Contract Eligibility Cap, OPUC Docket No. UM 1734, Order No. 15-241 at 1 (Aug. 14, 2015); http://apps.puc.state.or.us/edockets/docket.asp?DocketID=19097 (list of PacifiCorp Oregon QF PPAs). The 3 MW solar size threshold was made permanent on March 29, 2016. Re PacifiCorp, dba Pacific Power, Application to Reduce the QF Contract Term and Lower the QF Standard Contract Eligibility Cap, OPUC Docket No. UM 1734, Order No. 16-130 at 4-5 (Mar. 29, 2016).

[41] PacifiCorp is 2 MW, PSE is 5 MW, and Avista is 5 MW.

standard contracts will remove transaction costs and eliminate market barriers for QFs attempting to sell their power, and increase the ability of QFs to successfully negotiate contracts without unreasonable delays and obstacles.

57. PPA negotiations are far from those of a normal arm's length transaction. Establishing standard contracts protects QFs negotiating with unequal bargaining power, and reduces negotiation costs imposed upon QFs. Smaller QFs are particularly vulnerable during negotiations because they are less likely to approach negotiations with a robust team and may not be able to sustain long-term negotiations. Thus, one of the goals for standard contracts should be to eliminate these market barriers and reduce transaction costs.

58. While NIPPC and REC support a 10 MW size threshold for published prices, there is also an argument that standard contracts should be available for QFs up to 20 MWs. The majority of FERC cases granting relief from PURPA's mandatory purchase obligation apply to QFs 20 MW or larger. FERC's distinction may provide the most natural break between small and large QFs. The California Commission uses 20 MW net output as the threshold size for eligibility for standard contracts.[42]

59. Although standard contracts and prices tend to focus on small QFs, larger projects also face difficulties negotiating with a potential business partner that does not want to buy their product. Utilities are obligated to purchase QF power and capacity whether the QF is eligible for standard contracts or not. Developing mid-sized projects over standard

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[42] Winding Creek, 151 FERC ¶ 61,103 at P 6 (citing California Commission Decision D.10-12-035, pp. 14-15, 44-45).

contract size thresholds can be extremely difficult.[43] Even assuming *arguendo* that larger QFs are more sophisticated or have a more robust staff to work on PPA negotiations, something which is not always true, there is still asymmetric availability of information and an unlevel playing field. Larger QFs also often have no more bargaining power than small projects because their utility may be the only economic option to sell power given the lack of organized markets and a regional transmission organization, combined with an historical unwillingness of utilities to do business with independent producers.

60. Thus, Commission direction for non-standard negotiations can also help eliminate market barriers and reduce transaction costs. More specifically, the Commission should establish guidelines to provide both small and large QFs a clear expectation for how long their negotiation process may last. For example, in other states, PacifiCorp's tariffs list the information that PacifiCorp can request, and requires PacifiCorp to provide information in specific amounts of time and timely complete negotiations.[44] All the

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[43] PacifiCorp's Washington service territory is geographically similar to Oregon, with one quarter the size. As of early 2015, PacifiCorp had no PPAs with QFs above the 2 MW size threshold in Washington, and only 2 out of about 50 QF projects in Oregon were above that state's 10 MW size threshold. These two large Oregon QFs are both biomass projects. As of 2015, PacifiCorp had a modest 226 nameplate MW of Oregon QF development representing a wide variety of small and mid-sized hydro, biomass, CHP, wind and methane QFs between 2 and 10 MWs. Washington is simply losing out on similar non-utility resource development because of its PURPA policies. Information based on WUTC v. Pacific Power & Light Co., Docket No. UE-144160, Unopposed Joint Motion to Admit Evidence at Exhibit 1 List of QFs REDACTED (May 7, 2015), available at: https://www.utc.wa.gov/docs/Pages/DocketLookup.aspx?FilingID=144160.

[44] PacifiCorp's Oregon small and large rate schedules include timelines and information requirements, and the Oregon Commission has approved a specific process for setting QF large rates, and PacifiCorp's large rate schedule for Idaho, Utah and Wyoming include specific timelines and informational requirements and those commissions have approved specific processes for setting large QF rates.

Washington utilities' tariffs should determine reasonable time periods and informational requests for negotiations.

61. The Commission should also consider adopting negotiating guidelines for large QF prices to prevent the utilities from setting them below actual avoided costs. The Oregon Commission has also determined "that QFs greater in size than 10 MW face market barriers, such as asymmetric information and an unlevel playing field, that impede negotiation of a viable QF power purchase contract with electric utilities."[45] Due to these concerns, Oregon adopted "guidelines for negotiated contracts between utilities and large QFs, as well as procedures to be used when negotiations are not fruitful."[46] Oregon is not alone, as the Idaho, Utah and Wyoming Commissions require Idaho Power, Avista, and PacifiCorp to file tariffs outlining their negotiation process and method of setting large QF rates.[47] Without opining on the reasonableness of any particular state's approach or requirements, NIPPC and REC support the concept that utilities should be required to obtain Commission approval of the process, timelines, and information requirements used to set larger QF rates.

62. Moreover, the Commission should allow large QFs the option to utilize standard contract provisions. This will help ensure that contract negotiations loosely follow those for smaller facilities and help keep negotiations equitable and efficient for all QFs. For example, while Oregon recently lowered the size threshold for standard contract prices

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45 Re Investigation Related to Electric Utility Purchases from QFs, OPUC Docket No. UM 1129, Order No. 05-584 at 17 (May 13, 2005).

46 Re Investigation Related to Electric Utility Purchases from QFs, OPUC Docket No. UM 1129, Order No. 07-360 at 1 (Aug. 20, 2007).

47 See e.g., Re PacifiCorp dba Rocky Mountain Power's Application to Approve Elec. Service Schedule No. 38 Qualifying Facility Avoided Cost Procedures, IPUC Case No. PAC-E-16-01, Order No. 33474 at 1-4 (Mar. 3, 2016).

for solar QFs to 3 MWs, it continued to allow solar QFs access to standard contract provisions up to 10 MWs.[48] While NIPPC and REC oppose such a low threshold for standard rates, Oregon demonstrates that there can be higher threshold for the protections of standard contract provisions than for standard rates.

Issue B. 2. For the purposes of setting the maximum design capacity of a facility to qualify for the standard contract, is it necessary for the Commission to set a minimum distance between QFs belonging to the same owner? If so, what is the appropriate distance or test for determining a minimum distance? Should the Commission set different minimum distance requirements based upon the type of QF resource?

63. The Commission should simply adopt FERC's "one mile" rule for setting the minimum distance between QF projects belonging to the same owner. FERC regulations provide that generating facilities are considered a single QF if they are located within one mile of each other, use the same energy resources, and are owned by the same person or affiliate. This rule provides a simple, unambiguous, and workable solution to a potentially hyperbolic problem. FERC has confirmed that its "one-mile" rule is more than a mere presumption, and constitutes a safe harbor that developers are entitled to rely upon. There is no reason to adjust FERC's rule in Washington. Thus, the Commission should adopt FERC's policy.

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[48] Re Idaho Power Application to Lower Standard Contract Eligibility Cap and to Reduce the Standard Contract Term, for Approval of Solar Integration Charge, and for Change in Resource Sufficiency Determination, Docket No. UM 1725, Order No. 16-129 at 5-6 (March 29, 2016) (standard contracts provisions still available to solar QFs up to 10 MWs); Re PacifiCorp, dba Pacific Power, Application to Reduce the QF Contract Term and Lower the QF Standard Contract Eligibility Cap, OPUC Docket No. UM 1734, Order No. 16-130 at 4-5 (Mar. 29, 2016) (standard contracts provisions still available to solar QFs up to 10 MWs).

Issue B. 3. If the Commission were to specify the term length of a standard offer power purchase agreement, how should it best balance the preference of project developers for longer term agreements to mitigate their risks against the uncertainty that the avoided cost rates in effect at the time will actually reflect the true avoided cost to the utility in the future? Should the Commission differentiate standard contract lengths based on the type of resource?

64. Although 20 years is often needed for QFs to secure financing on a new project, 15 years is the bare minimum to allow most QFs the opportunity to obtain adequate financing. Most QF developers require contract terms with at least 15 years of fixed prices to meet financing requirements, make longer-term business plans, and operate during any contract periods when avoided cost prices are low. Existing QF projects may also need long contracts to establish financing for equipment upgrades, or to weather periods of low market prices. As a utility's standard contract length decreases, however, so does the opportunity for QF development. For example, the Idaho Commission recently prevented the utilities from offering contract terms more than two years for new wind and solar QFs, which effectively ended all new development in that state for wind and solar QFs.

FERC has consistently interpreted its own rules to entitle QFs to long-term contracts containing fixed prices for energy and capacity based on a forecast of the utility's avoided costs. FERC's rules state that:

> Each qualifying facility shall have the option . . . (2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility, … be based on . . . (ii) The avoided costs calculated at the time the obligation is incurred.[49]

[49] 18 C.F.R. § 292.304(d)(2)(ii) (emphasis added).

The option to sell energy and capacity over a "specified term" should be interpreted to mean that a QF has the choice to determine the length of a reasonable term.

The history and purpose of the regulation support a conclusion that QFs are entitled to long-term, fixed-price contracts or other legally enforceable obligations. As explained by FERC, the rule "is intended to prevent a utility from circumventing the requirement that provides capacity credit to the qualifying facility merely by refusing to enter into a contract with the qualifying facility."[50] FERC further explained that the rule "enables a qualifying facility to establish a fixed contract price for its energy and capacity at the outset of its obligation . . . ."[51] Long-term commitments are necessary because QFs have a "need for certainty with regard to return on investment in new technologies".[52] FERC has also explained that long term agreements provide "an investor … [the ability] to estimate, with reasonable certainty the expected return on a potential investment before construction of a facility."[53]

65. FERC has consistently relied upon these statements in its seminal Order No. 69.[54] FERC concluded that a state commission violated its rules where the PURPA implementation "offers the competitive solicitation process as the only means by which a QF greater than 10 MW can obtain long-term avoided cost rates."[55] FERC additionally

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50 FERC Order No. 69, at 12,224.

51 Id. (emphasis added).

52 Id.

53 FERC Order 69 at 30,868.

54 See Va Elec. and Power Co., 151 FERC ¶ 61,038, P. 24 (2015); Hydrodynamics, 146 FERC ¶ 61,193 at P 31; Cedar Creek, 137 FERC ¶ 61,006 at P 32; N.Y. State Elec. & Gas Corp., 71 FERC ¶ 61,027, 61,115-61,116 (1995).

55 Hydrodynamics, 146 61,193 at P 33 (emphasis added).

found that a 50-MW cap for purchases from certain QFs illegally prohibited QFs from obtaining "forecasted avoided cost rates."[56]

66. The practical experience with short contract terms demonstrates that they effectively prevent nearly all new QF development and can result in the shut down of existing projects. From 1980-1996 Idaho Power offered long-term QF contracts (between 20-50 years) and executed numerous contracts. From 1996-2001 Idaho Power switched to a five-year QF contract and had only one new PURPA project. From 2002-2015, Idaho Power switched back to long term contracts (20 years) and again executed new contracts, until the Idaho Commission allowed two year contracts last year and the cycle has repeated itself. In Washington, PacifiCorp insists on a maximum of five year contracts, which has resulted in only a few Washington QFs.[57] The Oregon Commission adopted five-year contracts for about a decade and similarly stifled QF development.[58] On the other side of the spectrum, utilities tend to finance their own project over 30 or more years. Thus, whatever contract term the Commission adopts for QFs will expose ratepayers to less risk than utility owned projects that are included in rates for the economic life of the resource.

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56 Id. at P 34.

57 Pacific Power & Light Co., Schedule 37 (Washington) at 2, available at: https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Washington/Approved_Tariffs/Rate_Schedules/Cogeneration_and_Small_Power_Production.pdf.

58 Re Investigation Related to Electric Utility Purchases from QFs, OPUC Docket No. UM 1129, Staff Testimony of Lisa Schwartz (200-202), Staff/200, Schwartz/2-6 (Aug. 3, 2004).

67. The Oregon Commission balanced the two goals of accurate prices with ensuring that QFs have "viable opportunities"[59] to sell their power as its basis for establishing a 20 year QF contract lengths, with 15 years of fixed pricing.[60] In four different proceedings in 2005, 2014 and 2016,[61] the Oregon Commission determined that 15 years of fixed prices was appropriate because it "enables eligible QFs to obtain adequate financing".[62] The Wyoming Commission determined that 20 year contracts seemed to allow an adequate opportunity for financing,[63] and the Utah Public Service Commission ("Utah Commission") recently determined that 15 year contracts best served the public interest and could allow QF developers a reasonable opportunity to obtain financing.[64]

68. Washington's policies significantly hinder QF development, as demonstrated by the paucity of projects in Washington compared with Oregon, Utah and even Idaho. A large part of this is related to the difficulty in obtaining long term contracts, and

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59 Re Investigation Related to Electric Utility Purchases from QFs, OPUC Docket No. UM 1129, Order No. 05-584 at 19 (May 13, 2005).

60 Id. at 20.

61 Id.; Re Investigation Into QF Contracting and Pricing, OPUC Docket No. UM 1610, Order No. 14-058 at 1-2 (Feb. 24, 2014) (making no changes contract provisions, other than specifically identified); Re PacifiCorp, dba Pacific Power, Application to Reduce the QF Contract Term and Lower the QF Standard Contract Eligibility Cap, OPUC Docket No. UM 1734, Order No. 16-130 at 1-2, 5 (Mar. 29, 2016); Re Idaho Power Application to Lower Standard Contract Eligibility Cap and to Reduce the Standard Contract Term, for Approval of Solar Integration Charge, and for Change in Resource Sufficiency Determination, Docket No. UM 1725, Order No. 16-129 at 1-2, 6-8 (Mar. 29, 2016).

62 Re Investigation Related to Electric Utility Purchases from QFs, OPUC Docket No. UM 1129, Order No. 05-584 at 19 (May 13, 2005).

63 See Re Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements With Qualifying Facilities, WPSC Docket No. 20000-481-EA-15, Record No. 14220 at 11-12 (June 23, 2016).

64 Re the Application of Rocky Mountain Power for Modification of Contract Term of PURPA PPAs with QFs, UPSC Docket No. 15-035-53, Order at 19-20 (Jan. 7, 2016).

negotiating projects above the size threshold. Washington is missing out on the many benefits of a robust independent renewable power development industry.

69. Given the clear impact that contract term length has on QF development, the Commission should consider whether the contract terms allow QFs to obtain financing, which other states have concluded is between 15 and 20 years. All QFs should have the option of selecting a contract term of its choosing. Any policy that effectively bars the vast majority of cost effective QFs from being constructed is inherently inconsistent with PURPA.

Issue B. 4. Should the Commission specify in rule the point in the standard offer contract process where a utility has a legally enforceable obligation to purchase a facility's output?

70. The concept of a LEO is unique, but essentially allows a QF to sell power to a utility under certain circumstances when the QF has been unable to finalize a contract with the utility.[65] FERC has established that a LEO is broader than a simple contract between a utility and a QF, and may exist without a written contract.[66] Utilities are not permitted to unreasonably delay the PURPA contract negotiation process or refuse to sign a PPA, because QFs have the right to receive a legally binding commitment to sell their power to a utility pursuant to either a contract or a LEO.[67] To establish a LEO, a QF

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65 Standard contract terms, timelines, specificity regarding information that can be requested, and negotiation guidelines significantly reduce the risk litigation; however, disputes can still arise for a variety of reasons and there is a need for the Commission to update its LEO policies.

66 Murphy Flat Power, LLC, 141 FERC ¶ 61,145 at P 24 (2012); Grouse Creek, 142 FERC ¶ 61,187 at P 38.

67 18 CFR § 292.304(d); FERC Order No. 69 at 12,224; Cedar Creek, 137 FERC ¶ 61,006 at PP 32, 36.

must generally commit itself, or otherwise be ready to sell its power.[68] Thus, QFs can require a utility to purchase its power at then current prices, even if the utility has refused to enter into a contract or raised other unreasonable delays.

71. NIPPC and REC recommend that the Commission adopt a LEO policy that establishes a LEO prior to contract execution if: 1) the QF demonstrates a reasonable dispute regarding prices or terms; or 2) there is a delay or obstruction of progress toward a final draft of an executable contract, such as the failure to provide required information or documents on a timely basis or the imposition of unreasonable contract provisions. If there is such a dispute or delay, then the QF should be allowed to "lock in" the current prices, commit to sell power to the utility under the terms and conditions the QF finds acceptable, and seek Commission resolution of the dispute without risk that it will no longer be eligible for the current prices at the end of any litigation.

72. FERC allows, within reasonable parameters, states to implement their own LEO policies, and thus, to determine precisely when a LEO has occurred. FERC has established limitations on state's authority and concluded that LEOs can occur "once a QF makes itself available to sell to a utility" and "may exist prior to the formation of a contract."[69] However, due to more recent FERC activity on this front and the fact that there is little Washington precedent on this topic, the Commission should focus on establishing clear milestones for a QF to trigger a LEO rather than try and pinpoint a precise time when contract negotiations have matured enough to establish a LEO.

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68 Cedar Creek, 137 FERC ¶ 61,006 at PP 36, 39; Snow Mountain Pine Co. v. Maudlin, 734 P.2d 1366, 1371, 84 Or. App. 590 (1987).

69 JD Wind 1, 129 FERC ¶ 61,148 at P 25.

73. The LEO concept was established to protect QFs from utility misbehavior. The LEO is designed to "prevent an electric utility from avoiding its PURPA obligations by . . . delaying the signing of a contract, so that a later and lower avoided cost is applicable."[70] LEO cases can also occur when the utilities have agreed to prices, provided final draft PPAs or even signed PPAs to QFs in the past, only to challenge the contracts after avoided cost rates dropped or other policy changes were made.[71] Thus, the LEO can counter the almost infinite array of options utilities have employed to stonewall

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70 Id.; see also FERC Order No. 69 at 12,224.

71 E.g., Re Application of Rocky Mountain Power for Approval of the Power Purchase Agreement between PacifiCorp and Thayn Hydro, LLC, UPSC Docket No. 16-035-04, Final Order (Mar. 4, 2016) (PacifiCorp refused to finalize a PPA until after prices dropped); Grouse Creek, 142 FERC ¶ 61,187 at P 6 (Idaho Power Company argued that a fully executed PPA no longer qualified for a standard contract based on a change in Idaho state PURPA policy that occurred months after execution); Murphy Flat, 141 FERC ¶ 61,145 PP 6, 18 (Idaho Power Company argued that a fully executed PPA no longer qualified for a standard contract based on a change in Idaho state PURPA policy that occurred after execution); Rainbow Ranch Wind, LLC, 139 FERC ¶ 61,077 at PP 6, 16 (2012) (Idaho Power Company argued that a fully executed PPA no longer qualified for a standard contract based on a change in Idaho state PURPA policy that occurred after execution); Cedar Creek, 137 FERC ¶ 61,006 at PP 5, 20 (Rocky Mountain Power/PacifiCorp argued that it should not be bound by PPAs that it delayed executing until after an Idaho state PURPA policy change); Re Farmers Irrigation District v. PacifiCorp, dba Pacific Power, OPUC Docket No. UM 1441, Order No. 10-493 at 2 (Dec. 27, 2010) (PacifiCorp raised a concern regarding a QF's continued eligibility, refused to sign a new or renewed PPA until after its prices changed, and then offered only the lower rates); Re Swalley Irrigation District v. PacifiCorp, dba Pacific Power, OPUC Docket No. 1438, Order No. 09-451 at 1 (Nov. 9, 2009) (QF had taken steps to establish a small power production facility, but PacifiCorp refused to execute a completed PPA unless the agreement included new, lower rates); Re International Paper Co. v. PacifiCorp, dba Pacific Power, OPUC Docket No. UM 1449, Order No. 09-439 at 6-7 (Nov. 4, 2009) (PacifiCorp refused to execute a PPA during a pending avoided cost rate change and then argued after the rate change that the lower rates should apply); Snow Mountain, 734 P.2d at 1370 (CP National would not execute a PPA prior to an avoided cost rate change and argued that the applicable avoided cost rates should be the avoided cost rates in effect after the rate reduction).

contract negotiations or to otherwise prevent or delay a QF from entering into a contract at rates they are legally entitled to.[72] One important aspect of the LEO, is that it provides a mechanism for QFs to "lock-in" current avoided cost rates when a utility is delaying or otherwise imposing unreasonable terms and conditions.

74. Historically QFs have faced unforeseen hurdles and roadblocks throughout their negotiations and rely upon the LEO to keep negotiations moving.[73] For example, a QF may think it is more than half-way done with their negotiations when a new requirement arises. Utilities may also impose obstacles to contract execution that are either impossible to meet, or that the utility itself has complete control over.[74] QFs in these positions can spend years trying to get their negotiations completed while rates drop, costs and risks mount, and financing dries up. Thus, a LEO empowers the QF, rather than the utility, to determine the date for which avoided costs are calculated by obligating itself to provide power.[75]

75. Utilities also use declining rates as leverage to force QFs into accepting new and less favorable contract provisions or milestones to force the QF end their negotiations before a looming rate decrease goes into effect.[76] QFs facing such a rate decrease are particularly vulnerable, and often face stalled negotiations from utilities until new rates

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72 Cedar Creek, 137 FERC ¶ 61,006 at P 36 (holding a utility cannot refuse to sign a contract simply "so that a later and lower avoided cost is applicable").

73 Id.; Grouse Creek, 142 FERC ¶ 61,187 at P 40.

74 E.g., FLS Energy, 157 FERC ¶ 61,211 at P 23 ("requiring a QF to tender an executed interconnection agreement is … inconsistent with PURPA and our regulations").

75 See Re Investigation Into QF Contracting and Pricing, OPUC Docket No. UM 1610, Order No. 16-174 at 24 (May 13, 2016) (citing Snow Mountain, 84 Or App at 598).

76 Cypress Creek Renewables, LLC v. PacifiCorp, OPUC Docket No. UM 1799, Order No. 16-378, (Oct. 12, 2016).

go into effect. Thus, litigation over a PPA dispute must not be allowed to delay the establishment of a LEO. Likewise, QFs must be entitled to the avoided cost rates in effect when a LEO is incurred rather than when contracts are finally executed or when a complaint is filed.[77]

76. Although typically a LEO would most naturally occur towards the end of power purchase negotiations, when parties have essentially agreed on most key provisions, QFs should be able to trigger a LEO at any time during their negotiations with a utility. For example, a recent Utah LEO case involved a situation where a small hydroelectric project was renewing its PPA while its utility's rates were decreasing. The parties agreed that all material terms were agreed to, but for an insurance requirement. PacifiCorp delayed signing the contract until after the rate change, and then refused to give the QF a contract under the older and higher rates.[78] Ultimately, the Utah Commission determined a LEO had been formed, but only after the QF filed a complaint and reached a settlement with PacifiCorp. This is the classic LEO situation that many commission policies are based upon.

77. In 1989, the Commission adopted the Idaho Commission's conclusion that only "mature" proposals trigger PURPA's mandatory purchase obligation.[79] The Commission

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77 Grouse Creek, 142 FERC ¶ 61,187 at P 40 (it is unreasonable for a state commission to require a QF to file a complaint to establish a LEO).

78 Re Application of Rocky Mountain Power for Approval of the Power Purchase Agreement between PacifiCorp and Thayn Hydro, LLC, UPSC Docket No. 16-035-04, Final Order at 7 (Mar. 4, 2016).

79 Re Petition of Wheelabrator Environmental Systems, Inc. for a Declaratory Ruling and Complaint, Docket No. U-89-3043-F, 1989 WL 1786664 at *7 (Sept. 28, 1989) (citing Empire Lumber Co. v. Washington Water Power Co., IPUC Case No. U-1008-241, Order No. 20281 (Mar. 4, 1986); Forest Fuel Power, Inc.

determined that utilities are "not required to sign a contract until such time as the proposed facility has reached sufficient maturity that principal conditions for a power purchase agreement can be identified, including a contract for construction of the facility, selection of a site, and completion of an environmental impact statement."[80]

78. Nevertheless, the Commission's "mature" standard is outdated. FERC has since established a number of factors to consider when deciding whether a QF has unequivocally committed itself to sell power and created a legally enforceable obligation. A non-exhaustive list includes: 1) the extent of negotiations; 2) whether the negotiations occurred before the new avoided cost rates changed; 3) whether the QF is certified; 4) whether the QF signed the contract or took other actions before the new rates became effective; and 5) what conditions had been agreed upon.[81] The majority of FERC's LEO decisions have not been as proscriptive, but have rather identified whether a particular unique set of facts established a LEO.

79. Given recent FERC precedent, the Commission should go farther that its nearly 30 year precedent and allow QFs to trigger LEO at any point during the contract negotiations. In *FLS Energy Inc.*, FERC opined that "just as requiring a QF to have a utility-executed contract, such as a PPA, in order to have a legally enforceable obligation is inconsistent with PURPA and our regulations, requiring a QF to tender an executed interconnection agreement is equally inconsistent with PURPA and our regulations."[82]

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v. Washington Water Power Co., IPUC Case No. U-1008-246, Order No. 20486 (May 15, 1986)).

80 Id. at *8.

81 Cedar Creek, 137 FERC ¶ 61,006 at P 36; Rainbow Ranch, 139 FERC ¶ 61,077 at PP 24-27; Grouse Creek, 142 FERC ¶ 61,187 at PP 37-39.

82 157 FERC ¶ 61,211 at P 23 (2016).

FERC explained that, "[s]uch a requirement allows the utility to control whether and when a legally enforceable obligation exists—e.g., by delaying the facilities study or by delaying the tendering by the utility to the QF of an executable interconnection agreement."[83]

80. This recent FERC order confirms the spirit and purpose of the LEO, and means that a LEO can be established even very early in the negotiation process if the utility imposes an unreasonable requirement that stalls negotiations. For example, if the utility refuses to even provide prices, a draft contract or otherwise initiate discussions, then the QF should be allowed to form a LEO at the start of the negotiation process.[84] This is fair even if the process has not reached the point of maturity that would form a LEO in other circumstances because the QF would have been prevented from taking actions to demonstrate its "maturity."

81. Rather than identify precisely when a LEO may occur, the Commission should implement a practical solution that allows for negotiations to progress by setting clear standards for the presumption of a LEO. It would be impossible for the Commission to establish a firm rule on LEOs that addresses all potential situations and stands up to FERC's ongoing interpretations. So, the Commission should opt for a simple policy instead.

82. As explained above, the utilities' rate schedules should lay out clear milestones that could establish a reasonable negotiation process that will help determine when a

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83 Id.

84 For example, Cypress Creek Renewable recently filed a complaint against PacifiCorp claiming that the utility refused to even initiate PPA negotiations. Cypress Creek Renewables, LLC v. PacifiCorp, OPUC Docket No. UM 1799, Order No. 16-429, (Nov. 09, 2016).

LEO has occurred. A LEO should be formed if the utility does not provide information or documents according to its Commission approved rate schedule, or act consistently with state or federal law and policies. Both the QF and the utility should be required to make a good faith effort to follow and comply with that process. This places obligations on the QF's need to provide information to the utility to prepare a draft contract, timely respond to reasonable requests for information, and inform the utility when they are ready to sign a contract.

83. PacifiCorp's Oregon tariffs provide a good road map for the process by which information should be exchanged and a process for both the utility and QF to finalize a PPA.[85] For example, once the QF has initiated the process and provided all required information, the utility should respond within a reasonable set amount of time. PacifiCorp's tariff allows 15 days. Likewise, once the utility has provided a draft standard contract, the QF should indicate whether that draft is acceptable within a set period. If a utility has not met its milestones or requested information or imposed conditions inconsistent with its tariff, and the QF has unequivocally committed to selling its net output in good faith negotiation, then a LEO should be presumed. Whether each party has met its milestones provides evidence of good faith negotiation.

84. By relying on milestones established by the utilities' tariffs, the Commission can provide a policy that permits a LEO at any time during the negotiations, but without deviating too far from its current "mature" standard. Under this framework, a LEO could

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[85] Available at: https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Oregon/Approved_Tariffs/PURPA_Power_Source_Agreement/Standard_Avoided_Cost_Rates_Avoided_Cost_Purchases_From_Eligible_Qualifying_Facilities.pdf.

exist any time after a QF expresses an unequivocal commitment to sell electricity to a utility, has provided all required project information to the utility, or has otherwise tried to negotiate in good faith with the utility. This is necessary to address situations where a utility refuses even to provide a QF with an initial PPA or imposes other unreasonable obstacles.

85. The Commission should be available to resolve issues without requiring litigation. If a breakdown in negotiations occur, the Commission should offer alternative dispute resolution that does not put either standard contract provisions, or the avoided cost rates in jeopardy. Additionally, the Commission must recognize that there is unequal negotiation experience and resources between the QF and a utility. Even the most sophisticated developer with resources to afford consultants and lawyers is at a disadvantage in terms of knowledge and control over the exchange of information and drafts. The Commission may protect the negotiation process simply by leveling the playing field between parties.

86. Finally, it is important to note that legitimate disputes between a QF and utility also arise in the absence of bad faith on either party. The QF, however, generally only has one purchaser to sell its power to, and time is the enemy to any project developer, especially QFs that are in danger of losing current rates. Therefore, it is critical for QFs to be able to seek resolution of disputed issues in a timely manner that ensures that they are able to "lock in" rates without being required to accept unreasonable and potentially illegal prices and contract provisions.

Issue B. 5. Should the rates and model standard offer agreements be disaggregated into separate tariffs?

87. Disaggregation of rates and standard offer agreements is a good idea because litigation over one area could unintentionally interfere with, or hold-up progress in negotiations on another area. A prolonged challenge to the meaning of certain terms and conditions in a utility's standard contract should not change to the rates available to QFs and vice versa. In other words, if there is no dispute about changes to standard contract provisions, but a challenge to the new rates, then the unopposed standard contract changes should be allowed to go into effect and allow the parties to litigate over the rate change. The opposite is also true if the rates are acceptable, but contract provisions are controversial, then a more accurate and updated rate change should not be delayed due to a dispute regarding unrelated contract changes.

88. This recently was a concern with PSE's last avoided cost rate filing in which the utility requested an update to its standard contract in addition to its standard rates.[86] PSE refused to sign and finalize any new power purchase agreements until both its new contract and its new rate are approved. This scenario put QFs in jeopardy of being forced to choose between accepting either lower prices or outdated contract provisions. Only after the issue was raised to the Commission did PSE commit to allowing the QFs to obtain the appropriate prices and contract provisions. If the contract provisions and tariffs had been disaggregated, then the Commission could have avoided dispute over at least one key and controversial issue associated with PSE's refusal to sign PPAs.

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[86] PSE Advice No. 2016-31 – Schedule 91 – Cogeneration and Small Power Production, Docket No. UE-161240, REC Comments at 3-6 (Feb. 6, 2017).

Other issues: What is the appropriate forum and time for setting avoided cost rates and contract provisions?

89. The Commission should continue its current process for updating avoided cost rates annually at the end of the year with utility rate filings with minimal changes. PSE also files standard contract forms, and PacifiCorp and Avista should be required to do the same. The utility has the burden of proof to establish the reasonableness of the rates, and the Commission first reviews the filings at a public meeting, and then either approves, rejects, or suspends the rates pending an investigation.[87] This process works well when the utilities do not make significant methodological changes, and should be continued in most circumstances. The primary exceptions should be that the utilities should be barred from making unscheduled updates, be required to identify all changes, be required to respond to discovery requests from interested parties, and obtain approval before making any methodological changes.

i. Stakeholders Should Be Provided a Forum to Challenge Avoided Cost Rate Changes

90. The Commission should ensure that Staff, QFs, and interested parties have a forum to review, challenge, and obtain resolution of the inputs and assumptions that the utilities unilaterally choose to include in avoided cost rates. History has shown that there are relatively few issues that Staff and QFs have regarding avoided cost rates, in part because most inputs and assumptions do not significantly alter the rates enough to justify the high litigation costs to challenge them. The Commission, however, should prevent

[87] See e.g., WUTC v. Pacific Power & Light Co., Docket No. UE-144160, Order 04 at 1-4 (Nov. 12, 2015)(describing process for that proceeding).

the utilities from having unfettered ability to set their avoided cost rates without meaningful participation by Staff or QFs.

91. Significant concerns regarding the utilities avoided cost rates include the failure to support (or even identify) changes, and refusal to provide responsive information. In addition, avoided cost rates often include inputs and assumptions from the utilities' IRPs, but the IRP is not a contested proceeding and the utilities are free to depart from the IRP when making its actual resource decisions. Thus, the IRP does not provide QFs an opportunity to litigate the reasonableness of any decisions made by the utilities, including those that have a material impact on avoided cost rates. Therefore, NIPPC and REC recommend that the Commission make it clear that:

- The utilities have the burden of proof and must establish by at least a preponderance of the evidence that their proposed avoided cost rates are just and reasonable.
- The utilities' avoided cost filing should generally be consistent with prior Commission methodologies and include inputs, assumptions, calculations, and methodologies from the most recent IRP. The utility should have the discretion to depart from past methodologies or the IRP assumptions, but must identify and explain the change as well as obtain Commission approval.[88]
- Any party should be allowed to challenge inputs and assumptions if they will not produce just and reasonable rates, regardless of whether they are consistent with the IRP.

[88] For example, in PSE's last avoided cost rate filing, the utility eliminated capacity payments during its short-run capacity deficit time period, but did not identify that major change in its filing. Instead, PSE inaccurately claimed that "[t]he methodology used to update the fixed-price alternative is consistent with the approach used in the 2007 through 2015 annual filings." PSE Advice 2016-31—Schedule 91 – Cogeneration and Small Power Production, Docket No. UE-161240 PSE Initial Filing at 2 (Nov. 23, 2016).

- The utilities should be required to respond to discovery requests and provide copies of workpapers.[89]

ii. Avoided Cost Rates Should Be Updated Only Once a Year at a Regularly Scheduled Time

92. There should be no updates outside of regularly approved or scheduled updates at the end of the year. Washington's policy of avoided cost updates once a year provides frequent updates that prevent rates from being stale and outdated, but provides QFs with necessary certainty regarding the negotiation process. QFs often plan to complete their negotiation process before a scheduled update will occur so that they can obtain price certainty and not have their avoided cost rates significantly change in the middle of the negotiation process. QFs and the utilities have an asymmetrical level of information, including whether an update will increase or decrease the avoided cost rates, and utilities have an incentive to delay the negotiation process or impose other barriers to finalizing a contract if avoided cost rates are declining, and the opposite incentive if avoided cost rates are increasing. Therefore, the Commission should ensure that QFs can plan on rates remaining in effect for a specific period of time, and make it clear that out of cycle updates close to normally scheduled updates are particularly inappropriate.

III. CONCLUSION

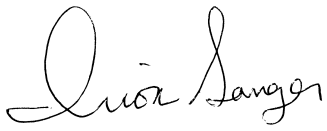
93. NIPPC and REC appreciate the Commission's willingness to take on a holistic approach to addressing the highly complex inter-related web of PURPA issues, and urge

[89] In PSE's last avoided cost rate filing, PSE refused to provide the information to REC that the utility provided to Staff, requiring REC to submit public records requests simply to review PSE's filing and PSE's explanations for its proposed changes.

the Commission to identify simple and clear policies that can be implemented consistently to minimize litigation and allow QFs to sell their net output at accurate avoided cost rates. NIPPC and REC look forward to participating in the public workshop on May 17.

Dated this 17th day of April 2017.

Respectfully submitted,



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