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Via E-filing

Mark Johnson
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. Johnson:

Please find the Comments of the Northwest and Intermountain Power Producers Coalition, and the Renewable Energy Coalition.

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	)	
	)	NORTHWEST AND INTERMOUNTAIN
Rulemaking for Public Utility Regulatory	)	POWER PRODUCERS COALITION AND
Policies Act, Obligations of the Utility to	)	RENEWABLE ENERGY COALITION
Qualifying Facilities, WAC 480-107	)	COMMENTS REGARDING PROPOSED
	)	PURPA RULES
	)	

I. INTRODUCTION

1. In accordance with the February 22, 2019 Notice in this docket of the Washington Utilities and Transportation Commission (the "Commission" or "WUTC"), the Northwest and Intermountain Power Producers Coalition ("NIPPC") and Renewable Energy Coalition ("REC") submit these joint comments regarding the Commission's proposed rules adopting a new chapter in WAC 480 and revisions to WAC 480-107.

2. NIPPC and REC appreciate the opportunity to engage with the Commission in this proceeding as it seeks to develop rules related to PURPA that better align with federal rules and law, and reflect a changing energy environment. We note that the rules have been subjected to a long process, but we are excited that the Commission is moving forward now with finalizing the rules, which is necessary to give independent developers of electric power facilities in Washington certainty as they look to develop and continue to operate beneficial projects in the state that will help provide customers with a diversity of energy resources.

3. NIPPC and REC ask the Commission's order adopting the rules to provide the utilities with strong guidance and direction in terms of how they should comply with the new rules.

NIPPC and REC expect that there will need to be some degree of process in implementing many aspects of the rules, but the Commission can circumvent an overly burdensome post-rules adoption process by removing ambiguity in its order and ensuring that the implementation of the new rules does not drag out over the course of 2019.

II. COMMENTS

A. The Commission Should Adopt the Joint Recommendations, and Not Separate Out Parts of What Was A Bundled Agreement That Reflected Compromises

4. NIPPC and REC recommend that the Commission modify the proposed rules to reflect the Joint Recommendation, filed February 26, 2018 in this docket. Those recommendations contained a stakeholder compromise on a number of key issues of this rulemaking. The Joint Recommendation was filed by Puget Sound Energy ("PSE") and outlines areas of common ground between PSE and the other Joint Parties, which included NIPPC, REC, Renewable Northwest, the Northwest Energy Coalition, and Climate Solutions. NIPPC and REC were pleased to have been able to identify common ground on the topic of how PURPA should be implemented, including obligations for utilities and qualifying facilities.

5. Those joint recommendations represented concessions by each party, but they supported the proposal as a comprehensive package. As is often the case with compromises, the individual Joint Parties may not necessarily support any single aspect of the Joint Recommendation taken in isolation, and thus NIPPC and REC urge the Commission not to pull apart the recommendation and adopt certain parts and not others. Such an approach reshuffles the tradeoffs that were made, leaving parties either disappointed about losing the benefit of any tradeoffs they gained through

concessions, or with a windfall of sorts, given that they may get something that they were willing to negotiate away, for no new consideration.

6. NIPPC and REC note that the Commission adopted many aspects of the Joint Recommendation by proposing rules consistent with their recommendations. These include:

- Requiring utilities to provide terms sheets for contract provisions, for non-standard contracts applicable to qualifying facilities over the 5 MW threshold;
- Requiring utilities' tariffs to specify the process for obtaining executable power purchase agreements ("PPAs");
- Providing a 5 MW size threshold for standard contracts, which falls at the lowest range of reasonable levels;
- Providing for a November annual update to avoided cost prices;
- Providing for a 60-day period before avoided cost changes can take effect when updated outside of the normal annual cycle; and
- Providing that the disposition of renewable energy credits and other environmental attributes is synched up with the payment of renewable or non-renewable rates.

7. NIPPC and REC also note that the Commission adopted certain of their other recommendations made by NIPPC and REC throughout this proceeding, including:

- Adopting the use of peaker-plant pricing during periods in which the utility is relying on the market to meet its capacity needs; and
- Certain clarifications regarding the process of forming a legally enforceable obligation.

8. Finally, NIPPC and REC have identified certain aspects of the rules which should be changed or clarified. These include:

- Ensuring that qualifying facilities, of all sizes, and both existing and new, gain access to 15 years of fixed pricing, starting from commercial operation date;

- Clarifying further the process for establishing a legally enforceable obligation;
- Clarifying that renewable qualifying facilities can opt for either the renewable rate or the non-renewable rate, with the appropriate disposition of environmental attributes; and
- Clarifying the definitions of new and existing qualifying facilities.

B. The Commission Should Modify the Rules to Allow for 15 Years of Fixed Pricing, After Commercial Operation

9. As described above, the Commission should adopt the Joint Recommendations as a package, and not reshuffle the deck to create new "winners" and "losers" from the group that was able to forge common ground. Unfortunately, in proposed WAC 480-106-050(4), the Commission proposes to do just that. The proposed WAC 480-106-050(4) provides that a new QF be provided with standard rates for purchases for a term of 15 years *beginning on the date of contract execution*, but not less than 12 years from the commercial operation date of the QF. This provision conflicts with the Joint Recommendations, which recommended that QFs have the option to elect up to 15-year contract terms starting *from the date of commercial operation*.[1] This was a key provision of the joint recommendations, and is an integral part of qualifying facilities' ability to get appropriate financing arrangements for their projects. Under the Commission's rules, it would be almost entirely infeasible for a project to get up to 15 years of certainty for pricing, because there would be an expected delay in probably every instance between a new QF's execution of a power purchase agreement and its commercial operation date. NIPPC and REC recognize that the Commission placed a "backstop" of at least 12 years of

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[1] *See Joint Recommendations* at 1 (Feb. 26, 2018).

price certainty into the rules, but note that this three-year difference can represent a material difference for a QF that is seeking to make a Washington project work.

10. NIPPC and REC point out that in Oregon, California,[2] and Utah[3], Portland General Electric, Pacific Power, and Idaho Power all provide for a full 15 years of price certainty from the date of commercial operation of a facility. Wyoming requires 20 years of fixed prices from commercial operation, and Idaho requires 20 years for all biomass, cogeneration, and hydro-electric QFs.[4] Pacific Power, and Portland General Electric Company have all recently completed requests for proposals that included 20 year contract terms. While the new rules result in a significant improvement from the current five-year standard contract for Pacific Power and Avista, they are outside of the industry norm for both PURPA and request for proposals.

11. This issue of when the fixed-payment opportunity begins was recently litigated in Oregon, and the Oregon Commission found that both new and existing qualifying facilities should enjoy 15-years of fixed prices, and that it was important for the fixed-price period to start at power deliveries and not contract execution (as the UTC's draft rules provide). In issuing its order, the Oregon Commission explained:

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[2] PacifiCorp operates in California, and we understand uses Oregon's PURPA policies in that state.

[3] *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).

[4] *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). The Idaho Public Utilities Commission has effectively decided that it does not want new wind and solar QF development by reducing the contract term for these projects to two years and the size threshold for eligibility to 100 kilowatts. *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).

> We take this opportunity [] to clarify our policy [] to explicitly require standard contracts, on a going-forward basis, to provide for 15 years [of] fixed prices that commence when the QF transmits power to the utility. Standard contracts, whether prepared by PGE, Idaho Power or PacifiCorp, all contain QF performance benchmark event dates that must be achieved before the QF can offer power to the utility. The 15-year period affixed prices is, of necessity, tied to these benchmarks. Prices paid to a QF are only meaningful when a QF is operational and delivering power to the utility. Therefore, we believe that, to provide a QF the full benefit of the fixed price requirement, the 15-year term must commence on the date of power delivery.[5]

12. The Oregon Commission had previously found that it was appropriate to allow for fixed price periods of at least 15 years in order to ensure that qualifying facilities could obtain necessary financing. The Commission, in analyzing that issue, explained:

> We conclude that establishing an appropriate maximum term for standard contracts requires us to balance two goals. A primary goal in this proceeding is to accurately price QF power. We also seek, however, to ensure that QF projects that are deemed eligible to receive standard contracts have viable opportunities to enter into a standard contract. To achieve this latter goal, it is necessary to ensure that the terms of the standard contract facilitate appropriate financing for a QF project. Consequently, we agree with Staff and other parties that our fundamental objective is to establish a maximum standard contract term that enables eligible QFs to obtain adequate financing, but limits the possible divergence of standard contract rates from actual avoided costs.[6]

13. In reaching its decision that it should establish 20-year contracts, with 15-years of fixed pricing, the Commission specifically noted that most qualifying facilities need this level of certainty. It explained, "we conclude that the contract term length minimally necessary to ensure that most QF projects can be financed should be the maximum term for standard contracts."[7]

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5 *Northwest Intermountain Power Producers Coalition, Renewable Energy Coalition, and Community Renewable Energy Association v. Portland General Elec.*, Public Utility Commission of Oregon, Docket No. UM 1805, Order No. 17-256 at 4 (July 13, 2017).

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

7 *Id*.

Other states have also made similar findings. The Wyoming Public Service Commission determined that 20 year contracts seemed to allow an adequate opportunity for financing,[8] and the Utah Public Service Commission recently determined that 15 year contracts best served the public interest and could allow QF developers a reasonable opportunity to obtain financing.[9]

14. NIPPC and REC urge the Commission to modify the rules to provide QFs with an option to gain up to 15 years of actual price certainty for their projects, for the same reasons identified recently by the Oregon Commission, as found by other states, and also to keep together the integral parts of the package that was offered under the Joint Recommendations.

15. If the Commission does not adopt NIPPC and REC's recommendation, then the Commission should recognize that the utilities' approved power purchase agreements should freely allow extension of the scheduled commercial operation date and the total length of its contract for utility caused delays. Often the most important factor contributing to a delayed commercial operation date is the interconnection process, which is entirely outside of the control of the QF. Utilities inherently have a strong incentive, and often act upon that incentive, to prevent the QF from being able to sell their power. When the utility causes the delay, then the QF should not lose any of its limited contract period and should receive an extension at least equal to that delay.

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8 *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).

9 *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).

C. The Fixed Price Terms for New and Existing Projects Should be Synched Up, or At Least Clarified

16. The proposed WAC 480-106-050(4) provides for different fixed price contract terms for "new" qualifying facilities, versus "existing" ones, with the former getting 15 years, and the latter getting ten. NIPPC and REC believe that both new and existing projects should be allowed 15 years, and NIPPC and REC are not aware of any states in the Pacific Northwest and Rocky Mountain West that discriminate in contract length between new and existing QFs. If the Commission does not modify the rules to allow 15 year contract lengths, then, at a minimum, the final rules should provide that:

- Existing and operating QFs are paid a full capacity payment based on the utility's next planned major capacity addition in all years rather than only after the date that the utility plans on acquiring its next major capacity addition.
- The ten year period for an existing QF starts at the time of power deliveries and not contract execution, because the vast majority (if not all) existing QFs cannot wait to enter into a new PPA until the day before their current contract expires (which would be the only way to get a full ten year contract if the ten year period started at power deliveries); and
- The definition of "existing QF" should mean a QF that seeks to enter into a new PPA with the same utility to which the QF is already selling power, and a "new QF" should be all other QFs, including those operating but intended to sell to a different utility.

17. When adopting administrative rules, the Commission should consider the unique circumstances of both new as well as existing QFs. Existing projects must enter into a replacement power purchase agreement when their current one expires. Under the UTC's draft rules, this means that existing QFs will almost always be denied a full capacity payment as compared to new QFs. Existing QFs will generally start their new agreement during a term that includes an initial, and sometimes extensive, period of very low capacity payments and prices.

This is because the draft rules only include a full capacity payment at the time the utility is planning on acquiring its next major capacity resource, which is generally at least several years out from the start of deliveries under the new contract. During the early contract years prior to this next major planned capacity payment, the QF is paid a smaller capacity payment.

18. The contract length provided to QFs must be considered in light of the fact that the draft rules do not provide for equal capacity payments in all years. For example, if a utility is acquiring a new major capacity resource in six years, then the QF is paid a lower capacity payment during the first six years and a higher capacity payment in last four years. In contrast, a new QF selling power to the same utility with a 15 year contract will be able capture more of these higher capacity payments, because they will be selling power over a longer period and can capture the higher capacity payments in the latter years of their contract.[10] Real world examples can be much worse, as Pacific Power's 2014 Integrated Resource Plan ("IRP") claimed that it would not build a new thermal resource until 2027, which would have put any existing QFs beyond the ten-year published price contract term. Pacific Power quickly changed its mind in its next IRP, and went on to acquired over 1,100 megawatts of Wyoming wind plus $700 million in associated transmission.

19. If the QF is already selling power to the utility, then the practical result will be a never ending cycle of renewal contracts in which they are never fully paid for capacity. For example, Yakima Tieton Irrigation District operates two of the only three existing QFs selling power to

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[10] The new QF will also not receive a full 15 years of payments, but it will be paid more years with higher capacity payments. Under the example above in which a utility has its next major planned capacity addition six years out, if a new QF takes three years to become commercially operational, then it will be paid for 12 years of power deliveries, with three of those at low capacity payments and nine at the higher capacity payments.

Pacific Power in Washington and, for the last 30 years, has sold its electricity to Pacific Power. Pacific Power can count on these two hydro facilities operating and providing capacity for decades, and they should reduce Pacific Power's capacity need into the future. Despite being part of Pacific Power's resource stack, Yakima Tieton would whipsaw between lower and higher capacity payments every time it renews a ten year contract.

20. If the Commission elects to discriminate in terms of contract lengths for new and existing QFs, then it should change how it pays existing QFs for capacity. Specifically, the Commission should pay these QFs a full capacity payment based on the next deferrable capacity resource in *all contact years*. This would ensure that they are not undercompensated for capacity, especially as compared to new QFs.

21. Many existing projects have been operating for years, and they often require upgrading of their equipment and facilities, including interconnections, at the time of their new agreements. These investments likely require financing, implicating the same need for long-term price certainty that applies to new facilities. This means that these QFs need to enter into new PPAs well in advance of the expiration of the current contract because the interconnection process, even for existing facilities, can take well over a year. For example, PacifiCorp recommends that a QF plan on three years to complete the process. Delays can cause the process to last even longer. Existing QFs often must first enter into a new power purchase agreement to obtain financing for both the interconnection and facility construction, and thus they too can experience a delay between when they sign an agreement and when they become "operational" under that contract.

22. At a recent PURPA workshop at the Oregon Commission, the issues faced by existing qualifying facilities were explored, including why any rational market structure should accommodate a smooth transition from one commercial arrangement to another. Biomass One, an existing, operational qualifying facility, made a presentation in that workshop that is attached to these comments; it explains why such projects often face difficulties when their existing power purchase agreements expire. Existing QFs are subject to whatever avoided prices are prevailing at the time, and they need to enter into contracts in advance of contract expiration in order to fund modernization and upgrades as well as negotiate contract terms because there will not be any standard Commission approved contract form available. Biomass One's recommendation was that the Oregon Commission continue its current policy in which all qualifying facilities, both existing and new, have access to long-term price certainty, and that they have an opportunity to enter into new PPAs several years before their current ones expire. In Oregon, existing QFs are allowed to sign a new PPA three years prior to the expiration of their existing contract,[11] and receive 15 years of fixed pricing just like new QFs.

23. If the Commission is not inclined to allow existing projects to have a 15-year fixed price contract, the Commission should make it clear that such projects are able to obtain at least a full 10-year fixed price agreement that is not reduced by any requirements that such a project may

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[11] *See* OAR 860-029-0120(4) (specifying that a qualifying facility may specify a scheduled commercial operation date anytime within three years from the date of agreement execution). *See also Re Public Utility Commission of Oregon Investigation into PURPA Implementation*, Order No. 19-051, Appendix A at 11 (Feb. 19, 2019) (Staff noting that an issue raised was the ability of existing QF customers to enter into new agreements prior to the expiration of their current contract, and noting that Commission order establishes a three-year window for signing power purchase agreements prior to commercial online date).

have to undertake after contract signing and before commencing operations under the new contract, including fulfillment of its current contractual obligations. The rules should thus clarify that existing projects are able to enter into fixed rate contracts "for a term of ten years after operation under the contract commences." Additionally, the rules should allow for an existing facility to sign an agreement with a utility far enough in advance of the expiration of its existing agreement that it can be assured of a seamless transition to the new contract. This is especially important in situations where a qualifying facility may be a cogeneration plant, which operates as an integral part of a broader industrial operation.

24. NIPPC and REC also note that the definition of an "existing" and a "new" qualifying facility are not clear in the rules. NIPPC and REC recommend that an existing qualifying facility be limited to one that already has a contract with the utility from which it seeks an additional contract. This would mean that a project is defined as "new" if it is seeking to sell to a utility to which it has not previously been selling its power. This is appropriate because of the different requirements and delivery obligations that can be entailed in arranging for a sale to a different utility.

D. The Commission Should Refine the Language Regarding the Formation of a Legally Enforceable Obligation

25. The primary and most fundamental purpose of a LEO is to prevent a utility from delaying the execution of a contract in order to ensure that lower avoided cost rate is applicable. States

have the initial power to determine the specific parameters of when a LEO is formed;[12] however, any state requirement that is inconsistent with federal law and regulations is invalid.[13]

1. The Rules Should Clarify that a QF has the Authority to Create a LEO

26. Under the proposed WAC 480-106-0030(2)(a), a legally enforceable obligation (or "LEO") "must be memorialized in an executed written contract between the utility and the qualifying facility prior to commercial operation." NIPPC and REC are concerned that the language "must be memorialized" seems to set out a default assumption that no LEO exists without being embodied in writing. Such a requirement is contrary to FERC precedent, and has been found unlawful under PURPA.[14] NIPPC and REC understand that this was not the intent of the Commission's proposed rules. But, because the rules should speak clearly on the topic, this language should be modified. NIPPC and REC recommend that the Commission's rules explicitly provide that the formation of a LEO is based on when the QF makes its commitment to sell power, and that the policies, rules, and tariffs related to the processing and negotiating of PPAs as well as the timing of avoided cost rate updates are all designed to facilitate, and not impede, the formation of a LEO.

27. The proposed rules do go on to state, in WAC 480-106-0030(2)(b) that a "legally enforceable obligation may exist prior to an executed written contract," but specify only that the commission will make such determination "based on the specific facts and circumstances of each case." Without more detail than this, NIPPC and REC are concerned that the goalposts within

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12 *West Penn Power Co.*, 71 FERC ¶ 61,153 at 61,495 (1995).

13 *Cedar Creek Wind, LLC*, 137 FERC ¶ 61,006 at P.35 (2011).

14 *Cedar Creek Wind, LLC*, 137 FERC ¶ 61,006 at P.35 (2011); *Grouse Creek, LLC*, 142 FERC ¶ 61,187 at PP. 37-38 (2013).

which a LEO can be formed are not sufficiently clear. It would be preferable for the rules to give some indication of the minimum criteria that must be met by a QF in order to establish that a LEO was formed, as well as to clarify that a LEO results from the QF's commitment to sell power to the utility upon meeting those minimum criteria. Washington's rules should not simply allow a QF that has not been working with the utility or previously provided any information to simply sign a power purchase agreement and email it to the utility to form a LEO. A QF should be required to provide certain minimum information and to have engaged in discussions with the utility, but the rules should recognize that, at its core, the law provides that a QF has the power to determine the date for which avoided costs are calculated by tendering an unequivocal agreement that obligates it to provide power. This is a critical aspect of PURPA, as it gives developers certainty about the pricing and other terms associated with their sale, at the time that they make a commitment to sell power to the utility. Neither a utility nor a state commission can impose restrictions or processes that have the practical effect of delaying the contract negotiation process so that a lower avoided cost or different terms are applicable.

28. The Commission should also consider providing guidance on what a QF needs to do to establish a LEO. NIPPC and REC understand that the Commission is reluctant to impose specific requirements because, while FERC has been extremely clear on whether certain specific obstacles are allowed (i.e., a QF cannot be required to sign a PPA or interconnection agreement or file a complaint), FERC has been less clear about what is sufficient to form a LEO and has left much of the implementation up to the states. However, the Commission could provide additional guidance that certain actions taken by a QF will establish a presumption that a LEO will be

formed. This would not encapsulate the universe of ways in which a LEO can be formed, but will reduce disputes and add clarity to the negotiation process.

29. In Washington, we are aware of only two Commission cases discuss the process for establishing a LEO.[15] NIPPC and REC point out that these cases are dated, and likely inconsistent with the current implementation of law regarding what QFs are required to do in order to form a LEO. Current law establishes that QFs cannot be required to execute a contract, file a complaint, or execute an interconnection agreement as preconditions to forming a LEO.[16]

30. If the Commission does not modify is rules, NIPPC and REC ask that the Commission, in adopting its rules, clarify that:

- A LEO results from the QF's commitment to sell power to the utility, upon meeting those minimum criteria;
- Neither a utility nor a state commission can impose restrictions or processes that have the practical effect of delaying the contract negotiation process;
- Identify specific actions that have the presumption of creating a LEO; and
- Specifically explaining that the prior orders *Spokane Energy,* and *In the Matter of the Petition of Wheelabrator Environmental Systems, Inc.* on this topic are superseded by more recent precedent.

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15 These are *Spokane Energy, Inc. v. the Washington Water Power Co.,* Case No. U-68-114, Commission Order (April 23, 1987) and *In the Matter of the Petition of Wheelabrator Environmental Systems, Inc., for a Declaratory Ruling and Complaint*, Docket No. U-89-3043-F, First Supplemental Order (Sept. 28, 1989).

16 Key FERC cases that discuss these requirements include *JD Wind 1, LLC*, 129 FERC ¶ 61,148 (2009), *Cedar Creek Wind, LLC*, 137 FERC ¶ 61,006 (2011), *Murphy Flat Power*, 141 FERC ¶ 61,145 at (2012); *Grouse Creek, LLC*, 142 FERC ¶ 61,187 (2013), and *FLS Energy, Inc.*, 157 FERC ¶ 61,211 (2016).

2. Process for Obtaining Executable Power Purchase Agreements Should be Put Into Context

31. REC and NIPPC support the proposed WAC 480-106-030(4), which provides that utilities' tariffs set out the process for obtaining executable power purchase agreements for QFs eligible for standard contracts. The proposed process is consistent with the Joint Recommendations, and will provide more certainty for all parties about how qualifying facilities should approach this important topic.

32. REC and NIPPC also support the proposed WAC 480-106-030(5), which provides that utilities' tariffs set out the process for obtaining executable power purchase agreements for QFs that exceed the size threshold for standard contracts. These requirements will help guard against instances where a utility could otherwise seek to make the process for developers unclear, or have the process change through time.

33. The Commission's proposed rules state that, for projects above the standard contract size threshold, "[s]uch contract provisions need not be the same as the standard contract provisions required pursuant to subsection (3) of this section, but shall be consistent with the commission's rules." NIPPC and REC believe that being "consistent with the commission's rules" means that these QFs are eligible for the 15-year price certainty that is afforded to QFs with standard contracts. These larger projects have every bit as much need, if not more, to obtain financing for their projects, and thus need the same level of access to fixed prices as smaller projects. It would be helpful to clarify this result in the language, by making their rights explicit. To accomplish this, NIPPC and REC recommend that the following phrase be added to the last sentence of this

subsection: ". . . including the provision of fixed rates for the terms provided for in the case of standard contracts."

34. Although NIPPC and REC support the requirement that utilities' tariffs provide the process to get a PPA and a LEO, we note that we are concerned that utilities could attempt to create obstacles through this process, where utilities use the requirements to slow down or prevent a LEO from being formed. We raise this issue here to provide notice of that concern, and will monitor utilities' tariff provisions, but ask now that the Commission clarify that these processes cannot be used to create arbitrary requirements on QFs' ability to gain a LEO.

3. The Commission Should Clarify that a Legally Enforceable Obligation Can Be Created in Under 60 Days

35. NIPPC and REC appreciate that, in WAC 480-106-0040, the rules make clear that changes to avoided cost rates, if done out of cycle, are not effective for 60 days after the utility requests them. This provision is important for both utilities and qualifying facilities. NIPPC and REC support regular and timely avoided cost rate changes, and believe that annual changes are appropriate. However, NIPPC and REC also recognize that there are legitimate reasons that an avoided cost rate change needs to occur sooner than the regular update.

36. Providing a 60 day notice provision is important in giving qualifying facilities certainty about their investments in Washington generation facilities, and gives an opportunity for qualifying facilities to enter into LEOs before the rates change. In order to secure this outcome, NIPPC and REC recommend that the Commission's rules in WAC 480-106-030(2) specify that the contracting procedures set out in utilities' tariffs clarify that the process for obtaining a LEO can be completed, assuming appropriate due diligence by QFs, within 60 days.

37. It is important to understand the business model for qualifying facilities. The developers of new resources, as well as those operating existing projects, look at the prices in the utilities standard tariffs and the date for when rates will change, and then begin the contracting process to ensure that they are able to obtain a contract prior to the next rate change. Preparing a request for a new project often takes considerable investment in time and materials prior to even requesting a contract, and even an existing project often needs to invest time and money, especially if there are upgrades necessary to continue operations. This is especially true for the small developers such irrigation districts, family owned businesses, municipalities, etc. The most responsible developers and project operators start this process well in advance of the expected rate change. An unexpected rate change can upset those plans, and they should be protected from unexpected rate changes and able to at least form a legally enforceable obligation prior to the effective date of these surprise filings. Finally, the Commission should recognize that the issue of timely notice and opportunity to complete contracts is an industry wide concern beyond any particular qualifying facility. It is difficult to have a stable climate for any developer, large or small, to have confidence in the market if they cannot count on a regular and timely process for price changes.

4. Proposed Modifications to Language Regarding Legally Enforceable Obligation

38. NIPPC and REC propose the following language, shown in redline to the proposed rules, to address their above recommendations:

> **Contracting procedures:** (a) In the tariff required in subsection (1) of this section, each utility must file contracting procedures that sets forth the obligations of the utility and the qualifying facility entering into contracts for the purchase and sale of qualifying facility output. Such contracting procedures shall provide that a legally enforceable obligation

~~must be~~ is memorialized in an executed written contract between the utility and the qualifying facility prior to commercial operation, and that a legally enforceable obligation may exist prior to an executed written contract, but not before a qualifying facility provides, at a minimum, the following information to the utility:
(i) Qualifying facility owner name, organizational structure and chart, and contact information;
(ii) Generation and other related technology applicable to the qualifying facility;
(iii) Design capacity, station service requirements, and the net amount of power, all in kilowatts, the qualifying facility will deliver to the utility's electric system;
(iv) Schedule of estimated qualifying facility electric output, in an 8,760-hour electronic spreadsheet format, including (to the extent applicable) any expected generation degradation per year;
(v) Ability, if any, of qualifying facility to respond to dispatch orders from the utility;
(vi) Map of qualifying facility location, electrical interconnection point, and point of delivery;
(vii) Proposed commencement date for the qualifying facility's delivery of electric output to the utility;
(viii) List of acquired and outstanding qualifying facility permits, including a description of the status and timeline for the acquisition of any outstanding permits;
(ix) Demonstration of the qualifying facility's ability to obtain qualifying facility status;
(x) Fuel type(s) and source(s);
(xi) Plans to obtain fuel and transportation agreements, if applicable;
(xiii) Plans to obtain transmission agreements to deliver power to the purchasing utility's system, in those cases where the qualifying facility is or will be interconnected to an electrical system other than the purchasing utility's system;
(xiv) Interconnection agreement status, including interconnection queue number; and
(xv) Proposed contracting terms and pricing provisions for the sale of electric output to the utility, including but not limited to term in years, fixed price and market indexed price.

(b) ~~A legally enforceable obligation may exist prior to an executed written contract.~~If an irreconcilable disagreement arises during the contracting process, the qualifying facility or the purchasing utility may petition the commission to resolve the disagreement, including making a determination about whether the qualifying facility owner is entitled to a legally enforceable obligation and the date that such obligation occurred based on the specific facts and circumstances of each case. In making its determination, the Commission will recognize that the formation of a legally enforceable obligation is based on when the qualifying facility makes its commitment to sell power, and that the policies, rules and tariffs regarding processing and negotiating power purchase contracts are designed to facilitate and not impede the formation of a legally enforceable obligation.

E. 5 MW Limit for Standard Contracts

39. NIPPC and REC continue to support the 5 MW limit on qualifying facilities that are eligible for standard contracts because this is a reasonable project size, although at the low end of the market for utility-scale facilities, and was part of the overall compromise reached in the Joint Recommendations. To help ensure the benefit of the Joint Recommendations in their totality, however, including the compromises agreed to by NIPPC and REC, they implore the Commission to adopt the provisions of the Joint Recommendations regarding the 15 years of price certainty described above while retaining the 5 MW limit.

F. NIPPC and REC Support the Pricing of Capacity Based on a Peaker Plant When a Utility's IRP Identifies Needed Capacity Coming from the Market

40. The proposed WAC 480-106-040 states,

> If the utility's most recently acknowledged integrated resource plan identifies the need for capacity in the form of market purchases not yet executed, then the utility shall use the projected fixed costs of a simple-cycle combustion turbine unit as identified in the integrated resource plan as the avoided capacity cost of the market purchases.

NIPPC and REC support this provision. In determining how to provide for capacity pricing when market purchases have not yet been executed, it is important that the rules provide for an approach that is not overly complex, or that obscures the utilities' true avoided costs. Such methodologies are susceptible to manipulation, and can result in lengthy and costly litigation at the Commission. NIPPC and REC also believe that it is appropriate that the methodology apply to all utilities, and are consistent with other resource planning decisions.

41. The use of a simple-cycle combustion turbine represents a good, clear, and straight-forward methodology, and is an ascertainable source of a utility's need for capacity. The

Commission's rules therefore set forth a workable approach that should bring more certainty to all parties involved on this important topic.

42. On this topic, the rules should be clearer that this methodology is required for both small and large qualifying facilities. This straight-forward approach works well for both instances, and appropriately scales to the size of the qualifying resources involved.

43. NIPPC and REC note that there appears to be a mistake that could be read as limiting the capacity payment for a period of ten years. WAC 480-106-040 states that the estimated avoided cost of capacity is "based on the projected fixed cost of the next planned capacity addition identified in the succeeding ten years in the utility's most recently acknowledged" IRP. There is no other provision of the rules that discusses limiting capacity payments to the first ten years of a contract and we do not recollect this being a proposal in this proceeding.

44. NIPPC and REC recommend that "ten years" be replaced with "twenty years", which is a more appropriate planning period in the IRP. The time period should not be "fifteen years" because it is possible that a utility's schedule of avoided costs remain in place for longer than a year, and an identification of only 15 years of prices could result in unintended consequences. For example, utilities will be required to file avoided cost rate changes in November every year; however, those new prices may be suspended and the then current rates remain in effect for a longer than a year. Listing only 15 years will mean that it will be unclear what the capacity payments will be in the last years of a contract that is entered into during the period in which the old rate remain in effect, and the new rate are suspended.

G. Qualifying Facilities Should Have an Option of Either a Renewable Rate, or a Non-Renewable Rate

45. Proposed WAC 480-106-050(c) provides that, unless they are specifically sold to the utility, a qualifying facility retains the renewable energy certificates and other environmental attributes associated with their power production. The rules also clarify that there is to be a matching of the rate paid and the entity that owns the certificates and environmental attributes, stating that "[d]uring any period in which the qualifying facility receives standard rates that are based on the avoided capacity costs of an eligible renewable resource, the utility shall receive the renewable energy certificates produced by the qualifying facility at no additional cost to the utility."

46. These provisions make sense, and NIPPC and REC support them. NIPPC and REC ask, however, that this section be made to include an express provision stating that qualifying facilities have the option to choose between a renewable rate (in which case the utility will receive the environmental attributes at no additional cost) and a non-renewable rate (in which case the qualifying facility will retain the attributes). This optionality helps qualifying facilities by giving them more choice about what to do with the environmental attributes associated with their projects, while still providing that the utilities will only pay the appropriate price for the power that they receive.

H. Avoided Costs Should Be Subject to Commission Review

47. The Commission's order adopting new rules should clarify that any inputs and assumptions regarding avoided cost changes can be challenged when filed by the utilities. In Washington, an IRP is not a contested case, and the information included in the IRP may be

subject to dispute, especially when that information can directly impact the price paid to QFs. The Commission should clarify existing practice, which is that any part can seek suspension and/or rejection of the utility's filing when it is made.

I. The Commission Should Open an Interconnection Rulemaking

48. NIPPC and REC continue to recommend that the Commission therefore recommend the Commission commence an interconnection rulemaking either as an additional phase of the instant rulemaking process or as a separate investigation.[17] The Commission's interconnection rules are not sufficiently detailed, and are unclear on key aspects. NIPPC and REC are aware that interconnection difficulties are increasing for QFs, especially on PacifiCorp's system. FERC's small and large generator interconnection procedures and agreements provide significant protections to for generators, including the requirement to respond and provide studies, the manner in which studies are performed, the ability to hire third parties, etc. Some states have more detailed rules than Washington as well. Washington QFs should be provided similar protections.

49. For example, the rules require the interconnection customer to pay for system and network costs on a nondiscriminatory basis. The rule is unclear as to whether this requirement is intended to be consistent with FERC's interconnection policies, which require reimbursement to the interconnection customer of all network interconnection upgrades on the transmission system. Network upgrades have system-wide benefits for all customers and should be charged to all customers. A single interconnecting generator should not bear the economic cost of system

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[17] NIPPC, REC, Renewable NW, Northwest Energy Coalition and Climate Solutions previously made this recommendation in their April 13, 2018 comments.

upgrades associated with the interconnection because they benefit all customers. The crediting policy articulated in FERC Order No. 2003 refunds the cost of system upgrades built to accommodate interconnecting generators through transferable transmission rate credits, or ultimate balloon payments.[18] The credits or refunds are available only if the generator achieves operation and are only paid back over a period of time to ensure that the upgrades are not completed for purely speculative purposes.

50. This is a well-established policy the Commission should formally adopt in a subsequent proceeding to end the extreme abuses of the interconnection process that have occurred. The problem is especially in PacifiCorp's service territory where PacifiCorp has produced numerous interconnection studies requiring very small generators to fund major backbone transmission projects in the range of hundreds of millions of dollars.

51. This approach is reasonable because the investor-owned utilities, acting as the interconnecting transmission provider, are not independent but have an interest in frustrating rival generators. By placing all the network costs on the customer creates opportunities for undue discrimination. FERC examined this issue in detail in developing its interconnection processes and its conclusions should be adopted expressly by this Commission to ensure Washington jurisdictional QF interconnections occur in a non-discriminatory manner compared to FERC-jurisdictional interconnections. Under the FERC's rules, affirmed by the courts,

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[18] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at PP. 813-14 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

"Network Upgrades, which are defined as all facilities and equipment constructed *at or beyond* the Point of Interconnection for the purpose of accommodating the new Generating Facility, are (ultimately) the responsibility of the Transmission Provider."[19]

52. FERC recognizes that a non-independent transmission provider, like Washington's investor-owned utilities, might engage in discrimination against the interconnection customer that is effectively its competing supplier in the generation market. For example, in an apt passage, the FERC rejected use of the "but for" test where the interconnection customer must pay for network upgrades that would not be needed "but for" the interconnection customer's generator:

> "[T]he Commission remains concerned that, when the Transmission Provider is not independent and has an interest in frustrating rival generators, the implementation of participant funding, including the 'but for' pricing approach [for interconnection network upgrades], creates opportunities for undue discrimination . . . [A] number of aspects of the 'but for' approach are subjective, and a Transmission Provider that is not an independent entity has the ability and incentive to exploit this subjectivity to its own advantage. For example, such a Transmission Provider has an incentive to find that a disproportionate share of the costs of expansions needed to serve its own customers is attributable to competing Interconnection Customers. The Commission would find *any policy that creates opportunities for such discriminatory behavior to be unacceptable*."[20]

19 *Nat'l Ass'n of Regulatory Util. Comm'rs*, 475 F.3d at 1284 (quoting Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 676) (emph. in *Nat'l Ass'n of Regulatory Util. Comm'rs*).

20 Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 696 (emphasis added).

III. CONCLUSION

53. NIPPC and REC urge the Commission to expeditiously adopt new PURPA rules, subject to the modifications and clarifications discussed herein.

Dated this 1st day of April 2019.

Respectfully submitted,

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Of Attorneys for the Northwest and Intermountain Power Producers Coalition and the Renewable Energy Coalition

Attachment to the Northwest and Intermountain Power Producers Coalition, and the Renewable Energy Coalition Comments
(Biomass One Comments on PURPA Implementation before the Oregon Public Utility Commission Special Public Meeting January 31, 2019)

Biomass One Comments on PURPA Implementation

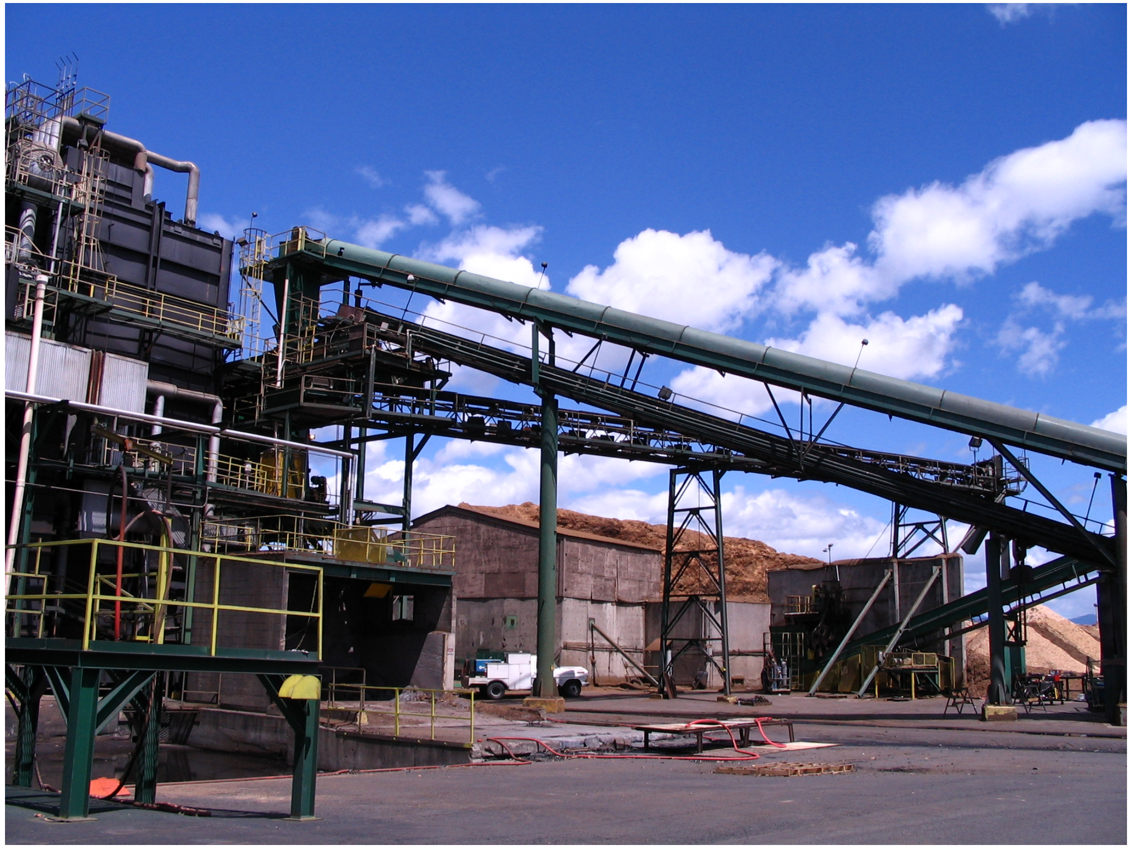
Oregon Public Utility Commission

Special Public Meeting

January 31, 2019

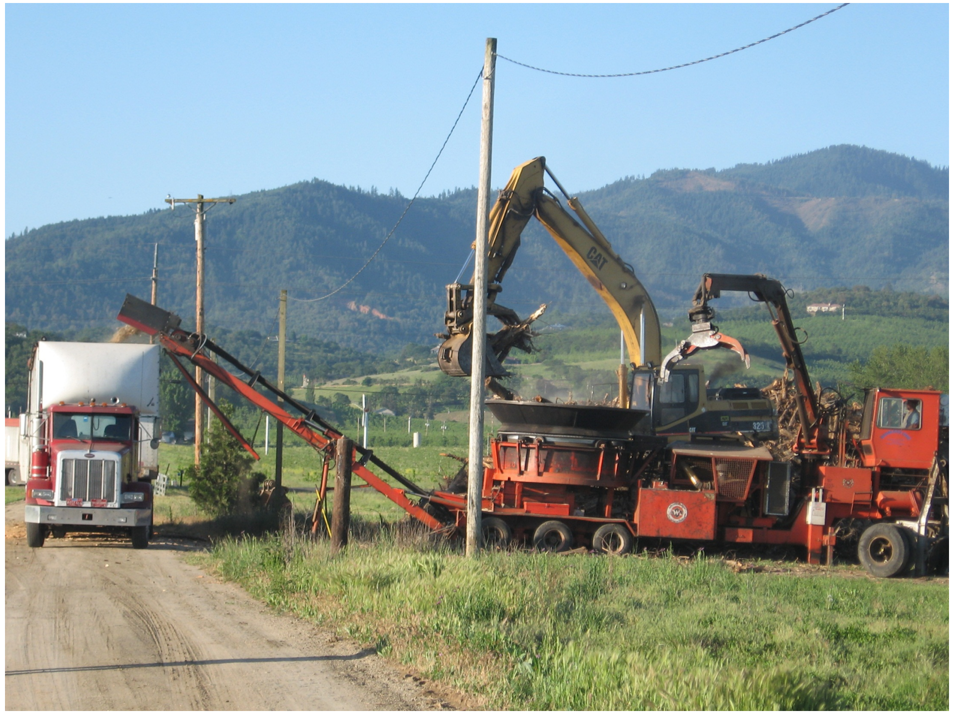
Biomass One

- A 30 MW wood-fired qualifying facility in White City, Jackson County, Oregon.
- Built in 1985, has continuously sold power to Pacific Power.
- Recovers an estimated 70% of this residual material that is generated in Jackson County.
- Reduces particulate emissions 500 to 1 compared to the avoided open pile burning that is offset.
- Employs nearly 70 employees directly and over 100 who work for regional fuel procurement and trucking contractors and other support enterprises.



Power Purchase Agreement Execution Timing

- PURPA policies should account for the unique circumstances associated with existing QFs that are an important part of this state's energy future.
- All QFs, including existing QFs, should be allowed to enter into new contracts years prior to the expiration of their current contract.



Existing QFs require capital investment

- Existing QFs typically need to enter into contracts in advance of contract execution to fund modernization and upgrades of generation and interconnection facilities.
- Upgrades:
  - Increase efficiency
  - Improve reliability
  - Reduce harmful environmental impacts
  - Improve safety
  - Comply with new regulatory requirements
  - Promote conservation

Long-term investment decisions often require long-term price certainty

- Biomass One is constantly making investment decisions that consider investment payback.
- Often must decide between temporary stop gap or long-term investment
- Decisions difficult without certainty regarding long-term revenues
- Examples include:
    - Boiler replacement
    - Emissions control technology
    - Control room systems

Existing QFs cannot time PPA execution

- Existing QFs have no flexibility when they will execute a new PPA
- Existing QFs cannot time contract execution to periods of high avoided cost prices or to delay power deliveries until resource deficiency periods

Existing QF Should Be Paid for Capacity in All Years

- Existing QFs are part of the utility's current resource mix
- Without their continued operation, utilities would need to acquire new generation sooner
- Avoided cost prices for QFs entering into contract extensions or renewals should include capacity payments for the full term of the extension or renewal