PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 29, 2019

VIA ELECTRONIC MAIL

To: Parties in Dockets UM 2000

Re: Docket UM 2000 Stakeholder Questions

As requested by Staff of the Public Utility Commission of Oregon (Commission), PacifiCorp d/b/a Pacific Power respectfully provides these answers to questions presented to stakeholders in Staff's March 15, 2019 email. Pacific Power understands that stakeholder responses to these questions will be used by Staff to develop the scope of the Commission's investigation in its implementation of the Public Utilities Regulatory Policy Act of 1978 (PURPA) and to facilitate stakeholder discussion at the upcoming April 5, 2019 workshop.

Staff presented two sets of questions to stakeholders; Set A is directed at the utilities and Set B is directed at all stakeholders, including utilities. Staff's questions and Pacific Power's responses are set forth below.

To the extent that PacifiCorp does not provide a response to a question at this time, PacifiCorp reserves the right to respond at a later time or respond to positions presented by stakeholders.

Set A

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**

Pacific Power offers four avoided cost price streams under four different methodologies, summarized in the table below:

	Standard Non-renewable	**Standard Renewable**	**Non-standard Non-renewable**	**Non-standard Renewable**
Methodology	Proxy	Renewable Proxy	PDDRR	Renewable Proxy w/ adjustments
Sufficiency Period	Blended Market	Blended Market	GRID redispatch	Blended Market w/ adjustments
Deficiency Period	CCCT fixed and variable costs	Proxy renewable costs, plus SCCT capacity adjustment	Thermal displacement, net GRID redispatch	Proxy Renewable + SCCT w/ adjustments
RECs	QF	Company (deficiency only)	QF	Company (deficiency only)

Standard non-renewable avoided costs during the sufficiency period are based on heavy load and light load market prices from PacifiCorp's official forward price curve, and are not further differentiated by time of day. The market price is a blend of Mid-Columbia, COB, and Palo Verde, reflecting the relative market impacts of an incremental resource in Oregon, as calculated within the Generation and Regulation Initiative Decision (GRID) model.

Standard non-renewable avoided costs during the deficiency period are based on the costs of a combined cycle combustion turbine (CCCT) proxy. Energy values, based on market gas prices and the proxy unit's heat rate, variable operation and maintenance (O&M), and capitalized energy costs reflecting the incremental capital cost of the CCCT proxy, relative to a simple cycle combustion turbine (SCCT) proxy. Energy values are differentiated by resource type. Capacity values are based on the SCCT proxy, representing the remainder of the CCCT proxy capital cost, and are adjusted to reflect the capacity contribution of each resource type. Market gas prices are derived from PacifiCorp's official forward price curve. Resource costs and characteristics are derived from PacifiCorp's most recently acknowledged integrated resource plan (IRP).

Standard renewable avoided costs during the renewable sufficiency period are the same as standard non-renewable avoided costs, and the qualifying facility (QF) retains the renewable energy credits (RECs) they generate. During the deficiency period, standard renewable avoided costs are based on the real-levelized cost per megawatt-hour of a renewable proxy, with an adjustment for differences in capacity contribution for each resource type based on the cost of a SCCT. Resource costs and characteristics are derived from PacifiCorp's most recently acknowledged IRP. During the renewable deficiency period, when avoided costs are based on a renewable proxy, PacifiCorp retains the RECs generated by the QF.

Non-standard renewable avoided costs are based on standard avoided costs, with adjustments for dispatchability, reliability, fossil fuel risk, line losses, and transmission and distribution (T&D) savings, relative to the sufficiency period proxy (market purchases) or deficiency period proxy (a renewable resource and a SCCT for incremental capacity). Dispatchability and reliability adjustments are calculated using the GRID model.

Non-standard non-renewable avoided costs are based on PacifiCorp's Partial Displacement Differential Revenue Requirement (PDDRR) methodology. The company populates a GRID model scenario with the most recent preferred portfolio from a filed IRP or IRP Update, as well as the most recent official forward price curve, loads, signed contracts, and other inputs. The capacity contributed by each signed contract partially displaces resources from the preferred portfolio, as does capacity contributed by prior QF requests. When the QF being evaluated is added, it partially displaces front office transactions from the preferred portfolio, followed by the next thermal resource. The effect is that, while the QF is compensated for the fixed costs of the resources it displaces, it must also compensate for the energy value provided by that resource. For instance, a CCCT would be economically dispatched, so when it generates it is earning a margin by displacing higher cost alternatives. Similarly, in intervals when it is cycled offline due to economics, the avoided costs are less than its operating costs.

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**

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.

A non-exhaustive list of the typical information requirements necessary to receive indicative avoided cost pricing are provided in Pacific Power's publicly-filed Standard Avoided Cost Rates Procedure and Non-Standard Avoided Cost Rates Procedure. Both procedures make clear that the stated list of information requirements is the minimum and can be expanded upon by the company, depending on the unique aspects of any particular project.

It is important to differentiate how the company uses and relies on project information provided by the QF developer. For purposes of preparing an indicative avoided cost price at the request of a QF developer evaluating a potential non-standard QF project, the company will rely on the simple representations of the QF developer. [Part B.1 of the Non-Standard Avoided Cost Rates Procedure] However, if after receiving the indicative pricing the QF developer requests to enter into an energy sales agreement, the company will then perform customary commercial due diligence to confirm that the proposed non-standard QF project can be developed consistent with the assumptions provided by the QF developer that informed the indicative avoided cost pricing. Non-standard contract negotiations will not commence until the QF developer has provided the Company for review documentation that supports the original representations made by the developer that informed the indicative avoided cost pricing. [Part B.3 & B.4 of the Non-Standard Avoided Cost Rates Procedure]

This same confirmatory due diligence review is performed for proposed <u>standard</u> QF projects as well, before entering into a standard form of energy sales agreement. [Part I.B.2 & I.B.3 of the Standard Avoided Cost Rates Procedure]

Pacific Power identified two potential data/information issues that could impede the contracting process. First, confirming the interconnection arrangements and expected schedule through the company's due diligence review has become a frequent obstacle to QF contracting. Specifically, the company will request from the QF developer copies of all interconnection studies available to confirm that the contents of such studies reasonably align with the developer's representations, as those representations informed the development of the indicative avoided cost price.

Frequently, a review of the interconnection studies provided to the company will reveal that the interconnection provider deems the QF developer's requested commercial operation date unachievable. Often times, the non-alignment between the QF's requested commercial operation date and the estimated commercial operation date in the interconnection studies can be several years. Consistent with the provisions of the standard and non-standard avoided cost rate procedures discussed above, in such circumstances where confirmatory due diligence does not support the assumptions provided by the QF developer when requesting indicative avoided cost pricing, the company will not execute a standard QF PPA and will not commence negotiation of a non-standard QF PPA.

Second, developers may locate multiple projects on the same property. When this occurs, developers occasionally submit multiple projects for requests for contracts or indicative prices. A delay can occur if the developer has not submitted documentation of project separation and ownership to meet Oregon rules.

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.**

Please see Attachment A, which is a flow chart of the typical generation interconnection process. Please note that this flow chart was created by the Federal Energy Regulatory Commission (FERC) in association with FERC's standard Large Generator Interconnection Procedures. Although specific generation interconnection request processes can vary based on specifics of the proposed request such as size, this flow chart is generally representative of the process the majority of generation interconnection requests follow.

Due to the number of variables associated with potential generation interconnection requests it is not possible to provide a complete list of the informational requirements for a QF seeking to interconnect to Pacific Power's system, however please see Attachments B, C, and D that are representative of the information required by Pacific Power to process generation interconnection requests. The attachments include Oregon's Application for Small Generating Facility Interconnection, Oregon's application for an Interconnection Request for a QF Large Generating Facility and PacifiCorp's Technical Data Checklist for Generation Interconnection Projects.

Data/information issues that can impede the interconnection process typically involve a lack of technical specifications of an interconnection request. Most commonly this includes an insufficient one-line diagram or dynamic stability study model. Additionally, in Pacific Power's experience, developers almost never purchase their solar panels/inverters or wind turbines at the time the interconnection request is studied by Pacific Power. As a result, Pacific Power frequently is required to go back and perform restudies far into the process once developers actually purchase their generation infrastructure because it is different than what was submitted initially.

Generally speaking the two most significant differences between FERC-jurisdictional interconnection service and state-jurisdictional interconnection service relate to interconnection service type and network upgrade cost allocation. FERC-jurisdictional interconnection customers: (1) fund the cost of the network upgrades necessary to grant their interconnection request upfront, subject to later refund (although refunds are not provided in all cases by all utilities across the country); and (2) can choose either energy resource interconnection service or network resource interconnection service[1]—a choice FERC developed on the express assumptions that the same entity would be arranging both interconnection service and the separate transmission service for a single generator, and that the entity would be engaging in *competitively* priced wholesale power sales.

Neither of these factors are present where a QF is making a retail sale of 100 percent of its power to the directly interconnected utility under PURPA because: (1) the QF is the interconnection customer and the utility's merchant function is the transmission service customer; and (2) the utility is subject to a federal mandatory purchase obligation at administratively determined prices—*i.e.*, the entity is not engaged in a *competitively* priced wholesale power sale. Under those circumstances, FERC has expressly and repeatedly found that its landmark Order No. 2003 (large) and Order No. 2006 (small) interconnection rules (including the choice between two service types and the network upgrade cost allocation structure) do not apply. FERC has stated, for example that "a QF selling at retail is ***not eligible*** to interconnect under either Order No. 2003 or Order No. 2006. Under the Public Utility Regulatory Policies Act of 1978, such interconnections are governed by state law."[2]

Rather, the controlling federal framework for state-jurisdictional interconnections is provided by FERC's PURPA regulations enacted in 1980 and unchanged by any of FERC's landmark open access orders, including Order No. 2003 issued in 2003 or Order No. 2006 issued in 2005. Indeed, as described by FERC, a state-jurisdictional interconnection is one that the utility must make under the section of FERC's PURPA regulations that includes a provision on a utility's obligation to interconnect with a QF (*i.e.*, 18 C.F.R. § 292.303):

[1] FERC-jurisdictional interconnecting generators that choose network resource interconnection service switch to the large generator interconnection procedures and agreement.
[2] Order No. 2006 at P 102 (citing Order No. 2003 at PP 813-14) (emphasis added).

> The Commission has regulations that govern a QF's interconnection with most electric utilities in the United States, including normally non-jurisdictional utilities. ***When an electric utility is required to interconnect under section 292.303 of the Commission's regulations***, that is, when it purchases the QF's total output, the state has authority over the interconnection and the allocation of interconnection costs.[3]

As a result, 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).[4]

And at their core, the Oregon requirements that a QF secure NR interconnection service and pay for the cost of its interconnection without reimbursement by the utility's retail customers are supported by PURPA's customer indifference requirement and FERC's requirements that QFs must be delivered on firm transmission and cannot be economically dispatched or curtailed outside of system emergencies. These core rationales are discussed at length by: (1) the Utah state commission in the attached order evaluating QF interconnection service type and cost allocation issues, attached here as Attachment E; and (2) the company on pages 6-20 of PacifiCorp's comments filed with FERC in the Blue Marmots proceeding, attached here as Attachment F.

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.**

   PacifiCorp assumes this question is referring to interconnection locations. Assuming that clarification, reviewing interconnection studies posted on OASIS provides a snapshot of whether and to what extent other entities have requested interconnection service in a particular area and, if so, 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.

[3] Order No. 2006 at P 516.

[4] 18 C.F.R. § 292.306(b). *See also* Order No. 69 at 89 (responding to comments seeking clarification on "the manner in which electric utilities would be reimbursed" by explaining that it is best left to the states to decide whether a QF should pay for its interconnection in an upfront lump sum or amortized over some period of time).

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.

There is limited state or federal guidance on the treatment of QFs that incorporate battery storage into their projects. The company is just beginning to see more QF developers proposing to co-locate battery storage with what would otherwise be a "typical" QF project qualifying as a "small power production facility" under FERC's rules implementing PURPA.[5] The only FERC case addressing battery storage in the context of PURPA is a 1990 decision titled *Luz Development and Finance Corporation*.[6] In this 1990 decision, FERC states that a battery resource can be part of a QF facility, provided the primary energy source for the battery is a QF-eligible renewable energy resource. The Commission has not provided guidance on this topic, including how avoided cost pricing would be developed for such potential "battery+renewable" QF projects.

Similarly, there is no state or federal guidance on how to determine the capacity of a QF+storage project. This topic is the subject of a request for declaratory order from FERC. Specifically, Northwestern Corporation filed a motion for revocation of qualifying facility status for four proposed Montana QF projects that each propose to integrate battery storage into what are otherwise proposed 80 MW wind small power production facility QFs.[7] When the capacity of the batteries are added to the capacity of the wind turbines, the total capacity exceeds the maximum 80 MW limit for projects qualifying as "small power production facility" QFs under PURPA. A decision from FERC in this proceeding remains pending, and Pacific Power has intervened in the proceeding and filed comments supportive of Northwestern Corporation's position.[8] Ultimately, while eligibility for standard rates for resources above 100 kW is determined by this Commission, the eligibility of all QFs is determined by FERC.

Under the currently approved avoided cost pricing methodologies discussed in item 1, PacifiCorp would account for the capacity contribution and avoided costs of QF+storage projects as follows:

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. Under standard rates, storage would allow a QF to deliver more output during higher-priced on-peak periods. Besides differences in timing already reflected in the standard rates, no special adjustments are necessary. Non-standard renewable rates are calculated using adjustments from standard renewable rates and would incorporate changes in the timing of expected output resulting from storage dispatch.

---

[5] *See* 18 CFR 292.203(a) & 292.204.
[6] *See Luz Development and Finance Corporation*, FERC Docket QF90-3 (Order issued April 26, 1990).
[7] *See Northwestern Corporation*, FERC Docket EL18-195, QF17-672 (Beaver Creek I, LLC), QF17-673 (Beaver Creek II, LLC), QF17-674 (Beaver Creek III, LLC), and QF17-675 (Beaver Creek IV, LLC).
[8] *See* PacifiCorp's Motion to Intervene Out-Of-Time and Comments in Support in FERC Docket EL18-195 (filed March 14, 2019).

Non-standard non-renewable rates are calculated using the PDDRR Methodology. Because the capacity contribution of renewables combined with storage varies significantly from what was identified for stand-alone resources in the IRP, capacity contribution values specific to the project's proposed output are calculated using the methodology and inputs from the IRP capacity contribution analysis. This capacity contribution is used to partially displace the next applicable proxy resource from the current preferred portfolio. The timing of expected output resulting from storage dispatch is also captured under the PDDRR Methodology.

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?**

Consistent with prior Commission guidance,[9] the company has allowed QF projects to request a new contract renewal up to 36 months before their existing contract expires. However, the company respectfully contends that it is unnecessary and inappropriate to set the avoided cost for an existing QF resource up to 36 months in advance. A QF seeking to renew their contract is not seeking to attract project financing, a primary rationale for allowing *new* QFs to have avoided cost pricing established years in advance of the online date. Setting avoided cost pricing for *new* QFs years in advance is a policy determination that sought a balance between two Commission objectives: ensuring accurate "avoided cost" pricing (consistent with FERC's "customer indifference" principle) and encouraging the development of a diverse mix of renewable resources. Once the QF project is operating, there should no longer be a need for this Commission to sacrifice customer indifference principles. The accuracy of the fixed avoided cost price should be paramount. Accordingly, the company recommends that in the case of a QF PPA renewal, the avoided cost pricing should be set no earlier than six (6) months in advance of the proposed effective date of the new contract.

The company recommends the renewal process be initiated no later than six to nine months before the expiration with the target of having the new contract executed three months before the end of the existing contract to ensure the new contract requirements are met by the QF and there is adequate time to complete any due diligence, drafting, or negotiating. In addition, the company's merchant function requires a minimum three months to have the network transmission arrangements completed with the company's transmission function in accordance with the OATT. Projects that have a pre-2000 vintage contract may need additional time beyond the six to nine months to ensure the interconnection requirements are up-to-date and a new interconnection agreement executed.

7. **Please explain transmission requirements for new QFs. Please explain any differences for existing versus new QFs related to transmission requirements.**

PacifiCorp assumes this question's reference to "transmission requirements" is intended to mean the modifications to the transmission system as a result of a QF's request for interconnection service. Generation interconnection requests proposing to interconnect to PacifiCorp's transmission system typically require some sort of modifications to PacifiCorp's transmission

[9] OPUC Order 15-130, dated April 16, 2015 (the "Phase II Order"), in Docket No. UM 1610.

system to allow interconnection. However, the specifics and extent of those modifications are dictated by the specifics of the request. Variables such as location, existing generation, higher priority generation interconnection requests and existing system conditions all influence requirements necessary to allow a new generation interconnection request to safely and reliably interconnect to PacifiCorp's system. Similarly, requirements for generation interconnection requests on PacifiCorp's distribution system are also influenced by these same variables and even very small projects can require modifications to PacifiCorp's transmission system.

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.**

Within the IRP, QF contracts are not assumed to renew at the end of their contract terms. For internal planning purposes, where QF output is linked to a customer load, for instance cogeneration at an industrial facility, that output is assumed to continue for the duration of the load. Since this is typically non-firm, it does not have a significant impact on resource planning.

Set B

1. **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.**

Standard pricing methodology should be updated in a way that aligns avoided cost prices with what a utility would otherwise acquire, which may reflect electricity market prices, renewable resource costs, or traditional thermal resources. This alignment is consistent with the customer indifference standard and ensures that customers do not pay more than avoided cost for QFs. Pacific Power recommends that the standard pricing methodology be modified to Pacific Power's PDDRR methodology and calculations within the GRID model, with like-for-like deferral of renewable resources from the preferred portfolio in the most recently filed IRP or IRP update, as currently employed for standard and non-standard rates in Utah.[10] A detailed methodology based on a generic resource of a given type achieves a more accurate avoided cost for small QFs. PacifiCorp currently provides public inputs, assumptions, and results upon request and as part of its filings, and provides confidential information subject to non-disclosure agreements.

[10] Approved 6/27/2018 in Utah docket 18-035-T02. Available online: https://psc.utah.gov/2018/04/06/docket-no-18-035-t02/.

The current standard avoided cost rates in Utah took effect in July 2018 and are based on deferral of proxy resources in the 2017 IRP Update preferred portfolio. The current standard avoided costs include partial displacement differentiated by resource type as follows:

- Solar: displacement of the 2030 Yakima solar resource from the 2017 IRP Update preferred portfolio. PacifiCorp retains the RECs generated starting in 2030.
- Wind: displacement of the Energy Vision 2020 new wind resource in Wyoming in 2020 and Aeolus-Bridger/Anticline transmission upgrade from the 2017 IRP Update. PacifiCorp retains the RECs generated starting in Nov. 2020.
- Baseload: Since the 2017 IRP Update preferred portfolio does not include any thermal resources, the avoided costs for a baseload QF reflect displacement of Front Office Transactions (FOTs) throughout the study term. The QF retains the RECs generated throughout its contract.

In Utah, the company makes a quarterly filing identifying changes to avoided cost inputs and methodologies. Routine updates, such as price or load forecasts, take effect immediately in the determination of non-standard avoided costs. Non-routine updates must first be filed and unchallenged for three weeks before being incorporated in the determination of non-standard avoided costs. Any party may challenge any modeling assumption at any time, and the Utah Commission considers what level of process is appropriate in the specific circumstance. Standard rates are calculated using the same methodology applied to non-standard resources at the time they are prepared, and are updated annually or when warranted by significant changes.

Once a methodology is established, the Utah implementation of avoided costs calculations allows for incremental changes with only as much process as is strictly necessary, and can help limit the scope when disputes do arise. Furthermore, all non-standard QF contracts in Utah are preliminary and do not take effect until approved by the Utah Commission, the approved methodology notwithstanding, such that the Commission is the ultimate arbiter of customer indifference. Given the scale of the commitment embodied by a purchase of up to fifteen years and 80 megawatts of capacity, this level of oversight and regulatory process is quite reasonable, and more in line with that applied to resources acquired through traditional means.

2. **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.**

Pacific Power is not opposed to offering separate non-renewable and renewable price streams to the extent they are both consistent with customer indifference, but would note that if there are concerns about methodology, or results, or maintaining customer indifference, a renewable price stream is not required for PURPA compliance. Because Oregon's Renewable Portfolio Standard (RPS) compliance involves annual obligations with multi-year banking, it is unlike avoided energy and capacity which must be balanced at each and every interval. The result is that bundled renewable energy certificates (RECs) generated in a given year (or potentially over several years) are equivalent, regardless of resource type. Therefore, the customer indifference standard dictates that the difference between the non-renewable and renewable pricing be identical, regardless of resource type. This is also true regardless of whether RPS compliance is driven by resources that provide RECs or changes in load (*i.e.*, energy efficiency).

The difference between renewable and non-renewable price streams should be based on the value of RPS compliance which, in the case of avoided costs, acts as a proxy for the value of the REC. PacifiCorp currently provides a value of RPS compliance as part of its RPS compliance reporting and, in PacifiCorp's most recent report, the compliance value is $1.92/MWh (2017$).[11] This is also consistent with the Commission's use of the RPS compliance value in PacifiCorp's resource value of solar values. Although PacifiCorp continues to have concerns with how the RPS compliance value is determined, the current result is a reasonable hedge against future RPS compliance costs. Note that due to PacifiCorp's current bank of RECs, incremental expenditures for RPS compliance will not be required for many years. PacifiCorp would also note that several renewable resources being added to its portfolio were cost-effective without considering RPS compliance value.

Since RPS compliance values are independent of the energy and capacity provided by QFs, avoided costs could be updated independent of RPS compliance costs.

3. **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?**

The current contracting process works well and PacifiCorp does not recommend major changes, including the creation of standard PPAs. The standardized approach suggested by the question would potentially require each utility to compromise its risk management and contract administrative functions through the collaboration with other utilities, as well as, presumably, other stakeholders in this proceeding. That said, the company does see a benefit in having a common contract structure across the utilities (*e.g.*, as outlined in a table of contents) so that a QF developer would have a common road map for QF contracts in Oregon.

PacifiCorp is not opposed to reporting inputs and outputs in a standard format, and would note that the RVOS template should contain most if not all of the necessary categories, though adjustments to inputs are likely to be necessary. It is likely that additional models will be necessary to develop appropriate inputs to the spreadsheet model.

---

[11] Approved September 11, 2018 in Docket No. UM 1959 pursuant to Order 18-337. Available online: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=21434.

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

PacifiCorp encourages contested case proceedings for resolution of PURPA-related issues as contested case proceedings are more likely to provide well-informed, concrete determinations that flexibly account for new information while retaining past determinations. Similarly, contested case proceedings are appropriate for the fact-specific inquires that are often necessary to resolve QF issues. This is comparable to the process used in the Transition Adjustment Mechanism, and is closer to the process used in a rate case when evaluating resource acquisitions.

5. **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.**

Generally speaking, the existing process—under which QFs and the utilities proceed under a defined process set forth in a utility's approved and posted procedure—does well in striking the balance between ensuring a utility is proceeding in good faith in complying with its "must purchase" obligation under PURPA and allowing the utility to perform customary due diligence to ensure PURPA's customer indifference principles are satisfied.

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

PacifiCorp has not identified any aspects of the current Oregon interconnection process that require changes. PacifiCorp is currently experiencing challenges in its broader interconnection study process for *all* generators (QFs and non-QFs) arising from its receipt of an unprecedented number of requests for interconnection service—numbers that far outstrip load levels. However, those interconnection process challenges are the result of the congested interconnection queue, not the Oregon interconnection rules and, therefore, PacifiCorp maintains that Oregon's interconnection rules are adequate.

7. **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.**

Please see the response to Question 5 above.

8. **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)**

Please refer to the company's response to Question 6 above.

From the standpoint of development of the avoided cost price, existing QF resources seeking to renew their contract should be treated no different than a new QF seeking a contract. From the standpoint of contracting, the company should have the ability to insist upon an updated form of PPA that reflects the specific circumstances for that resource. Updating the form of contract can be particularly important when the QF resource subject to renewal was previously operating under a form of PPA that is no longer reflective of current commercial contracting precedent or utility operations.

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

The company has not identified specific concerns with the existing dispute resolution process provided in its Standard Avoided Cost Rates Procedure or its Non-Standard Avoided Cost Rates Procedure.

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

PacifiCorp has not identified any specific recommendations to reduce litigation. However, clarity in Commission guidance and each utility's associated implementing procedures could help to limit the volume of litigation and complaints.

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

The company refers the Commission to 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. Although the company recommends these documents for educational purposes, the company does not necessarily support all positions expressed in these materials.

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

    The company does not have any specific recommendations at this time.

13. **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?**

Pacific Power is not aware of any utility practice of acquiring resources on an economic basis. PacifiCorp's IRP identifies the least-cost/least-risk combination of resources to meet load over a 20-year study period. The presence of front office transactions at the start of the study period shows there is not enough owned or contracted resources to meet load requirements. Given the time-sensitive nature of credits such as the production-tax credits, nearer-term acquisitions of resources can be a more cost-effective option but does not equate to acquisition of a resource divorced from need.

The time-sensitive resource acquisition is neither new, nor unique, except perhaps in its prominence. For many years, energy efficiency programs have presented comparable results, as acquisitions foregone in the beginning of the study period cannot be recaptured later.

With regard to the determination of capacity payments, Pacific Power recommends that it be conducted carefully and deliberately. The ideal outcome occurs during RFP evaluation, as the methodologies and models developed in the IRP are populated with real-world opportunities. While this cannot occur for every QF request, studies demonstrating the portfolio changes resulting from near-term QF resource additions would provide more concrete information than continued discussions about "time-sensitive" and "cost-effective" resources. This may be useful in a docket evaluating QF pricing methodologies. PacifiCorp believes the PDDRR method best captures the nuances of a more detailed study with a transparent and streamlined approach.

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

Oregon's existing rule for formation of a LEO for PURPA contracting is appropriate and consistent with FERC guidance.[12] Establishing the LEO through a written contract, except in extraordinary circumstances, is consistent with FERC requirements. As FERC has stated, "[I]f the electric utility refuses to sign a contract, the QF may seek state regulatory authority assistance to enforce the PURPA-imposed obligation on the electric utility to purchase from the QF, and a non-contractual, but still legally enforceable, obligation will be created pursuant to the state's implementation of PURPA."[13] Therefore, a written contract should, absent an extraordinary circumstance where a utility refuses to sign a contract, be the method for establishing a LEO. Contracts are important because they set the terms of the relationship between the parties; not just price. A written contract sets forth, among many other items, invoicing terms, events of default, remedies for default, operational requirements, and financial assurances of performance.

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, the state regulatory commission is to determine whether, and if applicable when, the LEO is established. Only in those situations where the utility refuses or fails to timely execute a contract (which can be determined through the prescribed contracting procedure already in place for Oregon utilities) should a LEO be established through a non-contractual means—and only then when the QF developer has been able to reasonably demonstrate an unequivocal commitment to sell its output to the utility. A QF sponsor's "unequivocal commitment" cannot be established by the naked representations of a QF sponsor alone, but must be reasonably demonstrated through customary due diligence by the utility. For example, if a QF sponsor

[12] *See* Part III.G. of OPUC Order 16-174, entered May 13, 2016, in Docket UM 1610. Codified at OAR 860-029-0010(37).
[13] *Cedar Creek Wind, LLC*, 137 FERC ¶ 61,006, P 32 (2011) (footnote omitted).

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.

15. **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.**

PacifiCorp does not have a specific recommendation at this time.

16. **What is required for a QF project to receive financing?**

PacifiCorp does not offer a response to this question at this time.

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

PacifiCorp does not have specific recommendations regarding the two-phase process, but believes that ongoing education and opportunities to review the complex jurisdictional federal and state frameworks for the interconnection service processes and agreements would be beneficial for the Commission and all stakeholders.

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

PacifiCorp does not have specific recommendations at this time.

19. **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?**

The Oregon interconnection rules appropriately maintain PURPA's customer indifference requirement by allocating the cost of the interconnection to the QF (unless, with respect to large interconnection customers, the QF can establish quantifiable system-wide benefits of the upgrade). Changing this cost allocation approach in a manner that shifts costs away from the QF will undoubtedly shift costs to retail customers in contravention of PURPA's customer indifference requirement and FERC's PURPA regulations. Please see PacifiCorp's response to question 3 (and the cited materials) above for additional detail on this issue.

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

PacifiCorp does not have specific comments or concerns at this time, but suggests that additional stakeholder processes and workshops may be necessary to better understand the complex issues in this investigation.

PacifiCorp appreciates the opportunity to collaborate with staff and stakeholders on these important issues, and looks forward to further discussion on this important topic.

Please contact Cathie Allen at (503) 813-5934 if you have any questions.

Sincerely,

Etta Lockey
Vice President, Regulation
Pacific Power & Light Company

Enclosures

Attachment A—Interconnection Flow Chart
Attachment B—Oregon Tier 2-3-4 Small Generating Facility Interconnection Application
Attachment C—Oregon QF Large Generating Facility Interconnection Application
Attachment D—PacifiCorp Technical Data Checklist for Generation Interconnection Projects
Attachment E—Utah Public Service Commission Glen Canyon Order
Attachment F—PacifiCorp Comments on Blue Marmots Petition

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's Stakeholder Questions on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

Service List
UM 2000

MARIE P BARLOW SANGER LAW PC 1117 SE 53RD AVE PORTLAND OR 97215 marie@sanger-law.com	WALTER CLEMENCE NEXTERA ENERGY RESOURCES walter.clemence@nexteraenergy.com
BEN INSKEEP EQ-RESEARCH binskeep@eq-research.com	NATHAN ROGERS ECOPLEXUS INC 650 TOWNSEND ST STE 315 SAN FRANCISCO CA 94103 nrogers@ecoplexus.com
AWEC	
BRADLEY MULLINS MOUNTAIN WEST ANALYTICS 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 brmullins@mwanalytics.com	RILEY G PECK DAVISON VAN CLEVE, PC 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 rgp@dvclaw.com
TYLER C PEPPLE DAVISON VAN CLEVE, PC 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 tcp@dvclaw.com	
OREGON CITIZENS UTILITY BOARD	
OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND OR 97205 dockets@oregoncub.org	MICHAEL GOETZ OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY STE 400 PORTLAND OR 97205 mike@oregoncub.org
ROBERT JENKS OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND OR 97205 bob@oregoncub.org	

PORTLAND GENERAL ELECTRIC	
ROB MACFARLANE PORTLAND GENERAL ELECTRIC 121 SW SALMON ST, 1WTC0702 PORTLAND OR 97204 rob.macfarlane@pgn.com; pge.opucfilings@pgn.com	COLIN WRIGHT PORTLAND GENERAL ELECTRIC 121 SW SALMON ST 1WTC0306 PORTLAND OR 97204 colin.wright@pgn.com
RENEWABLE NORTHWEST	
MAX GREENE RENEWABLE NORTHWEST 421 SW 6TH AVE STE 975 PORTLAND OR 97204 max@renewablenw.org	MICHAEL O'BRIEN RENEWABLE NORTHWEST 421 SW 6TH AVENUE #975 PORTLAND OR 97204 michael@renewablenw.org
SILVIA TANNER RENEWABLE NORTHWEST 421 SW 6TH AVE, STE 975 PORTLAND OR 97204 silvia@renewablenw.org	
STAFF	
BRITTANY ANDRUS PUBLIC UTILITY COMMISSION OF OREGON PO BOX 1088 SALEM OR 97308-1088 brittany.andrus@state.or.us	STEPHANIE S ANDRUS PUC STAFF--DEPARTMENT OF JUSTICE BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4096 stephanie.andrus@state.or.us
TED DRENNAN PUBLIC UTILITY OF OREGON PO BOX 1088 SALEM OR 97308-1088 ted.drennan@state.or.us	ELAINE PRAUSE PUBLIC UTILITY COMMISSION OF OREGON 3930 FAIRVIEW INDUSTRIAL DR SE SALEM OR 97302 elaine.prause@state.or.us
PACIFICORP	
JESSICA BUNO RALSTON SENIOR COUNSEL PACIFIC POWER 825 NE MULTNOMAH STREET, SUITE 1800 PORTLAND, OR 97232 Jessica.ralston@pacificorp.com	OREGON DOCKETS PACIFICORP 825 NE MULTNOMAH STREET, SUITE 2000 PORTLAND, OR 97232 oregondockets@pacificorp.com

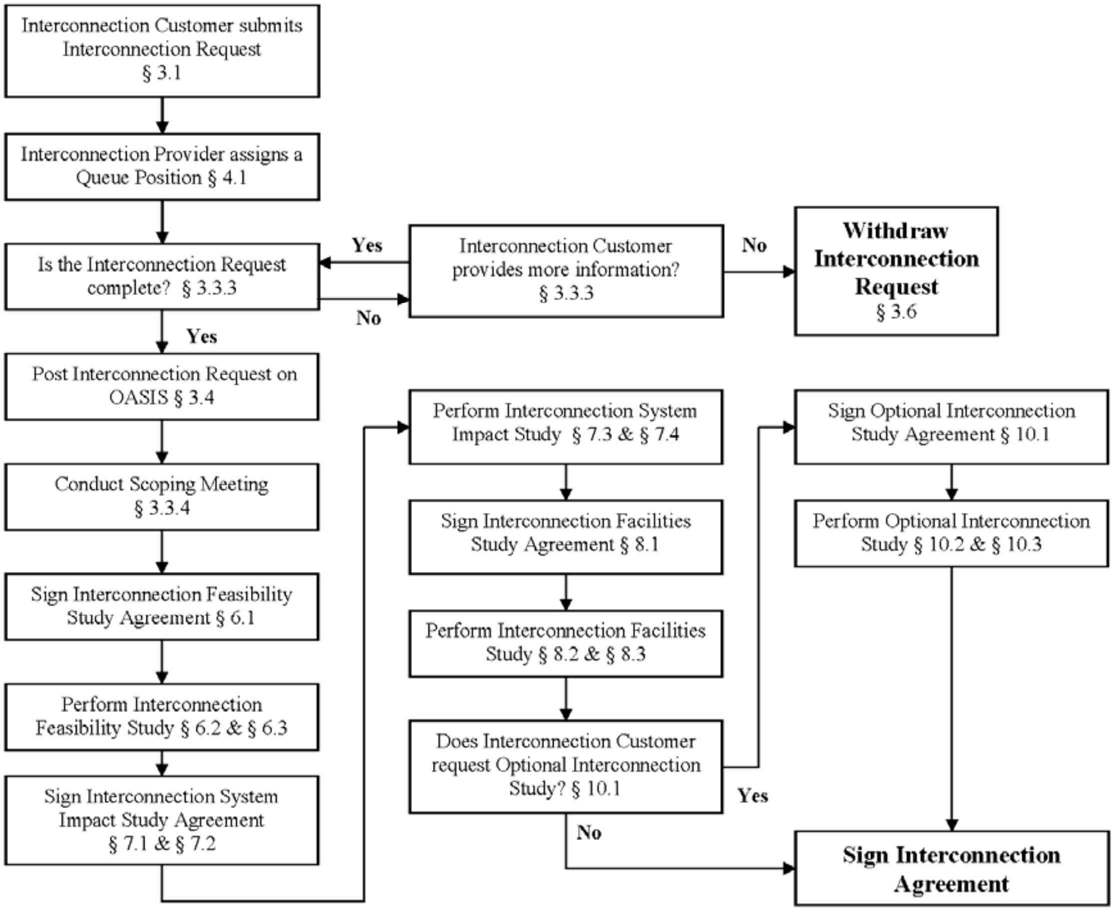
ETTA LOCKEY VICE PRESIDENT, REGULATION PACIFIC POWER 825 NE MULTNOMAH STREET, SUITE 2000 PORTLAND, OR 97232 etta.lockey@pacificorp.com	

Dated this 29th day of March, 2019.

Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations

Attachment A


Interconnection Customer submits Interconnection Request § 3.1
Interconnection Provider assigns a Queue Position § 4.1
Is the Interconnection Request complete? § 3.3.3
Yes
No
Interconnection Customer provides more information? § 3.3.3
Yes
No
Withdraw Interconnection Request § 3.6
Yes
Post Interconnection Request on OASIS § 3.4
Conduct Scoping Meeting § 3.3.4
Sign Interconnection Feasibility Study Agreement § 6.1
Perform Interconnection Feasibility Study § 6.2 & § 6.3
Sign Interconnection System Impact Study Agreement § 7.1 & § 7.2
Perform Interconnection System Impact Study § 7.3 & § 7.4
Sign Interconnection Facilities Study Agreement § 8.1
Perform Interconnection Facilities Study § 8.2 & § 8.3
Does Interconnection Customer request Optional Interconnection Study? § 10.1
Yes
No
Sign Optional Interconnection Study Agreement § 10.1
Perform Optional Interconnection Study § 10.2 & § 10.3
Sign Interconnection Agreement

Attachment B

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Form 2

Application for Small Generator Facility Interconnection
Tier 2, Tier 3 or Tier 4 Interconnection
(For Small Generator Facilities with Electric Nameplate Capacities of 10 MW and less)

Applicant Contact Information:

Name: ____

Mailing Address: ______________________________________

Physical Address: _____________________________________

City: ____________________ State: ____________ Zip Code: ______

Telephone (Daytime): ____________ (Evening): ____________________

Facsimile Number: ______________ E-Mail Address: _______________

Address of Customer Facility Where Small Generator Facility will be Interconnected:

(if different from above)

Street Address: _______________________________________

City: ____________________ State: ____________ Zip Code: ______

System Installer/Consulting Engineer:

Name: ____

Mailing Address: ______________________________________

City: ____________________ State: ____________ Zip Code: ______

Telephone (Daytime): ____________ (Evening): ____________________

Facsimile Number: ______________ E-Mail Address: _______________

Electric Service Information for Applicant's Facility Where Generator Will Be Interconnected:

Capacity: __________(Amps) Voltage: __________(Volts)

Type of Service: ☐ Single Phase ☐ Three Phase

Will a transformer be used between the generator and the point of common coupling? ___Yes ___No

Transformer Data (If Applicable, for Interconnection Customer-Owned Transformer):

Is the transformer: ____single phase _____three phase? Size: ___________kVA

Transformer Impedance: _______% on __________kVA Base

Tier 2, Tier 3 or Tier 4 Interconnection Application

(cont.)

If Three Phase:

Transformer Primary: _____ Volts _____ Delta _____Wye _____ Wye Grounded

Transformer Secondary: _____ Volts _____ Delta _____Wye _____ Wye Grounded

Transformer Tertiary: _____ Volts _____ Delta _____Wye _____ Wye Grounded

Requested Procedure Under Which to Evaluate Interconnection Request[1] :

Please indicate below which review procedure applies to the interconnection request.

☐ **Tier 2 -** Certified interconnection equipment with an aggregate Electric Nameplate Capacity of 2 MW or less. Indicate type of certification below. The application fee amount is $500.

☐ Lab Tested - tested to IEEE 1547.1 and other specified standards by a nationally recognized testing laboratory and is appropriately labeled.

☐ Field Tested – an identical small generator facility has been approved by the public utility under a Tier 4 study review process within the prior 36 months of the date of this interconnection request.

☐ **Tier 3 –** A Small Generator Facility connected to the T&D system that does not export power. The Electric Nameplate Capacity rating may be 50 kW or smaller, if connecting to area network or 10 MW or smaller, if connecting to a radial distribution feeder. The application fee amount is $1000.

☐ **Tier 4 –** Electric Nameplate Capacity rating is 10 MW or smaller and the Small Generator Facility does not qualify for a Tier 1, Tier 2 or Tier 3 review or has been reviewed but not approved under a Tier 1, Tier 2 or Tier 3 review. Application fee amount is $1000.

[1] **Note:** Descriptions for interconnection review categories do not list all criteria that must be satisfied. For a complete list of criteria, please refer to PUC Rule OAR 860, Division 082, (Rule).

Field Tested Equipment:

If the field tested equipment box is checked above, please include with the completed application the following information which will be required for review of Tier 2 field tested small generator facilities:

- A copy of the Certificate of Completion, signed by the public utility that has approved an identical small generator facility for parallel operation.
- A copy of all documentation submitted to the public utility that approved the Small Generator Facility for parallel operation under a Tier 4 study process.

Tier 2, Tier 3 or Tier 4 Interconnection Application
(cont.)

- A written statement by the Applicant indicating that the small generator facility being proposed is identical, except for Minor Equipment Modification, to the one previously approved by the public utility for parallel operation.
- If a Tier 2 Application, utilizing Field Tested equipment, is proposed the remainder of the application will not be required to be completed.

Small Generator Facility Information:
List interconnection components/system(s) to be used in the Small Generation Facility that is lab certified (required for Lab Tested, Tier 2 Interconnection requests only).

Component/System NRTL Providing Label & Listing
1.____
2.____
3.____
4.____
5.____

Please provide copies of manufacturer brochures or technical specifications

Energy Production Equipment/Inverter Information:

☐ Synchronous ☐ Induction ☐ Inverter ☐ Other __________

Electric Nameplate Rating: ___________ kW ___________ kVA

Rated Voltage: ________________Volts

Rated Current: ____________________Amps

System Type Tested (Total System): ☐ Yes ☐ No; (attach product literature)

Customer-Site Load: _________________(kW) (if none, so state)

Maximum Physical Export Capability Requested: ______________ (kW)

Individual Generator Power Factor

Rated Power Factor:

Leading: _____________Lagging: _______________

For Synchronous Machines:

Manufacturer: ____

Model No.: ________________ Version No.: ____________________

Submit copies of the Saturation Curve and the Vee Curve.

☐ Salient ☐ Non-Salient

Torque: _____ lb-ft Rated RPM: _______

Tier 2, Tier 3 or Tier 4 Interconnection Application
(cont.)

Field Amperes: ________ at rated generator voltage and current and ________% PF over-excited
Type of Exciter: ____
Output Power of Exciter: ____
Type of Voltage Regulator: _______________________________________
Locked Rotor Current: ________ Amps
Synchronous Speed: ______RPM
Winding Connection: _________
Min. Operating Freq./Time: __________
Generator Connection: ☐ Delta ☐ Wye ☐ Wye Grounded
Direct-axis Synchronous Reactance: (Xd) _______ohms
Direct-axis Transient Reactance: (X'd) _______ohms
Direct-axis Sub-transient Reactance: (X"d) _______ohms
Negative Sequence Reactance, X_2: _________ P.U.
Zero Sequence Reactance, X_0: ____________ P.U.
KVA Base: ___________________________
Field Volts: ______________
Field Amperes: ______________

Provide appropriate IEEE model block diagram of excitation system and governor system in accordance with the regional reliability council criteria (WECC/NERC Reliability Standard MOD-012-0). A copy of the manufacturer's block diagram may not be substituted.

For Induction Machines:

Manufacturer: ____
Model No.: ________________ Version No.: ____________________
Locked Rotor Current: ________ Amps
Rotor Resistance: (Rr)_____ohms Exciting Current: ____Amps
Rotor Reactance: (Xr)_____ohms Reactive Power Required: ________
Magnetizing Reactance: (Xm)_____ohms ___VARs (No Load)
Stator Resistance: (Rs)_____ohms ___VARs (Full Load)
Stator Reactance: (Xs)_____ohms
Short Circuit Reactance: (X"d)_____ohms
Phases: ☐ Single ☐ Three-Phase
Frame Size: _________ Design Letter: ____ Temp. Rise: ___________°C.

Tier 2, Tier 3 or Tier 4 Interconnection Application
(cont.)

Reverse Power Relay Information: (This section applies to Tier 3 Review Only)

Manufacturer: ________________Model:_______________________

Electric Nameplate Capacity rating: (kVA)________________

Additional Information For Inverter Based Facilities:

Inverter Information:

Manufacturer:_______________________ Model: ____________________

Type: ☐ Forced Commutated ☐ Line Commutated

Electric Nameplate Capacity Rated Output: _________ Amps ________ Volts ______kW

Efficiency: ________% Power Factor: ________%

DC Source / Prime Mover:

☐ Solar ☐ Wind ☐ Hydro ☐ Other _________________

Electric Nameplate Capacity Rating: __________ kW Rating: __________ kVA

Rated Voltage: ________________Volts

Open Circuit Voltage (If applicable): ________________Volts

Rated Current: ____________________Amps

Short Circuit Current (If applicable): ____________________Amps

Other Facility Information:

Is Facility a QF? Yes☐ No☐

If yes, has Applicant completed FERC "Notice of Self Certification"? Yes☐ No☐

Energy Source: ☐ Solar ☐ Wind ☐ Hydro ☐ Diesel ☐ Natural Gas
☐ Other ______________________________________

Prime Mover Type: ☐ Photovoltaic ☐ Reciprocating Engine ☐ Fuel Cell
☐ Turbine ☐ Other ____________________________

One Line Diagram attached: ☐ Yes ☐ No

Plot Plan attached: ☐ Yes ☐ No

Installation Test Plan attached: ☐ Yes ☐ No

Estimated Commissioning Date (if known): _________________________________

Enclose copy of site electrical one-line diagram showing the configuration of all Small Generating Facility equipment, current and potential circuits, and protection and control schemes.

Tier 2, Tier 3 or Tier 4 Interconnection Application
(cont.)

Enclose copy of any site documentation that indicates the precise physical location of the proposed Small Generating Facility (e.g., USGS topographic map, distance from public utility facility number, other diagram or documentation).

Enclose copy of any documents that provide proof of site control.

Applicant Signature:

I hereby certify that all of the information provided in this application request form is correct.

Applicant Signature: ________________________________

Title: ________________________________ Date:___________________

An application fee is required before the application can be processed. Please verify that the appropriate fee is included with the application:

Application fee included ☐

Amount____________________

Public Utility Acknowledgement:

I hereby acknowledge the receipt of a Interconnection Request and Application Fee,

Approval for a Tier 2, Tier 3 or Tier 4 Small Generator Facility interconnection is contingent upon the Applicant's Small Generator Facility passing the screens and completing the review process set forth in the PUC rules found in OAR 860, Division 082 and is not granted by the EDC's signature on this Application Form.

Public Utility Signature: ____________________________ Date: ____________

Printed Name:__________________________Title:__________________________

Note: The Public Utility shall retain a copy of this completed and signed form and return the original and any attachments to the Applicant.

Attachment C

APPENDIX 1 to QF-LGIP
INTERCONNECTION REQUEST FOR A
QF LARGE GENERATING FACILITY

1. The undersigned Interconnection Customer submits this request to interconnect its Large Generating Facility which is a Qualifying Facility with Transmission Provider's Transmission System pursuant to Transmission Provider's QF-LGIP.

2. This Interconnection Request is for (check one):
   _____ A proposed new Large Generating Facility that is a Qualifying Facility.
   _____ An increase in the generating capacity or a Material Modification of an existing Generating Facility that is a Qualifying Facility.

3. The type of interconnection service requested is Network Resource Interconnection Service.

4. _____ Check here if Interconnection Customer requesting Network Resource Interconnection Service has initiated the process of certifying the Large Generating Facility as a Qualifying Facility as provided in 18 C.F.R. 292.207.

5. Interconnection Customer provides the following information:

   a. Address or location or the proposed new Large Generating Facility site (to the extent known) or, in the case of an existing Generating Facility, the name and specific location of the existing Generating Facility;

   b. Maximum summer at ____ degrees C and winter at _____ degrees C megawatt electrical output of the proposed new Large Generating Facility or the amount of megawatt increase in the generating capacity of an existing Generating Facility;

   c. General description of the equipment configuration;

   d. Commercial Operation Date (Day, Month, and Year);

   e. Name, address, telephone number, and e-mail address of Interconnection Customer's contact person;

   f. Approximate location of the proposed Point of Interconnection (optional); and

   g. Interconnection Customer Data (set forth in Attachment A)

6. Applicable deposit amount as specified in the QF-LGIP.

7. Evidence of Site Control as specified in the QF-LGIP (check one)

____ Is attached to this Interconnection Request
____ Will be provided at a later date in accordance with this QF-LGIP

8. This Interconnection Request shall be submitted to the representative indicated below:

[To be completed by Transmission Provider]

9. Representative of Interconnection Customer to contact:

[To be completed by Interconnection Customer]

10. This Interconnection Request is submitted by:

Name of Interconnection Customer: ______________________________

By (signature): ______________________________

Name (type or print): ______________________________

Title: ______________________________

Date: ______________

Attachment A to Appendix 1
Interconnection Request

QF LARGE GENERATING FACILITY DATA

UNIT RATINGS

kVA ____________ °F _________ Voltage ____________
Power Factor ________
Speed (RPM) ________ Connection (e.g. Wye) ____________
Short Circuit Ratio ________ Frequency, Hertz ____________
Stator Amperes at Rated kVA _________ Field Volts ______________
Max Turbine MW ___________ °F ______

COMBINED TURBINE-GENERATOR-EXCITER INERTIA DATA

Inertia Constant, H = ____________________ kW sec/kVA
Moment-of-Inertia, WR^2 = ____________________ lb. ft.^{2}

REACTANCE DATA (PER UNIT-RATED KVA)

	DIRECT AXIS		QUADRATURE AXIS	
Synchronous – saturated	X_{dv}	_______	X_{qv}	_______
Synchronous – unsaturated	X_{di}	_______	X_{qi}	_______
Transient – saturated	X'_{dv}	_______	X'_{qv}	_______
Transient – unsaturated	X'_{di}	_______	X'_{qi}	_______
Subtransient – saturated	X''_{dv}	_______	X''_{qv}	_______
Subtransient – unsaturated	X''_{di}	_______	X''_{qi}	_______
Negative Sequence – saturated	$X2_v$	_______		
Negative Sequence – unsaturated	$X2_i$	_______		
Zero Sequence – saturated	$X0_v$	_______		
Zero Sequence – unsaturated	$X0_i$	_______		
Leakage Reactance	Xl_m	_______		

FIELD TIME CONSTANT DATA (SEC)

Open Circuit	T'_{do}	________	T'_{qo}	________
Three-Phase Short Circuit Transient T'_{d3}	________	T'_q	________	
Line to Line Short Circuit Transient T'_{d2}	________			
Line to Neutral Short Circuit Transient	T'_{d1}	________		
Short Circuit Subtransient	T''_d	________	T''_q	________
Open Circuit Subtransient	T''_{do}	________	T''_{qo}	________

ARMATURE TIME CONSTANT DATA (SEC)

Three Phase Short Circuit	T_{a3}	________
Line to Line Short Circuit	T_{a2}	________
Line to Neutral Short Circuit T_{a1}	________	

NOTE: If requested information is not applicable, indicate by marking "N/A."

MW CAPABILITY AND PLANT CONFIGURATION LARGE GENERATING FACILITY DATA

ARMATURE WINDING RESISTANCE DATA (PER UNIT)

Positive	R_1	________
Negative	R_2	________
Zero	R_0	________

Rotor Short Time Thermal Capacity I_2^2t = ________
Field Current at Rated kVA, Armature Voltage and PF = ________ amps
Field Current at Rated kVA and Armature Voltage, 0 PF = ________ amps
Three Phase Armature Winding Capacitance = ________ microfarad
Field Winding Resistance = ________ ohms ______ °C
Armature Winding Resistance (Per Phase) = ________ ohms ______ °C

CURVES

Provide Saturation, Vee, Reactive Capability, Capacity Temperature Correction curves. Designate normal and emergency Hydrogen Pressure operating range for multiple curves.

GENERATOR STEP-UP TRANSFORMER DATA RATINGS

Capacity   Self-cooled/
Maximum Nameplate
____________/____________kVA

Voltage Ratio(Generator Side/System side/Tertiary)
____________/____________/____________kV

Winding Connections (Low V/High V/Tertiary V (Delta or Wye))
____________/____________/____________

Fixed Taps Available ________________________

Present Tap Setting ________________________

IMPEDANCE

Positive Z_1 (on self-cooled kVA rating)____________ % ________ X/R

Zero Z_0 (on self-cooled kVA rating)____________ % ________ X/R

EXCITATION SYSTEM DATA

Identify appropriate IEEE model block diagram of excitation system and power system stabilizer (PSS) for computer representation in power system stability simulations and the corresponding excitation system and PSS constants for use in the model.

GOVERNOR SYSTEM DATA

Identify appropriate IEEE model block diagram of governor system for computer representation in power system stability simulations and the corresponding governor system constants for use in the model.

WIND GENERATORS

Number of generators to be interconnected pursuant to this Interconnection Request:

____

Elevation: ____________ _____ Single Phase _____ Three Phase

Inverter manufacturer, model name, number, and version:

____

List of adjustable setpoints for the protective equipment or software:

____

Note: A completed General Electric Company Power Systems Load Flow (PSLF) data sheet or other compatible formats, such as IEEE and PTI power flow models, must be supplied with the Interconnection Request. If other data sheets are more appropriate to the proposed device, then they shall be provided and discussed at Scoping Meeting.

INDUCTION GENERATORS

(*) Field Volts: ________________
(*) Field Amperes: _____________
(*) Motoring Power (kW): ________
(*) Neutral Grounding Resistor (If Applicable): ___________
(*) I_2^2t or K (Heating Time Constant): ___________
(*) Rotor Resistance: ___________
(*) Stator Resistance: __________
(*) Stator Reactance: ____________
(*) Rotor Reactance: ____________
(*) Magnetizing Reactance: __________
(*) Short Circuit Reactance: __________
(*) Exciting Current: _______________
(*) Temperature Rise: _______________
(*) Frame Size: ______________
(*) Design Letter: ____________
(*) Reactive Power Required In Vars (No Load): _______
(*) Reactive Power Required In Vars (Full Load): _______
(*) Total Rotating Inertia, H: _______Per Unit on KVA Base

Note: Please consult Transmission Provider prior to submitting the Interconnection Request to determine if the information designated by (*) is required.

Attachment D

Technical Data Checklist for Generation Interconnection Projects

The following are the critical pieces of information that PacifiCorp requires for the Interconnection Customer's project.

Required for Application

Please ensure that the application contains all the information listed below prior to submission or the Interconnection Customer's application may be deemed incomplete and not assigned a queue number in the PacifiCorp project queue.

Company Name

Project Name

Requested Commercial Operations Date

Point of Interconnection (Address, Lat/Long, PacifiCorp substation, etc.)

Alternate Point of Interconnection (if applicable)

Qualifying Facility (Y/N) – If yes, QF Attestation Form must also be provided and it is recommended that a Voluntary Consent Form also be provided.

Site Control

Single Line Diagram containing all of the following at a minimum:

Maximum Nameplate MW
Generator make, model, specifications
Power Factor
Number of Transformers
Transformer size, impedance and winding configurations

Required for Study

The items listed below do not need to be provided with the application but will be required (as applicable) prior to the first study. Other pieces of information may be required depending on the project specifications.

Collector System Data (impedances, lengths, etc.)

Tie Line Data (impedances, lengths, etc.)

Supplemental Reactive Compensation (location/size & increments)

Dynamic Stability Study Model – A WECC approved PSSE standard model in version 33 and above as well as a detailed user written model if the generating facility is renewable generation (wind, solar)

Attachment E

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

Application of Rocky Mountain Power for Approval of the Power Purchase Agreement between PacifiCorp and Glen Canyon Solar A, LLC	DOCKET NO. 17-035-26
Application of Rocky Mountain Power for Approval of the Power Purchase Agreement between PacifiCorp and Glen Canyon Solar B, LLC	DOCKET NO. 17-035-28
Glen Canyon Solar A, LLC and Glen Canyon Solar B, LLC's Request for Agency Action to Adjudicate Rights and Obligations under PURPA, Schedule 38 and Power Purchase Agreements with Rocky Mountain Power	DOCKET NO. 17-035-36 CONSOLIDATED ORDER

ISSUED: December 22, 2017

The Public Service Commission denies the Request for Agency Action, Motion to Dismiss and Motion for Preliminary Injunction filed in Docket No. 17-035-36 and stays a decision in Docket Nos. 17-035-26 and 17-035-28 until, at least, January 16, 2018 unless the parties file a stipulation requesting an order issue sooner.

1. BACKGROUND

Glen Canyon Solar A, LLC and Glen Canyon Solar B, LLC (collectively, "Glen Canyon") are subsidiaries of sPower, each of which seeks to develop a solar generation project eligible to be a "qualified facility," ("QF") as the term is used in the Public Utility Regulatory Policies Act ("PURPA").[1] Glen Canyon plans to locate the projects in southern Utah and to sell the projects' output to PacifiCorp dba Rocky Mountain Power ("RMP") according to RMP's

[1] *See generally* 16 U.S.C. § 824a-3.

obligations under PURPA and a Utah statute, both of which require public utilities to purchase electricity from QFs.[2]

This consolidated Order addresses three dockets involving Glen Canyon's projects. In Docket Nos. 17-035-26 and 17-035-28, RMP asks the Public Service Commission ("PSC") to approve power purchase agreements ("PPAs") for each Glen Canyon project. In Docket No. 17-035-36, Glen Canyon filed a Request for Agency Action ("Request"), wherein Glen Canyon asks the PSC issue an order requiring RMP to influence PacifiCorp's transmission function ("PacTrans") to make certain assumptions in preparing studies pertaining to the interconnection and transmission costs associated with Glen Canyon's projects.

a. Legal and Regulatory Background

PURPA requires utilities, such as RMP, to purchase electricity from QFs, a defined class of wholesale generators. *See* Utah Code Ann. § 54-12-2; 16 U.S.C. § 824a-3(f). To attain QF status, a facility must meet certain requirements, including fuel source (*e.g.*, wind or solar) and capacity (no greater than or equal to 80 megawatts or "MW"). *See* 18 C.F.R. §§ 292.203(a), 292.203(c), 292.204 and 292.207. "When the facility satisfies the … criteria, it can force a utility to buy the energy for its 'avoided cost.'" *Northern Laramie Range Alliance v. FERC*, 733 F.3d 1030, 1033 (10th Cir. 2013).

[2] The Utah statute imposes obligations that are generally redundant of those existing under federal law, and utilities' obligations under PURPA are much more extensively defined in regulation and precedent than their obligations under the state law. We have identified no reason to distinguish state requirements from those PURPA imposes for the purposes of this Order. Therefore, although RMP has obligations under both state and federal law to purchase electricity from QFs, we refer primarily to and discuss PURPA in this Order.

Generally, the transmission and wholesale of electricity fall within the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). *See, e.g.*, 16 U.S.C. § 824(b). However, federal law delegates certain responsibilities to state regulators in the administration of PURPA that would otherwise fall under FERC's jurisdiction. For example, PURPA expressly charges state regulators with establishing the "avoided cost" (wholesale) pricing that utilities must pay to QFs for their output.[3]

The parameters of state and federal jurisdiction are not everywhere unambiguously defined under PURPA. For purposes of this docket, it should suffice to note that, in addition to establishing avoided cost pricing, state regulators have jurisdiction over and are responsible for assessing interconnection costs, which FERC regulations require QFs to pay.[4]

i. The Process in Utah for Establishing a New QF under Schedule 38

Schedule 38 of RMP's tariff, as approved by the PSC, outlines the procedures QFs follow to sell power to RMP. Broadly, Schedule 38 outlines two parallel processes both of which are independent requisites for a QF to sell to RMP: (i) a process for obtaining and executing a PPA (an agreement between RMP and the QF for the purchase of electricity) and (ii) a process for obtaining and executing an interconnection agreement (an agreement between the QF and

[3] *See, e.g.*, 18 C.F.R. § 292.304.

[4] 18 C.F.R. § 292.306(a) ("Each qualifying facility shall be obligated to pay any interconnection costs which the State regulatory authority … may assess against the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics.").

PacifiCorp's transmission function, PacTrans, for the QF to interconnect to PacTrans's transmission system).[5]

Schedule 38 conditions RMP's obligation to purchase from a QF on "all necessary interconnection arrangements being consummated." (Schedule 38 at 38.9.) It explains "[g]enerally, the interconnection process involves (1) initiating a request for interconnection, (2) completion of studies to determine the system impacts associated with the interconnection and the design, cost, and schedules for constructing any necessary interconnection facilities, [and] (3) execution of an interconnection agreement." (*Id.* at 38.10.)

Consistent with FERC regulations, Schedule 38 provides a "QF project owner is responsible for all interconnection costs assessed by [RMP] on a nondiscriminatory basis." (*Id.*) For projects greater than 20 megawatts, like the Glen Canyon projects, Schedule 38 provides interconnection applications will be processed "through [PacTrans] generally following the procedures for studying the generation interconnection described in [PacifiCorp's] Open Access Transmission Tariff" or "OATT." (*Id.*)

[5] We will not encumber this Order with an attempt to explain federal requirements that necessitate the separation of PacifiCorp's transmission function from its other divisions. For our purposes, we note that PacifiCorp's transmission function, PacTrans, generally must operate independently of its retail utility business (*e.g.*, RMP). PacTrans may serve PacifiCorp's other business divisions, including RMP, but must provide nondiscriminatory transmission service to outside customers. PacTrans provides these services pursuant to its OATT, which is approved and regulated by FERC.

ii. PacTrans Provides Multiple Categories of Interconnection and Transmission Service, and Performs Studies Dependent upon the Kind of Service Requested

Under the OATT, the interconnection customer submits a request that specifies whether the customer is seeking "energy resource interconnection" ("ER") or "network resource interconnection" ("NR"). (OATT at 137.) In both cases, PacTrans conducts studies ("Studies") as enumerated in the OATT to determine the impact the interconnection will have on the system and what upgrades may be necessary to facilitate it.

ER interconnection facilitates a connection that will allow the customer to connect to the transmission system and to be eligible to deliver output on an "as available" basis. (*Id.* at 138.) The Studies associated with ER interconnection analyze the requirements and upgrades necessary to accommodate the customer simply connecting to the system. (*Id.*) In contrast, NR interconnection facilitates a connection intended to allow the customer's facility to function as a "network resource," which is generally expected to enjoy firm, uninterrupted transmission of its output. (*See id.* at 138-139.) The Studies associated with NR interconnection determine whether "at full output, the aggregate of generation in the local area can be delivered to the aggregate of load" on the transmission system consistent with established reliability criteria. (*Id.* at 139.)

Notably, whether studied as NR or ER interconnection, the service facilitated by an interconnection request only results in interconnection. The PacTrans customer must also arrange for one of several potential forms of transmission service, which will govern the actual transportation of the customer's energy over PacTrans's transmission system.

PacTrans's OATT provides several types of transmission service. For example, "network transmission service is used to serve load" and is "designed to flexibly deliver the output of multiple generating resources (called designated network resources or 'DNRs') to load at different locations." (Brown Direct Test. at 3:61-64.) In contrast, "point-to-point service" is less flexible and facilitates moving power from one specific point to another. (*Id.* at 4:69-70.) As for interconnection service, PacTrans performs Studies to assess the impact and costs that will be associated with the requested transmission service.

Commonly, the interconnection customer and the transmission service customer are the same entity. When RMP, for example, seeks interconnection for one of its own resources, it will file an application for interconnection service for the resource and seek transmission service for the output of that resource.[6] Under this scenario, RMP is both the "interconnection customer" and the "transmission service customer." However, in the PURPA context, utilities are legally responsible for providing transmission service whereas QFs are generally responsible for interconnection. Therefore, with respect to QFs selling power to RMP, the QF is ordinarily PacTrans's "interconnection customer" while RMP will be PacTrans's "transmission customer" with respect to the QF's output.

[6] As discussed in FN 5, according to federal law and regulations, PacifiCorp must operate its "transmission function," PacTrans, independently from its "energy supply management function," often referred to by the parties as the "merchant function" or "PacifiCorp ESM." PacifiCorp's utility business operates under different business names (e.g., Rocky Mountain Power and Pacific Power) in different states. For simplicity, we do not distinguish between RMP and PacifiCorp ESM here. We refer to them collectively as "RMP."

b. Factual and Procedural Background

i. *Glen Canyon's Projects*

In early 2015, Glen Canyon's parent company, sPower, began development efforts for a 380 MW solar facility in Kane County, Utah, which would rely on PacTrans's Sigurd-to-Glen Canyon 230 kV transmission line ("Sigurd Line") for the transportation of its output to northern load. (Request at ¶ 5.) After sPower learned the Sigurd Line has a total capacity less than 380 MW, it downsized its project to 240 MW and asked PacTrans to prepare interconnection Studies for the project (which was not a QF). (*Id.* at ¶ 6.) The Studies for sPower's 240 MW project estimated significant costs to upgrade transmission facilities. (*See id.* at ¶ 7.) Specifically, Glen Canyon represents the Studies estimated costs totaling approximately $415 million for interconnection and network upgrades required for firm network transmission service of sPower's output. (*Id.*) Consequently, sPower withdrew the request and its subsidiary, Glen Canyon, submitted new interconnection pricing requests for two different, smaller QF projects. (*Id.* at ¶ 8.) Initially, Glen Canyon submitted requests for the projects with a combined capacity of 136 MW but revised the combined capacity down to 95 MW after reviewing avoided cost pricing information from RMP showing RMP owns 95 MW of firm network transmission rights on the Sigurd Line. (*Id.*)

ii. *RMP's Transmission Rights on the Sigurd Line*

PacifiCorp owns the Sigurd Line and PacTrans provides transmission service, subject to FERC's jurisdiction, over the line pursuant to its OATT. (Brown at 5:96-98.) RMP is one of PacTrans's customers on the Sigurd Line and holds 95 MW of northbound transmission rights. (*Id.* at 5:98-100.) RMP represents it holds the rights primarily to comply with existing contracts (collectively, "APS Contract") between RMP and Arizona Public Service ("APS"), an Arizona electric utility. (*Id.* at 5:109-7:154.) In the winter months, RMP takes power from APS, as a designated network resource, and uses firm network transmission service over the Sigurd Line to move that electricity to northern load. (*Id.*) In the summer months, RMP is a seller under its agreement with APS and does not need APS's power as a designated network resource. (*Id.*) Therefore, RMP does not hold network transmission rights in the summer, but it still holds 95 MW of point-to-point rights under the OATT. (*Id.*) These summertime point-to-point rights allow RMP to honor its contractual obligation to APS, which holds "call rights" to move up to 100 MW of power north "between the Glen Canyon/Four Corners Substations and the Borah/Brady Substations in Idaho." (*Id.*)

iii. *The Parties Executed PPAs and RMP Filed Applications for Their Approval but a Dispute Exists as to the Nature of the Interconnection Studies, Prompting Glen Canyon to File the Request*

Glen Canyon has requested new interconnection Studies from PacTrans for the Glen Canyon projects, but the Studies have not been completed. (Request at ¶ 11.) To avoid the transmission upgrades reflected in the Studies for its parent company's abandoned project, Glen Canyon asserts RMP is obliged to use its existing transmission rights to move Glen Canyon's output and must exercise its option to redispatch pursuant to a FERC-approved amendment to RMP's Network Operating Agreement ("NOA Amendment"). The NOA Amendment allows PacTrans to "grant additional Designated Network Resource applications on behalf of [RMP] in order to enable firm delivery from QFs even in the absence of [available transfer capacity]." (*Id.* at ¶ 16.)

Glen Canyon "has asked PacTrans to confirm that the interconnection [Studies] for [Glen Canyon's projects] will reflect the assumption that RMP will use Existing RMP Transmission Rights, allowing avoidance of most or all" of the costs to upgrade transmission facilities reflected in the Studies for sPower's prior, larger project. (*Id.* at ¶ 11.) PacTrans has represented it will only make such assumptions in the Studies if RMP provides written confirmation it will use its existing transmission rights and redispatch options as Glen Canyon requests. (*Id.*) RMP has declined to do so, claiming the rights are not available because of its obligations under the APS Contract and redispatch is not logistically feasible under these circumstances. (*Id.* at ¶ 12.) RMP further takes the position that it has no obligation under PURPA to devote its existing transmission rights to Glen Canyon's projects or to exercise its redispatch option under the NOA Amendment. (*Id*.)

Despite this disagreement, between April 24, 2017 and May 1, 2017, RMP and Glen Canyon executed PPAs for both of Glen Canyon's projects. On May 1 and May 3, 2017, respectively, RMP filed applications with the PSC for approval of each of the PPAs under Docket Nos. 17-035-26 and 17-035-28.[7]

[7] On May 1, 2017, the date RMP filed its application for approval of the first Glen Canyon PPA, RMP also filed a Request for Declaratory Ruling in Docket No. 17-035-25, seeking a declaratory ruling that QFs are required to pay all interconnection costs necessary to allow RMP to receive QFs' net output on a firm basis. RMP's request referenced the interconnection Study performed for sPower's proposed 240 MW project as illustrative of the need for such relief from the PSC. Glen Canyon filed initial comments in that docket, objecting to the relief RMP sought. After Glen Canyon filed its Request in Docket No. 17-035-36 (as discussed below), the parties stipulated to stay Docket No. 17-035-25. Consequently, on June 19, 2017, the PSC issued an order suspending the schedule and staying Docket No. 17-035-25.

On June 7, 2017, Glen Canyon filed its Request. Subsequently, the PSC held a scheduling conference and issued a scheduling order, establishing deadlines for the filing of dispositive motions and written testimony and setting the matter for hearing on October 5, 2017.

iv. *RMP Filed a Motion to Dismiss and Glen Canyon Filed a Motion for Preliminary Injunction, but the Parties Stipulated to Postpone Oral Argument on Both Motions Until the Hearing on the Merits*

On July 14, 2017, RMP filed a motion to dismiss Glen Canyon's request ("RMP's MTD"), requesting the PSC dismiss the Request. On August 11, 2017, Glen Canyon filed a Motion for Preliminary Injunction ("Glen Canyon's MPI"), seeking "an order requiring RMP to submit a request to PacTrans that it consider and evaluate the use of RMP's existing transmission rights and planning and redispatch options in connection with [Glen Canyon's interconnection Studies.]" (Glen Canyon's MPI at 34.) Glen Canyon argued it would suffer irreparable harm unless the PSC granted the MPI because "[a]ny delay in studies related to the interconnection requests" may cause the parties' failure to satisfy established deadlines under Glen Canyon's PPAs. (*Id.* at 27.)

After the filing of RMP's MTD and Glen Canyon's MPI, RMP filed an unopposed Motion to Amend Procedural Schedule on August 24, 2017, which the PSC granted, resulting in the modification of certain deadlines in the adjudication schedule and the setting of oral argument on the two pending motions for September 28, 2017. The hearing date of October 5, 2017 was preserved.

On September 27, 2017, Glen Canyon filed an unopposed Motion to Reschedule Oral Arguments on Pending Motions, asking the PSC to reschedule oral arguments on RMP's MTD and Glen Canyon's MPI to the same day as the scheduled hearing on the merits of Glen Canyon's Request. The PSC granted the unopposed motion.

v. *After Holding a Two-Day Hearing on the Merits, the PSC Issued Notice of Its Decision and the Parties Stipulated to Stay Approval of the PPAs*

On October 5 and October 6, 2017, the PSC held a consolidated hearing to consider evidence on all requests for relief and motions in Docket Nos. 17-035-26, 17-035-28, and 17-035-36, including the two applications for approval of Glen Canyon's respective PPAs, Glen Canyon's Request, RMP's MTD and Glen Canyon's MPI. APS intervened in Docket No. 17-035-36 but did not file written testimony or comment and did not register an appearance at hearing. RMP, Glen Canyon and the Division of Public Utilities ("DPU") participated in the hearing and submitted evidence in all three dockets. Near the conclusion of the hearing, Glen Canyon expressed interest in staying a decision on the PPAs pending final resolution of the issues in Docket No. 17-035-36.

On October 31, 2017, the PSC issued a Consolidated Notice of Decision and Notice of Deadline to File Stipulation or Motion to Stay Order in Docket Nos. 17-035-26 and 17-035-28 ("Notice"). In the Notice, the PSC gave notice of its intention to deny the Request, the MPI and the MTD and instructed the parties to file any motion to stay a decision on the PPAs by November 14, 2017. On November 9, 2017, Glen Canyon filed an unopposed, Stipulated Motion to Stay ("Motion to Stay"), requesting a stay of any order in Docket Nos. 17-035-26 and 17-035-28 for a period of two weeks after the date of the issuance of a Report and Order in Docket No. 17-035-36.

2. CLARIFICATION OF RELIEF GLEN CANYON REQUESTS

The record is somewhat muddled as to the specific relief Glen Canyon seeks.[8] In its Request, Glen Canyon asks the PSC issue an order providing "RMP must" do the following:

(i) "Utilize all of its existing network transmission right [sic] and resources, including planning and operational redispatch options, to avoid unnecessary and uneconomic Network Upgrades";
(ii) "Submit a timely and appropriate transmission service request pursuant to Schedule 38 … for the [Glen Canyon projects] that requests that studies done by [PacTrans] include studies and analyses of all available planning and operational redispatch options designed to avoid uneconomic Network Upgrades";
(iii) "Submit a timely and appropriate request that PacTrans perform interconnection studies for the [Glen Canyon projects] in a manner consistent with transmission studies that assume resource redispatch";
(iv) "Utilize and request studies of operational redispatch options consistent with the redispatch of resources assumed in setting avoided cost prices in [Glen Canyon's PPA's]";
(v) "Avoid imprudent actions or failures to act that might trigger unnecessary, uneconomic Network Upgrades, the costs of which could fall on PacifiCorp and its customers under applicable regulations and precedent";
(vi) "Avoid unlawful discrimination by utilizing available operational dispatch options for [Glen Canyon's projects]."

(Request at 2-3.)

However, later at hearing, Glen Canyon's counsel qualified its request for relief at some length. (Hr'g Tr. Day Two at 134:3-137:6.) Primarily, Glen Canyon explained it does not wish for the PSC to dictate how RMP will or may actually utilize its transmission or redispatch rights; rather, Glen Canyon seeks an order ensuring PacTrans assumes, for purposes of preparing interconnection and transmission service Studies, that RMP will use them as outlined in the Request. These assumptions include (1) RMP will "utilize all of its existing network

---

[8] As Glen Canyon acknowledged at hearing, the "specific nature or wording of our [R]equest has morphed a bit." (*See* Hr'g Tr. Day Two at 134:3-5.)

transmission rights and resources, including planning and operational redispatch options to avoid … [transmission] network upgrades"; (2) RMP will "utilize and request studies of operational redispatch options consistent with the redispatch of resource[s] assumed in setting avoided cost prices in the Glen Canyon PPA[s]." (Hr'g Tr. Day Two at 134:12-15, 135:21-24.)

This is consistent with the relief Glen Canyon seeks in its MPI, where Glen Canyon asks the PSC to issue an order "requiring RMP to submit a request to PacTrans that it consider and evaluate the use of RMP's existing transmission rights and planning and redispatch options in connection with the Interconnection [Studies]." (MPI at 34.) Glen Canyon asserts it is "seeking a simple and a practical solution" that will allow it to deliver power "over existing transmission rights that will avoid the necessity of anyone running the risk of $400 million worth of network upgrades." (Hr'g Tr. Day Two at 120:12-18.)

Therefore, as best the PSC can discern, the primary relief Glen Canyon seeks is an order instructing RMP to make any representations or requests necessary to prompt PacTrans to prepare Studies that assume (i) RMP will make full use of any existing transmission rights it has on the Sigurd Line and devote them to the transmission of Glen Canyon's output and (ii) RMP will volunteer to exercise to the fullest extent possible any opportunities it has to redispatch resources to accommodate the transmission of Glen Canyon's output.

3. DISCUSSION, FINDINGS AND CONCLUSIONS

The issues in this docket, as the parties have presented them, are highly complex and invoke difficult questions concerning the parameters of and interplay between state and federal jurisdiction in implementing PURPA. While the parties discussed FERC-jurisdictional issues at length in their arguments and testimony, including FERC-jurisdictional agreements (*e.g.*, the

NOA Amendment) and subject matter (*e.g.*, transmission), we believe the issues can be greatly simplified for our purposes by observing, at the outset, the parameters of our jurisdiction. Namely, we are responsible for assessing "interconnection costs" as PURPA's implementing regulations define that term. 18 C.F.R. § 292.101(b)(7). It is not our role to interpret transmission rights, RMP's Network Operating Agreement, the NOA Amendment or any other matter reserved to FERC.

We also note the parties' positions evolved throughout the course of this proceeding. We have not attempted here to paraphrase or address every argument raised in written testimony, motion briefing and the two-day hearing. However, we have endeavored to address the primary bases on which Glen Canyon relied to support its request for relief.

a. Nothing in PURPA or Its Implementing Regulations Requires RMP to Devote All of Its Existing Transmission Rights to a New QF's Output, and Absent Express Direction from FERC the PSC Will Not Invent Such a Requirement

Glen Canyon's argument assumes RMP has an obligation, under PURPA or otherwise, to devote any and all of RMP's existing transmission rights to transmitting Glen Canyon's output, or, at a minimum, to ensure PacTrans assumes all available existing transmission rights will be so used in studying interconnection and transmission service costs.[9] Like the parties, we are unable to locate any provision in PURPA or its implementing regulations that requires this result. (*See*, *e.g.*, Hr'g Tr. Day One at 67:16-19 (general counsel of sPower testifying he could not point

[9] This premise seems to us fundamental and inherent to Glen Canyon's argument, although Glen Canyon did not often articulate it. (*See, e.g.,* Request at 8 (explaining RMP has 95 MW of transmission rights on the Sigurd Line and assuming any "appropriate study request" will presume RMP will devote its 95 MW of existing transmission to moving Glen Canyon's output).)

to any provision in PURPA requiring a utility to use its existing transmission rights to transmit QF output).)

We recognize the policy underlying PURPA likely frowns upon allowing a utility to deter QF development by unreasonably refusing to employ existing resources so as to unnecessarily inflate interconnection costs. Conversely, we are not confident that policy requires utilities to devote every resource they possess, including transmission rights, to insulate QFs from costs arising out of their projects.

Here, Glen Canyon concedes it sized its project to exactly match the availability of RMP's existing transmission rights. (*See, e.g.,* H. Isern Direct Test. at 4.) That is, Glen Canyon observed RMP appeared to have 95 MW of available transmission rights and assumed it could claim all 95 MW for its own purpose. We find nothing in PURPA's plain language that supports this proposition, and we decline to read an unarticulated requirement as to the deployment of transmission resources into PURPA or its implementing regulations.

Moreover, even if a persuasive case might be made that such a requirement is implied in federal law, we are not persuaded it is our role, absent express direction from FERC, to adopt and enforce it. As noted above, PURPA and its implementing regulations identify certain, specific roles that state commissions are to play in implementing these federal mandates, including (but not limited to) establishing avoided cost pricing and assessing interconnection costs. Compelling utilities to exhaust their existing transmission rights for the benefit of QFs and/or compelling federally regulated transmission service providers to make assumptions about the use of such rights in preparing Studies are not among the tasks delegated to state commissions.

Glen Canyon has not identified a legal basis to support its assertion RMP is required to devote all of its available transmission rights to avoid costs otherwise assessable to Glen Canyon. Absent direction from FERC or other appropriate authority, we conclude it is not our role to invent and enforce such a requirement.

b. Glen Canyon Has Not Shown RMP Has 95 MW of Unencumbered Transmission Rights

Even if our conclusion in the foregoing subsection were different, Glen Canyon has not shown that RMP has 95 MW of unencumbered, existing transmission rights on the Sigurd Line. The evidence is undisputed that APS holds a firm "call right" on RMP's transmission capacity.

Nevertheless, Glen Canyon has argued (i) APS's call rights do not pose a legal restriction on RMP's otherwise available transmission rights; (ii) APS's call rights do not pose a practical restriction on RMP's transmission rights; and (iii) RMP could take actions to mitigate or resolve its obligations to APS such that RMP's transmission rights would be available to transmit Glen Canyon's output.

i. APS's Call Rights are Almost Certainly a Legal Encumbrance on RMP's Transmission Rights, and the PSC Cannot Assume Otherwise

As a legal matter, Glen Canyon argues the APS Contract "requires [RMP] to honor an APS call option from either the Glen Canyon **or** Four Corners substations and [RMP] has flexibility to decide how the power is scheduled through their system." (K. Moyer Rebuttal Test. at 2:36-38.) This is important because, if the APS power is routed through the Four Corners substation, it will not interfere with the transmission of Glen Canyon's output on the Sigurd Line. However, Glen Canyon mischaracterizes the contract's text, which provides "APS shall have 100 MW of net bidirectional firm transfer rights through PacifiCorp's system between the

Glen Canyon/Four Corners substations and the Borah/Brady Substations in Idaho ….” (Restated Transmission Agreement at 8, attached as Exhibit KAB-2 to the Direct Testimony of K. Brown.) That is, the contract does not use the disjunctive “or” but rather a backslash between “Glen Canyon” and “Four Corners.”

We understand Glen Canyon and Four Corners are two geographically distinct substations in southern Utah and, similarly, Borah and Brady are distinct substations in Idaho. Glen Canyon, essentially, argues RMP has the right, when APS exercises its call, to choose whether to move APS’s power through the Glen Canyon or the Four Corners substations.

RMP argues Glen Canyon is “simply wrong” on this point. (K. Brown Surrebuttal Test. at 3:48.) RMP asserts that when APS chooses to exercise and schedule its call option, “it would have [identified] a power source and a transmission arrangement … to get that power to PacifiCorp’s system at either the Four Corners substation or the Glen Canyon substation.” (*Id.* at 3:58-61.) Where APS identifies and schedules a resource deliverable to the Glen Canyon substation, RMP claims it would be interfering with APS’s call right if it required APS to deliver the power, instead, to Four Corners. RMP notes this would pose logistical problems for APS, especially where APS does not have the ability to deliver to the alternate substation. (*Id.* at 3:64-66.)

While the plain language of the contract is, arguably, ambiguous as to which party retains discretion to dictate the point of delivery, we conclude RMP’s interpretation is more plausible and more likely to be enforced. Glen Canyon’s interpretation renders APS’s call right contingent on its ability to deliver to whichever of the two substations RMP prefers, a condition that finds no support elsewhere in the agreement. Of course, it is not within our jurisdiction to render orders adjudicating two utilities' respective rights under an interstate transmission agreement. Therefore, we offer no conclusion as to what constitutes a correct or enforceable interpretation of the contract. We conclude, however, that FERC or another body with jurisdiction over the agreement is far more likely to interpret the contract consistent with RMP's position. We cannot, therefore, assume FERC would adopt Glen Canyon's less plausible interpretation.

ii. We Cannot Assume, Based on Historical Usage, that APS Will Not Exercise Its Call Rights in the Future

Glen Canyon argues APS has historically seldom exercised its call rights and that the APS Contract will likely expire only one year after Glen Canyon's commercial operation date. (*See, e.g.*, K. Moyer Rebuttal Test. at 2-3:39-48.) Neither of these observances justifies an assumption the transmission rights will be unencumbered and available for transmitting Glen Canyon's power.

Regardless of whether APS has frequently exercised its call rights in the past, the fact remains APS has a firm call right on the transmission capacity upon which Glen Canyon wishes to rely. We cannot assume, and we will not direct RMP to assume, APS will not elect in the future to exercise its rights to the transmission capacity.

Similarly, Glen Canyon's assertion the APS contract will be "relevant for only the first year of the Glen Canyon Solar QF PPAs" does little to further its cause. First, the APS Contract will only terminate if RMP retires a specified generation resource,[10] which is projected but not certain to occur one year after Glen Canyon plans to commence operation.[11] More importantly, the transmission capacity would, in any case, be encumbered at the time Glen Canyon commenced operations and for the first year thereafter, during which RMP would be forced untenably to either (i) risk breaching its contract with APS; (ii) violate PURPA by curtailing its purchases from a QF; or (iii) purchase power that it cannot use from Glen Canyon.[12]

iii. Nothing in PURPA Requires a Utility to Take Extraordinary Steps and Enter Ancillary Third Party Agreements to Accommodate a QF's Desire to Avoid Otherwise Assessable Costs

Finally, Glen Canyon asserts RMP can simultaneously satisfy any obligations to it under PURPA and its contractual obligations to APS, without conducting the anticipated transmission upgrades, by taking various affirmative steps, such as (i) curtailing Glen Canyon's output under the emergency provisions of the contract; (ii) exercising "creative ways" to honor the APS

---

[10] As Glen Canyon's witness explains, "[t]he [APS] contract terminates once Cholla 4 is retired." K. Moyer Rebuttal Test. at 2:43; s*ee also* Restated Transmission Agreement at 6, attached as Exhibit KAB-2 to the Direct Testimony of K. Brown (providing agreement terminates on the same date as the Asset Purchase and Power Exchange Agreement dated September 21, 1990); Asset Purchase and Power Exchange Agreement dated September 21, 1990, attached as Exhibit KAB-1 to the Direct Testimony of K. Brown (providing agreement terminates on the date as of which Unit 4 of the Cholla Generating Station has been retired and all costs of terminating the unit have been paid).

[11] RMP's 2017 Integrated Resource Plan projects Unit 4 of the Cholla Generating Plant will be retired in 2020. As RMP points out, the IRP provides "that individual unit retirements reflected in the [IRP], while reasonable for planning purposes, are not firm commitments for early unit closures." (K. Brown Surrebuttal Test. at 5-6:110-113 (quotation omitted).) RMP further argues the IRP makes clear all projected retirements are based on assumptions regarding market conditions that may not materialize. (*Id.* at 6:113-114.)

[12] We discuss the potentiality of (ii) *infra* at 26-29.

contract through "power swaps and scheduling swaps"; and/or (iii) whenever transmission capacity to RMP load is unavailable for Glen Canyon's output, send Glen Canyon's output south and sell it on the southwest market. (Hr'g Tr. Day One at 181:20-183:4.)

We address the first suggestion, concerning curtailment, *infra* at 26-29. With respect to the other suggestions, Glen Canyon points to nothing in statute or rule imposing a duty on RMP to take such measures to spare a QF otherwise assessable costs. For example, Glen Canyon suggests, as a potential power/scheduling swap, RMP could "curtail the APS schedule at Glen Canyon, but do no harm to APS by making up that schedule with [RMP] generation resources … thereby making APS whole on their commitment to deliver power to Borah-Brady." (*Id.* at 182:17-22.) Assuming such a mechanism would make APS whole and not constitute a breach of contract, which is not an assumption we are prepared to make, Glen Canyon offers no legal support for its assertion a utility is required to go to such lengths to accommodate a QF's desire to avoid assessable costs.

Similarly, Glen Canyon's assertion that RMP should be forced to buy its output during transmission constrained periods for resale on a secondary market rather than obtain transmission service sufficient to use the output for RMP's load finds no support in the law. The Code of Federal Regulations explains QFs are responsible for interconnection costs, including transmission, "to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations [with the QF], but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources." 18 C.F.R. § 292.101(b)(7). Glen Canyon would have us conclude a QF may avoid these costs by compelling the utility to purchase power it cannot use for lack of transmission capacity and sell it into a secondary market, thereby imposing on its retail customers whatever market risk may exist between the price it is contracted to pay the QF and the market price. Glen Canyon offers no legal basis to support this extraordinary claim, and we conclude no such requirement exists.

c. FERC Has Jurisdiction to Interpret RMP's Rights under the NOA Amendment, and the Record Does Not Allow Us to Find Opportunities for Redispatch Exist to Accommodate Glen Canyon's Output

Glen Canyon argues RMP has an obligation to use any opportunity to "redispatch" resources to avoid transmission upgrades otherwise necessary to accommodate Glen Canyon's output. In so arguing, Glen Canyon focuses heavily on the NOA Amendment, which allows PacTrans to grant otherwise unavailable DNR transmission service to RMP provided RMP agrees to curtail or redispatch its own resources such that sufficient capacity will exist to meet all PacTrans's obligations. In approving the NOA Amendment, FERC was careful to note it "will not affect the transmission service received by other customers [*i.e.*, transmission customers other than RMP]." (Order Accepting Proposed Network Operating Agreement Amendment, attached as Exhibit 2 to K. Moyer Direct Test.)

RMP argues redispatch under the NOA Amendment "is a transmission service concept, and it belongs in the transmission service request study." (Hr'g Tr. Day Two at 38:10-13.) Indeed, PacTrans has never conducted an interconnection study, for ER or NR, that assumed any form of generation redispatch. (*Id.* at 38:7-10.) According to PacTrans, interconnection Studies never make any specific assumptions about use of parties' existing transmission rights; the

Studies look only at what the available transmission capacity is and what rights have already been assigned, making no assumptions about how those rights may be used. (*Id.* at 38:14-20.)[13]

As an initial matter, the NOA Amendment is a FERC-approved document subject to FERC's jurisdiction. While we plainly have jurisdiction to determine and assess interconnection costs for QF projects, it is generally not our role to interpret and compel a utility or its transmission service provider to take action under a FERC-jurisdictional document that governs transmission service. We do not suggest that we may never rely on FERC-imposed or FERC-jurisdictional obligations in making findings or conclusions that fall within our jurisdiction. We recognize circumstances may exist where the obligation is sufficiently unambiguous or essential such that we could reliably infer what the FERC-approved outcome would be and be justified in relying on that inference. These are not such circumstances. Whether FERC contemplates the flexibility afforded to RMP in the transmission service context extends to the interconnection service context is unclear, and it is not our role to decide the issue.

Moreover, Glen Canyon has not identified any generation resources that exist "behind the constraint" that might be redispatched to alleviate the need for additional transmission capacity. Indeed, the available evidence suggests no such generation resources exist. (*See, e.g.,* Hr'g Tr. Day Two at 37:20-24.) As RMP explains, a "more typical redispatch scenario would involve a new resource that is more integrated on the transmission system … in which case dispatch

---

[13] We note, while Glen Canyon's witnesses and briefing relied heavily on the NOA Amendment, Glen Canyon's counsel stated at hearing: "We're not saying [the redispatch] has to be under the NOA Amendment. We reference that because it's such a good explanation of what we're trying to do in avoiding unnecessary upgrade costs …." (Hr'g Tr. Day Two at 136:3-6.)

scenarios are possible to accommodate the output of the QF using a portfolio of owned and contracted resources." (Brown Direct at 9:186-193.) Here, the record identifies only one other DNR behind the transmission constraint, the APS Contract (which is only a DNR in the winter months). (*See, e.g.*, Hr'g Tr. Day Two at 42:14-19.) As discussed above, RMP does not have discretion to redispatch APS's rights at its convenience. Therefore, we find no evidence in the record to support Glen Canyon's assertion that RMP could avoid the need for additional transmission capacity by exercising "redispatch" options, under the NOA Amendment or otherwise.

In sum, we conclude it is not the PSC's role to interpret RMP's rights and extend its obligations under a FERC-approved agreement pertaining to transmission service. Further, even if RMP had an unambiguous obligation to exercise its rights under the NOA Amendment to spare Glen Canyon assessable costs, the record does not allow us to find RMP has or controls generation resources behind the constraint sufficient to alleviate such costs.

d. The PSC-Approved Avoided Cost Methodology Does Not Subsume Interconnection Costs Even Where Curtailment is Assumed for Avoided Cost Calculations

Glen Canyon argues the modeling RMP performed to determine its avoided cost pricing already captured any costs associated with transmission constraints associated with its projects. Specifically, Glen Canyon points out "[a]voided cost prices are adjusted accordingly when modeling constraints prevent QF [e]nergy from serving load or prevent other resources from being backed down, or redispatched." (K. Moyer Direct Test. at 23:480-82.) Glen Canyon asserts the avoided cost pricing model "is self-correcting in that avoided cost prices are reduced, potentially to zero, for a QF project located in a transmission constrained area." (*Id.* at 23:482-

83.) The model "thus ensures that avoided cost prices are no higher than the costs the utility expects to avoid as a result of the incremental generation from the QF project, maintaining customer indifference." (*Id.* at 23:484-24:487.)

RMP responds that avoided cost price modeling and the interconnection study process are "entirely separate processes, with different study parameters and different questions to be answered." (D. MacNeil Direct Test. at 8:182-183.) "The goal of [the avoided cost] study is to project the incremental resources that could potentially be avoided [as a result of the QF's generation] for purposes of developing an avoided-cost rate." (*Id.* at 8:184-186.). "By contrast, the interconnection and [transmission service request] study processes are studies of the physical capability of the transmission system to accommodate the additional requested interconnection or [transmission service]." (*Id.* at 8:186-9:188.)

We understand the model used for determining Glen Canyon's avoided cost pricing assumes power moves through the Four Corners substation, rather than the Glen Canyon substation. As RMP's witness explained, "[t]he GRID model cannot account for the optionality in APS's rights, and therefore (for simplicity) these rights have been represented as a reduction in the transfer capability out of the Four Corners [as opposed to the Glen Canyon] transmission area, an assumption that has not changed in many years and is not specific to the Glen Canyon avoided-cost studies." (D. MacNeil Surrebuttal Test. at 4:80-83.) We also understand "[w]hen resources in an area exceed load and export capability, the GRID model considers any remaining imbalance between resources and requirements as 'trapped energy'" and removes the QF's output and associated estimated avoided cost from the model for those undeliverable periods. (*Id.* at 5:100-112.)

In other words, GRID makes certain assumptions about the deliverability of a QF's output in calculating avoided cost pricing. However, RMP emphasizes the avoided cost methodology does not "identify any transmission system upgrades that may be required to address reliability or constraint issues before [PacTrans] can grant the QF's interconnection request or [RMP's transmission service request] to deliver the QF's power to load." (D. MacNeil Direct Test. at 9:199-202.) These are the functions of the interconnection and transmission service request Studies. (*Id.* at 9:202-203.) Moreover, RMP testified that when a QF's avoided cost pricing is modeled, RMP generally does not yet know the outcome of a QF's interconnection study. "A QF can request, and [RMP] must provide, indicative pricing before the QF has an interconnection study." (D. MacNeil Direct Test. at 8:171-179.)

That transmission upgrades are not included in the avoided cost study appears undisputed. In fact, the DPU has expressed concern the current avoided cost methodology does not account for such costs. (*See, e.g.*, Hr'g Tr. Day One at 34:5-10 (C. Peterson expressing concern that RMP "in preparing the avoided cost pricing … made no effort to model a significant [transmission] constraint that was known to [RMP] and unique to the specific transmission" line Glen Canyon seeks to utilize).)[14]

As discussed in greater detail *infra* at 29-32, interconnection costs are distinct from avoided costs. No evidence was introduced suggesting GRID captures associated transmission infrastructure upgrades necessary to deliver QF output. Therefore, we find no merit in Glen

---

[14] While the DPU expresses concern about the failure of the model to capture such costs, the parties generally agree that RMP calculated Glen Canyon's avoided cost pricing consistent with the PSC-approved method.

Canyon's assertion the avoided cost study already captures all costs associated with insufficient transmission capacity.

e. FERC Has Jurisdiction to Determine Whether PURPA Requires RMP to Procure Firm Transmission for Glen Canyon's Output and Whether Allowing Glen Canyon to Agree to Curtail during Constrained Periods Runs Afoul of PURPA; the PSC Cannot Make Assumptions that Shift the Regulatory Risk of an Adverse Outcome to Ratepayers

FERC's "PURPA regulations permit a purchasing utility to curtail a QF's output in [only] two circumstances: (1) in system emergencies … or (2) in light load periods, pursuant to section 292.304(f) … but only if the QF is selling its output on an 'as available' basis." *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215 at ¶ 38 (2013) (citing 18 C.F.R. §§ 292.307(b), 292.304(f)). FERC regulations define a "system emergency" as "a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property." (*Id.* at ¶ 39 (quoting 18 C.F.R. § 292.101(b)(4).) Accordingly, "the purchasing utility cannot curtail the QF's energy as if the QF were taking non-firm transmission service on the purchasing utility's system." (*Id.* at ¶ 26.)

Nevertheless, Glen Canyon argues "PacifiCorp cannot mandate, based on PURPA, that only a firm NR transportation arrangement can work under all circumstances for QFs." (Hr'g Tr. Day Two at 125:23-25.) Glen Canyon further asserts "[t]here's nothing in FERC law that mandates a firm transmission arrangement as opposed to a … firm purchase obligation." (*Id.* at 126:7-10.) Instead, Glen Canyon maintains PURPA "does not mandate anything except that this utility accommodate a QF by buying its energy when it's delivered on [a] firm basis and then dealing with it." (*Id.* at 126:12-16.)

Additionally, Glen Canyon "has indicated it's willing to take the risk" of being curtailed. (Hr'g Tr. Day Two at 121:4-11.) Glen Canyon contemplates "few situations when it could be curtailed … [such as] when APS is using its full call rights, and [RMP] is not able to procure short-term, non-firm, or firm transmission to deliver [Glen Canyon's output] to load." (*Id.* at 78:10-15.) Glen Canyon asserts such curtailment is allowed under the "emergency exception" of its PPA. (*Id.* at 78:21-22.)

While *Pioneer Wind* does not expressly hold a utility must purchase firm transmission to accommodate a QF, it does unequivocally provide the utility cannot curtail a QF outside of an emergency or a "light load" condition as enumerated in the C.F.R. RMP's breaching a contract with APS by failing to honor its call right on the Sigurd Line would not likely "result in imminent significant disruption of service to customers" or likely "endanger life or property." Therefore, we conclude FERC is unlikely to consider the lack of transmission capacity on the Sigurd Line to be an emergency condition warranting curtailment.

Further, it is far from certain that FERC would hold firm transmission is not required for QFs. As Glen Canyon's counsel conceded at hearing: "There is no regulation that specifically says one way or the other whether [the PSC] could do what we're asking [it] to do." (Hr'g Tr. Day Two at 144:4-11.) Nonetheless, Glen Canyon argues the PSC should not assume FERC would disallow voluntary QF curtailment. (*Id.*)

For its part, the DPU believes existing FERC precedent "point[s] fairly strongly" toward the conclusion that "firm transmission … [is] a pretty solid requirement." (*Id.* at 151:7-17.) The DPU acknowledges it is aware of no precedent that prohibits a QF from voluntarily selling on something less than a firm basis and believes no answer presently exists as to how FERC would rule on the issue. (*Id.* at 151:17-21.)

We acknowledge that whether utilities are required to ensure firm transmission for QF output and whether QFs may agree to voluntarily curtail their sales in transmission-constrained areas to avoid being assessed interconnection costs are matters for FERC to decide. We do not believe the answers to these questions are obvious and will not speculate as to the probable outcome before FERC. Allowing QFs to voluntarily curtail to avoid being assessed prohibitive interconnection costs seems reasonable, but FERC may conclude it is inconsistent with PURPA. Indeed, *Pioneer Wind* expressly found a utility's proposed agreement to curtail owing to lack of transmission capacity was inconsistent with PURPA and its implementing regulations. Even where a QF affirmatively volunteers to curtail to avoid incurring interconnection costs, FERC may conclude such an agreement is unlawful.

Similarly uncertain is whether FERC would require a utility to procure firm transmission service under these circumstances. FERC may adopt Glen Canyon's position, *i.e.*, the utility's obligation is simply to purchase the QF's output and whether the utility has means to deliver the output to load is a separate issue. Alternatively, FERC may conclude NR interconnection and firm transmission is required.[15]

---

[15] We note that, in either case, the costs attendant to a QF's choosing to site in an area without sufficient transmission capacity should not be borne by the utility and its customers. As discussed *infra* at 30-31, if a QF may compel a utility to purchase its output even though the utility has no means to deliver it to load, rendering the purchase useless, then it would be essential to capture the diminution in value in the avoided cost calculation.

We will not make assumptions about FERC's conclusions on these matters, and we cannot assume FERC would agree with Glen Canyon that (i) it may voluntarily curtail and/or (ii) no requirement mandates RMP obtain firm transmission for Glen Canyon's output. Indeed, we believe a substantial chance exists that FERC would conclude voluntary curtailment is unlawful and a significant chance exists it would conclude firm transmission is required. In any event, we cannot assume FERC would hold otherwise. To do so would shift the regulatory risk of an adverse outcome to RMP's ratepayers who would bear the costs of any undeliverable power and additional transmission.

f. Transactions between RMP and QFs Must Account for Otherwise Unnecessary Transmission Costs, and the CFRs Contemplate Such Costs May be Assessed as Interconnection Costs, If Not Otherwise Captured in Avoided Cost Pricing

Glen Canyon argues that, under the OATT and FERC precedent, a distinction exists between "interconnection facilities" — "all facilities and equipment between the Generating Facility and the Point of Interconnection" — and "network upgrades" — "upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System." (*See, e.g.,* K. Moyer Direct Test. at 12:258-15:304 (quoting OATT § 36).) Glen Canyon argues the interconnection customer (*e.g.,* Glen Canyon) is responsible for the former while the transmission service customer (e.g., RMP) is responsible for the latter.

We conclude Glen Canyon's emphasis on these distinctions in the OATT, which applies to all PacTrans's customers, is largely irrelevant because FERC regulations expressly define "interconnection costs" within the context of PURPA.

> Interconnection costs means the reasonable costs of connection, switching, metering, *transmission*, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. *Interconnection costs do not include any costs included in the calculation of avoided costs*.

18 C.F.R. § 292.101(b)(7) (emphasis added). The PSC is responsible for ensuring these interconnection costs, as FERC defines them, are assessed to QFs. 18 C.F.R. § 292.101(b)(7).

The proposition that interconnection costs should include any otherwise unnecessary investments in transmission facilities should not be controversial. This is easily demonstrable by hypothetical: suppose, for the sake of argument, a QF chooses to site its project in an area where no transmission capacity is available, the deficiency cannot be remedied through redispatch or otherwise, and the cost to upgrade the transmission capacity sufficient to accommodate the QF's output is more than $400 million. Under such a scenario, does PURPA contemplate the QF may nevertheless unilaterally elect to site in the transmission constrained area, force PacTrans to invest more than $400 million to upgrade its transmission network to accommodate the QF's output and see those costs passed through to RMP and its ratepayers? We conclude the answer is "no." Allowing QFs to make inefficient siting decisions and to shift the attendant costs to ratepayers is inconsistent with the primary objective of ratepayer indifference.

Glen Canyon emphasizes that QFs are responsible for delivering their output to the point of interconnection and that, thereafter, the utility is responsible for transmitting the output to load. This is precisely the reason it is essential that interconnection costs, including investments in transmission infrastructure, be accurately estimated and assessed as a component of interconnection costs. If the QF avoids those costs at the interconnection assessment stage, no mechanism exists to later assess them and ratepayers will bear the burden.

Even if Glen Canyon's position were correct, and transmission upgrades beyond the point of interconnection are not assessable as interconnection costs, it would not alleviate our responsibility to identify those costs and ensure they are properly accounted for in Glen Canyon's transactions with RMP. The alternative would be to load such costs into the avoided cost methodology, which would decrease, probably significantly, the price RMP must pay to Glen Canyon for its output. As the DPU explained, "two levers can move," (i) avoided cost pricing and (ii) assessed interconnection costs, to ensure QFs are held responsible for transmission upgrades that are made necessary by their projects. (Hr'g Tr. Day Two at 150:1.)[16] The DPU appears ambivalent about which lever is used but maintains these mechanisms "need to be coordinated so that a [QF] … isn't either paying twice for the same network upgrade or not paying at all for a network upgrade that's caused by [its] project." (*Id.* at 150:1-5.) If neither lever moves to account for such costs, they will become "socialized transmission system costs and spread among all customers." (*Id.* at 150:17-22.)

[16] The DPU quotes *Pioneer Wind* in noting that "[c]orrespondingly, implicit in [FERC's] regulations, transmission or distribution costs … may be accounted for in the determination of avoided costs if they have not been separately assessed as interconnection costs." (Hr'g Tr. Day Two at 149:17-24.)

The record suggests even Glen Canyon recognizes that such costs need to be accounted for in the avoided cost methodology, if not elsewhere. At hearing, Glen Canyon's counsel suggested "on a forward-looking basis" the method for calculating avoided costs should be revised to "reflect in some manner the overall cost implications to the [u]tility." (Hr'g Tr. Day Two at 147:14-19.)

The current PSC-approved avoided cost methodology is the product of extensive litigated proceedings. That method does not account for transmission upgrades of the nature Glen Canyon seeks to avoid in this docket. Glen Canyon has not asked that we modify the method in this docket, and we decline to do so. We conclude it is appropriate and consistent with PURPA's implementing regulations to include transmission costs, which are not captured in the avoided cost calculation, as a component of "interconnection costs."

g. Glen Canyon Has Not Demonstrated a Legal or Factual Basis Warranting PSC Intervention in the Process to Study and Ascertain Interconnection and Transmission Costs.

Finally, we note the relief Glen Canyon seeks asks us to avoid these issues altogether by influencing PacTrans to make assumptions in its Studies that ensure results agreeable to Glen Canyon. We conclude no basis exists under the law for us to do so.

We are charged with assessing interconnection costs but no interconnection costs have been proposed. Rather, Glen Canyon is concerned about the results its parent company received on a different project and asks us to preemptively intervene in the study process for its new projects, loading assumptions into it that will minimize projected costs related to transmission upgrades. No basis exists for us to do so. We cannot make findings of fact pertaining to such costs with a record void of evidence of those costs, and we will not “put our finger on the scale” to preemptively distort the evidence.

We do not suggest the results of PacTrans’s Studies must be uncritically accepted and the costs therein passed onto Glen Canyon without scrutiny. Arguments may exist that some portion of the costs are unnecessary, exaggerated or inappropriate to assess against Glen Canyon. We cannot make such determinations in a vacuum. If and when such costs are proposed to be assessed against Glen Canyon, it will have an opportunity to offer evidence in opposition. Glen Canyon may not, however, rely on the authority of the PSC to interfere with the study process and prevent such costs from being measured and ascertained in the first instance.

4. ORDER

For the foregoing reasons, we order as follows:

(1) Glen Canyon’s Request in Docket No. 17-035-36 is denied;

(2) Glen Canyon’s MPI in Docket No. 17-035-36 is denied;

(3) Having heard the parties’ evidence at hearing and made findings and conclusions on the merits, RMP’s MTD in Docket No. 17-035-36 is denied as moot; and

(4) The unoppposed Motion for Stay in Docket Nos. 17-035-26 and 17-035-28 is granted, and, in light of the holidays, the PSC will issue no decision on the merits of these dockets before January 16, 2018 unless the parties jointly request such a decision.

DATED at Salt Lake City, Utah, December 22, 2017.

/s/ Thad LeVar, Chair

/s/ David R. Clark, Commissioner

/s/ Jordan A. White, Commissioner

Attest:

/s/ Gary L. Widerburg
PSC Secretary
DW#298691

Notice of Opportunity for Agency Review or Rehearing

Pursuant to Utah Code Ann. §§ 63G-4-301 and 54-7-15, a party may seek agency review or rehearing of this order by filing a request for review or rehearing with the PSC within 30 days after the issuance of the order. Responses to a request for agency review or rehearing must be filed within 15 days of the filing of the request for review or rehearing. If the PSC fails to grant a request for review or rehearing within 20 days after the filing of a request for review or rehearing, it is deemed denied. Judicial review of the PSC's final agency action may be obtained by filing a Petition for Review with the Utah Supreme Court within 30 days after final agency action. Any Petition for Review must comply with the requirements of Utah Code Ann. §§ 63G4-401, 63G-4-403, and the Utah Rules of Appellate Procedure.

CERTIFICATE OF SERVICE

I CERTIFY that on December 22, 2017, a true and correct copy of the foregoing was delivered upon the following as indicated below:

By Electronic-Mail:

Data Request Response Center (datarequest@pacificorp.com)
PacifiCorp

Jana L. Saba (jana.saba@pacificorp.com)
Yvonne Hogle (yvonne.hogle@pacifcorp.com)
Daniel Solander (daniel.solander@pacificorp.com)
Rocky Mountain Power

Sarah K. Link (sarah.kamman@pacificorp.com)
Karen Kruse (karen.kruse@pacificorp.com)
Pacific Power

Gary A. Dodge (gdodge@hjdlaw.com)
Phillip J. Russell (prussell@hjdlaw.com)
Hatch, James & Dodge, P.C.

Jennifer L. Spina (jennifer.spina@pinnaclewest.com)
Pinnacle West Capital Corporation

Elizabeth M. Brereton (lbrereton@swlaw.com)
Snell & Wilmer L.L.P.

Patricia Schmid (pschmid@agutah.gov)
Justin Jetter (jjetter@agutah.gov)
Robert Moore (rmoore@agutah.gov)
Steven Snarr (stevensnarr@agutah.gov)
Assistant Utah Attorneys General

Erika Tedder (etedder@utah.gov)
Division of Public Utilities

By Hand Delivery:

Office of Consumer Services
160 East 300 South, 2nd Floor
Salt Lake City, Utah 84111

____
Administrative Assistant

Attachment F

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Blue Marmots V LLC,	)	
Blue Marmots VI LLC,	)	**Docket No. EL19-13-000**
Blue Marmots VII LLC,	)	
Blue Marmots VIII LLC,	)	
Blue Marmots IX LLC,	)	
	)	

MOTION TO INTERVENE AND COMMENTS OF PACIFICORP

In accordance with Sections 212, 213 and 214 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or the "Commission"),[1] PacifiCorp moves to intervene in the captioned proceeding, and submits comments on the subject petition for declaratory order.

I. Executive Summary

The key issue in dispute in this docket arises from Blue Marmots' decision to deliver qualifying facility ("QF") power from a point of interconnection with PacifiCorp's system to a congested point of delivery on Portland General Electric's ("PGE") system. PGE has characterized the costs of network upgrades required by Blue Marmots' point of delivery as state-jurisdictional interconnection costs subject to the Oregon Public Utility Commission's ("Oregon PUC") Public Utility Regulatory Policies Act of 1978 ("PURPA") interconnection cost allocation policies. While PacifiCorp has historically considered these types of costs as arising out of the FERC-jurisdictional transmission service arrangements made to deliver the QF power

[1] 18 C.F.R. §§ 385.212, 385.213 and 385.214 (2018).

to load, PacifiCorp is aligned with PGE that the Oregon PUC should address the costs in the state-jurisdictional QF power purchase agreement ("PPA"). Regardless of which service — interconnection or transmission — FERC considers to be triggering the costs at the Blue Marmots' chosen delivery point, it is critical they be addressed with PURPA's customer indifference requirement in mind. The Oregon PUC is best-situated to address this issue in the first instance given PURPA's system of cooperative federalism.[2]

On its face, the Blue Marmots' petition purports to present narrow issues related to Blue Marmots' proposed QF sales to PGE. However, the Blue Marmots' petition touches on a host of transmission and interconnection concerns that affect other similarly-situated utilities and that strike at the core of state and federal policy under PURPA. Specifically, QFs seeking must-take, avoided-cost PURPA contracts are increasingly siting projects in or, as in the case of off-system QFs like the Blue Marmots, delivering power to transmission-constrained areas and creating implementation concerns that put an electric utility's customers at risk of bearing costs well beyond the avoided costs envisioned by PURPA.

Perhaps due to a perceived lack of clarity on how interconnection and transmission issues should be addressed in the PURPA system of cooperative federalism, QFs like Blue Marmots are increasingly seeking to exploit the jurisdictional divide between state and federal authority to argue, for example, that the costs associated with constructing the network upgrades necessary to

---

[2] As the Commission knows, the thoughtful and appropriate implementation of PURPA relies on a system of "cooperative federalism" under which the states and FERC systematically address the PURPA issues within their respective jurisdiction to ensure that PURPA's statutory goals are met. *Compare* 16 U.S.C. § 824a-3(a) (2012) (giving FERC authority to promulgate rules "to encourage cogeneration and small power production" including rules that "require electric utilities to offer to . . . purchase electric energy from such facilities") *with* 16 U.S.C. § 824a-3(f) (providing that "each State regulatory authority shall . . . implement [any] rule [prescribed by FERC under § 824a-3(a)]."); *see also FERC v. Mississippi*, 456 U.S. 742, 767 (1982) (quoting *Hodel v. Virginia Surface Mining & Reel. Assn*., 452 U. S. 264, 289 (1981), and noting that PURPA '"… establishes a program of cooperative federalism that allows the States, within limits established by federal minimum standards, to enact and administer their own regulatory programs, structured to meet their own particular needs.'").

make QF interconnection and transmission arrangements — sometimes on the order of hundreds of millions of dollars for a single QF — should be allocated to a utility's customers rather than to the QFs who control the costs they cause by their siting or point of delivery choices. Alternatively, QFs argue that a utility need not construct the necessary network upgrades if the utility has existing firm transmission service rights in the constrained area where the QF chose to site or deliver its project because, according to the QFs, PURPA requires that the utility use those existing firm rights to deliver power from the new QF resource to load instead of to deliver power from the resources for which the rights were originally arranged. In essence, QFs argue that no incremental service arrangements need to be made for the QF resource if the utility has any existing firm rights in the constrained area, and that those existing rights should be used to deliver QF power regardless of where they are held (*e.g.*, on the utility's own system or a third-party system) or the nature of the rights (*e.g.*, firm network rights, firm point-to-point rights, or firm legacy contract rights).[3]

This exploitation of jurisdictional seams, if successful, has the potential to degrade existing firm transmission rights or foist hundreds of millions of dollars of costs on customers due to disagreement about a state's authority to send price signals for QF siting decisions, or to

[3] PacifiCorp is unaware of any state that has looked favorably on this QF interpretation of PURPA's requirements. *See, e.g., In Re Application of Rocky Mountain Power for Approval of the Power Purchase Agreement Between PacifiCorp and Glen Canyon Solar*, (Utah Pub. Serv. Comm'n Docket No. 17-035-26 et al), 14 (Dec. 22, 2017) (hereinafter "Glen Canyon Order") ("Glen Canyon's argument assumes RMP has an obligation, under PURPA or otherwise, to devote any and all of RMP's existing transmission rights to transmitting Glen Canyon's output, or, at a minimum, to ensure PacTrans assumes all available existing transmission rights will be so used in studying interconnection and transmission service costs. Like the parties, we are unable to locate any provision in PURPA or its implementing regulations that requires this result. We recognize the policy underlying PURPA likely frowns upon allowing a utility to deter QF development by unreasonably refusing to employ existing resources so as to unnecessarily inflate interconnection costs. Conversely, we are not confident that policy requires utilities to devote every resource they possess, including transmission rights, to insulate QFs from costs arising out of their projects.") (internal citations omitted).

allocate interconnection and/or transmission costs under PURPA. Any FERC decision on the Blue Marmots' petition will not stand in isolation; it will have a ripple effect.

PacifiCorp respectfully makes the following requests to the Commission in considering the petition. First, PacifiCorp respectfully requests that the Commission clarify that the issues raised by the Blue Marmots' petition are best addressed at the state level. From a procedural perspective, the petition is not ripe for decision at FERC. Blue Marmots' complaints are still pending before the Oregon PUC, rendering any FERC petition premature. The Oregon PUC has ample authority to resolve the issues raised by Blue Marmots.

Second, should the Commission decide to address the merits of Blue Marmots' petition, PacifiCorp respectfully requests that FERC be mindful of existing state precedent addressing QF interconnection requirements and costs — an area of clear state authority under PURPA. Certain states have deliberately and comprehensively developed state-specific QF interconnection policies, while others have very clear customer indifference policies that inform their interconnection policies. PacifiCorp would ask FERC to leave existing state interconnection policies intact.

Finally, should the Commission elect to address Blue Marmots' petition on the merits and require PGE's customers to bear the costs of network upgrades necessary to accommodate the Blue Marmots' power at the Blue Marmots' chosen congested delivery point, FERC should provide guidance on how state commissions can implement and utilities can comply with the obligations of PURPA in a manner that harmonizes its dual statutory requirements to encourage QF development and ensure the utility's customers remain indifferent to the costs associated with the utility's purchase of that power. Insulating QFs from the cost of upgrades they cause will encourage QFs to choose sites or delivery points without regard to transmission system constraints or proximity to load. If this "siting indifference" steamrolls "customer indifference," customers will lose.

II. Communications

PacifiCorp requests that all correspondence, pleadings, and other communications concerning this filing be served upon the following individuals who should be included on the official service list in this proceeding:

Christopher R. Jones*
TROUTMAN SANDERS LLP
401 9th Street, N.W., Suite 1000
Washington, DC 20004
(202) 662-2181
Christopher.Jones@TroutmanSanders.com

Karen J. Kruse
Deputy General Counsel
PacifiCorp
825 N.E. Multnomah, Suite 2000
Portland, Oregon 97232
(508) 813-5863
karen.kruse@pacificorp.com

III. PacifiCorp

PacifiCorp is an Oregon corporation. PacifiCorp is a vertically-integrated public utility primarily engaged in providing retail electric service to approximately 1.9 million residential, commercial, industrial, and other customers in portions of the following states: California, Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp provides electric transmission service in nine Western states, and owns or has interests in approximately 16,500 miles of transmission lines and 71 thermal, hydroelectric, wind-powered generating, and geothermal facilities. PacifiCorp provides open access transmission service in accordance with its Open Access Transmission Tariff ("OATT"), which is on file with the Commission. PacifiCorp operates two balancing authority areas ("BAAs"), PacifiCorp East ("PACE") and PacifiCorp West ("PACW").

IV. Motion to Intervene

PacifiCorp moves to intervene in the captioned proceeding. PacifiCorp is a neighboring utility to PGE and is also regulated by the Oregon PUC. PacifiCorp is also facing significant transmission-related challenges related to QFs siting in or delivering to constrained areas, and many of those issues are potentially implicated by the Blue Marmots' petition. The Commission's disposition of the Blue Marmots' petition may therefore directly impact PacifiCorp and its customers. Accordingly, PacifiCorp has a unique interest in this case and its interests cannot be adequately represented by another party.

V. Comments

The following comments first provide a brief overview of PURPA's cornerstone customer indifference requirement in Section A, followed by a description of the complementary authority over QF interconnection rates, terms, and conditions reserved for state commissions in Section B. As particularly relevant to the issues raised in this docket, PacifiCorp next addresses how transmission constraints and generation-to-load ratios can significantly affect the cost or timing of interconnection service requests in Section C, and then offers examples of how some state commissions have chosen to address congestion-related issues through their QF interconnection policies in Section D. Section E examines why the type of off-system QF issues raised by the Blue Marmots' petition should be addressed by the Oregon PUC, with the thoughtful and long-standing state policies on QF interconnection policies remaining intact. Finally, Section F explains why the Blue Marmots' petition should be denied.

A. Overview of Customer Indifference Requirement under PURPA

PURPA was passed in 1978 with the goal of encouraging greater domestic development of renewable energy resources from cogeneration and certain small power production facilities, or QFs. That mandate, however, came with an important protection for customers. Congress did not intend to support QF development at any cost, and certainly not at the expense of a utility's other customers. It is a federal requirement — embodied in statute,[4] regulation,[5] and precedent[6] — that utility customers remain financially indifferent to a utility's purchase of QF power. This "customer indifference" standard is a pillar of PURPA that must be read in conjunction with PURPA's "encouragement" mandate.

In enacting PURPA, Congress' intention was to open up a market for QF power that encouraged their development but in a way that makes "ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives."[7] Congress was not asking utilities or their customers to subsidize QF development by paying more for QF power than they otherwise would have paid for electric service.[8] The fact that PURPA was not meant to harm customers or subsidize QF development is clearly expressed in PURPA's legislative history.[9] It is also clearly expressed in the statute and FERC's regulations. PURPA provides that "[n]o such rule prescribed under [16 U.S.C. § 824a–3](a) shall provide for a rate

---

[4] *See, e.g.*, 16 U.S.C. §§ 824a-3(b), 824a-3(d) (2012).

[5] *See, e.g.*, 18 C.F.R. § 292.304(a)(2) (2018) ("Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases."); *id*. § 292.101(b)(6) (defining "avoided costs" as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility…, such utility would generate itself or purchase from another source."); *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 45 (1980) (hereinafter "Order No. 69") (discussing industry comments on section 304(a) of the then-new regulations and noting that utility customers would be kept whole, paying the same rates as they would have paid had the utility not purchased energy and capacity from the QF).

[6] *See, e.g.*, *S. Cal. Edison Co., San Diego Gas & Elec. Co.*, 71 FERC ¶ 61,269, 62,080 (1995) (discussing, inter alia, what state policies would violate PURPA by imposing costs on utilities in excess of avoided costs); Order No. 69 at 29 (Under the definition of "avoided costs" in this section, the purchasing utility must be in the same financial position it would have been had it not purchased the QF's output).

[7] *S. Cal. Edison Co.*, 71 FERC ¶ 61,269 at 62,080.

[8] *S. Cal. Edison Co.*, 71 FERC ¶ 61,269 at 62,080.

[9] *See* Conference Report on PURPA, H.R. Rep. No. 1750, 95th Cong., 2nd Sess. 97-98 ("The provisions of this section are not intended to require the rate payers of a utility to subsidize cogenerators or small power producers.").

which exceeds the incremental cost to the electric utility of alternative electric energy."[10] Section 210(d) of PURPA defines "incremental cost of alternative electric energy" as "the cost to the electric utility of the electric energy which, ***but for*** the purchase from [the QF], such utility would generate or purchase from another source."[11] Each of these concepts is mirrored in FERC's PURPA implementing regulations.[12]

In addressing FERC's avoided cost rulings soon after PURPA's enactment, the Supreme Court rightly assumed that utility rates charged to consumers would remain the same after PURPA's enactment "for, by hypothesis, the utilities would have incurred the same costs had they generated the energy themselves or purchased it from other sources instead of purchasing from a qualifying facility."[13] The Court noted that, although requiring utilities to purchase QF power at avoided cost would not provide direct rate savings to customers, FERC reasonably deemed it more important for the rule to provide sufficient incentive to develop QFs and that customers and the nation as a whole would benefit from reduced reliance on fossil fuels and a more efficient use of energy.[14] That incentive, however, was not intended to drive increases in customer utility rates.

Thus, when analyzing arguments about whether states are properly encouraging QF development, the Commission should be mindful of the legislative intent that PURPA should not

---

10 16 U.S.C. § 824a-3(b).

11 16 U.S.C. § 824a-3(d) (emphasis added).

12 18 C.F.R. § 292.304(a)(2) ("Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases."); *id*. § 292.101(b)(6) (defining "avoided costs" as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility..., such utility would generate itself or purchase from another source.").

13 *American Paper Institute, Inc. v. American Electric Power Service Corp. et al*, 461 U.S. 402, 415 n. 9 (1983).

14 *American Paper Institute, Inc*., 461 U.S. at 403.

harm a utility's customers. To the extent PURPA's customer indifference standard is in tension with any other federal statutes committed to the Commission's discretion, or any policies the Commission has enacted under such statutes — *e.g.*, the Commission's transmission pricing policies that direct all system users to share the cost of the network upgrades necessary to arrange FERC-jurisdictional services — the Commission must strive to harmonize and give effect to all of the competing statutory mandates within its purview.[15] Absent a clearly expressed congressional intent for one statute to displace another, statutory directives like the PURPA customer indifference standard must be read in conjunction with other statutory requirements and the policies that flow from them.

B. States Have Exclusive Jurisdiction over QF Interconnections and Associated Costs

States have long sought to give effect to PURPA's principle of customer indifference. States can and should ensure customer indifference through accurate avoided cost pricing and appropriate non-rate terms and conditions of QF PPAs, issues commonly known to be within the states' jurisdiction. Less attention has historically been paid to how states can and should ensure customer indifference through state-jurisdictional QF interconnection policies.

The costs of network upgrades associated with a QF's interconnection and transmission service arrangements can have a significant impact on customer rates. This concern is especially acute because of the Commission's requirement that QFs are required to be delivered on firm

[15] *See e.g.*, *Epic Sys. Corp. v. Lewis*, 138 S. Ct. 1612, 1624 (2018) (citing *Morton v. Mancari*, 417 U.S. 535, 551, (1974)) (heeding that when confronted with two Acts of Congress allegedly touching on the same topic, the Court is not at "'liberty to pick and choose among congressional enactments' and must instead strive 'to give effect to both.'"); *see also Vimar Seguros y Reaseguros, S.A. v. M/V Sky Reefer*, 515 U.S. 528, 533 (1995) (noting if two statutes cannot be harmonized, the challenging party has a heavy burden to show a clear congressional intention for one statute to displace the other.).

transmission with curtailment limited to system emergencies.[16] For example, if a QF sites in a constrained area where it can directly interconnect with a utility's system, and $100 million in network upgrades is needed to provide the QF with interconnection service, that $100 million can be allocated one of two places: to the QF, or to the utility's customers. The allocation to the QF is typically direct and simpler to follow — the costs are identified in the QF's interconnection studies and incorporated into its interconnection agreement with the utility's transmission function.[17] The allocation to the utility's customers is less direct but no less impactful. More specifically, if the cost of the network upgrades necessary to make the QF's arrangements are rolled into a utility's transmission rate base, then those costs are shared by all users of PacifiCorp's transmission system through increased transmission rates. Given that over 88 percent of PacifiCorp Transmission's annual transmission revenue comes from providing load service to PacifiCorp's retail customers, PacifiCorp's retail customers are the ones predominantly left bearing the burden if the costs are not directly allocated to the QF. PacifiCorp therefore next provides an overview of state QF interconnection authority and the problems that have arisen in its service territory related to QF interconnections and delivery.

---

16 Unless the QF is selling its power to the utility on an as-available basis (an uncommon situation not relevant here), Commission precedent prohibits the curtailment of QF resources except in system emergencies. *PacifiCorp*, 151 FERC ¶ 61,170 at P 27 (2015); *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215 at P 38 (2013); *Exelon Wind 1, LLC*, 140 FERC ¶ 61,152 at P 50 (2012); 18 C.F.R. § 292.307(b) (2018).

17 This assumes the QF has a direct interconnection with the purchasing utility and that the state chooses to capture the costs of the QF's interconnection in the interconnection agreement instead of in the rate, terms, or conditions of the PPA. In addition, as discussed in detail below, the state may choose to handle congestion-related issues and costs in a different manner where there is no direct interconnection between the QF and the purchasing utility.

1. Overview of State Jurisdiction Over PURPA Implementation

When a generator interconnects with a utility's transmission system, that interconnection is ordinarily under FERC's jurisdiction.[18] Under PURPA, however, the state has unique authority over QF interconnections, regardless of whether that interconnection is with a utility's transmission or distribution system.[19]

More specifically, a utility is required to interconnect with a QF to permit purchases from and sales to the QF as contemplated under PURPA.[20] FERC's PURPA-implementing regulations give state regulatory authorities exclusive jurisdiction over QF interconnections.[21] Order No. 69 clarifies that state regulatory authorities "must enforce this [must-interconnect] requirement as part of its implementation of the Commission's rules"[22] and "have the responsibility and authority to

---

[18] FERC has exclusive jurisdiction over the "transmission of electric energy in interstate commerce," and over the "sale of electric energy at wholesale in interstate commerce," and over "all facilities for such transmission or sale of electric energy." 16 U.S.C. §824(b) (2012).

[19] The exception to this rule is where the QF has the right to make sales to third parties. *PJM Interconnection, L.L.C.*, 114 FERC ¶ 61,191 at P 15 (2006) ("As the Commission determined in *Western Massachusetts Electric Co.*, when a QF sells its total electric output to the host utility and the host utility takes title to the electric output at the point of interconnection to its local distribution system…there is no Commission-jurisdictional delivery service associated with the QF's sales.") (citing *W. Mass. Elec. Co*., 61 FERC ¶ 61,182, 61,662 (1992), *aff'd*, *Western Mass. Elec. Co. v. FERC*, 165 F.3d 922, 925-27 (D.C. Cir. 1999)). By contrast, FERC jurisdiction attaches as soon as and only if the QF is provided with an express right to sell output to third parties, rather than on the date that sales to third parties occur. *Fla. Power & Light Co*., 133 FERC ¶ 61,121 at P 21 (2010) (…[A]s we explained in Order No. 2003 and reiterated in *Niagara Mohawk*, we will exercise jurisdiction or require the filing of an interconnection agreement only if there is some manifestation of a QF's "plan to sell" output to third parties.").

[20] 18 C.F.R. § 292.303(c)(1) (2018).

[21] *See e.g.*, 18 C.F.R. §§ 292.303(c), 292.306 (2018); *Prior Notice and Filing Requirements Under Part II of the Federal Power Act*, 62 FERC ¶ 61,128 (1993), *order on reh'g*, 64 FERC ¶ 61,139, 61,991 (1993), *order on reh'g*, 65 FERC ¶ 61,081 (1993) (landmark order addressing various jurisdictional issues and reiterating previous FERC rulings that "the states have exclusive jurisdiction over direct interconnections between a QF and the public utility which purchases its power."); *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103 at PP 813-14 (2003) ("Order No. 2003"). FERC has also found that state jurisdictional QF agreements do not need to be filed with FERC. *See e.g., Florida Power & Light*, 133 FERC ¶ 61,121 at P 21 (2010) (noting that FERC "will exercise jurisdiction or require the filing of an interconnection agreement only if there is some manifestation of a QF's 'plan to sell' output to third parties").

[22] Order No. 69 at 38.

ensure that the interconnection requirements are reasonable, and that the associated costs are legitimately incurred."[23]

2. States Have Authority to Allocate the Cost of QF Interconnection

State jurisdiction over QF interconnections includes broad cost-allocation authority.[24] The "must interconnect" mandate in FERC's PURPA implementing regulations provides that the obligation to pay for any interconnection costs shall be determined in accordance with Section 292.306, which authorizes state regulators to decide what QFs pay for interconnection. More specifically, Section 292.306(a) provides as follows:

> (a) <u>Obligation to pay</u>. Each qualifying facility shall be obligated to pay any interconnections costs which the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may assess against the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics.[25]

As the Commission noted in Order No. 69, the definition of "interconnection costs" in Section 292.101(b)(7) "is designed to provide the State regulatory authorities and nonregulated electric utilities with the flexibility to ensure that all costs which are shown to be reasonably incurred by the electric utility as a result of interconnection with the qualifying facility ***will be considered as part of the obligation of the qualifying facility under § 292.306***."[26] The

---

[23] Order No. 69 at 88.

[24] Order No. 2003 at P 813 ("When an electric utility is obligated to interconnect under Section 292.303 of the Commission's Regulations, that is, when it purchases the QF's total output, the relevant state authority exercises authority over the interconnection and the allocation of interconnection costs.").

[25] Section 292.306(b) notes that the state also 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. *See, e.g.*, Order No. 69 at 89 (responding to comments seeking clarification on "the manner in which electric utilities would be reimbursed" by explaining that it is best left to the states to decide whether a QF should pay for its interconnection in an upfront lump sum or amortized over some period of time).

[26] Order No. 69 at 13-14 (emphasis added).

Commission has been firm with its position that "under these rules the utility is not obligated to incur any additional costs by reason of interconnected operation with these facilities."[27]

The Commission's PURPA regulations further set forth a cost allocation test that identifies the "interconnection costs" over which a state has jurisdiction, which are defined to include the following wide range of facility costs that would not be incurred ***<u>but for</u>*** the QF:

> [T]he reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities is necessary to permit interconnected operations with a qualifying facility, ***<u>to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations</u>***, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources.[28]

This broad definition[29] includes all interconnection costs attributable to a QF, and it allows a state commission to allocate these "but for" interconnection costs to a QF because, as noted above, the alternative is for the utility's customers to pay for these costs in violation of PURPA's customer indifference requirement.

---

27 *Small Power Production and Cogeneration Facilities – Qualifying Status*; *Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 70, FERC Stats. & Regs. Regulations Preambles 1977-1981 ¶ 30,134, 36 (1980) (subsequent history omitted).

28 18 C.F.R. § 292.101(b)(7) (2018) (emphasis added).

29 Of note, FERC's definition of "interconnection costs" includes the "reasonable costs of…***transmission***…incurred by the electric utility directly related to…the physical facilities necessary to permit interconnected operations with a [QF]," which specifically contemplates network upgrades triggered by the QF's interconnection. *See also Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215 at P 38, n.73 (2013) (stating that PURPA requires a utility to make firm transmission arrangements for the QF power, but that "[t]his is not to suggest that the QF is exempt from paying interconnection costs, which may include transmission or distribution costs directly related to installation and maintenance of the physical facilities necessary to permit interconnected operations.") (emphasis added). The Commission has further explained that a QF may also be responsible for "the costs of installation of equipment elsewhere on the utility's system necessitated by the interconnection[.]" Order No. 69 at 14.

C. Transmission Constraints and Generation-to-Load Ratios Affect the Cost or Timing of Interconnection Service

The general principles of cost allocation related to QF interconnections outlined above are amplified when a significant increase in interconnection requests, transmission constraints, and generation-to-load ratios are taken into account.

First, the sheer volume of interconnection requests has increased dramatically over the last few years, with currently over 29,000 MW of requests in PacifiCorp's generator interconnection queue. This increase has exacerbated the cost or timing requirements associated with accommodating requests for interconnection service because, even if a particular interconnection request does not trigger a specific network upgrade requirement, each interconnection study starts with the baseline assumption that all higher-queued requests *and* any network upgrades associated with those higher-queued requests are in-service.[30]

Second, when QFs choose to site their projects in either: (1) transmission-constrained areas; or (2) discrete load center areas (also referred to as load "pockets" or load "bubbles")[31] where there is insufficient load to sink additional generation, it places pressure on the cost and timing of the QF's interconnection service because significant network upgrades may be required to stabilize the system and/or make the interconnecting generator eligible for firm delivery to

---

[30] *See, e.g.*, PacifiCorp OATT Section 42.3 ("The Interconnection System Impact Study will consider the Base Case as well as all generating facilities (and with respect to (iii) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the Interconnection System Impact Study is commenced: (i) are directly interconnected to the Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the Transmission System; and (iv) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC.").

[31] Generally speaking, PacifiCorp has two BAAs that are further divided into smaller load bubbles for purposes of studying and analyzing transmission requirements necessary to reliably serve forecasted loads, to accommodate new service requests, and for operational purposes. *See, e.g.,* PacifiCorp, *Local Transmission System Plan (2016-2017 Biennial Cycle)* 13, 20 (Dec. 14, 2017), *available at* www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_Report_121417.pdf (hereinafter, PacifiCorp Transmission System Plan); PacifiCorp OATT, Attachment C, Sec. 3(b)(2) ("PacifiCorp's system is composed of multiple load and resource "bubbles").

load — load that may be located beyond the constraint, or even in an entirely different load bubble that is not part of the utility's contiguous transmission system.[32]

Making a QF eligible for firm delivery to load in the interconnection service context is a short-hand way of describing the provision of state-jurisdictional QF interconnection service analogous to FERC's network resource ("NR") interconnection service, which requires a utility's transmission function to study the transmission system under a variety of severely stressed conditions to determine whether, with the new interconnecting generator at full output, the aggregate of generation in the local area can be reliably delivered to the aggregate of system load.[33] This means the scope of the network upgrades required for state-jurisdictional interconnection service will include those that will allow the interconnecting generator to qualify

---

32 For instance, the dominant transmission provider in the Pacific Northwest is the Bonneville Power Administration ("BPA"), a federal power marketing administration operating over 15,000 miles of high-voltage transmission lines, or roughly 75 percent of the transmission network in the region. PacifiCorp's transmission system is intertwined with BPA's system, which means that some of PacifiCorp's load bubbles — especially those located in PacifiCorp's western BAA — are connected by BPA transmission lines over which PacifiCorp's merchant function has various firm transmission service rights under BPA's tariff and long-standing grandfathered agreements. *See, e.g.,* PacifiCorp Transmission System Plan at 20.

33 PacifiCorp OATT, Section 38.2.2.2. The load-focused nature of the NR-style interconnection analysis is challenged as the constraints and excess-generation conditions associated with the siting choices of generators requesting interconnection service (and the volume of interconnection requests) increase. While this has thus far resulted in increasing network upgrade requirements — sometimes reaching rather extraordinary levels — PacifiCorp anticipates it may soon reach a "breaking point" where no additional load is available sufficient to satisfy the interconnection service requirements, and it may therefore be compelled to deem certain requests for generator interconnections infeasible until a change in system conditions or queued requests occurs. PacifiCorp does not appear to be alone in this challenge. *See, e.g., Pub. Serv. Co. of Colorado*, FERC Docket No. ER19-366 (Nov. 19, 2018) (explaining that: (1) the Public Service Company of Colorado's interconnection queue contains over 23,400 MW of requests, which is more than three times the utility's peak network load; and (2) "[t]he sheer number of Interconnection Requests and amount of generation seeking to interconnect vastly outstrip the amount of load to which the output from these potential Generating Facilities can sink. This makes it impossible for PSCo to model the majority of the existing requests for Network Resource Interconnection Service ("NRIS"), as well as any new requests we may receive in the future. The more recent requests for NRIS, including all requests received in 2018, can be modeled only after a number of higher (earlier) queued requests withdraw.").

for designation as a network resource, *i.e.*, the precise type of transmission service arrangement used to deliver QF power to load.[34]

As described in more detail in the next section, state policies support requiring QFs to secure a comprehensive level of state-jurisdictional interconnection service that is consistent with the Commission's requirement that a utility must accept 100 percent of a QF's output (regardless of when it is generated), deliver the QF output to load on a firm basis, and limit QF curtailments to emergency conditions.[35] Requiring a comprehensive level of state jurisdictional interconnection service does not, of course, mean the QF is required to arrange for transmission service[36] — that service is arranged through a separate request submitted by a different customer (the utility's merchant function), governed by an entirely different contract (a transmission service contract), subject to FERC (rather than state) jurisdiction, and may require additional network upgrades beyond those required for interconnection service.[37]

---

34 Order No. 2003-B at P 69; *PacifiCorp*, 151 FERC ¶ 61,170 at PP 3, 27 (2015) (summarizing PacifiCorp proposal to amend its Network Operating Agreement to better ensure QF deliveries on a firm basis and finding proposal to be "consistent with PURPA"). To be clear, any type of interconnection service request can require the construction of network upgrades. *See, e.g.*, Order No. 2003 at P 767. In the absence of transmission constraints, a generator may have little or no difficulty obtaining either ER or NR interconnection service, and both types of interconnection may have the same cost and timing requirements. As system constraints increase, it may still be possible to grant a certain number of ER interconnections without the need for significant upgrades because that type of service does not involve a deliverability analysis.

35 Unless the QF is selling its power to the utility on an as-available basis (an uncommon situation not relevant here), Commission precedent prohibits the curtailment of QF resources except in system emergencies. *PacifiCorp*, 151 FERC at P 27; *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215 at P 38 (2013); *Exelon Wind 1, LLC*, 140 FERC ¶ 61,152 at P 50 (2012); 18 C.F.R. § 292.307(b).

36 As FERC has stated, NR-interconnection service "(which is an Interconnection Service) is not a replacement for [Network Service] (which is a delivery service)." *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003-A, 106 FERC ¶ 61,220 at P 533 (2004) ("Order No. 2003-A"). FERC has also explained that NR-interconnection service "does not ensure physical delivery to specific loads or locations, and it does not provide delivery service rights to specific loads or locations." *Id*. at P 531.

37 *See, e.g.*, Order Nos. 2003 at PP 753-57, 2003-A at PP 502, 516, 533, 542-45; 890-A at P 927; *PPL Montana, LLC*, 133 FERC ¶ 61,206 at PP 26-28 (2010); *Interstate Power & Light Co. v. ITC Midwest, LLC*, 144 FERC ¶ 61,052 at P 36 (2013) ("[E]ach generator, or other transmission customer, seeking to use the transmission system to deliver power from the generator must take transmission service and pay the transmission provider's transmission service rates separate from paying for any interconnection-related network upgrade costs.").

D. Current State Regulation of QF Interconnections in PacifiCorp States

Together, PURPA's must-take and customer indifference requirements and the Commission's firm delivery and limited curtailment requirements make QFs particularly challenging to integrate into constrained or generation-heavy areas of a utility's system. And as the costs of interconnection and delivery increase, QFs are increasingly disputing the obligation to bear them. As examples of how some of these issues have been addressed at the state level, PacifiCorp provides a brief overview of state orders holding that: (1) interconnection-related network upgrades must be allocated to the QF without reimbursement unless the QF can demonstrate system benefits; and (2) QFs must obtain a comprehensive level of interconnection service.[38]

1. Oregon Policy: Interconnection-related network upgrades are allocated to QFs unless QFs can demonstrate system benefits

Nearly a decade ago, the Oregon PUC began reviewing its interconnection policies as they relate to QFs. The Oregon PUC recognized that PURPA's goals were the appropriate drivers for state QF interconnection policy. As a result, instead of relying solely on the FERC *pro forma* interconnection agreement and procedures, the Oregon PUC ordered Oregon-regulated utilities to adopt form Oregon LGIAs that, while largely modeled on FERC's pro forma LGIA, modified those requirements to ensure customer indifference for PURPA interconnections.

The key modification undertaken was a change to Article 11.4 of the LGIP to state that interconnection customers, rather than the utility, are responsible for all costs associated with network upgrades driven by the interconnection unless they can establish quantifiable system-

38 While interconnection and transmission issues have compelled some states to confront these questions more directly and more quickly than others, each of PacifiCorp's states have enunciated PURPA policies mandating customer indifference.

wide benefits of the upgrade.[39] For QFs with a nameplate capacity of 10 MW or less, the Oregon PUC adopted a different set of interconnection procedures.[40] In accordance with OAR 860-082-0035, "a public utility must design, procure, construct, install, and own any system upgrades to the public utility's transmission or distribution system necessitated by the interconnection of a small generator facility." As is relevant here, OAR 860-082-0035 requires that the QF (or interconnecting generator) "must pay the reasonable costs of any system upgrades."

The Oregon PUC thus attempts to maintain customer indifference under this aspect of its QF interconnection policies by ensuring that interconnection costs follow cost-causation.

2. Utah Order: QFs must obtain a comprehensive level of interconnection service

The Utah Public Service Commission ("Utah PSC") recently held that it is appropriate for the state to require a QF to obtain a level of interconnection service analogous to FERC's network resource-level interconnection service.[41]

The Utah PSC was cognizant that QF-created costs would shift from the QF to utility customers under a lesser interconnection requirement. The Utah PSC observed that a QF might site its project in a constrained area that required $400 million in upgrades to accommodate the QF's output (as it, in fact, did in that case). In such a case, the Utah PSC asked, "does PURPA contemplate the QF may nevertheless unilaterally elect to site in the transmission constrained area, force [PacifiCorp] to invest more than $400 million to upgrade its transmission network to

---

39 *See In re Public Util. Comm'n of Oregon Investigation into Interconnection of PURPA Qualifying Facilities with Nameplate Capacity Larger than 20 Megawatts*, Docket UM 1401, Order No. 10-132 at 3 (Apr. 7, 2010).

40 *In the Matter of a Rulemaking to Adopt Rules Related to Small Generator Interconnection*, Docket AR 521, Order No. 09-196 (Jun. 8, 2009). The rules for small generator interconnections in Oregon are found at OAR 860-082-0005 through 860-0882-0085.

41 Glen Canyon Order at 26-29.

accommodate the QF's output and see those costs passed through to [Rocky Mountain Power] and its ratepayers? We conclude the answer is 'no.' Allowing QFs to make inefficient siting decisions and to shift the attendant costs to ratepayers is inconsistent with the primary objective of ratepayer indifference."[42]

Recognizing that QF siting decisions could have a significant impact on customers, the Utah PSC observed that the level of interconnection service obtained by the QF had the potential to greatly affect that impact. The Utah PSC rejected the QF's assertion that a QF should be free from any requirement to obtain the robust level of state interconnection service actually needed to accommodate its output:

> Glen Canyon emphasizes that QFs are responsible for delivering their output to the point of interconnection and that, thereafter, the utility is responsible for transmitting the output to load. This is precisely the reason it is essential that interconnection costs, including [interconnection-driven] investments in transmission infrastructure, be accurately estimated and assessed as a component of interconnection costs.[43]

Therefore, with regard to the network upgrades necessary for a QF to obtain interconnection service, the Utah PSC concluded that interconnection-driven network upgrades need to be borne by the QF, either through the interconnection agreement or avoided-cost rates:

> Even if Glen Canyon's position were correct, and transmission upgrades beyond the point of interconnection are not assessable as interconnection costs, it would not alleviate our responsibility to identify those costs and ensure they are properly accounted for in Glen Canyon's transactions with RMP. The alternative would be to load such costs into the avoided cost methodology, which would decrease, probably significantly, the price RMP must pay to Glen Canyon for its output."[44]

In other words, the Utah PSC has appropriately recognized that network upgrades to the utility's system resulting directly from a QF's siting choices should be the QF's — not the utility

---

[42] *Id*. at 30.

[43] *Id*. at 30-31.

[44] *Id*. at 31.

customers' — cost responsibility in accordance with PURPA's customer indifference requirement.

E. The Type of Off-System QF Issues Raised by the Blue Marmots' Petition Should Be Addressed by the State Commission

PacifiCorp has provided the above description of state QF interconnection policies, as well as the state and federal requirements that support them, to provide the larger context within which FERC is being asked to rule in this docket. In particular, as interconnection and delivery costs increase in constrained areas, QFs are increasingly searching for ways to avoid state interconnection rules that require QFs to bear those costs, often by attempts at jurisdictional arbitrage or gaming that leverage FERC's open access transmission and interconnection pricing policies against federal and state customer indifference-focused PURPA policies. QFs seeking interconnection service on PacifiCorp's system have even argued, for example, that selling some portion of the QF's "test energy" in the market would be sufficient to shift the jurisdiction of the interconnection from the state to FERC, thus creating an end-run around the service-type and cost-allocation requirements embedded in state interconnection rules.[45]

QFs have also attempted to secure an exemption from state QF interconnection rules by doing precisely what the Blue Marmots have done in this docket — interconnect with one utility, wheel power over that first utility's system, and deliver to a constrained point on a second utility's system. This approach allows the QF to avoid the state's QF *interconnection* policies (because the QF is obtaining FERC-jurisdictional, rather than state-jurisdictional,

[45] As noted above, the Commission and the Courts have found that states will have exclusive jurisdiction over QF interconnections except in cases in which the QF has an express right to sell output to third parties. *Fla. Power & Light Co.*, 133 FERC ¶ 61,121 at P 21 (2010) (…we will exercise jurisdiction or require the filing of an interconnection agreement only if there is some manifestation of a QF's 'plan to sell' output to third parties."); *see also Niagara Mohawk Power Corp.*, 121 FERC ¶ 61,183 (2007), *order denying reh'g*, 123 FERC ¶ 61,061 (2008) (asserting Commission jurisdiction over the interconnection because the PPA affirmatively released the interconnecting utility from its obligation to purchase the QF's full output).

interconnection service on the first utility's system) and delays the identification of the costs necessary to relieve the congestion at the QF's chosen point of delivery until the second utility requests *transmission* service to deliver the QF power from the point of delivery to load.[46]

As discussed in more detail below, however, the lack of a direct interconnection with the purchasing utility does not prevent the state from having the authority to appropriately capture congestion costs at the QF's chosen point of delivery consistent with PURPA's customer indifference mandate.[47] It simply means that instead of capturing the required upgrades in the QF's state-jurisdictional interconnection study and interconnection agreement, the state can consider whether and how best to protect customers from these costs (or prevent them altogether) when it decides on the appropriate rates, terms, and conditions for the state-jurisdictional QF PPA. To that end, PacifiCorp has developed a step-by-step approach, which is currently at issue in a docket pending before the Wyoming state commission,[48] for addressing these issues in state-jurisdictional PPA negotiations with off-system QFs.

---

[46] In particular, PacifiCorp's merchant function makes transmission service arrangements for off-system QF power by requesting designation of the off-system QF PPA as a network resource using the process set forth in PacifiCorp Transmission's OATT. *See* PacifiCorp OATT Sec. 30.2 (setting out the procedures for designating a new network resource); 29.2(v) (setting out the procedures for both on- and off-system network resources applications).

[47] Indeed, FERC has specifically recognized that the customer indifference mandate still applies in the context of off-system QFs delivering to a utility to which the QF is not directly interconnected. *See, e.g.*, Order No. 69 at 32 ("The ***electric utility to which the electric energy is transmitted*** has the obligation to purchase the energy at a rate which reflects the costs which it can avoid as a result of making such a purchase.") (emphasis added).

[48] In the Matter of the Complaint Filing by VK Clean Energy Partners LLP Against Rocky Mountain Power, 20000-533-EC-18 (Record No. 14954).

1. PacifiCorp's off-system PPA negotiation approach

Like PGE, PacifiCorp strongly opposes any suggestion that off-system QFs can force purchasing utilities to take power at a constrained point of delivery chosen by the QF *unless* the QF is financially responsible for the network upgrades needed to accommodate that QF's power consistent with customer indifference. PacifiCorp has developed a pragmatic approach to addressing this transmission service study issue in the context of the PPA negotiation — an agreement that falls within state authority. The process is as follows:

1. PacifiCorp's merchant function begins negotiations with the off-system QF under the ordinary process mandated by the state regulatory authority for negotiating a QF PPA;

2. Before finalizing avoided-cost pricing, PacifiCorp's merchant function submits a request for network transmission service from the off-system QF's proposed point of delivery on PacifiCorp's system to load (*i.e.* a request for DNR status) in order to confirm the reasonableness of the commercial operation date in the draft QF PPA and the reasonableness of the proposed POD;[49]

    a. If PacifiCorp Transmission can grant the DNR request without requiring network upgrades, PacifiCorp's merchant function will execute the PPA with the off-system QF;

    b. If PacifiCorp Transmission determines that the DNR request cannot be granted without the construction of network upgrades that affect the proposed PPA COD or that would impose significant costs on PacifiCorp's customers, PacifiCorp's merchant function takes the following additional steps:

        i. PacifiCorp's merchant function works with the off-system QF to determine if there is an alternative POD that reduces or eliminates the transmission-service requirements, limitations, or other adverse conditions identified in the transmission-service study;

        ii. If these efforts are unsuccessful, PacifiCorp's merchant function evaluates whether the PURPA-based planning redispatch provisions

[49] Such a request for network service is permitted under the OATT where, among other requirements, the network customer, here, PacifiCorp's merchant function, has negotiated all of the rates, terms, and conditions of the PPA assuming transmission service is available, and execution of the contract is contingent only upon confirmation, through submittal of a transmission service request and receipt of a transmission service study, that transmission service is indeed available. PacifiCorp OATT Sec. 29.2(vii).

of its Network Operating Agreement[50] with PacifiCorp Transmission applicable to the network transmission service (PacifiCorp's merchant function takes from PacifiCorp Transmission) can potentially mitigate the issues;

iii. If the NOA planning redispatch provisions do not offer a solution that balances PURPA's customer indifference requirement and the QF developer's right to sell the QF's output under PURPA, PacifiCorp's merchant function will promptly seek guidance from the state utility commission in calculating an appropriate avoided cost price or other contractual terms for the off-system resource.

This policy, which injects into the PPA negotiation a requirement that the utility and the QF engage in good-faith discussions regarding a variety of possible non-rate (*e.g.*, delivering to a different POD, employing planning redispatch protocols) and rate (*i.e.*, avoided-cost rate adjustment) solutions to congestion issues, subject to state regulatory oversight, provides a pragmatic mechanism for addressing congestion issues present at an off-system QF's chosen delivery point. State authorities have the tools they need to address disputes involving the PODs chosen by off-system QFs if negotiations fail.

2. PGE's characterization as interconnection service

PacifiCorp recognizes that PGE has characterized the cost of the network upgrades required by Blue Marmots' chosen point of delivery as state-jurisdictional interconnection costs subject to the Oregon PUC's QF interconnection cost allocation policies, rather than costs arising out of the PGE's FERC-jurisdictional transmission service arrangements to deliver the QF power to load. Despite the difference in service characterization between the utilities, both advocate for the same result: leave it to the state to appropriately account for the POD congestion issues in the

[50] *PacifiCorp*, 151 FERC ¶ 61,170 (2015) (approving a transmission service-related planning redispatch protocol that PacifiCorp's merchant function, as network transmission customer, can choose to use, if available, as an alternative to constructing certain network upgrades required for a resource's DNR status if PacifiCorp's merchant function also agrees that it will limit QF schedules last to the extent limitations are necessary to remain within existing transmission rights).

PPA. If FERC decides instead to address the merits of the Blue Marmots' petition, regardless of which service — interconnection or transmission — FERC considers to be triggering the congestion costs at the QF's chosen POD, PacifiCorp asks that FERC rule in a manner that leaves intact the thoughtful and long-standing state precedent on QF interconnection requirements and cost allocation described above — an area of clear state authority under PURPA.

F. The Blue Marmots' Petition Should be Denied

1. The issues raised by the Blue Marmots' petition are not ripe for FERC review

PacifiCorp asks FERC to clarify that the issues raised by the Blue Marmots' petition are best addressed at the state level. As other commenters will address in more detail, the petition is not ripe for decision at FERC. Blue Marmots' complaints are still pending before the Oregon PUC, rendering any FERC petition premature. The Oregon PUC is capable of handling the complaint before it, and the Blue Marmots' petition is at an advanced procedural stage before the Oregon PUC.

2. The Oregon PUC has the authority to resolve the issues raised by Blue Marmots

The Oregon PUC has the authority to resolve the issues raised by Blue Marmots and should get an opportunity to do so. Under PURPA, states have authority over the rates, terms, and conditions of PURPA contracts, in addition to having authority over QF interconnections. If the Oregon PUC is concerned that retail customers may be forced to pay the cost of network upgrades associated with off-system QFs delivering power to heavily congested areas, whether by Blue Marmots or by future QFs, the Oregon PUC should have opportunity to implement policies that allow it to achieve that goal. The Oregon PUC could do so in any number of ways.

For example, if the Commission agrees with PGE that the cost of network upgrades necessitated by Blue Marmots' delivery to PGE's system are properly classified as QF interconnection costs, then the Oregon PUC should be permitted to allocate those costs to the QF as it sees fit, consistent with state QF interconnection policy. If, on the other hand, the Commission believes the costs are properly classified as transmission costs, then the Oregon PUC should have the opportunity to address these costs through any other mechanism within its authority.

For instance, in its role as arbiter of QF PPA rates, terms, and conditions,[51] the Oregon PUC might order the Blue Marmots to deliver their power to a different, uncongested point on PGE's system in order to avail itself of PGE's avoided cost pricing in a manner that protects PGE's customers from additional costs.[52] Alternatively, the Oregon PUC might elect to make an adjustment to Blue Marmots' avoided cost pricing to account for the cost of any network

---

[51] *See, e.g., West Penn Power Co.*, 71 FERC ¶ 61,153, 61495 (1995) ("It is up to the States, not this Commission, to determine the specific parameters of individual QF power purchase agreements, including the date at which a legally enforceable obligation is incurred under State law. Similarly, whether the particular facts applicable to an individual QF necessitate modifications of other terms and conditions of the QF's contract with the purchasing utility is a matter for the States to determine. This Commission does not intend to adjudicate the specific provisions of individual QF contracts."); *Massachusetts Institute of Technology*, 74 FERC ¶ 61,221, 61,749-50 (1996) ("Under PURPA and our implementing regulations, states have broad authority to determine the specific parameters of QF contracts. Consistent with the states' broad authority in that regard, it is our long-established policy to leave to the states issues relating to the application of PURPA requirements to the circumstances of individual QFs."). *See, also, Metropolitan Edison Co.*, 72 FERC ¶ 61,015, 61,049-50 (fact-based determinations and PURPA enforcement issues are within the province of the states), *order on clarification*, 72 FERC ¶ 61,269 (1995); *West Penn Power Co.*, 71 FERC ¶ 61,153, 61,494 (1995) (same).

[52] The Oregon PUC might start by ordering Blue Marmots and PGE to engage in the kind of negotiations that PacifiCorp requires for off-system QFs to seek a mutually agreeable point of delivery. Under PacifiCorp's policy for off-system QFs, if no mutually agreed upon point of delivery can be found, then the parties approach the state PUC for assistance with finding an appropriate solution. The Oregon PUC has not had the opportunity to encourage this type of discussion.

upgrades that may be identified as necessary to delivery Blue Marmots' power to load.[53] In any case, the Oregon PUC has a variety of options for choosing to address this issue under its PURPA authority and based on the specific facts and circumstances of the open docket before it.

3. Should FERC require PGE's customers to pay for network upgrades to accommodate Blue Marmots' power, FERC should provide guidance regarding PURPA implementation and customer indifference

Finally, should FERC decide to rule on the merits of the petition and conclude that the network upgrades required by Blue Marmots' chosen POD simply fall under FERC's generic transmission pricing policies because they are associated with PGE's QF transmission service arrangement and, thus, that PGE's customers are required to pay for the costs of relieving congestion caused by Blue Marmots' chosen delivery location, PacifiCorp would respectfully request FERC provide guidance regarding how utilities and states can comply with and implement PURPA in a manner that protects customers from the costs of QF-chosen siting and delivery locations.

PacifiCorp submits that QFs are not like any other generators. No other generator can require a utility to purchase 100 percent of its generation at avoided costs, even when the power

---

53 FERC has held that the cost of transmission network upgrades can be factored into QF avoided costs. *See, e.g.*, *Cal. Pub. Utils. Comm'n*, 133 FERC ¶ 61,059 at P 31 (2010) (approving in theory a California proposal to provide an adder to avoided cost rates for specific QFs that site in load centers with transmission constraints, so long as the bonus reflects "actual" network upgrade costs that the utility will avoid as a result of the QF's beneficial siting choice). Applied here, while PacifiCorp is unfamiliar with all of the specific facts and circumstances at issue in the open docket before the Oregon PUC, if the Blue Marmots' choice of a congested point of delivery resulted in a transmission service study identifying the cost of the network upgrades necessary to provide transmission service, FERC's precedent would support those "actual" costs to be incurred by the utility and its customers being factored into avoided-cost rates. The Utah PSC has recognized its authority to factor congestion-related costs into avoided-cost rates if they cannot be captured in the interconnection agreement — the precise circumstances presented when an off-system QF chooses to deliver its power to a constrained delivery point. Glen Canyon Order at 31 ("Even if Glen Canyon's position were correct, and transmission upgrades beyond the point of interconnection are not assessable as interconnection costs, it would not alleviate our responsibility to identify those costs and ensure they are properly accounted for in Glen Canyon's transactions with RMP. The alternative would be to load such costs into the avoided cost methodology, which would decrease, probably significantly, the price RMP must pay to Glen Canyon for its output.").

is not needed to serve the utility's load. No other generator can unilaterally choose a congested point of delivery without any consequences — operational, cost, or otherwise. Blue Marmots are asking FERC to relieve them of all responsibility for the costs they alone have caused and they alone control. FERC should decline to do so consistent with the PURPA customer indifference requirement.

V. Conclusion

For the reasons discussed above, PacifiCorp respectfully requests that the Commission deny the petition for declaratory order, or, in the alternative, rule narrowly as discussed above, so that state authority over key PURPA implementation matters is preserved, as intended by Congress.

Respectfully submitted,

Karen J. Kruse
Karen J. Kruse
Deputy General Counsel
PacifiCorp
825 N.E. Multnomah, Suite 2000
Portland, Oregon 97232

Christopher R. Jones
Christopher R. Jones
TROUTMAN SANDERS LLP
401 9th Street, N.W., Suite 1000
Washington, DC 20004
(202) 662-2181
Chris.Jones@troutman.com

Counsel for PacifiCorp

Dated: December 7, 2018

Washington, D.C.

CERTIFICATE OF SERVICE

I hereby certify that on this 7th day of December, 2018, I have caused a copy of the foregoing document to be served electronically on each person listed on the Secretary's official service list for the above-referenced proceeding.

/s/ Meghan A. Mandel
Meghan A. Mandel
TROUTMAN SANDERS LLP
401 9th Street, NW, Suite 1000
Washington, D.C. 20004
(202) 274-2893