Introduction

Federal law lays out general requirements for implementation of Public Utility Regulatory Policies Act (PURPA), but provides broad authority to state commissions to establish their own implementation policies. On January 31, 2019 the Oregon Public Utility Commission (Commission) held a Special Public Meeting (SPM) to solicit input from stakeholders on PURPA implementation in Oregon. Stakeholders raised issues on fairness of current processes, as well as current avoided cost rates. At the SPM Staff stated their agreement with the need for a broad PURPA investigation and laid out three principles that successful Oregon PURPA implementation would encompass. These three design principles would:

- Promote development of a diverse array of sustainable energy resources
- Ensure that utilities pay just and reasonable prices, maintaining a customer indifference standard
- Create a regulatory process that provides efficiency, clarity, and engenders confidence from all stakeholders.

There are a host of identified issues with PURPA implementation in Oregon today that make achievement of these principles challenging. There are lengthy and incessant lawsuits before the Commission and Staff has heard from prior investigations that projects cannot interconnect; influx of QF PPAs for projects that may not appear creates difficulties for utilities in planning; a large number PURPA projects sit in contracting limbo while Oregon utilities procure other resources; and avoided costs do not reflect market realities, nor do they align with utility procurement. A review of PURPA implementation at this juncture is a timely way to address multiple issues.

This draft white paper provides a draft scope and recommended direction this investigation into PURPA implementation could take to address several key policy issues, including the ones listed above, so that PURPA more effectively serves the interests of ratepayers. It incorporates feedback from an additional stakeholder workshop, written comments from parties, as well as topics raised in past Commission orders.[1] The main principles remain the same as those stated at the January 31, 2019 SPM, with fair, efficient, transparent and timely as the determinants of success.

[1] *In the Matter of PacifiCorp dba Pacific Power, Application to Update Schedule 37 Qualifying Facility Information* (UM 1794); Order No. 17-239, p. 3 ("We acknowledge a need to address, among other matters: 1. Challenges that may exist with examining a utility's resource deficiency date for avoided cost purposes*** and 2. Avoided cost implications where a utility is pursuing near-term capacity investments not driven by reliability, RPS, or load-service needs."); *In the Matter of PacifiCorp dba Pacific Power, Updates Standard Avoided Cost Purchases from Eligible Qualifying Facilities* (UM 1729), Order 18-289, p. 6 ("PacifiCorp's motion correctly observes that many elements of our avoided cost methodology are based on the supposition that renewable energy is generally more expensive than nonrenewable alternatives. We find that PacifiCorp has presented significant policy questions regarding our determination in Order No. 11-505 to offer renewable QFs access to their choice of pricing options, which should be addressed in the new comprehensive proceeding."); and *In the Matter of Obsidian Renewables LLC Petition to Amend OAR 860-029-0040, Relating to Power Purchases by Public Utilities From Small Qualifying Facilities* (AR 593); Order No. 18-422, p. 6. ("Finally, we note these provisions have implications regarding impacts of speculation in a falling price market, which brings up broader questions regarding our overall implementation of PURPA, which we expect to address in further proceedings to investigate PURPA.").

UM 2000 Process

In the Notice and Agenda sent out before the January 31, 2019 SPM the Commission asked stakeholders three questions:

1) What are the key characteristics of successful future PURPA implementation in Oregon?
2) What are the top two PURPA implementation issues the Commission should address?
3) Should the Commission make interim changes to PURPA implementation while it undertakes a broader review?

The meeting included presentations and comments from many stakeholders. Comments addressed issues of most concern to stakeholders, including, but not limited to, interconnection issues, cost disparity between actual avoided costs and avoided cost rates, as well as contractual concerns. As a result of the meeting, the Commission directed Staff to examine immediate, interim actions, as well as the potential for a general investigation.

At the February 14, 2019 Public Meeting Staff presented options for interim actions and potential issues to examine in a broader investigation. At Staff's recommendation, the Commission opened this investigation docketed as UM 2000,[2] and also opened an investigation into interim actions, docketed as UM 2001.[3] The two dockets have moved on separate paths, with UM 2001 focused on enhanced avoided cost rate updates and making interconnection data more readily available to developers. The UM 2000 docket has focused on longer-term issues with some overlap with UM 2001 activities.

Following the Commission's order opening the UM 2001 docket, Staff commenced a process to draft this white paper to define a proposed scope for the investigation. Staff obtained stakeholder input on the issues to be addressed in this docket and whether any of the issues could be prioritized. Staff followed a twofold approach to define a draft scope by first examining issues that can be resolved in a short-term fashion and then identifying those issues that may require a longer timeframe for examination and a recommended process for that examination.

Identification of Issues

Staff sent a questionnaire to stakeholders on March 15, 2019 with responses due on March 29, 2019. This questionnaire was presented in two parts. The first part was directed at the utilities, to explore their current processes, and establish a baseline understanding for all stakeholders. There was some concern from non-utility stakeholders that at least some of these questions should have been directed to all stakeholders. As mentioned, Staff was looking to establish a framework for all parties to understand current utility approaches.

The second part of the questions looked to all stakeholders to address a set of myriad issues. These questions were developed, in part, based on information and comments provided in response to the January 31, 2019 SPM regarding PURPA implementation. Staff was looking for a better understanding of:

[2] *In the Matter of the Public Utility Commission of Oregon Investigation into PURPA Implementation* (UM 2000), Order No. 19-051.
[3] *In the Matter of the Public Utility Commission of Oregon Investigation into Interim PURPA Action* (UM 2001), Order No. 19-052.

- Areas where current processes could be improved;
- Difficulties faced by developers or utilities;
- The treatment and value of resources, both existing and new;
- Interconnection in Oregon;
- Legally enforceable obligations (LEOs); and
- Standard contracts, as both a document and its associated process.

The list of questions, as well as a summary of responses, can be found in Appendix A.

Staff scheduled a workshop for April 5, 2019 to discuss responses received, as well as other issues raised by stakeholders. At the workshop, Staff presented some high-level themes from the March 29, 2019 comments including some areas of potential agreement. There was a collaborative, small-group exercise that broke attendees into four parties that rotated around the room to discuss four main categories of issues: Avoided Cost, Contracts, Interconnection, and Planning. Participants in each party noted their concern and had a chance to explain their concern to their small-group.[4] Several stakeholders felt the categories were not comprehensive. They suggested potential additional categories such as transmission. Also, it was noted that a common theme through all categories was process. That is, the process to get a contract, the process for receiving an interconnection agreement, and dispute resolution, for example.

In response to Stakeholder feedback at the April 5, 2019 workshop regarding the fast progress of UM 2000, Staff revised the informal schedule to allow for more time for comments that would help scope the docket. Parties were asked to provide any additional comments to the March 15, 2019 questions by April 26, 2019. In their responses parties were asked to add any additional concerns they may have following the workshop. A high-level summary of the responses received is included as Appendix C.

Parties were also offered additional time to comment during the scoping phase of the docket, which is proposed to be end in July. The current schedule envisioned for the remainder of this first phase is below.

- Week of May 27, 2019 – Staff draft whitepaper posted
- June 7, 2019 – Stakeholder comments on Whitepaper
- June 11, 2019 – Commissioner workshop
- June 25, 2019 – Stakeholder comments on Commissioner workshop
- July 16, 2019 – Public meeting for presentation of Staff memo and final whitepaper

History of PURPA Implementation in Oregon

The Commission commenced implementation of PURPA in 1980 with two rulemaking proceedings, one to adopt rules related to the determination of avoided cost prices and another for rules related to contracting.[5] After adopting rules in 1981, the Commission determined and modified policies over the

[4] Results of this exercise are included in Appendix B.

[5] *In the Matter of the Investigation into Electric Utility Tariffs for Cogeneration and Small Power Production Facilities* (R-58), Order Nos. 81-319 and 81-755.

course of the 1980s and 1990s by issuing orders and by adopting and modifying rules. For example, during this period of time, the Commission increased the eligibility cap for standard contracts from 100 kW to one MW), modified the length of contracts, modified the role of Commission Staff in the dispute resolution process, allowed and then rejected levelization of rates, relied on competitive bidding to serve as an avenue for non-standard contracting and to inform standard avoided cost prices.[6]

In 2004, the Commission commenced a broad general investigation into PURPA policies docketed as Docket No. UM 1129, resulting in orders that established, modified, or clarified several implementation policies. Most notably, the Commission confirmed that standard avoided cost prices for PGE and PacifiCorp would continue to differentiate between periods of resource sufficiency and deficiency[7] but rejected the historic method of basing sufficiency-period prices on the utilities' variable costs of operating existing resources.[8] Instead, the Commission required the utilities to base sufficiency-period prices on monthly on- and off-peak forward market prices as of the utility's avoided cost filing.[9] With respect to deficiency-period prices, the Commission continued the methodology of basing avoided costs on the variable and fixed costs of a proxy resource. The Commission specified that the proxy resource would be a natural gas-fired CCCT.[10]

The Commission also addressed several other policies for standard contracts in Docket No. UM 1129. The Commission increased size eligibility for standard contracts from one MW to 10 MW, specified that the maximum contract term was twenty years with a maximum fixed-price term of 15 years, and determined policies related to security, construction credit and insurance and indemnity, and damages.[11]

In 2007 the Commission established policies and adopted "Guidelines" for non-standard avoided cost prices and contracting.[12] In 2010, the Commission determined the methodology it would use to determine when a utility is resource deficient and decided it was appropriate for utilities subject to

---

[6] *Re Investigation of Avoided Costs and Cost-Effective Fuel Use and Resource Development* (UM 21), Order No. 84-720; *In the Matter of Proposed Amendments to Rules Related to Cogeneration and Small Power Production Facilities* (AR 102); Order No. 84-742; *In the Matter of the Adoption of Administrative Rules Relating to Cost Effective Fuel Use and Resource Development* (AR 112), Order No. 85-010; *In the Matter of Proposed Rules Relating to Cogeneration and Small Power Production* (AR 116), Order No. 86-488; *In the Matter of the Investigation into Rules For Cogeneration and Small Power Production Facilities* (AR 174), Order No. 87-1154; *Re Competitive Bidding by Investor-Owned Elec. Utility Companies* (UM 316), Order No. 91-1065; and *In the Matter of a Rulemaking to Amend OAR 860-029-0040 (Eligibility Cap)* (AR 246), Order No. 91-1383.

[7] The Commission allowed Idaho Power Company to use the Surrogate Avoided Resource "SAR Methodology" used in its Idaho jurisdiction. This method bases the avoided costs on a proxy CCCT for all years whether the Company is resource sufficient or deficient. In 2012, the Commission ordered Idaho Power to file avoided cost prices using the "Oregon Method" used by PGE and PacifiCorp that differentiates between periods of resource sufficiency and deficiency. Idaho Power has continued to use the Oregon Method for standard prices. *In the Matter of Idaho Power Company Report Re Avoided Cost Schedule in Compliance with OAR 860-029-0040(4)(a)* (UM 1593), Order No. 12-146.

[8] *In the Matter of Public Utility Commission of Oregon Staff's Investigation Related to Electric Purchases from Electric Utilities* (UM 1129), Order No. 05-584, p. 26.

[9] *Id.*

[10] *Id.,* p. 27.

[11] *Id.,* pp. 1-3.

[12] *In the Matter of Public Utility Commission of Oregon Staff's Investigation Related to Purchases from Electric Utilities* (UM 1129), Order No. 07-360, App. A.

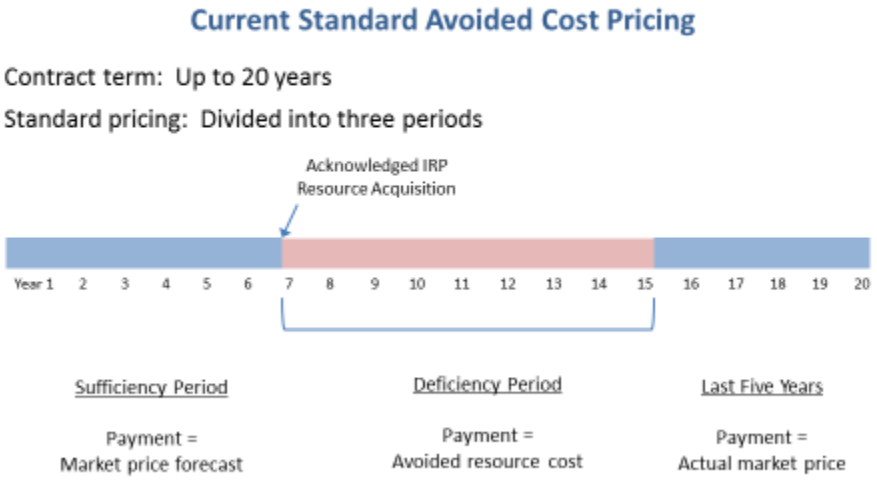
Oregon's Renewable Portfolio Standard (RPS) to offer renewable avoided cost prices.[13] In 2011, the Commission established the methodology for determining renewable avoided cost prices.[14] The Staff, utilities and stakeholders disagreed about implementation of renewable avoided cost prices and the utilities did not actually offer renewable avoided cost prices not offered until after Commission issued Order No. 14-058 in UM 1610.

In 2010, the Commission issued an order specifying the methodology for determining when a utility should be considered resource deficient and also specifying that PGE and PacifiCorp would calculate two different avoided cost price streams, one based on the costs of an avoided natural gas-fired CCCT and one based on the costs of the next planned utility-scale renewable resource in the utility's IRP.[15] Idaho Power is not subject to compliance with the RPS until 2025 and therefore the Commission has not yet required Idaho Power to offer renewable avoided cost prices. In 2011, the Commission issued an order adopting additional policies related to the provision of "renewable" avoided cost prices.[16]

In 2012, the Commission opened a multi-phased general investigation into PURPA implementation and issued orders concluding Phase I in 2014, adopting a stipulation in 2015, and concluding Phase II in 2016. The Commission's 2014 order retained the 10 MW cap for standard contracts and avoided rates, the twenty-year contract term with a fixed-price term for 15 years (see Figure 1 below) and the differentiation between sufficiency period and deficiency period prices.[17] However, the Commission ordered that adjustments would be made to deficiency-period avoided cost rates to take into account the capacity contribution of different resource types. The Commission also created an annual update process for avoided cost rates under which the utilities file avoided cost prices every May 1, with updated inputs for on- and off-peak forward market prices, natural gas prices, changes to the status of the Production Tax Credit, and any other action or change in an acknowledged IRP update relevant to the calculation of avoided costs. Also, the Commission authorized utilities to charge QFs for third-party transmission costs when a utility must acquire third-party transmission to move a QF's generation to load when the QF is located in a load pocket.[18] Each utility filed avoided costs using the new methodology in 2014 in Docket No. UM 1610. Beginning in 2015, updates to avoided costs were tracked in a single docket per utility.[19]

[13] *In the Matter of Public Utility Commission of Oregon Investigation into Resource Sufficiency* (UM 1396), Order No. 10-488.
[14] *In the Matter of Public Utility Commission of Oregon Investigation into Resource Sufficiency Phase II* (UM 1396), Order No. 11-505.
[15] Order No. 10-488.
[16] Order No. 11-505.
[17] *See* Order No. 14-058, pp. 2-3.
[18] Order No. 14-058, pp. 25-26.
[19] Docket Nos. UM 1728 (PGE), UM 1729 (PacifiCorp), and UM 1730 (Idaho Power).

Figure 1.



In Order No. 15-130 issued in Docket No. UM 1610, the Commission adopted a stipulation specifying that QFs may unilaterally select a period of up to three years between the date of contract execution and the scheduled commercial online date (COD) of the generating resource, clarifying provisions related to default for failure to achieve commercial operation by the scheduled COD and when a utility can terminate a contract for such a failure, the penalties for failing to meet the Minimum Availability Guarantee (MAG) in a contract, and clarifying or modifying a few other policies.

In Order No. 16-174 concluding Docket No. UM 1610 Phase II, the Commission authorized PacifiCorp to use a model-based methodology rather than the seven-factor method historically used for establishing non-standard avoided cost prices. The Commission also specified that utilities own the Renewable Energy Credits associated with a QFs generation during the non-fixed term of a PURPA contract, that if the proxy resource for deficiency-period prices is an on-system resource there is a rebuttable presumption that there are no avoided transmission costs, the same process should continue to be used for determining avoided cost prices (updated avoided cost rates filed after IRP acknowledgment and limited updates every May 1), and that a legally enforceable obligation is established once a QF signs the final draft of an executable contract or earlier if a QF demonstrates delay or obstruction of process towards a final draft of an executable process.[20] The Commission also directed Staff to work with parties to determine how a utility should calculate charges to a QF for third-party transmission costs when a QF locates in a load pocket and the utility acquires third-party transmission service to move the QF's output to load.[21]

In 2016, the Commission lowered the eligibility cap for standard prices for solar QFs in Idaho Power's and PacifiCorp's territories from 10 MW to three MWs and reduced the eligibility cap for standard prices for solar QFs in PGE's territory in 2017 on an interim basis and in 2019 on a final basis.[22]

[20] See Order No. 16-174, pp. 1-3.
[21] Order No. 16-174, p. 3
[22] Order No. 16-129 (Idaho Power); Order No. 16-130 (PacifiCorp); Order Nos. 17-310 and 19-016 (PGE).

Current Status of PURPA in Oregon

Summary

Figures 2 and 3 below depict general trends for the last several standard avoided cost updates, levelized over a specific 15-year period of fixed prices. As can be seen in the graphs, there can be significant changes to utility avoided costs when updated. As explained above, since 2014 the nonrenewable wind and solar capacity contribution values are adjusted in relation to the avoided CCCT, while renewable baseload and solar capacity contribution values are adjusted in relation to the avoided wind resource.

In examining the avoided costs it is important to keep in mind that the base assumptions vary by utility. Resource costs are dependent on the particular cost forecast the utility uses, some develop in-house assumptions, while others may look to outside experts. These base assumptions are driven by characteristics and location of the utility's specific avoided resource. For example, transmission is added to PGE's avoided costs because the IRP resources require transmission to deliver that resource to its system.

Also of note, there are two specific sets of capacity inputs that have the largest impact on avoided costs: the resource deficiency date; and, changes to the capacity contributions of wind and solar. Under the avoided cost methodology, these two important inputs are updated following IRP acknowledgment, but not in the annual updates.

Figure 2.

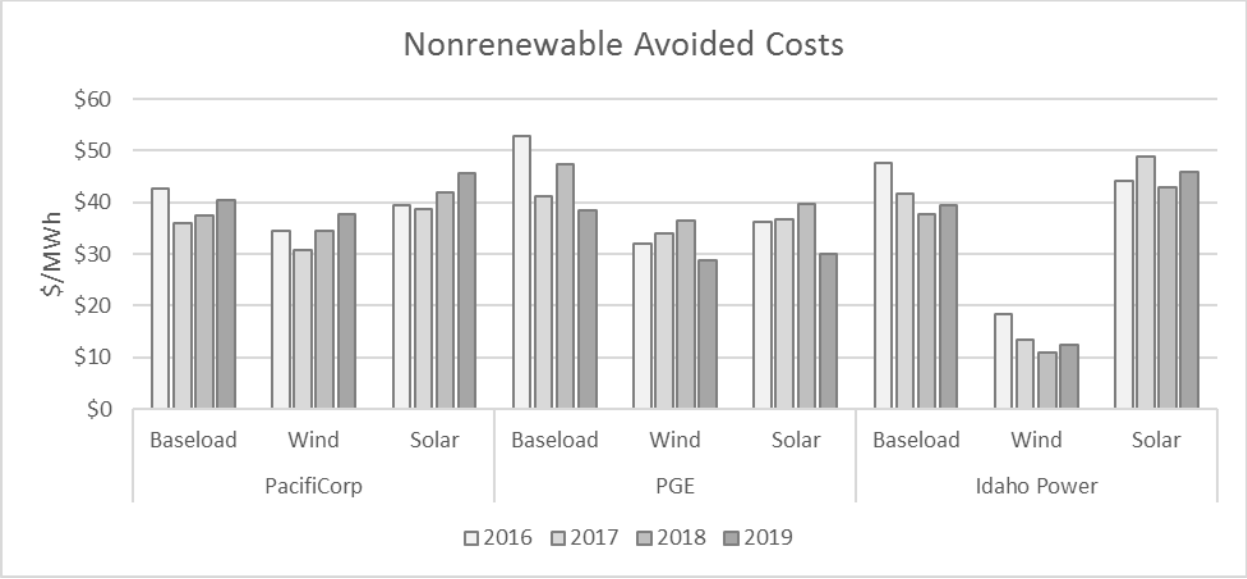


Figure 3.

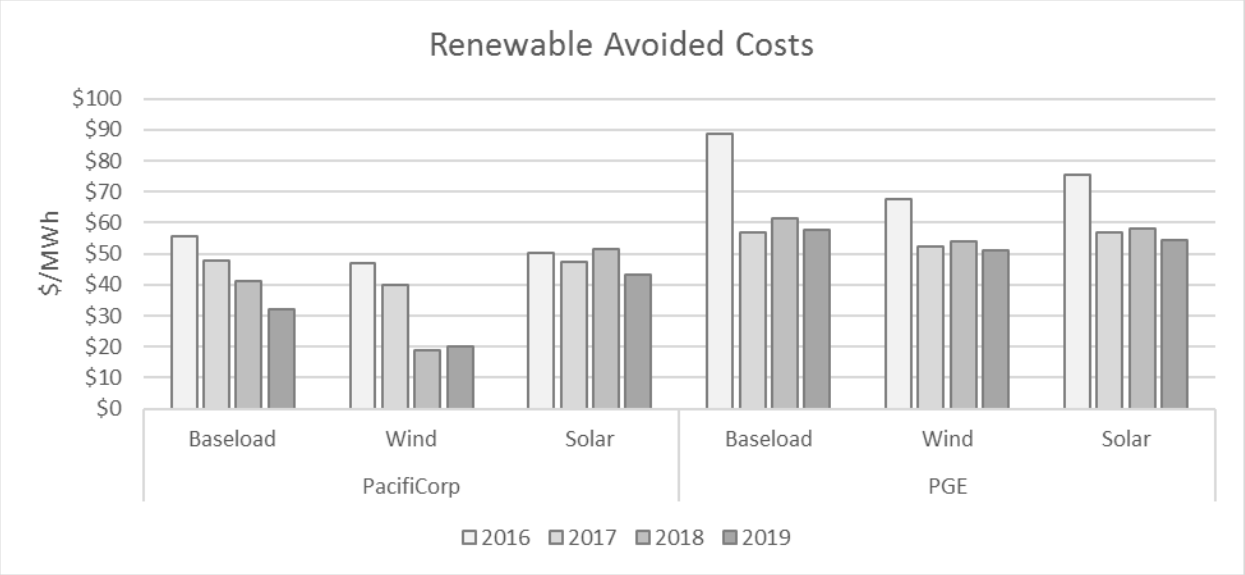


Table 1 shows the November 2018 status of all executed QF PPAs in three categories for the Oregon utilities. These categories are: Operating, Under Development, and Terminated. In examining the data some points of note stand out. While PGE has fewer solar QF resources operating than either of the other two utilities, it has a much higher number under development.[23] Both PacifiCorp[24] and Idaho Power have small numbers of QFs under development

Table 1: Current Status of QF Development in Oregon by Utility

Number of QF Projects and Total Capacity				
		Operating	Under Development	Terminated
Idaho Power	Baseload	5 totaling 17 MW	na	na
	Solar	6 totaling 50 MW	5 totaling 27 MW	na
	Wind	6 totaling 53 MW	na	na
PacifiCorp	Baseload	35 totaling 130 MW	na	na
	Solar	18 totaling 152 MW	3 totaling 26 MW	1 totaling 10 MW
	Wind	11 totaling 84 MW	6 totaling 60 MW	na
PGE	Baseload	6 totaling 18 MW	5 totaling 46 MW	5 totaling 30 MW
	Solar	12 totaling 30 MW	102 totaling 478 MW	16 totaling 125 MW
	Wind	1 totaling 9 MW	na	2 totaling 20 MW
Data as of November 2019				

[23] Nearly all of PGE's under-development QF PPAs were executed in the last three years.
[24] PacifiCorp has not executed a solar QF PPA in Oregon since 2015 though it has executed contracts with baseload and wind QFs.

The following graphs show the number, and associated capacity (in MW) of QF contracts executed prior to 2014, and annual numbers since. Both Idaho Power and PacifiCorp have seen an overall decline in the number, and MWs of contracts executed in recent years. PGE in contrast saw a spike in 2016 in capacity, with total numbers of contracts executed spiking in 2018.

The patterns shown below, and in the table above could indicate issues with PURPA implementation in the state. That is, one might expect less volatility in a well-functioning market. The variability is both by individual utility, and across utilities. These changes are also driven by changes in federal and state policies, such as access to Business Energy Tax Credit (BETC) state tax credits, and federal Production Tax Credits (PTC) or Investment Tax Credits (ITC).

Figures 4 through 6 below show for each utility the number of PPAs executed and associated MW, and the number of QFs and MW newly online, by year.

Figure 4.

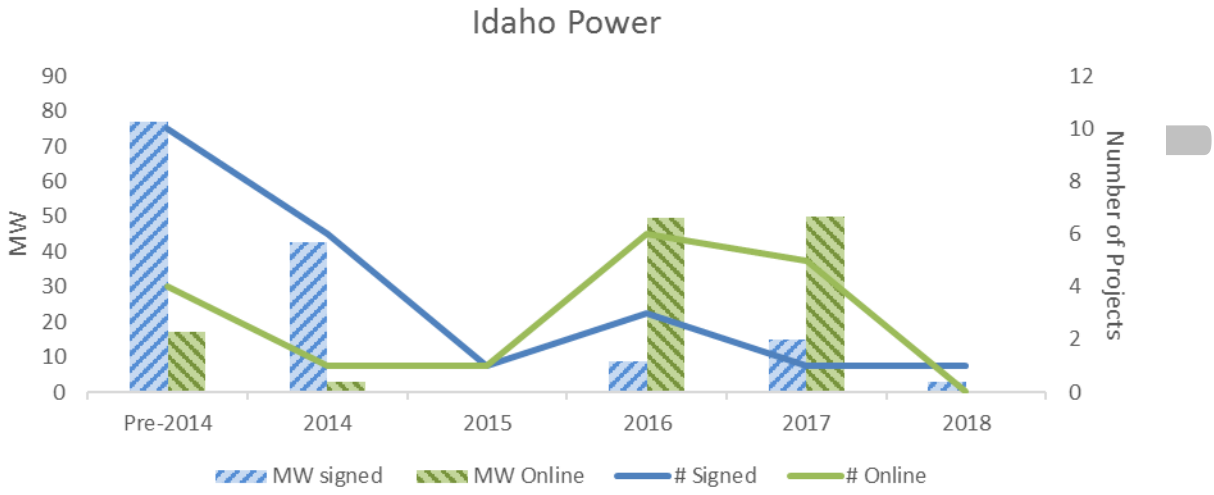


Figure 5.

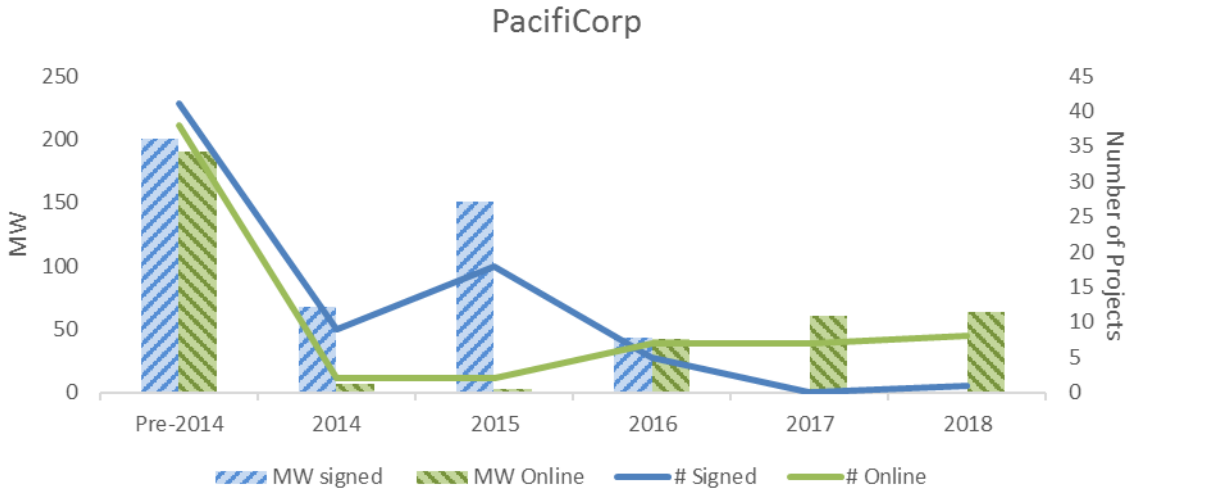
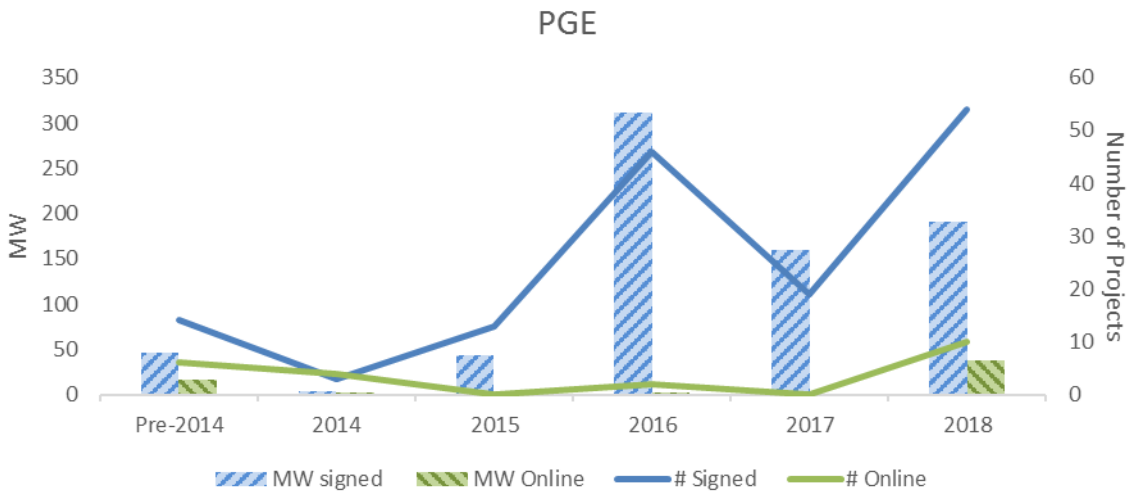


Figure 6.



Litigation

One of the motivations for a broad investigation of PURPA and the development of modifications to current process is the potential to decrease litigated proceedings. Since 2009, the Commission has overseen more than 60 contested cases regarding the interaction between QFs and regulated electric utilities. In 2017, 45 of these cases were filed; of those, eleven are still pending. The primary cause of this litigation centers on challenges associated with the execution of power purchase agreements (PPAs) between the utility and the QF.

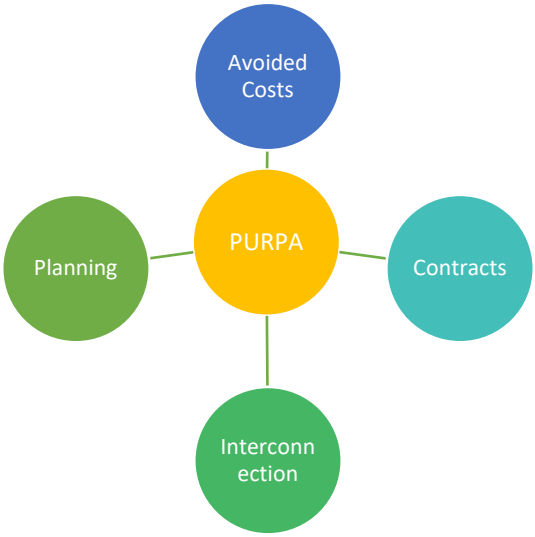
Most of these cases lasted nine months on average after which most were settled or withdrawn. Two sets of pending cases involving several parties are approaching the two-year mark. As such, addressing contracting issues that have been the cause of repeated confusion, delay, and litigation by developing solutions based on input received from stakeholders is an important element of this docket.

Key Issues Categorized

The issues raised by Stakeholders generally fall into four categories as mentioned above. In supplemental comments received from 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) a fifth category of transmission was suggested because these parties believe it has separate and distinct issues from interconnection. While Staff believes there can be confusion between transmissions and interconnection, issues raised in this docket generally concern the latter as opposed to the former.[25] As such, Staff does not propose adding transmission as a standalone category. Staff agrees with the QF Trade Association that 'process' is an important consideration that underlies all of the categories. Each

[25] The stand-alone transmission issue raised in UM 2000 is how to allocate costs of third-party transmission for load pockets. A Commission order in UM 1610 that addresses this is pending.

category is listed below with a general description of some of the issues facing implementation of PURPA in Oregon.



Avoided Cost Calculations

In order to maintain customer indifference, and treat QFs fairly, the Commission sets avoided cost rates that the utilities pay for QF power. The Commission is required to establish prices based on the cost of avoided energy in all years of a contract, even in the years when the purchase does not allow the utility to avoid purchases of energy. The Commission is required to establish prices based on the cost of avoided capacity and energy in the years when purchase from QF could allow the utility to avoid purchase of capacity. The Commission has previously concluded that a purchase from a QF allows the utility to avoid purchase of capacity in all years, but the capacity component of prices is much larger in years when utility is considered resource deficient. As discussed above, a utility's next planned acquisition of a major resource in its most recently acknowledged IRP demarcates the start of the utility's deficiency period for purposes of avoided cost prices in a PURPA contract.

The current avoided cost methodology may not reflect the realities of the market, for multiple reasons. Staff has identified four major issues that are impacting avoided costs. These are rapid technological advances, staleness of data used to set avoided costs, utility procurement practices, and resource size. Any changes to the current practices for setting avoided cost should align for both energy and capacity and leave utility ratepayers indifferent between utility or QF generation.

The Commission adopted the resource sufficiency/deficiency period pricing methodology for PacifiCorp and PGE in 2005. Fifteen years ago the utility acquisition of resources tended to be lumpier, the Renewable Portfolio Standard (RPS) was not in effect, and the Energy Imbalance Market (EIM) did not exist. Another driver of current market evolution is the rapid advances in technology, and associated declining costs, especially storage and renewable resources. The costs are also closely tied to state and federal tax treatments. Also, utility procurement may not adhere as closely to IRPs as it has in the past. The utilities conduct RFPs for resources that are not included in IRPs, or are outside of the identified need, and the utilities regularly purchase hundreds of megawatts of capacity of various durations in

short-term markets (see the IRP filings for reference). Meanwhile QFs are generally paid for avoided capacity costs associated with the utility's resource sufficiency/deficiency demarcation in their acknowledged IRP, which may not match the utilities actual acquisitions.

Even in 2005, the practice of updating avoided cost prices with inputs from acknowledged IRPs raised concerns due to the potential staleness of the data. Now, these concerns are heightened because the costs of proxy renewable resources used in today's calculations are more prone to significant variations than costs of proxy resources used in 2005. Additionally, the forward market prices were assumed to contain a capacity component when the Commission approved the current avoided cost pricing models. That assumption may not be as true today given the current market mix that contains a greater share of low- to zero-cost marginal units as compared to 2005. These units are shaping market prices and may not include capacity values for at least a subset of hours. Note, staleness can present risks in both directions. In a period of rapidly escalating costs, locked-in avoided cost prices could benefit the utility at the expense of a QF.

Part of any avoided cost examination may lead to the need for more frequent and complete updates. As storage is rapidly becoming cost-competitive rules may need to be adopted for allowing the most efficient use of resources.

Contracts

As noted earlier, disputes regarding the contracting process and contract terms have flooded the Commission. QFs believe that utilities take advantage of the standard contract contracting requirements to delay the preparation and execution of contracts. Utilities are concerned that some QFs submit incomplete requests for standard contracts and expect the requests to result in a legally enforceable obligation for the utility to purchase the QFs' output at the prices in effect at the time of the request.

Other contracting issues arise from the complexity of the process to finance and build a QF and the stress that a lengthy and uncertain process places on both the utility's planning, and QF project development. The Commission has previously adopted policies to attempt to balance the interests of both the development community and utilities and ratepayers. These efforts have not stopped litigation between QFs and utilities regarding contract terms.

Still other contractual issues arise because renewable resources improvements and innovations outpace the relatively slow process of PURPA contracting and resource construction. QFs point out that inflexible PURPA implementation policies and contracting processes could mean QFs cannot take advantage of these advances to improve the efficiency and value of their projects.

Interconnection

Though many interconnections between a generator and transmission provider fall within the jurisdiction of the Federal Energy Regulatory Commission (FERC), the Commission has jurisdiction over interconnections between QFs and their host utility when the host utility purchases all of the QF's output. In 2009, the Commission adopted rules setting forth the policies and procedures for

interconnections for generators 10 MW and less.[26] In 2010, the Commission adopted policies and procedures for interconnections for generators 20 MW and larger.[27]

Interconnection processes are another issue of contention between parties. Developers see the interconnection process as an area where the utilities will throw up multiple barriers to projects, and add on additions costs. Conversely, utilities believe they are following requirements for interconnection requests. The Commission has taken interim steps to increase the transparency of interconnection-related information.

Other interconnection issues relate to the type of interconnection service available to small QFs subject to Oregon's jurisdiction and the allocation of costs associated with upgrades to the utility's transmission system associated with interconnection. Currently utilities require QFs to apply for Network Resource Integration Service (NRIS). NRIS can necessitate more "Network Upgrades" than other interconnection service such as Energy Resource Interconnection Service. Network Upgrades are upgrades to the transmission provider's transmission system at or beyond the point of interconnection. And, unlike FERC's policy for non-independent transmission providers such as PGE, PacifiCorp, and Idaho Power, Oregon's small and large generators are generally required to pay for Network Upgrades to the transmission provider's transmission system. Staff intends to examine whether it is appropriate to require QFs to select NRIS and in any event, whether it is appropriate to allocate costs of Network Upgrades to QFs.

QFs are also concerned about the pace of production of the interconnection studies and facility construction, and want the ability to pay for third-party contractors to do some of this work. The utilities are concerned about the usability of third-party studies and also the integrity of the system and resist the idea of using third parties.

Planning

Planning generally revolves around the treatment of QFs for IRP purposes. This investigation should address both planning for existing QFs, as well as new QFs with power purchase agreements. Parties are also interested in examining assumptions used in the IRP as they form much of the basis of the avoided costs. Issues to address include the resource cost assumptions, and the sufficiency/deficiency determination.

Parties' suggestions

Stakeholders offered many suggestions on what should be examined, and the process for such an examination. Some parties had more direct suggestions than others, a brief non-exhaustive summary of some of these suggestions is provided below, and a more complete summary can be found in the Appendix materials. In general, most stakeholders seem to approve of the proposed two-track process, with the exception of Idaho Power. Idaho Power would prefer a single-phase docket due to overlap in the issues, and suggest any issues list should be "generally defined, and broadly construed." Similarly,

[26] *In the Matter of a Rulemaking to Adopt Rules Relating to Small Generator Interconnection* (AR 521), Order No. 09-196.

[27] *In the Matter of Public Utility Commission of Oregon Staff's Investigation into Interconnection of PURPA Qualifying Facilities with a Nameplate Capacity Larger than 20 Megawatts to a Public Utility's Transmission or Distribution System* (UM 1401), Order No. 10-132.

the QF Trade Associations noted the issues are "inherently intertwined and it is difficult to parse out issues for separate resolution."[28]

Avoided Costs

AWEC

- Base capacity payments on date utility is projected to be capacity deficient.

Idaho Power:

- Eliminate reliance on a CCCT, match rates paid with estimated hourly generation of QF.
- Make rates effective upon filing with a potential true-up process.

PacifiCorp:

- Change methodology to more closely align with costs utility would pay.
- Allow PDRR both standard and non-standard contracts as is done in Utah, coupled with quarterly filing of avoided cost inputs.

PGE:

- Use information gathered via an RFP process to inform avoided cost calculation.
- Establish non-renewable rates by subtracting the value of environmental attributes from a renewable price stream.

QF Trade Associations:

- Maintain current methodology with adjustments to compensate QF for capacity, including market purchases.
- Include all costs associated with the avoided resource including transmission costs in the determination of avoided costs.
- Ensure methodology comports with both Oregon and FERC PURPA guidelines.
- Ensure methodology accounts for locational value of QFs.
- Improve transparency of utilities' spreadsheets showing avoided cost Inputs.
- Establish and adhere to avoided cost update process and allow for meaningful QF participation.
- Address PacifiCorp's artificially low rates.

RNW and OSEIA:

- Retain current methodology, with adjustments to compensate QFs for capacity when utility avoiding "short-term market capacity purchases."[29]
- Modify utility spreadsheets to improve transparency.

Contracts

AWEC

[28] See page 28 of comments submitted March 29, 2019 Responses of NIPPC, The Coalition, and CREA TO Staff's Questions to Stakeholders.
[29] Current approach of WUTC.

- Allow QF to establish LEO when QF makes a binding commitment to sell facility output to utility.
- Assume storage co-located with generating facility is eligible for PURPA contract . (Stand-alone storage likely not a QF.)
- Avoided cost prices should reflect motive force.

Idaho Power:

- Allow QFs to lock in rates via a LEO no more than one year prior to scheduled commercial operation date.
- Treat existing projects new projects for purposes of new contracts.
- Allow liquidated damages in case of non-performance.
- Allow QFs with storage to be eligible for rate and contracts in the same manner as their source of generation.

PacifiCorp:

- Current process works well, although a common contract structure could work.
- Modify dispute resolution process.
- Make determination of when a LEO is incurred a fast-track issue.
- Allow storage as long as energy source is renewable as long as size implications are considered.

PGE:

- Common contract form could be helpful, must recognize utilities' different business practices.
- Require more certainty that a QF will come online to ensure sufficient development has occurred prior to PPA execution.
- Modify how a LEO is incurred because it currently is a free option with no real penalty for failure to perform.
- Allow existing contracts to execute new contract no sooner than one year prior to contract expiration.
- Apply same pricing to renewing existing projects and new QFs.
- Include provisions re: performance assurance in contracts.
- Establish process for timely updates to standard contracts.
- Include provisions for carbon emissions/cap and trade costs in contracts.
- Include provisions regarding damages for a renewable QF's failure to deliver RECs in contracts.
- Include provisions for real-time communications requirements for QFs in contract.
- Base eligibility for standard PPAs on nameplate of capacity of generators.
- Allow QFs with storage to receive pricing associated with the underlying generator.
- Investigate allowing intermittent resource to receive base load pricing if QF with storage demonstrates baseload characteristics.

QF Trade Associations:

- Adopt same standard contract forms for all three utilities, while recognizing the need for flexibility based on the specific utility.
- Adopt expedited dispute resolution process.

- Revised what is otherwise generally acceptable contracting process to remove opportunities for utilities to delay the process.
- Allow QF to unilaterally form a LEO when contracting process breaks down.
- Allow QFs operating under existing contract to enter a new contract at least three years prior to expiration of existing contract.
- Provide certainty to QFs in contracting queue when avoided cost updates are filed.
- Base capacity of project with storage on maximum output to grid.
- Encourage use of storage for more efficient use of transmission system.

RNW and OSEIA:

- Reaffirm that existing guidelines require publication of sample non-standard PPA for initial negotiations.
- Develop an expedited dispute resolution process.
- Allow QFs to establish a LEO if breakdown in contracting process occurs.
- Allow intermittent QFs with storage to be eligible for baseload rates if resulting production behaves like baseload QF.

Interconnection

Idaho Power:

- Prefers QFs to use pre-application process to analyze project viability.

PacifiCorp:

- Developers rarely have actual solar panels when requesting interconnection – facility specification changes can necessitate additional studies.
- Generators requesting interconnection frequently require transmission system upgrades as well.

PGE:

- Decrease the existing 3 MW cap in OAR 860-082-0070 on QFs that are not required to pay for the data acquisition or telemetry equipment necessary to allow the public utility to remotely monitor the small generator facility's electric output.

- Adopt Institute of Electrical and Electronics Engineers (IEEE) 154 7- 2018 standard.

QF Trade Associations:

- Allow QFs to retain third party contractors to perform studies, and construct interconnection facilities
- Improve transparency, communications, access to studies and underlying data
- Adopt a process for prompt resolution of disputes
- Have enforceable timelines
- Allow opportunity for meaningful consideration of interconnection options (routes, transmission or distribution).
- Allow alternative means of meeting functional requirements.
- Provide remedies for utility violations of rules (offsetting extensions).

- Ensure appropriate requirements (no gold-plating).
- Provide appropriate cost sharing.
- Address network resource interconnection service requirement for QFs and lack of eligibility for refunds for network upgrades.
- Address lack of procedures for generators between 10 and 20 MW.

RNW and OSEIA

- Strengthen requirements related to initial information available to QFs prior to interconnection application.
- Make timelines more predictable.
- Do not require QFs to bear full costs of network upgrades that are used by others.

Planning

The major issue associated with planning raised by parties is the treatment of QFs in the IRP process. There was also a strong desire for the opportunity for meaningful participation in the IRP process by stakeholders. That is, it will be hard for stakeholders to challenge variables and results from an acknowledged IRP. These variables in turn will form the basis of the avoided cost rates.

QF Trade Associations:

- Address capacity value of existing QFs
- Create realistic opportunity to challenge IRP inputs.

Prioritization of Actions

The intent of this white paper is to develop a well-defined scope for the UM 2000 investigation that will ensure PURPA implementation is fair, efficient, transparent and timely for both QFs and utility ratepayers. Staff suggests some items to focus on in the near term on a 'fast-track' agenda, as well as some items that will take more time to investigate. Staff proposes to bifurcate these issues into different processes to ensure timely progress on items that can be resolved in short order to improve PURPA implementation in Oregon while creating a place to address long-term issues. The proposed near-term actions in this draft whitepaper have the potential to resolve many issues related to litigation.

Both near- and longer-term processes can take place in parallel to hopefully mitigate any timing issues.

Near-Term (fast-track) Actions

Avoided cost:

To address the issue of inconsistent and complex tools that are difficult for Staff and other stakeholders to review in a timely manner, Staff will work with stakeholders to develop a standardized template for avoided cost modeling inputs and outputs. This template will be used for the current modeling methodology. A broader investigation into the appropriate modeling methodology will be part of the longer-term activities. Note, this methodology and associated rates could be impacted by the general capacity investigation in Docket No. UM 2011.

Contracts:

Staff proposes to draft a straw proposal of standard contract procedures and terms to initiate a holistic review of contract terms. The terms of a contract are interdependent and previous changes to certain

terms of a contract after a complaint proceeding or general investigation can have unintended consequences for the application or implementation of other terms. A holistic examination of PURPA standard contracts, with emphasis on obtaining internal consistency that balances the interests of the utility and QFs would benefit the Oregon wholesale market and ratepayers. The following are some of the broad issues that Staff would want to attempt to address in the near-term:

(1) What would contract timing, term, project size, compensation, security, and renewal encompass?

(2) What is the minimum levels of information to be provided?

(3) Will there be any contractual flexibility due to technology improvements (pre- and post-construction)?

(4) How should damage provisions be incorporated?

(5) What is the appropriate treatment of storage?

Interconnection:

Near-term activities for interconnection are being covered in UM 2001. Proposals for UM 2000 should build on the work that's being done in that docket. The QF Trade association included a list of near-term interconnection issues they believe could help end litigation. Staff believes the majority of the issues identified could be addressed on a fast track. These fast-track issues include more transparent process, access to studies, dispute resolution, and treatment of costs associated with network upgrades, among others. Some of the questions that could be resolved as part of the near-term Staff activities would include:

(1) What is the appropriate level of detail to provide in interconnection studies?

(2) What options does a QF have to perform its own studies, or upgrades?

(3) Should there be modifications to the current process, including more enforceable timelines?

(4) Should independent third parties be retained to review studies?

(5) Are there further data access issues not captured in Docket UM 2001?

(6) In designing the interconnection, are there lower-cost alternatives that are being overlooked?

(7) What is the level of SCADA data needed – and for what size QF?

(8) What rules/guidelines apply to 10-20 MW projects?

Planning:

Staff believes issues related to planning and contract renewals could be addressed on a fast track. There are issues related to planning that have been discussed in multiple dockets, including UM 1610, and PacifiCorp's IRP related to treatment of QFs long-term planning. These revolve around the issues of how to consider QFs and the potential for contract renewals in the IRP. The issue will get at the potential for renewing QFs to receive capacity payments at the beginning of their second contract. Staff believes this

is an issue that could be fast-tracked, recognizing that the general capacity investigation could play a role in this value as well.

Additional questions relate to the amount of executed PPAs for QFs that are not yet on-line and how they are treated in the IRP process. As shown above, the amount of QF projects undergoing development is large (especially for PGE) as compared to their resource needs. Assuming all these QFs come online may not be appropriate. How many to include would benefit from stakeholder review. These assumptions may impact the sufficiency/deficiency demarcation, and impact pricing.

Long-Term Actions

Staff believes the issues below will require additional time to develop a record prior to a Commission decision and are not included Staff's proposed scope of near-term activities.

Avoided Costs:

Appropriate avoided cost pricing is fundamental to the fairness for both QFs and utility ratepayers. As such it is important to examine the appropriate methodology for calculating avoided costs as a longer-term issue. Staff believes the current methodology may not reflect market realities. The process to incorporate changing technology and market conditions should be thoroughly reviewed in developing an avoided cost methodology. There are issues that need to be fully examined in order to ensure PURPA implantation is fair, transparent, and flexible enough to adapt to such transformations.

There is a major transformation underway in the market, as the industry transitions to more open markets we will need to see what impact it will have on appropriate avoided cost pricing. Issues such as EIM impacts would be considered here.

Parties have made several suggestions for improving avoided cost pricing, including examining the results of an RFP, treatment of transmission costs, and valuing capacity. Staff believes any change to the current methodology should go through a rigorous analysis prior to implementation.

Staff proposes to examine alternative methodologies for setting avoided costs. Depending on the results of the investigation the outcome could range from minor tweaks, to a complete methodological changes. Other questions to examine may include:

(1) Should all or some QFs (i.e., existing QFs) have the option for levelized prices during the fixed-price term?

(2) Should utilities be allowed to use a modeling approach to determine non-standard prices?

(3) Should there continue to be both renewable and non-renewable price streams?

(4) Should variable QFs with storage be allowed access to baseload QF pricing?

(5) What are the implications of renewable pricing less than non-renewable pricing?

(6) Should renewable QFs be allowed to take non-renewable prices and keep the associated RECs in the case of a price inversion?

General Capacity Investigation

The Commission called for an investigation to examine generic capacity values in the recent Commission orders from Resource Value of Solar (RVOS) dockets.[30] As stated in those orders, a comprehensive approach to establishing greater understanding of capacity value may inform and harmonize how capacity is assessed across several dockets. Order No. 19-155, dated April 26, 2019, opened the investigation as Docket No. UM 2011. That investigation will examine capacity and all of its attributes, and values across a multitude of potential resources. While there are capacity related issues in the current PURPA docket, there are potential ramifications that could occur depending on what transpires in the UM 2011 docket.

Contracts:

Staff believes development of standard contract terms in the fast-track part of the investigation could alleviate many contracting issues. However, other issues such as improving the negotiation process, use of non-standard contracts, and Commission involvement and oversight of the non-standard contract process may take longer. Staff believes more use of non-standard contracts could result in equitable treatment for all parties, as well as minimize complaints. Parties have raised the potential for extensions more than three years in advance for instance. This is something that could be discussed here.

Another longer-term item to examine here is the treatment of storage when determining facility size. There is a current case in front of FERC that should provide guidance on how to handle this question that should inform the Commission's decision.

Interconnection:

Longer-term interconnection issues may include whether it is appropriate to require QFs to apply for and receive NRIS or whether a different interconnection service more like Energy Resource Interconnection Service would be appropriate. However, Staff is not sure whether this question is more appropriate for a fast track. Other potential questions to address include:

(1) What is the best way to ensure progress in interconnection queue?

(2) Is first-ready, first-served a viable solution?

(3) What are the possibilities of cluster studies instead of serial studies?

(4) How should 'load pockets' be dealt with?

(5) How should QFs with scheduled CODs delayed due to interconnection be treated?

Recommendation:

After examining the issues raised and potential paths forward, Staff recommends a series of near-term and longer-term actions. Staff has also considered a variety of regulatory processes (such as rulemakings and investigations) in its recommendations for specific actions to take. These separate approaches for near- and long-term issues with differing process will allow the flexibility to fully address

[30] *In the Matter of PacifiCorp dba Pacific Power Resource Value of Solar* (UM 1910), Order No 19-021; *In the Matter of Idaho Power Company Resource Value of Solar* (UM 1911), Order No. 19-022; and *In the Matter of Portland General Electric Company Resource Value of Solar* (UM 1912), Order No. 19-023.

the questions of PURPA implementation in Oregon. Staff believes this will resolve some issue quickly while allowing the time needed to address others.

Near-Term Actions

Staff believes there are five major issues that could be addressed in the near-term. There are two different processes proposed: a targeted investigation into near-term planning; and one or more rulemakings covering four discreet issues. Settling these five items would have a measurable, positive impact on PURPA implementation as they are intended to increase efficiency, transparency and fairness in the Oregon implementation of PURPA.

Stand-Alone Investigation for Near-Term Item: Planning

One issue that is easily separated from the others is the treatment of QFs in utility planning processes. Order No. 07-002 established thirteen specific guidelines that govern the current requirements for utility IRPs. These guidelines have not been static though, the original Guideline 8: Environmental Costs was replaced following further analysis and stakeholder process. Order 08-339 included the replacement for Guideline 8.

Later there was an investigation into the electric vehicle charging, Docket No. UM 1461. This docket examined "matters related to the charging infrastructure for plug-in hybrid vehicles and electric vehicles". One result of this investigation was a new IRP Guideline directing utilities to forecast both the demand for, and supply of flexible capacity. Utilities were directed to treat flexible resources on a consistent and comparable basis to other resources.

The Commission discussed the planning issue in UM 1610, and the potential value associated with capacity deferral depending on IRP assumptions related to QF renewals. The Commission directed utilities to address this in their forthcoming IRPs. Thereafter PacifiCorp's IRP assumed no QF renewals. It is not clear that this was the intent of the Commission direction given. As such, Staff proposes a short, streamlined investigation devoted strictly to treatment of QFs (existing and in the queue) in long-term planning with the intent of producing an IRP guideline on this subject for use by all three electric utilities in developing their IRPs.

Rulemaking(s) for Near-Term Actions

Staff recommends one or more rulemakings for issues related to: avoided cost inputs/outputs, contracting, dispute resolution, and treatment of network upgrades. The issues that would be addressed are detailed below.

Avoided cost inputs/outputs

A consistent framework for inputs and outputs associated with avoided cost calculations would eliminate confusion amongst parties. Rules establishing how these factors are presented would ensure transparency and consistency. As such, Staff recommends a set of rules to enforce such consistency.

Contracting

Staff believes a series of rules related to the standard contract, and contracting process (updating current rules as needed) would bring more transparency to their current state.

Dispute Resolution

Formalized rules related to dispute resolution could mean a less-litigious atmosphere around PURPA implementation. As such, Staff recommends the Administrative Hearings Division be tasked with promulgating such rules in the near-term.

Interconnection

Improvements to the dated interconnection rules could improve process for all parties. Staff suggests a rulemaking to examine a subset of interconnection issues.

Staff recommends evaluating whether Oregon's treatment of network upgrades, which differs from established FERC policies, is appropriate via a rulemaking. This rulemaking would also examine data issues which are currently being discussed in UM 2001.

Longer-term Issues for Consideration

Staff believes the UM 2000 framework could continue forward and address the remaining issues not covered in the near-term. These issues are discussed more fully below. Note that some of the issues will potentially overlap with near-term considerations, and could be further impacted by the UM 2011 General Capacity Investigation.

Following the long-term investigation there may be need for additional process, such as a rulemaking. Staff would bring a further proposal to the Commission should it be necessary.

Avoided Cost Modeling

Any changes to the current approach of modeling avoided costs would benefit from a thorough analysis. Markets and technology are rapidly evolving, pricing for QFs needs to be nimble enough to match these changes more accurately. That is, prices paid to QFs should accurately match the avoided costs faced by the utilities to ensure fairness.

Contracts: Non-standard, and negotiations

Many contractual issues raised can be addressed in the near-term via a rulemaking. However, Issues raised with non-standard contracts, and negotiations between QFs and utilities may need additional discussion. With that in mind Staff has left this issue for the longer-term investigation.

Interconnection

While UM 2001 is intended to bring clarity to the interconnection discussion there will be other issues for continued discussion in the long-term investigation. Chiefly here would be issues related to the lack of progress in the interconnection queue.

Summary of Recommendations

The following table contains a summary of Staff's recommend actions, and the timeframe for completion.

Issue Category	**Issue Addressed**	**Action taken - timeframe**	
		Short-Term	*Long-Term*
Avoided Cost	Template for Standard Inputs and Outputs	Rulemaking	

	Appropriate cost methodology		UM 2000 Investigation
Contracts	Development of Standard Contract	Rulemaking	
	Dispute Resolution	Rulemaking	
	Non-standard contract development and negotiation		UM 2000 Investigation
	Treatment of storage in determining facility size		Ongoing FERC issue – suggest mirroring their approach once determined
Interconnection	Transparency of data	Addressed in UM 2001	
	Treatment of network upgrades	Rulemaking	
	Lack of progress in interconnection queues		UM 2000 Investigation
Planning	Treatment of QFs in utility IRPs	Separate investigation	
Miscellaneous	Issues not included above		UM 2000 Investigation

- Appendix
  - Summary of parties comments – March 15, 2019
  - Summary of comments – April 5, 2019 workshop
  - Summary of comments – April 26, 2019

No.	Question	AWEC	QF Trade Association	RNW &OSEIA
1	Please provide a high-level description of modeling used to set avoided cost prices, including: a. A description of variables included b. Modeling methodology including software used			
2	Please explain the process that a QF goes through when requesting an energy sales agreement with a utility. For this process include the following information, and note any differences between applications for standard rates, standard contracts, or non-standard contracts. a. List any software programs that aid in the application process b. Provide a complete timeline, with breakdowns for each step of the process c. Provide a complete list of informational requirements from the QF d. Provide a list of data/information issues that could impede the contracting process			
3	Please describe the interconnection process that a QF is currently required to follow. With this description please note any differences between QFs and any other projects requesting interconnection and explain the rationale behind any such differences. a. List the point of contact in the utility. b. Provide a timeline that an interconnection request follows. Please include all relevant steps from submission request to actual connection. c. Provide a complete list of informational requirements from the QF. d. Provide a list of data/information issues that could impede the interconnection process. e. Provide a description if and/or how this process interacts with requesting an energy sales agreement.		d. Utilities' failure to provide information can impede interconnection.	
4	Please provide a list of any utility resources that could help inform QF developers as to locations that would benefit from, or face challenges to development.			

No.	Question	AWEC	QF Trade Association	RNW &OSEIA
5	How do utilities treat QFs with storage currently for PURPA purposes? a. How is the capacity determined for such a project b. Would a renewable generator collocated with storage be eligible for renewable avoided cost pricing? Please explain.			
6	When can existing QF projects renew their QF contracts? Can a renewal occur prior to the expiration of the current contract? If so, how long before expiration of the current contract can a QF enter into a new contract?		Question 6 should have been posed to all due to ongoing Middlefork Irrigation District complaint in UM 1995.	
7	Please explain transmission requirements for new QFs. Please explain any differences for existing versus new QFs related to transmission requirements.			
8	How are QF contracts treated in long-term planning processes? Are the assumptions consistent for IRP planning as those used in other internal planning processes? Are existing QF contracts assumed to renew or not renew at the end of a contract? Please explain.			

No.	Question	AWEC	QF Trade Association	RNW &OSEIA
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.		considerations. PURPA requires "that the price accurately reflect the cost that the utility would otherwise incur…" Need to consider law's goals and policies. Should've asked how to comply with FERC and Oregon PURPA goals and policies. Retain current methodology with adjustments: - Compensate QFs for capacity when utility procures a resource not anticipated in last IRP; - Compensate for all costs associated with the resource, including transmission - Include capacity for market purchases; see WUTC new rules; - Account for locational value of QFs, including transmission. Concerns about ELCC and LOLP. - Should only include updates for QFs with ICA's, not just PPAs. - Modify spreadsheets for transparency. - Commission needs to follow its AC update process. - No realistic opportunity to challenge IRP inputs. - Concerns about Staff's questions assuming too much process, when there is already insufficient process for QFs to review. - Commission should establish methodology and have Staff perform analysis and calculate rates, as they do in Idaho.	Retain current methodology, with following adjustments: - Compensate QFs for capacity when utility avoiding "short-term market capacity purchases," a la WUTC - Redo spreadsheets for transparency

No.	Question	AWEC	QF Trade Association	RNW &OSEIA
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.		Retain separate price streams.	Yes, retain separate price streams - Next planned renewable procurement (renewable) - Next planned major capacity procurement (nonrenewable)
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?		Commission should consider adopting same methodology and standard contract forms for all three utilities. Could help alleviate issues such as UM 1805 (start of 15-year period of fixed prices). Standardization must allow some flexibility for specific utility situations. Models should be easy for all to understand. Sample non-standard draft PPAs for initial negotiation should be available. Commission should have an expedited dispute resolution process	Reaffirm existing guidelines, require publication of sample non-standard PPA for initial negotiations, expedited dispute resolution process.

No.	Question	AWEC	QF Trade Association	RNW &OSEIA
12	Please provide any ideas related to generally improving the efficiency of the regulatory process associated with updating avoided cost prices.		Current process does not provide certainty around when filing will be made, and meaningful participation for QFs. Necessary to improve transparency, allow meaningful participation and certainty in the regulatory process. Process may be extended slightly, but should increase accuracy and decrease complaints.	Requests clarification on 'efficiency' and how improving efficiency of regulatory process would address ORS 758.515(3)(b) (settled and uniform climate for QFs)
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.		Trade Association: Fair and balanced approach has been developed, current process is generally acceptable. Revisions needed to remove opportunities for utilities to unduly delay the process. Such issues may include: changes in information required to submit, utility errors, delays due to QF typos, unnecessary step of "final draft" PPA. QFs need time to review documents when price changes on the horizon. Non-standard contracts virtually impossible to negotiate – Commission should examine certain contract provisions a QF could unilaterally select. Approval should be required for rate-setting methodology with actual rates and executed contract forms made public.	No comment at this time

No.	Question	AWEC	QF Trade Association	RNW &OSEIA
14	Please describe an optimal interconnection process for a QF requesting interconnection.		(1) The FERC process may be preferable. The current rules provide some mandated deadlines that have not always been followed. Putting some sideboards on the length of time permitted would create greater certainty in the interconnection process. (2) Interconnection studies should be sufficiently clear and detailed such that an independent engineer can review the study and re-create the results. (3) 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. (4) Lack of procedures for generators between 10 and 20 MW should be addressed. (5) Should be a meaningful interconnection process (6) Commission should enforce rules.	No Response
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.	Unresolved issues related to storage, stand-alone storage likely not QF eligible, Commission should assume storage co-located with storage is eligible, avoided cost prices should reflect motive force.	Utilities have mandatory purchase obligation, Commission should require utilities to explain storage may be used with QF resources. Capacity of project with storage should be based on maximum output to the grid. Commission clarification of use of this metric will encourage use of storage and more efficient use of transmission system. If energy input is renewable then power from QF should be eligible for renewable rates. Energy production profile should determine eligibility for higher rates, even if underlying resource is intermittent.	Capacity based on maximum amount of power the facility is able to deliver. Variable renewable QFs with storage eligible for non-variable rates, if production operates like non-variable QFs.

No.	Question	AWEC	QF Trade Association	RNW &OSEIA
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)		Existing QFs should be able to enter new contracts at least three years prior to current contract expiration. Some contracts may need additional time – see hydro and relicensing. QF renewals should receive capacity payments immediately as they are already relied upon as a capacity resource.	No comment at this time.
17	Should the existing dispute resolution process be continued? If not, how should it be changed?		Current dispute resolution over whether a LEO was formed should be more expedited. See Montana - where decisions are made with 180 days.	No comment on this issue at this time.
18	Please share your recommendations to reduce the volume of litigation regarding complaints.		Several suggestion: Allow courts of law to settle disputes Utility shareholders pay for QF litigation Do not re-litigate same issues Allow meaningful QF participation in avoided cost updates Limit delays-impose penalties on utilities Require utilities follow timelines in interconnection process, provide data, allow third-party consultants to perform study and work.	No comment on this issue at this time.
19	What existing resources (educational, etc.) do you know of that could benefit the Commission and other stakeholders during or prior to the investigation?		Implementation techniques across the US could be beneficial. Topic-specific information can be provided as the proceeding becomes more defined.	No suggestions at this time.

No.	Question	AWEC	QF Trade Association	RNW &OSEIA
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?		Investigation process currently employed provides meaningful participation opportunities, but consideration needed for time and resources of non-utility stakeholders. Policy changes should be incorporated in administrative rules or formal guidelines where they are easy to locate.	Consider staffing and capacity limitations of non-utility stakeholders by adopting timelines that will allow full participation in PURPA implementation.
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)? a. If yes, how should the Commission determine eligibility and pricing for capacity payments?	Yes – capacity payments for any resource should be based on the date the utility is projected to be capacity-deficient. Deficiency date for renewables should be based on date utility needs additional renewable resources to meet RPS compliance w/ capacity payments based on resource capacity contribution.	Resources acquired on an "economic basis" still fill a need. Recommend elimination of the concept of sufficiency/deficiency.	Disagree with premise that acquisition has been completed outside of need. Encourage Commission to change practice of basing sufficiency/deficiency on IRP major resource acquisition. Note that market-based rates in sufficiency period do not compensate QFs for costs of capacity utilities avoid.

No.	Question	AWEC	QF Trade Association	RNW &OSEIA
22	When in the process of contracting should a legally enforceable obligation (LEO) be obtained?		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.	At least in certain circumstances, QFs eligible for standard contracts should be able to establish a LEO even before receiving an executable contract. Where a breakdown in the contracting process occurs, a QF should be able to establish a LEO by signing a copy of the utility's standard contract that includes its scheduled commercial operation date and performance information such as its minimum and maximum annual deliveries.

No.	Question	AWEC	QF Trade Association	RNW &OSEIA
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.	AWEC recommends that the Commission follow established FERC precedent on this issue by making clear that a LEO is created at the time the QF makes a binding commitment to sell its output to the utility.	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 and that utilities benefit when a QF is not built.	No response at this time, but believe QFs may have insight and recommends further discussion of this question.
24	What is required for a QF project to receive financing?		Do not have, cannot share specific financing information. This is an important issues with follow up information to be provided in the proceeding at a later date.	No comment at this time, it is an issue that would require significantly more time to explore.
25	Assuming a two-phase process, what issues do you believe could be fast-tracked within Phase 1?		Issues inherently intertwined. If Commission wants to rehash al of PURPA it may not be wise to do in two parts. If goal is to generally keep status quo and only modify a few elements some may be modified quickly, with some taking more time.	No comment at this time, reiterate non-utility stakeholder constraints. After the workshop may have more clarity on issues sufficiently non-contested.
26	Assuming a two-phase process, what issues do you believe need additional time for analysis? (i.e. should be addressed in Phase 2)		Issues inherently intertwined. If Commission wants to rehash al of PURPA it may not be wise to do in two parts. If goal is to generally keep status quo and only modify a few elements some may be modified quickly, with some taking more time.	No comment at this time, reiterate non-utility stakeholder constraints.

No.	Question	AWEC	QF Trade Association	RNW &OSEIA
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?		Network upgrades that have system-wide benefits should be charged to all customers. (Discusses FERC precedent regarding non-independent Transmission providers incentive to discriminate.)	No comment at this time.
28	Please provide any additional comments or concerns that you would like to see addressed in this investigation.		Intend to identify issues at a later date.	No comments at this time.

No.	Question	Idaho Power	PacifiCorp	PGE
1	Please provide a high-level description of modeling used to set avoided cost prices, including: a. A description of variables included b. Modeling methodology including software used	For standard rates the modeling used to set avoided cost prices is a surrogate avoided resource model that assumes the utility avoided the cost of constructing a combined-cycle natural gas turbine For non-standard rates Incremental Cost Integrated Resource Plan ("ICIRP") modeling is used to set avoided cost prices	PacifiCorp has four rates, 2 standard, two non-standard, with separate rates for renewable and non-renewable QFs. The standard non-renewable rate is based on market prices in sufficiency years followed by CCCT costs in deficiency period. Standard renewable is based on market and a proxy resource. Nonstandard renewable pricing is based on standard pricing, with adjustments for FERC factors. Dispatch is with GRID model. Non-standard non-renewable is based on PacifiCorp's Partial Displacement Differential Revenue Requirement (PDDRR) methodology.	Standard rates based on energy value for sufficiency period, and fully allocated costs of proxy resource for deficiency period. Non-standard avoided costs not discussed.
2	Please explain the process that a QF goes through when requesting an energy sales agreement with a utility. For this process include the following information, and note any differences between applications for standard rates, standard contracts, or non-standard contracts. a. List any software programs that aid in the application process b. Provide a complete timeline, with breakdowns for each step of the process c. Provide a complete list of informational requirements from the QF d. Provide a list of data/information issues that could impede the contracting process	Process included in Idaho Power's Schedule 85 Cogeneration and Small Power Production Standard Contract Prices located at: https://www.idahopower.com/about-us/company-information/rates-and-regulatory/oregon-special-agreements/.	The process for QFs requesting an energy sales agreement—both standard and non-standard contracts—is laid out in Pacific Power's publicly filed Standard Avoided Cost Rates Procedure (formerly referred to as "Schedule 37") and Non-Standard Avoided Cost Rates Procedure (formerly referred to as "Schedule 38"). Pacific Power does not use a software program to aid in the application process. Two potential issues could impede process, interconnection arrangements, and multiple projects on the same property. Interconnection may not be achievable within QFs requested COD. Multiple projects on same property may not meet Oregon separation requirements.	Steps and timeline included in PGE's Schedules 201 and 202. Goggle maps used to verify no projects owned by applicant within 5 miles of proposed project. If information in IIR not complete/clear PGE contacts the seller to seek further clarification.

No.	Question	Idaho Power	PacifiCorp	PGE
3	Please describe the interconnection process that a QF is currently required to follow. With this description please note any differences between QFs and any other projects requesting interconnection and explain the rationale behind any such differences. a. List the point of contact in the utility. b. Provide a timeline that an interconnection request follows. Please include all relevant steps from submission request to actual connection. c. Provide a complete list of informational requirements from the QF. d. Provide a list of data/information issues that could impede the interconnection process. e. Provide a description if and/or how this process interacts with requesting an energy sales agreement.	Answer to d. 1. Proposed point of interconnection not clearly stated and/or located. 2. Single line diagram incorrect or missing data. 3. Transformer connection configuration and grounding incorrect. 4. Selected inverters not capable of meeting reactive power requirements. 5. Selected inverters are not IEEE 1547-2018 or UL 1741 SA compliant. 6. Supplied models not in WECC approved format. 7. Equipment changes during the study process. 8. Allowing time for "affected systems" to review the studies.	d. Data/information issues that can impede the interconnection process typically involve a lack of technical specifications of an interconnection request, i.e. insufficient one-line diagram or dynamic stability study model. Additionally, developers rarely have acquired solar panels at the time interconnection and facility specs change when they do get them, necessitating re-study.	Answer to d: (1) Application is missing information; (2) Inaccurate or conflicting information in different documents, i.e., application and one-line diagram conflict); (3) Inaccurate or insufficient location coordinates; (4) Applicant does not indicate up front if they are a QF or not. QF status dictates process and jurisdiction.
4	Please provide a list of any utility resources that could help inform QF developers as to locations that would benefit from, or face challenges to development.	Examination of the publicly available queue information from Idaho Power's OASIS website, request and examine previous study reports, and take part in the official pre-application process.	Reviewing interconnection studies posted on OASIS provides a snapshot of what requirements have been identified as necessary for granting service to that point. Small interconnection customers can also request a pre-application report, which provides an overview of the same high-level information on a non-binding basis.	(1) Pre-Application process as outlined in OAR 860-082-0020. (2) Upon request PGE will provide the following information regarding the interconnection queue: Project Queue Number; County the Project is in; Application Tier; Application Status; AC Nameplate Rating; Energy Source; Feeder; Substation; Application Complete Date. (3) Upon request PGE will provide redacted studies for specific feeders. (4) After formal Interconnection Application filed, PGE will have scoping call for the application, the Applicant is provided their standing in the queue, how many projects are in queue, the aggregate generation on the feeder, the daytime minimum load of the feeder, and the rating of feeder conductors. PGE's engineering team also discusses possible interconnection requirements with the Applicant.

No.	Question	Idaho Power	PacifiCorp	PGE
5	How do utilities treat QFs with storage currently for PURPA purposes? a. How is the capacity determined for such a project b. Would a renewable generator collocated with storage be eligible for renewable avoided cost pricing? Please explain.	No QFs with storage have been proposed. IPUC determined such projects would be eligible for rates and contracts in the same manner as their source of generation.	Cites Luz Development and Finance Corporation allowing battery as part of QF as long as energy source for battery is renewable. Capacity determination under review by FERC – Northwestern Corporation requested revocation of QF status for 80 MW wind projects that then incorporated storage on grounds facilities exceeded 80 MW total. Pricing should be based on timing of expected output. "Avoided cost pricing for QF that include battery storage is primarily dependent on the timing of expected output. To the extent the project output is predominantly from the underlying resource (wind, solar), rather than via the battery, it is appropriate for avoided cost pricing to primarily be based on the rates and methodology applicable to that underlying resource."	Eligibility for standard PPAs determined based upon nameplate of capacity of generators. QFs with storage receive pricing associated with the underlying generator. PGE would consider offering base load pricing if QF/storage combo could demonstrate baseload characteristics.
6	When can existing QF projects renew their QF contracts? Can a renewal occur prior to the expiration of the current contract? If so, how long before expiration of the current contract can a QF enter into a new contract?	Online QFs can seek replacement agreements at any time, will receive pricing from avoided costs updated closest to date of current contract expiration.	QF projects can request a new contract renewal up to 36 months before their existing contracts expire. They do not believe there is need for price certainty for existing QFs as there is with new projects. Would suggest pricing set no earlier than 6 months in advance of proposed effective dates.	Current rules allow projects to lock in avoided cost prices up to three years before commencement of energy deliveries. (Commission should examine rate impacts).

No.	Question	Idaho Power	PacifiCorp	PGE
7	Please explain transmission requirements for new QFs. Please explain any differences for existing versus new QFs related to transmission requirements.	A new proposed PURA QF must be designated a NR. After application for interconnection, the ensuing studies will identify potential system upgrades required for that project to interconnect to the utility's system and be designated as a network resource. A transmission service request must also be made by the utility's merchant of load serving operations on behalf of the QF's generation. If there is no available transmission capacity to accommodate the QF's generation to be designated as a network resource to serve load, then system impact and facility studies must be performed to identify any required network transmission related upgrades that may be required to accommodate the QF's generation. Depending upon the timing and sequencing of the QF's requests for interconnection as a network resource, and its request for a power sales agreement with the utility, it may be possible to study interconnection and transmission requirements simultaneously.	Generation interconnection requests proposing to interconnect to PacifiCorp's transmission system typically require some sort of modifications to PacifiCorp's transmission system, but the specifics and extent of those modifications are dictated by the specifics of the request.	There are no differences in transmission requirements for new versus existing QFs. Sellers developing off-system QFs must obtain sufficient long-term firm transmission rights from the Seller's project to a delivery point on PGE's system with sufficient capacity for the output to be received. Long-term firm transmission is necessary because the Seller must be able to reliably deliver the QF's output. Importantly, the avoided cost prices paid to QFs during the deficiency period include a capacity premium, which assumes that they will be able to deliver their output during the hours when they are generating. PGE relies on the QF's output to serve load even during periods of transmission constraints. If QFs do not have secure long-term firm transmission, customers will be paying for capacity that they cannot rely on. Finally, Sellers are kept whole for the transmission costs because PGE's avoided costs include the cost of one leg of long-term firm transmission on BPA's system. PGE obtains long-term firm point-to-point or network transmission service to deliver both on- and off-system QF output to its load, once the QF has delivered the output to PGE. However, QFs are responsible for any network upgrade or third-party transmission costs imposed by such delivery, if the costs are not accounted for in PGE's avoided cost rates.
8	How are QF contracts treated in long-term planning processes? Are the assumptions consistent for IRP planning as those used in other internal planning processes? Are existing QF contracts assumed to renew or not renew at the end of a contract? Please explain.	Signed QF contracts are included as must-run generators in resource stack. Generation projections based on 5-year rolling average. Forecast assumes all resource types request replacement contracts as seen historically, with the exception of wind which does not have an established track record.	QF contracts not assumed to renew in IRP. Internal planning assumes cogenerator QFs will renew, but not a significant impact on resource planning.	2016 IRP and IRP Update assumed 100% of QF contracts executed as of a specified date result in projects that enter PGE's portfolio as in executed contract. IRP analysis does not assume QF contracts are renewed after they expire. Order No. 18-405 covers treatment of QFs in NVPC filings.

No.	Question	Idaho Power	PacifiCorp	PGE
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.	No. Eliminate reliance on avoided CCCT. ICIRP better cost estimate, uses estimated hourly generation of proposed QF. - Better method to base on "transparent firm and non-firm electric market price index," based upon QF's ability to deliver on a firm, scheduled basis.	No. Should align standard pricing with what a utility would otherwise acquire. - Use PDDRR as is done for both standard and nonstandard AC in Utah. - In Utah: ---PAC files quarterly to identify changes to avoided cost inputs and methodologies; "routine updates" such as price and load forecasts take effect immediately for nonstandard pricing; "non-routine" updates take effect in three weeks if unchallenged, and if challenged, Commission considers what level of process is appropriate for specific circumstances --- All nonstandard contracts are preliminary and don't take effect until approved by Commission; Commission is "ultimate arbiter of customer indifference."	No. - Use RFP-based - May be other approaches; PGE "looks forward to exploring alternatives…" - "…PGE is planning to conduct regular RFPs in order to meet Oregon's steeply increasing RPS standards and to provide low cost energy in a cap and trade environment. PGE anticipates a 2-year procurement cadence which may provide regular market-based pricing updates." - Recent RFP $40.70 levelized; Solar QFs currently receive $45.19. - Current procurement provides high capacity value; adjusting the $40.70 for lower CTP is $36.83.
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.	n/a	Not opposed to separate streams, though renewable not required under PURPA. - The difference between renew and non-renewable should be consistent regardless of resource type - Propose method similar/same as in UM 2001; "Although PAC continues to have concerns with how the RPS compliance value is determined, the current result is a reasonable hedge against future RPA compliance costs." - Given PAC's current REC bank, incremental expenditures for RPS " will not be required for many years."	PGE recommends subtracting value of environmental attributes from renewable price to value nonrenewable.

No.	Question	Idaho Power	PacifiCorp	PGE
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?	Documents and methods are generally consistent. Some variations among utilities are necessary.	Current process works well, don't recommend any major changes. Same contracts might not work, but common contract structure could work. Not opposed to reporting inputs and outputs in a standard format.	Common contract forms could be helpful – but utilities do have different business practices. Models are already transparent – would listen to suggestions to make models easier to use. QFs will usually prefer standard contract versus negotiation.
12	Please provide any ideas related to generally improving the efficiency of the regulatory process associated with updating avoided cost prices.	New avoided costs effective upon filing subject to true-up process following Commission and stakeholder review.	Contested-case proceedings for resolution of PURPA-related issues.	Reference to RFP-based avoided cost modeling proposal.
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.	Optimal process for QF is to follow specific process outlined in each utility's schedule.	Current process does well in striking a fair balance.	More certainty that QF with executed contract will come online. Optimal process would ensure sufficient development activities had occurred prior to contract execution.
14	Please describe an optimal interconnection process for a QF requesting interconnection.	The QF would request a series of redacted studies in a particular area to analyze the possibility of interconnection in that area. The QF would then utilize the pre-application process to further analyze viability of availability in that area. Once the pre-application data is analyzed, the regular interconnection processes would be followed.	No response.	First, PGE would receive a complete application along with the application fee. Included with the application would be the supporting documentation such as electrical one-line diagram, site plan, specification sheets, proof of site control, telemetry design and FERC notice of self-certification. The information in the supporting documentation would accurately reflect the information contained within the interconnection application.

No.	Question	Idaho Power	PacifiCorp	PGE
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.	FERC would need to rule on QF eligibility for stand-alone or non-renewable energized storage. Use ICIRP method for piecing evaluation. Idaho Commission found that collocated storage eligible for rates associated with motive force.	Cite Luz Development and Finance Corporation allowing battery are part of QF as long as energy source for battery is renewable. Capacity determination under review by FERC – Northwestern Corporation requested revocation of QF status for 80 MW wind projects that then incorporated storage on grounds facilities exceeded 80 MW total. Pricing should be based on timing of expected output. "Avoided cost pricing for QF that include battery storage is primarily dependent on the timing of expected output. To the extent the project output is predominantly from the underlying resource (wind, solar), rather than via the battery, it is appropriate for avoided cost pricing to primarily be based on the rates and methodology applicable to that underlying resource."	PGE is just beginning to consider complexities associated with combined QF/storage projects. Pricing should consider value of projects provided to customers
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)	Existing projects should be treated line new projects. Some current terms and conditions may be carried over to new contract. Idaho Commission has determined if a QF project is being paid for capacity at end of current contract term, it is eligible for immediate payment of capacity in its new contract.	Existing process strikes a fair balance. From standpoint of development of avoided cost price, existing QFs should be treated no differently than new QFs. Company should have ability to insist on updated form of PPA.	Would be open to entering contracts up to 12 months prior to expiration of existing PPA. Existing QFs should receive the same pricing as new QFs since they are under no obligation to continue to provide output at expiration of current contract.
17	Should the existing dispute resolution process be continued? If not, how should it be changed?	Complaints are a normal, the best way to handle a volume of complaints is to move them to a final resolution, and through a due process proceeding.	The Company has not identified any issues in current dispute resolution process	Current processes are not used, current process do not have adequate timelines. The Commission should adopt processes that are efficient, fair, and adaptable to disputes.

No.	Question	Idaho Power	PacifiCorp	PGE
18	Please share your recommendations to reduce the volume of litigation regarding complaints.	Complaints are a normal, the best way to handle a volume of complaints is to move them to a final resolution, and through a due process proceeding.	No specific recommendations, clarity in Commission guidance could help limit complaints.	Institute an effective informal dispute resolution process and require that it be used prior to filing a formal complaint. Provide clear guidance in the policy docket. Continuously evaluate PURPA policies to ensure they remain up-to-date and to timely respond to policy changes (e.g., cap and trade) to ensure customer indifference is maintained. Answer questions and resolve disputes that arise promptly and comprehensively so that all parties benefit from Commission guidance on common issues.
19	What existing resources (educational, etc.) do you know of that could benefit the Commission and other stakeholders during or prior to the investigation?	Commission is only party that can properly answer that question – proceedings such as this are good to educate.	FERC's pending PURPA reform docket AD16-16. Other potentially useful educational resources are EEI/NARUC's 2014 PURPA Manual and NARUC's 2018 PURPA white paper.	Stakeholder comments filed in FERC Docket No. AD16-16 for Implementation Issues Under PURPA, and "Aligning PURPA with the Modern Energy Landscape" Whitepaper published in October 2018 by the National Association of Regulatory Utility Commissioners (NARUC).
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?	Commission is only party that can properly answer that question – proceedings such as this are good to educate.	No specific recommendations at this time.	Supports direction as included in questions. Investigating PURPA in phases will also help with regular, clear schedules for workshops, comments.
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)? a. If yes, how should the Commission determine eligibility and pricing for capacity payments?	No – current practice is appropriate. Resources acquired outside of the IRP process are due to low prices and are beneficial to customers. Additional QF capacity payments without corresponding low prices would harm customers.	Pacific Power is not aware of any utility practice of acquiring resources on an economic basis. The IRP identifies least-cost/least-risk combination of resources. Any determination of capacity payments should be done carefully and deliberately.	PGE proposes to maintain the current concept for determining sufficiency/deficiency. Combined with avoided cost pricing based on RFPs to be conducted every two years for the immediate future.

No.	Question	Idaho Power	PacifiCorp	PGE
22	When in the process of contracting should a legally enforceable obligation (LEO) be obtained?	In addition to the current requirements of the Commission regarding formation of a LEO, a QF should not be able to lock-in outdated and higher avoided cost rates pursuant to a LEO for longer than one year. Avoided cost rates update at least on an annual basis, and one year provides more than sufficient time for a QF to move into development of its facility after the LEO is established—the legally enforceable obligation that the QF will build a project and deliver generation.	When a QF can demonstrate that the utility failed to satisfy its obligations under PURPA, and the QF developer has otherwise demonstrated an unequivocal commitment to sell the QF output to the utility. A QF sponsor's "unequivocal commitment" cannot reasonably demonstrated through customary due diligence by the utility. For example, if a QF sponsor seeks to establish a fixed price long-term purchase obligation that is based on a commercial operation date in 2020, the electric utility has the ability to reasonably confirm through its customary due diligence that the QF can reasonably commence commercial operation on the represented date that informed the indicative avoided cost pricing.	The LEO has become a free option for developers, in that developers are able to establish a LEO early in the contracting process to lock in the most advantageous avoided cost pricing, without any real penalty for failing to follow through and develop the project. As a result, PGE is unable to adequately plan for QF resources coming online. For these reasons, PGE believes that the LEO should occur later in the contracting process. This concept of delaying the LEO until the QF establishes "viability" has been implemented in other states (e.g., Texas, New Mexico), and it has been validated by appellate courts.

No.	Question	Idaho Power	PacifiCorp	PGE
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.	First must get avoided cost price right. Secondly, enforcement of a LEO upon a QF; i.e., assuring that it lives up to its obligation to construct and deliver energy, is not a penalty, but is based upon damages. Rather than a traditional differential between market and contract price, a liquidated damages calculation could be set in the contract that would be applicable and forfeit if the project is not built, or not built on time. For example, the posting of delay damage security in the amount of $45 per kW of nameplate, which would be forfeit as liquidated damages for facility to bring the facility on-line by the scheduled commercial operation date.	No response.	PGE views the Standard contract as a 'free option'. Sellers need complete very little to no prior due diligence before submitting a PPA request. As previously shared, project locations are selected without factoring in deliverability constraints or interconnection costs, PPA milestones are provided without any permitting or construction timeline considerations, and project attributes are provided without selection of generation equipment. Furthermore, individual developers will submit multiple concurrent PPA requests, each under a newly created LLC, only some of which ever reach fruition. PGE recommends adding Performance Assurance criteria to help mitigate the 'free option'. PGE proposes Sellers pay Performance in the form of Cash or Letter of Credit as a condition of PPA execution, calculated based on the project's nameplate rating (in kW). If the PPA fails to achieve commercial operation and is terminated by the Buyer or if it is terminated by the Seller prior to commercial operation, Seller forfeits the Performance Assurance and the funds are provided to customers. This would encourage developers to execute PPAs for projects that have a high likelihood of reaching commercial operation. Additionally, this would discourage the submission of multiple PPA requests without sufficient development due diligence.
24	What is required for a QF project to receive financing?	Appropriate phrasing is, does PURPA require the Commission to promote the development of QFs through providing terms and conditions that result in favorable financing to build projects?	No response at this time.	Understands an executed PPA with fixed pricing of 15 years is sufficient, shorter time frames may be adequate as well.
25	Assuming a two-phase process, what issues do you believe could be fast-tracked within Phase 1?	A two-phase process should not be assumed. A definitive schedule should be set to conclude within one year. PURPA issues do not lend themselves to division in two phases.	No specific recommendations, but believes education on interconnection service process and agreements would be beneficial for Commission and stakeholders.	Avoided cost pricing methodology, Existing QF contract renewals, LEO Criteria and Performance Assurance
26	Assuming a two-phase process, what issues do you believe need additional time for analysis? (i.e. should be addressed in Phase 2)	A two-phase process should not be assumed. A definitive schedule should be set to conclude within one year. PURPA issues do not lend themselves to division in two phases.	No specific recommendations at this time.	Interconnection requirements, Standard Contract Cap, Treatment of Storage, Standard Contract among utilities

No.	Question	Idaho Power	PacifiCorp	PGE
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?	QFs must bear costs of NUs. Socializing these costs would be entirely improper and a direct violation of the requirement that customers not be harmed, and remain neutral to the PURPA transactions.	The OPUC's current method appropriately allocates cost to maintain customer indifference standard. [PAC's Response to Question No. 3:] The rules governing QF interconnections can be, and have always been expected to be, different than those governing federal interconnections. For example, with respect to cost allocation issues, FERC's 1980 PURPA regulations provide for a framework that is the opposite of (and was left unchanged by) FERC's landmark interconnection orders. More specifically, FERC's PURPA regulations note that the state has the authority to decide whether there should be a reimbursement mechanism associated with the QF's payment of its interconnection costs. Notably, however, the reimbursement mechanism would be from the QF to the utility (to the extent the utility pays for the costs upfront), not the other way around, as in the case of a FERC jurisdictional interconnection agreement where the generator pays its interconnection costs upfront, subject to later reimbursement by the utility (and ultimately the utility's retail customers).	Current policy is legally correct and must be maintained (citing Order No. 10-132).
28	Please provide any additional comments or concerns that you would like to see addressed in this investigation.		No specific recommendations at this time, additional process and workshops may be necessary.	Improvement in QF scheduling, integration charges for all variable resources, 5-mile rule strengthened, improve MAP, consider minimum delivery obligations, strengthen credit support requirements, determine prices for QFs that are not wind/solar but don't offer case load capacity, require increases in QF nameplate to be compensated at then-current avoided cost prices.

Appendix B
April 5, 2019 – Workshop Notes

From Exercise

Avoided Costs

- Process
    - Stability and Commission following its own rules
    - Out of cycle changes – visibility justification process rules reliability
    - LEO formation (interacts with contract process)
    - Timing - Update process
    - Ability to understand how non-standard prices are set
    - Avoided costs should be determined under its own process
    - Administratively determined inputs frequently stale
    - If actually avoidable? – Always avoidable? (Broader application)
    - Certainty in timing of Avoided Cost changes
    - Timing for price changes
    - How to capture in avoided costs procurements outside of action plan
    - Need for including PURPA goal of increasing use of renewable energy with other goals such as customer indifference
    - Calculated by Staff instead of utilities?
    - Difficulty of forecasting future resource costs
    - Resource deficiency date vs. inputs RPS
    - Introduce market competition
- Modeling /Methodology
    - Rebuilding methodology from ground up
    - Ability to update with market changes
    - Anomalies and outliers in average cost concept
    - Consideration of environmental and social benefits
    - Best Avoided Cost practice in IRP tools and models
    - Sufficiency Deficiency
        - Resource deficiency date – capacity
        - Define sufficiency and deficiency
    - Including transmission?
    - Firm vs non-firm eligibility
    - Avoided cost methodology (Changes to…)
    - Transparent comparison with cost treatment of utility's own assets
    - Need to account for effects of competition and market
    - Market-based avoided cost – cost of a resource utility can avoid vetted by competitive process
    - Market component
    - Accounting for resources acquired outside of IRP plan
    - Market index pricing
- Assumptions / Inputs
    - Apples to apples on inputs and PPA terms 15 year vs 40 year
    - Carbon compact
    - Cap and trade

    - Ability to challenge prices
    - Capacity (value of)
        - Project's capacity contribution
    - Verification of inputs
    - Account for rapidly decreasing technology costs
    - One REC, one price
- Technology (Assessing and Incorporation)
    - Storage
    - Battery pricing

Appendix B
April 5, 2019 – Workshop Notes

Contract

- Process Issues
  - Seller provided vs utility discretion
  - Timing for existing project to re-new contract (timeline to lock in prices)
  - Process Interactions with utilities email only vs actual need – 15 business days only
  - PPA contracting process – info requests by utilities
  - PPA drafting process – utilities only – no redlines
  - Lead time on
  - Time period for existing projects to "lock" avoided costs
  - Timing of standard PPA process (between 3-10 MW) 15 business days versus 30 business days
  - LEO issue – ability to form without utility action
  - Contract process takes too long
  - Arbitrary timelines in contracting process
  - Contract – No official(?) will answer phone or call
  - Contracting process – every issue and question, anything 15 business days or 30 business days
  - Treatment of contract renewals
  - Contract renewals – need a shorter timeframe for renewals given existing QF projects
  - Non-standard PPA (all aspects)
  - Contraction - No penalties for bad behavior by utilities
  - Post – communication problems
  - Time built into process for QF response
- Provisions
  - Need for "Performance Guarantee"
  - Need LEO tied to project viability – currently a free option
  - EIM – contract changes to standard PPA
  - Forecasting and scheduling provisions
  - Liquidated damages
  - Term number of years
  - Adjusting price during term
  - Resource types differences vs similarities
  - Changing standard terms over time – evolution
  - Definition of baseload
  - Interconnection impact on PPA compliance
  - Ability to change COD based on interconnection delays
  - Lender protection provisions – estoppels, notices, consent to assign (Fast track?)
  - Intra-hour
  - Changes in contract information requirements
  - Interconnection study requirements prior to contracting/LEO
  - Availability of long term contracts (e.g. schedule 202)
  - Ability to change QF size at the end of the interconnection process
  - Sufficient long-term firm transmission must be obtained to deliver power on utility system
  - With sufficient ATC

    - Need for concrete project info and future milestones during process
    - Finance
    - Treatment of battery
    - Ability to update standard contracts expeditiously
    - Upgrades and storage
    - Time before PPA starts for existing QFs
- Disputes
    - Contested case process
    - Fair decision made, access to court
    - Efficient and effective dispute resolution
    - Disputes – during – after
    - LEO
- Rates/Timing
    - Interaction of contract process with avoided cost changes
    - Load pocket generation surplus
    - Relationship of timing of avoided cost changes
    - Update of PPA tariffs and standard PPA processes and timing
- Other
    - One standard contract offer
    - Number of separate standard contracts
    - OPUC policies implemented differently

Appendix B
April 5, 2019 – Workshop Notes

Interconnection

- Utility-Developer Interaction
  - Better communication between developer and utility engineer
  - Studies – ability to: audit, self-perform, challenge, discuss
  - NR eligibility – Audit – Self perform
  - Interconnection – need customer right to self-perform studies, builds with quality vendors
  - Studies – ability to: audit, self-perform, challenge, discuss
  - Study – Inputs develop interconnection, right to have so can validate
  - Third party studies and construction
  - Access to previous studies
  - More transparency access to data
  - Additional transparency
  - Transparency – access to data – study data - regs
  - Analytics – history on how process is working
  - Data on study process – audit/analyze
  - Third party engineering firm allowed to review substance of interconnection report
  - Communication with engineers
  - Requirement that studies receive stamps
  - Timing of requests in relation to purchase contracts
  - Sources of utility cost assumptions
- Overall Process
  - No response obligation for utilities – silence!
  - Network upgrade costs as a means to burden QF interconnection
  - Who pays for network upgrades vs customer indifference education
  - Education on difference between interconnection and transmission
  - Requirement for back and forth on interconnection study report
  - Timing of advance payments, refunds for overpayments
  - Interconnection options fundamental options
  - Remedy if utility is short-staffed
  - Utility Staff for interconnection studies (why delay? Short staffed?)
  - Enough information to verify study results
  - Process – barriers in implementation
- Classification
  - Special QF process – NR resource
  - The requirement that QFs take NRIS
  - #1 NR requirements for QF PPA eligibility is garbage not consistent with variable resource $$$
  - Requirement to identify as QF (or not) at beginning of process
  - Inordinately high costs of network upgrades without sufficient technical justification
  - Prompt payments
  - Appropriate cost assignment for upgrades
- Other
  - AR 521 language – third party contractor reschedule
  - IOU RFPs use interconnection bid criteria to exclude RFP participation – ratepayers screwed

  - Interconnection queue issues deny ratepayers competitive options QFs RFP bidders
  - Transmission – utility claim conditional firm isn't long-term firm
  - Education
  - Real-time communication (SCADA) data
  - Data protection cyber/physical security issues
- Oversight
  - No consequences for utility bad behavior
  - Education difference between open access policies and PURPA policies
  - Utilities not making schedule – studies – tariff – builds
  - Conflicts between PPA and interconnection agreements
  - PPA and interconnection agreements interaction
  - Changes to PPA COD due to delays
  - Need more strict requirements for utilities to follow timelines.
  - Enforcement of existing rules
  - Utility penalties on utility for failure to complete interconnection
  - Publication of interconnection study requirements
  - Utilities need to comply with rules
  - Lack of effective dispute resolution
- Queue
  - Lack of movement by PAC in processing the IC queue
  - Keeping queue up to date
  - Education on serial queue order interconnection process requirements for QFs and non-QFs
  - Make load queue public (load vs generation effects) study outcomes
  - Education appropriate use of publicly available interconnection data
- Load Pockets
  - Exist? Load pockets
  - "Load pockets"
  - Queue and load pockets
  - Education on load pockets
  - Customer indifference in constrained areas
  - Responsibility to locate project
- State – federal guidelines
  - Entire QF-specific interconnection study construct is bogus (vs FERC OATT)
  - Comparison of current OATT tariff – policy different from federal mandate
  - What rules/guidelines apply to 10-20 MW projects?
  - Use of "QF interconnection process/rules" artificial barrier to evade PURPA
- Costs
  - No cost sharing
  - Cost allocation responsibility
  - Lack of refunds for network upgrades
  - Cost
  - Lower cost equipment alternatives
  - Cost – What – How much

- Other
    - Informal technical dispute advisory board of industry representatives like OJUA
    - Mini focused issue workshops
    - Option put all options on the table
    - Communication

Appendix B
April 5, 2019 – Workshop Notes

Planning:

- Online assumptions
    - QF renewal assumptions
    - Do not assume all QFs in the queue or requesting contracts will reach COD
    - Treatment of QF queue in IRP assumptions, need, avoided cost
    - QF success rate vs use/assumptions in IRP and avoided costs
    - Utility plans for QF coming online but PPAs do not provide binding provisions for them to actually do so
    - Batch/timeframe for QF application and contract execution
    - Realistic assumptions for QFs to come online
- IRP-Issues
    - Ability to challenge IRP
    - Timing mismatch in IRP and avoided costs
    - Long-term planning assumptions not developed for pricing assumptions
    - Stale data
    - QF ability to rely on process vs IRP vs Avoided Cost Updates/tying
    - Review and inputs from stakeholders on inputs to Avoided Costs
    - How sufficiency and deficiency dates are determined, IRP might not be accurate
    - Is the IRP the appropriate place to derive avoided cost inputs?
    - What is utility need, e.g. need = FOTs
    - Sufficiency/deficiency
    - Sufficiency/deficiency
- Process
    - Timing how IRP timeline fits into other processes
    - IRP-RFP
    - IRP is a planning document, not a binding document
    - Very little scrutiny outside of IRP action plan window
    - Inconsistent with actual plans/actions
    - Its tie to Avoided Cost pricing or not
    - Standard for avoided cost changes vs IRP process
- Other
    - PacifiCorp: merch. Priority
    - Distribution System Planning
    - Can IOUS reserve transmission capacity for themselves
    - Meaningful damage provisions
    - ATC at delivery points
    - Real-time capacity contribution values
    - Not reflected

Supplemental comments:

Idaho Power

No formal issues list needed, any party can raise any issue in its opening testimony. If there is an issues list – "generally defined, and broadly construed". Also – only a single phase of the case for a holistic review.

PacificCorp

Fast-track issues:

- Amendments to the dispute resolution process
- Determination that a LEO has been created
- Provision of data by utilities (confidentiality addressed in UM 2001)

Fast track would have three rounds of testimony, not five.

PGE

Supplemental response to question #28 requests Commission address:

- Contract provisions for carbon emissions/cap and trade costs.
- Contract provisions regarding damages if a renewable QF fails to deliver RECs.
- Contract provisions for real-time communications requirements for QFs.
- Changes to the existing 3 MW cap in OAR 860-082-0070 (interconnection requirements for metering and monitoring a small generator facility).
- Inconsistency between Order No. 15-130 stipulation and OAR 860-029-0120(6) (allowing utility to terminate standard agreements for failure to meet COD regardless of sufficiency position) and OAR 860-029-0130(4)(d) (prohibiting termination of negotiated agreements for failure to meet COD if the utility is resource sufficient).
- Interconnection rules - adoption of Institute of Electrical and Electronics Engineers (IEEE) 154 7-2018 standard (if it is not adopted as part of another docket).

Fast-track items:

- Performance assurance criteria – desire for more certainty in QFs coming online. Cash or letter of credit at contract execution as well as damage provisions for failure to meet milestones would increase certainty.
- Contract renewals for existing facilities – PGE uncertain that Commission has decided this.
- Update to standard contracts – need an established process for timely updates to standard contracts.

Need a prompt review (not fast-track) of aligning avoided costs and market prices.

QF Trade Association

In addition to four categories presented at workshop calls for 'transmission' to be added as fifth category, and emphasize process throughout all categories.

Fast-track items

Capacity value of existing QFs – call for capacity payments of some form for contract renewals. Cite UM 1610 - utilities directed to address this in their IRPs, PacifiCorp then assumed no QFs would renew. Issue has been discussed since at least 2014 – ripe for a decision.

Interconnection – resolving this has a high potential to reduce disputes. Recognize industry has changed since AR 521, process are outdate. Community solar will likely use similar interconnection process – industry will get 'most bang for buck' by addressing this now

- QFs may retain third party contractors to perform studies, and construct interconnection facilities
- Improve transparency, communications, access to studies and underlying data
- Prompt resolution of disputes
- Have enforceable timelines
- Consideration of interconnection options (routes, transmission or distribution)
- Allow alternative means of meeting functional requirements
- Provide remedies for utility violations of rules (offsetting extensions)
- Ensure appropriate requirements (no gold-platting)
- Provide appropriate cost sharing
- Address network resource interconnection service requirement for QFs wo eligibility for refunds for network upgrades

Contracting issues

- Clarify standard contract negotiation process
- Provide certainty to QFs in contracting queue when avoided cost updates are filed
- Better contracting process for non-standard negotiations
- Expedited dispute resolution

Key data gathering for remainder of docket

- Utility avoided costs
- QF PPA contracting process
- Interconnection process

Storage should be addressed both in combination with other resources, and on a stand-alone basis. Categories to cover include avoided cost prices, eligibility, and interconnection issues.

PacifiCorp's artificially low rates should be addressed.

Additional issues:

Process improvements in updating standard contracts and tariffs. This is for minor changes, not significant policy changes.

Address interconnection O&M reimbursements for QF allocated costs.

Establish alternative term length provisions

Address non-standard PPA forms agreements and settlements agreements being considered confidential.

What changes to the facility would constitute a material change requiring re-starting the negotiations, and what upgrades are allowable.

RNW

Optimal process for a QF would be transparent and predictable. Timelines would be public and reasonable, with any changes approved by the Commission. QFs should not be unreasonably penalized for non-substantive errors in their applications.

Optimal interconnection process would require initial information available to QFs prior to interconnection application. Would also provide predictability in timelines.

Fast-track items related to transparency in interconnection and contracting processes. Also prioritize storage and issues of cost allocation.

QFs should not have to bear full costs of network upgrades that are used by others.