**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**UM 2000**

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| In the Matter of<br><br>PUBLIC UTILITY COMMISSION OF OREGON,<br><br>Investigation Into PURPA Implementation. | RESPONSES OF THE NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION, THE RENEWABLE ENERGY COALITION, AND THE COMMUNITY RENEWABLE ENERGY ASSOCIATION TO STAFF'S QUESTIONS TO STAKEHOLDERS |

## I. INTRODUCTION

The Northwest and Intermountain Power Producers Coalition ("NIPPC"), the Renewable Energy Coalition (the "Coalition"), and the Community Renewable Energy Association ("CREA," and collectively with NIPPC and the Coalition, the "QF Trade Associations") appreciate the opportunity to comment on the scope of this proceeding. The responses below respond to Staff's March 15, 2019 UM 2000 Initial Questions ("Staff's Questions").

As a preliminary matter, the QF Trade Associations note that two weeks is an inadequate amount of time to fully analyze and respond to Staff's Questions as many of them go to the core of the Public Utility Regulatory Policies Act ("PURPA") implementation and encompass wide-ranging issues from avoided cost methodologies to interconnection processes to the treatment of storage. Staff's Questions appear to come from a place of stripping away the current established processes and completely re-evaluating PURPA from the ground up. The very act of asking these types of questions and in a manner which appears to accept the utilities worldview unsettles the institutional climate in Oregon. The Commission has already allowed PacifiCorp to end PURPA in its Oregon service territory, and, from the outside, the way these questions have been asked give the appearance that the direction of this proceeding is intended to allow PGE to do the same. The QF Trade Associations request that additional time be provided to supplement these answers before the scope of the docket is defined. The Commission should also consider establishing a core set of principles to determine what are the key characteristics of successful future PURPA implementation in Oregon, including but not limited to how the Commission can best address the utility incentive and actions to refuse to purchase power from QFs.

With that, however, the QF Trade Associations provide the following responses:

## II. RESPONSES TO STAFF'S QUESTIONS SET A

Staff directed a set of eight questions to the utilities only, stating that they are factual questions to understand how the process works to establish a common baseline to inform consideration of PURPA implementation in Oregon. The QF Trade Associations are very surprised that Staff would look to only the utilities to provide "a common baseline" given that the utilities and independent power producers often have completely divergent views regarding basic factual situations.

Some examples of how it is inappropriate to only ask the utilities to answer these questions are:

Question 6 asks about when a QF can renew its contract, can a renewal occur before expiration of the current contract and "how long before expiration of the current contract can a QF enter into a new contract." There is a complaint right now between

Portland General Electric Company ("PGE") and Middlefork Irrigation District in Docket No. UM 1995 on this exact question. It is remarkable that only the investor owned utilities would be asked to provide its answer to this question that is the subject of litigation.

Questions 3 and 4 ask about the interconnection process, including "issues that could impede the interconnection process" and utility resources that could help inform qualifying facility developers about locations that are most optimal to site their facilities. The QF Trade Associations look forward to the utilities' responses. However, in case they do not provide a complete list of issues that could impede the interconnection process, a starting point for additional information is the complaint between PGE and Sandy River Solar in which both Sandy River Solar and the Coalition have identified a number of ways in which PGE is impeding the interconnection process. This is Docket No. UM 1967. In that case, Sandy River Solar requested that PGE be required to provide basic interconnection studies and agreements that PGE treats as confidential and withholds, but is the same information that PacifiCorp publicly provides. The QF Trade Associations suggest that be another starting point for "a list of utility resources that could help inform QF developers as to the locations that would benefit from, or face challenges to QF development." There are also other complaints between QFs and PGE that could provide additional ways in PGE has been impeding the interconnection process.[1]

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1 These include Docket Nos. UM 1902-1907, UM 1963, and UM 1971. One illustrate example was PGE refusing to remove the requirement to install a particular piece of equipment until the QF drove out to the site and took a

The QF Trade Associations request that they be provided an opportunity to respond to the utilities' answers, and that any future attempt to create a common baseline include more than just the utilities' point of view.

## III. RESPONSES TO STAFF'S QUESTIONS SET B

**Question 9:**

Should the current standard pricing methodology be retained? If not, what should the methodology be? Please describe in detail, and provide examples of where the proposed methodology may currently be in use. If not, in this description include the following:

a. How proposal meets customer indifference standard
b. How proposal meets need for transparency
c. Ability to update avoided costs on a regular basis without the need for an extended regulatory process.

**Response:**

The phrasing of this question does not capture the multitude of considerations that must go into the setting of avoided cost prices. While customer indifference is part of it, the core consideration in setting avoided costs under PURPA is that the price accurately reflect the cost that the utility would otherwise incur by producing or purchasing the power in the absences of the purchase from the QF. Specifically, FERC's rules require:

> Avoided costs means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.[2]

In addition, Oregon law includes PURPA goals and policies are:

> (1) The State of Oregon has abundant renewable resources.
> (2) It is the goal of Oregon to:

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photograph of a piece of equipment that had the same functionality as PGE's proposed "upgrade." UM 1963 complaint at page 2.

[2] 18 CFR § 292.101

> (a) Promote the development of a diverse array of permanently sustainable energy resources using the public and private sectors to the highest degree possible; and
> (b) Insure that rates for purchases by an electric utility from, and rates for sales to, a qualifying facility shall over the term of a contract be just and reasonable to the electric consumers of the electric utility, the qualifying facility and in the public interest.
> (3) It is, therefore, the policy of the State of Oregon to:
> (a) Increase the marketability of electric energy produced by qualifying facilities located throughout the state for the benefit of Oregon's citizens; and
> (b) Create a settled and uniform institutional climate for the qualifying facilities in Oregon.[3]

The Commission Staff's question should have asked how the Commission should comply with FERC's code of regulations and Oregon's PURPA goals and policies, rather than asking the question using the utilities biased way of paraphrasing the standard as being only a customer indifference standard. We hope that when Staff provides it white paper, it starts with federal and Oregon law and not the utilities' interpretation of it.

By setting accurate avoided costs, the customer is held indifferent. In reviewing possible changes to the current methodology, Staff, stakeholders, and the Commission should consider whether the methodology accurately reflects "avoided cost," rather than the narrower consideration of whether it meets the customer indifference standard.

The current standard pricing methodology should be retained but with adjustments to more accurately compensate qualifying facilities for the capacity that they provide, to compensate QFs for avoided costs when the utility procures a resource that was not anticipated in its last integrated resource plan, and compensate QFs for all the avoided costs associated with the alternative generation resource, including transmission

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[3] ORS 758.515.

costs. The basic structure of the current methodology has been well-established in the Oregon PURPA industry and there is no reason to dramatically change it now.

However, the methodology has some holes that enable the utilities to evade paying the full avoided costs of energy and capacity much of the time. It does not capture the price of capacity for market purchases and the incremental cost of energy and capacity that the utility would avoid from unplanned acquisitions because QFs are generally only paid for avoided capacity costs associated with a major resource included in the utility's approved integrated resource plan. The Commission could consider the Washington Utilities and Transportation Commission's new rules which will require the utilities to pay QFs for capacity during the "sufficiency" period based on the costs of a simple cycle peaking unit rather than only market purchases. It does not compensate existing QFs for the capacity they have already been providing when they renew their contracts. It does not account for the locational value of QFs, including the avoided costs of transmission when a project is sited nearer to load then the utility's resource acquisition. We also have concerns about whether the Effective Load Carrying Contribution method and tying capacity value to a resource's impact on the Loss of Load Probability are appropriate. Any updates to the supply curve in the avoided cost models should only include supply contributions from QFs that have signed interconnection agreements since not all projects may actually get built. Including all QFs with a signed PPA will artificially skew the supply up and prices down. For QFs that already exist or will definitely get built, this unjustly subjects these resources to artificially low prices during the entirety of their PPA term.

Overall these adjustments the methodology would better reflect the "avoided cost" because it calculates the incremental cost to an electric utility of electric energy and capacity that the utility would generate itself or purchase from another source but for the purchase from the QF. We are likely to raise additional issues as this proceeding develops.

The Commission should also require that the utilities modify their spreadsheets used to calculate avoided cost rates so that they are sufficiently clear to enable QFs to estimate avoided costs using publicly available information. The utilities should be required to include certain minimum information in their avoided cost filings sufficient to understand the basis for the input or assumption. This increases transparency into the process by allowing QFs the opportunity to estimate avoided costs.

Numerous parties worked hard in UM 1610 over a couple years to come up with a fair manner in which avoided cost updates can be updated on a regular basis without the need for an extended regulatory process. After the Commission listened to multiple rounds of testimony and legal briefing, it moved from the then-current rule of updates every other year (and an update following IRP acknowledgement) to annual updates (and an update following IRP acknowledgement). This allowed regular updates and was intended to provide certainty to when rates would change.

The main problem with the current approach is that the Commission does not follow it regularly (which results in QFs not understanding when rates will change), and there is insufficient regulatory process to review the inputs, assumptions, and other aspects that set avoided cost rates. Currently, the utilities unilaterally select the inputs and assumptions in the IRP, there is no realistic opportunity to challenge those inputs and assumptions, and the Commission simply approves whatever the utilities want. QFs also have no idea prior to the utilities making their filings how much the rates will change. The QF Trade Associations are very concerned by the manner in which Staff asks the question, which is that there is too much process, when there is already insufficient due process for QFs to review, understand and challenge utility avoided cost filings.

The QF Trade Associations also suggest that the utilities simply be removed from the avoided cost calculation process. The Commission should establish a methodology and have Staff perform the analysis and calculate the rates. This is how it is done in Idaho, and there is far less litigation on the topic. Staff should reach out the Idaho Public Utilities Commission Staff and understand how that process works and how it has reduced litigation over price changes.

**Question 10:**

Should separate price streams be offered for a nonrenewable and a renewable avoided resource? If yes, please explain why and provide a description of the proposed avoided cost pricing methodology. In this description include the following:

a. How proposal meets customer indifference standard
b. How proposal meets need for transparency
c. Ability to update avoided costs on a regular basis without the need for an extended regulatory process.

**Response:**

Separate price streams for renewable and non-renewable QFs should be retained because renewable QFs offer different attributes (such as renewable energy certificates) to utilities and which the utilities are otherwise required under existing law to acquire (for example, under the renewable portfolio standard). If utilities were permitted to only offer to pay a non-renewable price to renewable QFs, the price would not capture the incremental cost to the electric utility of renewable electric energy and capacity that the utility would generate itself or purchase from another source but for the purchase from the QF. Further, the non-renewable price stream should be retained because utilities continue to operate non-renewable resources and not all QFs generate renewable attributes.

**Question 11:**

Should documents and models used in the standard pricing and contracting practices be changed to be consistent for all utilities?

a. Should standard PPAs be modified such that the bulk of the document is the same for each utility? Please explain.
b. Should the spreadsheet models used to calculate standard prices be modified so that inputs and outputs are easily found and compared?
c. If standard contracts become homogenized across utilities with less flexibility, how could the OPUC be involved in non-standard contract development and negotiation?

**Response:**

Yes, the Commission should consider adopting the same methodology and standard contracts for all three utilities. If standard PPAs are modified such that the bulk of the document is the same for each utility, the Commission could avoid issues like what was observed in Docket No. UM 1805 (regarding when the 15-year period of fixed pricing commences) where the Commission adopted a policy that was applied or interpreted differently by different utilities. Adopting the same language for all utilities would encourage more careful drafting of the language and discussion about what that language means before disputes arise. If the Commission is going to continue its new process of taking jurisdiction over QF post-contract execution disputes (which is generally not done in other states and was historically not done in Oregon), then the Commission needs to increase its vigilance over standard contract provisions. Additionally, the regulatory burden on stakeholders and the Commission would be substantially reduced every time the terms or conditions of the standard contract and pricing schedules had to updated if a single standard contract were used.

While standardization of documents and processes across utilities is desirable for a variety of reasons, there may be some instances where non-standard terms or processes may be desirable to account for different or unusual circumstances related to each utility. For example, Idaho Power is not subject to the requirements under the Oregon renewable portfolio standard at this time, and should not need to offer a renewable rate.

As discussed in response to question 9, the spreadsheet models used to calculate avoided costs should be modified so that inputs and outputs are easily found and understood, and all three utilities should be required to provide the same minimum filing requirements, assuming that Staff does not calculate the rates.

The process for non-standard contract negotiation should ensure that there are not unreasonable hurdles to receive indicative pricing and executable contracts. There are already established negotiating guidelines, which do not require substantive revision. The utilities should be required, however, to make publicly available, a sample non-standard draft PPA that serves as the starting point for negotiations. Once the negotiation is underway and if a dispute arises, the Commission should establish an expedited dispute resolution process. The tariffs currently contain an alternative dispute resolution mechanism; however, the process takes too long and complaints take too long. Delay, by itself, could turn a QF project uneconomic so there is a need for more expedited resolution.

**Question 12:**

Please provide any ideas related to generally improving the efficiency of the regulatory process associated with updating avoided cost prices

**Response:**

Question 12 asks how the "efficiency" of regulatory process can be improved, but this is the wrong question. Once again, it appears that the question has adopted the utilities' talking points, leaving out other equally if not more important considerations. First, it is not clear what "efficiency" refers to here. Second, accuracy, transparency, and meaningful participation are also important and need to be weighed against any potential "efficiencies." The current process for updating avoided cost prices does not provide meaningful participation and transparency, and therefore the accuracy of the results is questioned. It allows the utilities to make filings with short turnaround times for QF advocates to review and comment on. QFs in negotiations with utilities in the months leading up to an avoided cost change have no assurance that the utility will not simply delay their contract process to a point where the executable PPA is provided after the avoided cost price change. The result is after-the-fact complaint filings asserting that a legally enforceable obligation was or should have been formed prior to the price change.

This established process is inefficient because it does not provide certainty around when avoided cost filings will be made, when and how QFs can meaningfully participate, request hearings, or review the inputs and outputs of the calculations, or when the avoided costs will ultimately go into effect. By improving transparency, allowing meaningful participation and certainty in the avoid cost regulatory process, the avoided cost process itself may become slightly more lengthy, but its results will be more accurate and the Commission will be able to avoid other complaint filings thereby improving the Commission's overall efficiency.

**Question 13:**

Please explain an optimal process for a QF requesting an energy sales agreement with a utility. For this process please note any differences between applications for standard rates, standard contracts, or non-standard contracts.

**Response:**

The PUC established an overall fair and balanced approach, but it is impossible to take into consideration the creativity or ingenuity of a utility to create obstacles to prevent a QF from completing the contracting process. The purpose of a standard contract is to eliminate negotiations and thereby remove transaction costs associated with QF contract negotiation. Overall, the current process the Commission adopted for all utilities is generally acceptable but should be made consistent and should be revised to remove opportunities for utilities to unduly delay the process. The major problem is that instead of being a tool to facilitate contract negotiations, sometimes the contracting process is used as a series of constantly changing obstacles that are used to prevent a QF from reaching the finish line to obtain an executed contract.

Under the current standard PPA process, a QF requests a standard PPA with certain minimum information on the facility and the utility has up to a maximum 15 business days to provide a draft. Additional drafts are exchanged until no further changes are needed, at which point the utility must provide an executable PPA. Under this process, the following non-exhaustive list of the types of issues have delayed the process and should be limited:

- Changes to the utilities' requirements for what information is initially required.
- Errors made by the utility in inputting the QF's information into the standard form, providing documents, and providing inaccurate explanations of facts and law.
- Unreasonable delays imposed due to minor typos made in the QF's initial information submission or edits to a draft of PPA.
- The utility requiring an unnecessary interim step of a "final draft" PPA identical to the prior "draft" PPA and identical to the ultimately provided "executable PPA."

Additionally, under the established process, in cases where the Commission sets a date by which the rates will change the QF is allotted virtually no time to review. For example, it has often be articulated that under PGE's view of its process, it takes approximately 45 business days (three stages at 15 business-day increments). This assumes that the QF is able to review immediately and provide feedback to the utility. If there is going to be an avoided cost update process whereby, for example, the new prices won't go into effect for "x" number of days to allow QFs in the queue to complete their negotiations, then there should be time factored into that timeline to allow the QF to meaningfully review and respond to the drafts provided by the utility.

The negotiations for non-standard contracts face almost insurmountable challenges. The same obstacles apply to larger projects, but there are no protections associated with a standard contract form or transparency into avoided cost prices. And, the utilities have an even stronger disincentive to negotiate a contract because it will result in an even greater loss of potential investment in rate base resources. While the QF Trade Associations believe that there needs to be some flexibility to negotiate the unique characteristics of larger projects, the Commission should consider adopting certain provisions that a QF can unilaterally select. The Commission should also reaffirm its large QF negotiation guidelines, and adopt administrative rules that reflect these guidelines. The Commission should also require the utilities to obtain approval of their methodology for setting rates. Finally, the actual rates and contract forms for all executed contracts should be made public to prevent undue discrimination and facilitate the negotiation process.

**Question 14:**

**Please describe an optimal interconnection process for a QF requesting interconnection.**

**Response:**

The current interconnection process articulated in the OARs is well intended; however, it may be preferable for the Commission to simply use the Federal Energy Regulatory Commission process. The current rules provide some mandated deadlines that have not always been followed, so these simply need to be enforced. For example, PacifiCorp appears to have simply stopped processing many interconnection applications and PGE has historically been unable to timely complete studies. There are a few areas of utility discretion that can be problematic including that when the utility provides an agreement to perform an interconnection study the utility has discretion to set the schedule for completion of that study. Putting some sideboards on the length of time permitted would create greater certainty in the interconnection process.

The current rules provide that a certain level of detail is required to be provided in the interconnection studies and what is being provided is not sufficient. If changes are made to the study detail, it should be sufficiently clear and detailed such that an independent engineer can review the study and re-create the results. PGE in particular does not provide industry standard information to QFs, including information that other utilities make publicly available. A QF should be able to review and replicate a utility's study information, which is not currently possible with the information provided by PGE. There is no way for QFs to objectively verify that utility interconnection requirements are in fact necessary to alleviate adverse system impacts and perform a safe interconnection, and the utilities resist in providing justification for their requirements. In some cases, QFs' own professional electrical engineers with experience in utility systems are not able to obtain acceptable answers to technical questions.

The Commission should reaffirm that the QF has the right to perform its own studies and upgrades, subject to the public utility's reasonable approval and oversight.

There is a gap between the small generator interconnection rules which apply to projects 10 MWs and below, and the large generator interconnection policies which apply to projects 20 MWs and above. There have been disputes about what rules or policies apply to projects in the 10-20 size.

Additionally, the current rules need to be enforced against the utilities and there needs to be an expedited process for resolving disputes prior to execution of the interconnection agreement. When disputes arise, it can be difficult to obtain the necessary relief or technical information. Currently there is a process for arbitration of pre-execution disputes, the Commission's standard complaint process, and a process for enforcement of executed interconnection agreements. The arbitration process is not adequate and the complaint process takes far too long. The root issue for interconnection customers is that the rules are not being followed and that customers lack an enforcement mechanism that provides an efficient and fair outcome. Since the interconnection rules require utilities to perform commercial interconnection services for interconnection customers, the Commission should require utilities to administer the process in a manner that fully complies with Oregon's established rules and statutes that govern the practice of engineering found in OAR 820 and ORS 672.

The QF Trade Associations plan to identify additional interconnection related issues at a later date.

**Question 15:**

How should storage be treated under PURPA implementation? Please discuss treatment for stand-alone storage, storage collocated with non-renewable generation, and storage collocated with renewable generation. Provide the applicable avoided cost pricing approaches for the listed possibilities.

**Response:**

QFs can be paired with a storage application and compel mandatory purchases of the stored QF output.[4] If the energy input is qualified energy of a QF (either renewable or non-renewable), then the energy output of the storage unit is QF energy for which the utility has a mandatory purchase obligation, and the Commission has an obligation to compel such purchases under its implementation of PURPA. However, without direct

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[4] *Luz Development & Finance Corp*., 51 FERC ¶ 61,078 (1990).

Oregon precedent on important issues, prospective storage QFs will face resistance from Oregon utilities.

The Commission should require the utilities to explain in their PURPA pricing schedules that storage may be used with QF resources. Standard contracts should be available for storage QFs with the eligibility criteria being based on the maximum net output to the grid as designed, not simply gross capacity of the generator. For purposes of measuring size of the QF resource, which must be under 80 MW under federal law, FERC has long used the metric of maximum net output to the grid, as opposed to gross power production capacity of the individual generators. In the leading case on the point, FERC specifically approved qualification of a QF that would generate in excess of 80 MW at times but was equipped with an "automatic control system" that could "maintain an 80-MW net output level, on average, over any 60-minute time span" as measured at the point of interconnection.[5] This treatment allows for deductions for losses and conversion from DC to AC power before the energy is input to the grid. The Commission should clarify that it uses this metric also for eligibility for the standard rates and standard contract. This will encourage use of storage and result in more efficient use of transmission system.

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[5] *See American Ref-Fuel Co.*, 54 FERC ¶ 61,287, 61,816 (1991) (explaining this precedent). Additionally, FERC has designed its Form 556 for QF self-certification at page 9 to remove parasitic station load, electrical interconnection losses, and conversion for DC to AC power from the calculation of the "maximum net power production capacity," which may not exceed 80 MW. *See* https://www.ferc.gov/docs-filing/forms/form-556/form-556.pdf.

Next, if the energy input is qualified under Oregon's RPS, the energy output of the QF power from the storage unit should be eligible for the renewable avoided cost rates. This should be clearly specified in the utilities' PURPA pricing schedules.

Further, Storage QFs (renewable and non-renewable) should be eligible for higher rates than the intermittent resource rates even where the energy input to the storage device is an intermittent resource. The energy production profile of the energy output is determinative of the avoided costs of the resource.

Finally, the Commission should adopt policies to encourage existing intermittent QFs to add storage to their facilities and be compensated for the added value of output thereafter. Again, this will enable more efficient use of the transmission system and reduce the intermittency of the utilities overall resources portfolios as renewable penetration levels increase.

**Question 16:**

How should existing projects be treated under PURPA implementation? Please address the following, in addition to any other relevant topics.

a. Renewals
b. Pricing (including capacity treatment)

**Response:**

Existing projects should be able to negotiate and enter into a new PPA at least three years prior to their renewed commercial operation date so that there is time to plan for the continued operation and perform any needed upgrades or modernizations to the existing interconnection. In some cases, more than three years will be necessary. For example, if a hydro QF's FERC license expires in the same timeframe as the legacy PPA, that QF will need to assurance of a new PPA with a commercial online date years in advance to justify the expense of completing the FERC re-licensing process, which normally takes five years or more. Existing QFs should also be paid for capacity commencing immediately since they are already relied upon as a capacity resource.

**Question 17:**

Should the existing dispute resolution process be continued? If not, how should it be changed?

**Response:**

The existing dispute resolution process for determination of whether and when a legally enforceable obligation is established should be improved to provide a more expedited review. Delay by itself often can make QFs uneconomic and the utilities know this. As the saying goes, justice delayed is justice denied. So, if the utilities are able to raise enough issues or obstacles that require a complaint filing, the complaint process should be expedited so that the utilities do not simply win by delay. An example of an expedited process can be found in the Montana Code Annotated 69-3-603 which provides "[t]he commission shall determine the rates and conditions of the contract upon petition of a qualifying small power production facility . . . The commission shall render a decision within 180 days of receipt of the petition." Similar to all of these issues, we will continue to consider and may provide additional recommendations.

**Question 18:**

Please share your recommendations to reduce the volume of litigation regarding complaints.

**Response:**

The following improvements can be made to decrease the volume of litigation:

- Allow courts of law to adjudicate disputes between QFs and utilities over executed PPAs.
- Requiring utility shareholders to pay for all litigation expense associated with PURPA implementation because their efforts benefit shareholders rather than ratepayers.
- Prevent utilities from constantly re-raising the same issues (i.e., the appropriate size threshold for QFs has been litigated in most years since 2006).
- Requiring an established process for avoided cost price updates including time for meaningful QF participation and input, transparency, and set timelines for when prices will take effect (see more in response to Question 12).
- Limiting the delay tactics utilities can take in the PPA negotiation process (see more in response to Question 13) by imposing penalties for utility violations of the rules and procedures.
- Requiring that the utilities follow the timelines required in the interconnection process, provide studies within a reasonable time, provide necessary interconnection technical data to verify the study results, and enforce existing policies that allow a QF to retain a third party consultant to conduct studies and perform work, and require that all interconnection engineering services be performed in a manner that fully complies with Oregon's professional requirements for engineering (see more in response to Question 14).

**Question 19:**

What existing resources (educational, etc.) do you know of that could benefit the Commission and other stakeholders during or prior to the investigation?

**Response:**

As PURPA is implemented at the state level, it benefits from a variety of implementation techniques used across the U.S. The NIPPC and the Coalition have participated in proceedings in a number of other Western states and could provide some information about how the processes in those states have been managed. This information would likely need to be topic-specific and can be investigated as the scope of this proceeding becomes more defined.

**Question 20:**

What is the best process for the Commission to educate, inform and engage itself and its stakeholders around the questions related to PURPA implementation?

**Response:**

The investigation process currently employed provides stakeholders with meaningful participation, however in setting deadlines and the schedule it is necessary to consider the time and cost limitations of non-utility stakeholders who cannot devote the same level of resources as a utility. Also, while an investigation is helpful to educate, inform, and engage on the topics, it is important that any policy changes be incorporated into administrative rules or in formal guidelines published in a manner that makes them easy to locate. QFs should never be required to review prior tariffs, contract forms or a series of orders to understand basic PUC policies.

**Question 21:**

Given recent utility practice of acquiring resources on an economic basis, outside of need, should the Commission change the current practice of using IRP resource acquisition to define resource sufficiency/deficiency (thereby defining payments for capacity)?

If yes, how should the Commission determine eligibility and pricing for capacity payments?

**Response:**

Resources acquired on an "economic basis" still fill a need of the utility, whether that is replacing market purchases, running those new resources instead of less economic ones, or simply acquiring a resource earlier than what would have otherwise occurred. As such, the Commission should account for these resource acquisitions in setting avoided cost prices and the sufficiency/deficiency demarcation. Specifically, the QF Trade Associations recommend that the Commission eliminate the concept of resource sufficiency and deficiency. This was also discussed in response to Question 9 above.

**Question 22:**

When in the process of contracting should a legally enforceable obligation (LEO) be obtained?

**Response:**

The Commission's current rule is generally acceptable for establishing a LEO, however when the contracting process breaks down, the QF should be able to form a LEO by unequivocally committing itself by executing the standard contract that includes its schedule commercial operation date and minimum and maximum deliveries. This would help guard against delays in the contracting process and shifting expectations from the utilities about how to form a LEO especially in light of an impending avoided cost rate change. The current process rewards the utilities because they can stonewall and obfuscate until prices drop. The utilities role should not be to decide if a developer gets a contract, but administratively processing a contract, which for standard contracts is a simple fill in the blank document.

**Question 23:**

Currently, a QF can have a LEO or executed contract, fail to achieve commercial operation, and as a practical matter not be required to pay a penalty to the utility because the utility's costs to replace the QF's power do not exceed the costs the utility would have incurred under the contract. Would imposing a different type of penalty for non-performance once a LEO is obtained or a contract executed be appropriate? Please explain.

**Response:**

The QF Trade Associations are open to discussing whether there should be changes to the failure to achieve commercial operation penalties at this time, however, it is important to recognize that the utility is not subject to any penalties for failure to construct the interconnection by the commercial operation date. The primary reason that any QF is not able to become commercially operational is because of actions that the utility takes to prevent commercial operation. For example, by delaying the interconnection process, the utility can force a QF to be in default under its PPA and eventually preventing the project altogether. The utility essentially receives a bounty for each project killed.

**Question 24:**

What is required for a QF project to receive financing?

**Response:**

The QF Trade Associations do not possess and cannot share specific financing information about facilities developed by individual members of the associations; however, this is an important issue and an issue that we intend to provide follow up information in this proceeding.

**Question 25:**

**Assuming a two-phase process, what issues do you believe could be fast-tracked within Phase 1?**

**Response:**

Issues regarding PURPA implementation are inherently intertwined and it is difficult to parse out issues for separate resolution. The issue regard what parts may be addressed more quickly may be better resolved after the Commission decides which issues, at all, it will be addressing. If the Commission's desire is to completely re-hash PURPA, then it would not be wise to tackle it in two parts so that each of the elements can be weighed against each other and a balance can be reached. However, if the goal is to generally keep to the status quo but only slightly modify a few elements, then some may be able to be modified quickly where others may require more investigation.

**Question 26:**

Assuming a two-phase process, what issues do you believe need additional time for analysis? (i.e. should be addressed in Phase 2)

**Response:**

See response to Question 25. We will provide additional information on this after we have been provided sufficient time.

**Question 27:**

Please share one to two specific suggestions you would make to change how the cost of network upgrades are assigned and socialized? Describe why your suggestion is reasonable in terms of how the cost would allocated?

**Response:**

Network upgrades that have system-wide benefits should be charged to all customers. A single interconnecting generator should not bear the economic cost of system 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.[6] 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. This is a well-established policy the OPUC should adopt 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.

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 OPUC-jurisdictional QF interconnections occur in a non-discriminatory manner compared to FERC-jurisdictional interconnections. Under the

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[6] *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).

FERC's rules, affirmed by the courts, "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."[7]

FERC recognizes that a non-independent transmission provider, like Oregon's investor-owned utilities, will 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*."[8]

The recent experience in Oregon proves that FERC was correct and it is time to eliminate the opportunity for Oregon utilities to discriminate against Oregon QFs.

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7 *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*).

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

**Question 28:**

Please provide any additional comments or concerns that you would like to see addressed in this investigation.

**Response:**

We intend to identify additional issues at a later date.

Dated this 29th day of March 2018.

Respectfully submitted,

Irion Sanger

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