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March 11, 2022

VIA ELECTRONIC FILING

Attention: Filing Center
Public Utility Commission of Oregon
P.O. Box 1088
Salem, Oregon 97308-1088

Re: AR 631 –Rulemaking to Address Procedures, Terms, and Conditions Associated with Qualifying Facilities (QF) Standard Contracts.

Attention Filing Center:

Attached for filing in the above-captioned docket are the Joint Utilities' Initial Comments on Staff's Proposed Rules.

Please contact this office with any questions.

Sincerely,

Alisha Till

Alisha Till
Paralegal

Attachments

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

AR 631

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Rulemaking to Address Procedures, Terms, and Conditions Associated with Qualifying Facilities Standard Contracts.	**JOINT UTILITIES' INITIAL COMMENTS ON STAFF'S PROPOSED RULES**

I. INTRODUCTION

Portland General Electric Company (PGE), PacifiCorp dba Pacific Power (PacifiCorp), and Idaho Power Company (Idaho Power) (together, the Joint Utilities) welcome this opportunity to comment on the draft rules that were proposed by Staff of the Public Utility Commission of Oregon (OPUC or Commission) and adopted by the Commission to serve as the subject of the formal phase of this rulemaking docket (Draft Rules). The Joint Utilities greatly appreciate all stakeholders' participation in the informal phase of this docket and are particularly thankful for the hard work put in by Staff to gain a greater understanding of the parties' concerns, and to develop draft rules that incorporate many of the customer protections that the utilities have requested. That said, the Draft Rules do include key provisions that are inconsistent with market (non-qualifying facility, or non-QF) power purchase agreements (PPAs) and that the Joint Utilities fear will cause significant harm to utility customers. As discussed below, the Joint Utilities believe that non-market terms will violate the customer indifference standard, distort competitive markets by creating incentives for inefficient development, and encourage speculative contracting—all to the detriment of utility customers. Conversely, adopting QF PPAs that are consistent with non-QF PPAs will help to protect customers and competitive markets, to the benefit of all stakeholders.

Moreover, given the size, financial strength, and sophistication of the vast majority of QF developers, requiring terms and conditions consistent with market PPAs is highly unlikely to hinder QF development.

Much has changed since the 2008-2009 period when the Commission first embarked on an effort in docket UM 1129 to develop detailed terms and conditions for standard contracts. At that time, the market for QFs was nascent, and even the non-PURPA renewable market was relatively new. In that context, arguments that QFs were inexperienced, unsophisticated, lacked other development opportunities outside of PURPA, and required special protections and subsidies, may have had some basis in fact. That is no longer the case. The overwhelming majority of QFs are developed by regional, national, and even global corporations, most of whom have entered into scores of PPAs, and who are competing with non-QF developers to respond to the same meteoric increase in demand for renewable energy. These QFs do not need special protections or subsidies to remain viable, and Commission policies should no longer accord them such special treatment. Instead, consistent with PURPA's mandate that customers remain indifferent to the purchase of QF power, the Commission should instead seek to place all independent market participants on an equal footing to encourage the most cost-effective clean energy for utility customers.

In the following comments, the Joint Utilities first address the critical legal and policy background that should guide the Commission's consideration of the Draft Rules, and then comment on, and make suggestions for, key provisions. The Joint Utilities do not present minor wordsmithing proposals in these initial comments and will instead save those suggestions for a later round.

II. LEGAL AND POLICY BACKGROUND

The Joint Utilities advocate for rules that incorporate market terms and conditions into QF contracts because doing so is necessary to satisfy the customer indifference standard and avoid distortion of competitive markets.[1] Throughout this proceeding the QF Parties have argued against incorporating market terms and conditions into QF contracts by insisting that many QFs are small, unsophisticated developers that would not have the ability to participate in the market without streamlined PPAs with significantly more favorable terms. Based on this view, the QF Parties have argued for many terms that typically would not be incorporated into a market PPA—including development periods of more than three-years; lengthy cure provisions; security and default provisions with little or no real teeth; and advantageous (for the QFs) damages, termination, force majeure and insurance terms. However, these non-market terms act together to (1) encourage speculative contracting that increases litigation risk and costs; (2) shift significant risks from the developers to utility customers, resulting in contracts that do not leave customers indifferent and that distort competitive renewable markets to the detriment of utility customers; and (3) threaten the utilities' abilities to plan for and reach mandated renewable energy targets in the future.

A. Incorporation of market terms and conditions is necessary to satisfy the customer indifference standard.

Updating the Standard PPA terms and conditions to conform to current market practices is necessary to protect customers so that they remain indifferent and receive the same contractual protections they are afforded when the utility executes a non-QF PPA. Because the rules controlling QF PPA terms, conditions, and processes necessarily allocate risks and financial burdens between customers and developers, the rules must be consistent with prevailing market

[1] "Distortion" in this context means that contract terms and conditions that are materially different from market terms and conditions create an unnecessary advantage or subsidy for QF developers at the expense of customers.

practices to reasonably protect utility customers and satisfy the customer indifference standard. To ensure QF transactions do not harm utility customers: (1) state rules implementing PURPA must be consistent with the customer-indifference requirement; (2) QF PPAs must have the same customer protections as non-QF PPAs; and (3) rules governing contracting cannot subsidize QFs by allowing them to obtain PPAs with preferential terms and conditions relative to non-QFs (*i.e.*, providing QFs a contracting advantage over their market competitors).

PURPA's customer indifference requirement mandates that customers be no worse off if the utility purchases electricity from a QF rather than a non-QF resource.[2] PURPA is a federal statute that operates under traditional principles of cooperative federalism whereby "the Federal Government [may] use state regulatory machinery to advance federal goals."[3] In choosing to participate in the regulation of transactions between utilities and QFs, states must consider and comply with PURPA's standards.[4] Because PURPA preempts conflicting state laws and enactments,[5] Oregon laws implementing PURPA *must* remain consistent with the customer indifference standard, and may not provide additional protections to QF developers that violate that standard.[6] The Commission has long recognized its obligation to implement PURPA

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[2] *See, e.g.*, *S. Cal. Edison Co. San Diego Gas & Elec. Co.*, 71 FERC ¶ 61,269, 62,079-80 (1995).
[3] *FERC v. Mississippi*, 456 U.S. 742, 759 (1982).
[4] *See id.* at 759-61.
[5] *Id.* at 759.
[6] When implementing PURPA, states are bound by PURPA's mandates and have no authority to exceed its boundaries. Indeed, without PURPA, states would have no authority to set prices for any wholesale sale of power from a generator to a regulated utility, nor to dictate contract terms or conditions for such transactions. Both would fall under the Federal Energy Regulatory Commission's (FERC) exclusive jurisdiction. PURPA allows states to exercise authority over these issues, but subject to the condition that states exercise that authority consistent with PURPA—including its customer indifference mandate. *See, e.g.*, *S. Cal. Edison Co.*, 71 FERC ¶ 61,269, 62,079-62,081. While states may take many types of actions to encourage renewable development beyond PURPA's limitations to encourage development of renewable resources, those actions must be founded in state law (such as providing tax incentives, mandating construction of specific types of generation, passing a carbon tax, etc. through state legislation), rather than PURPA. *Id.* Given this customer indifference mandate, states lack authority to implement PURPA in a manner that exposes customers to additional cost, risk, or harm as a consequence of the purchase of QF power when compared to the utility's alternatives.

consistent with the mandate of customer indifference.[7] Moreover, there is nothing in Oregon's PURPA statute that conflicts with the customer indifference standard or that suggests that it would be appropriate to provide protections for QF developers above and beyond those afforded other market participants.[8]

While the customer indifference requirement is most often associated with the avoided cost prices paid to QFs, the Commission has noted that the standard must also extend to all the terms and conditions in a QF PPA.[9] PPA terms that govern how avoided cost prices are paid and those that allocate real financial risk between developers and utility customers have the potential to harm customers. If a non-QF PPA negotiated at arm's length and governed by prevailing market practices provides customer protections that are not included in a standard QF PPA, then customers are exposed to additional financial harm as a result of the QF transaction that lacks the same protections. For example, non-QF long-term power purchase and sale agreements contain robust security provisions designed to protect the utility in the event of non-performance by the seller. If QF PPAs do not contain similarly meaningful security requirements, then the utility may well be unable to collect damages in the event of a default, ultimately exposing customers to financial harm that would not be present under a non-QF PPA. As another example, if QFs are allowed substantially longer intervals to come online than those afforded non-QFs, (e.g., if the Commission allows QFs to choose a Scheduled Commercial Operation Date (COD) that is more than three

[7] *See, e.g.*, *In re Staff's Investigation Relating to Elec. Util. Purchases from Qualifying Facilities*, Docket UM 1129, Order No. 07-360 at 1 (Aug. 20, 2007) ("This Commission's goal is to encourage the economically efficient development of QFs, while protecting ratepayers by ensuring that utilities incur costs no greater than they would have incurred in lieu of purchasing QF power (avoided costs).").

[8] *See, e.g.*, *In re Portland Gen. Elec. Co. v. Pac. Nw. Solar, LLC*, Docket UM 1894, Order No. 18-025 at 7 (Jan. 25, 2018) ("[O]ne critical feature of our implementation of PURPA, including (but not limited to) the terms and conditions of our regulated PURPA contracts, is the need to ensure that ratepayers remain financially indifferent to QF development.").

[9] *See* Docket UM 1894, Order No. 18-025 at 6-7 (observing that the Commission reviews terms and conditions of QF PPAs to ensure they are consistent with PURPA's customer indifference standard).

years from the execution date of the PPA and/or adopts cure periods for failure to achieve commercial operation by the Scheduled COD that are longer than three months) then utility customers will pay more stale—and typically higher—prices than they would pay under a non-QF PPA.

QF PPA terms and conditions must not subsidize QFs at customers' expense. The market-based terms of non-QF PPAs are negotiated to protect customers from the shifting of risk—and thus costs—from project developers and owners, thereby avoiding customer subsidization of project development and operation.[10] Under both Federal Energy Regulatory Commission (FERC) Order No. 872 and the Oregon statutes, it is clear that a QF must be responsible for assuming the reasonable financial and operational risks associated with developing its own project, even if the project ultimately proves financially unviable.[11] And if the rules do not allow utilities to obtain contractual protections that are consistent with market norms, the only way to satisfy the customer indifference standard would be to modify the applicable avoided cost pricing (which at this point does not account for any shift to utility customers of operational or financial risks typically borne by developers) by applying a discount to account for the additional risk that customers would be assuming under the rules.

B. Incorporation of market terms and conditions is necessary to avoid a distortion of competitive markets.

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[10] *See*, *e.g.*, *In re PacifiCorp, dba Pac. Power Request for Approval of Draft 2009R Request for Proposals for New Renewable Resources,* Docket UM 1429, Order No. 09-272, Appendix A at 46 of 71 (July 15, 2009) (adopting the Oregon Independent Evaluator (IE) recommendation that utility benchmark bids be modified to account for additional customer risk to make them comparable to PPA bids into the utility's Request for Proposals (RFP), in which "[m]ost risks are shifted to the seller, including capital cost risk (i.e. the risk of cost overruns) and operating cost risk").

[11] *See* Order No. 872, 172 FERC ¶ 61,041 at P 12 (July 16, 2020) [hereinafter, Order No. 872] ("Nothing in the text of PURPA requires the establishment of a subsidy for QFs."); *Id.* at P 344 ("The Commission also disagrees with those commenters who assert that, as a consequence of the above factors, the Commission should 'require[] the variable energy component to be structured in a way that removes market risk from the QF.' This argument runs directly counter to one of the fundamental premises of PURPA, which is that QFs must accept the market risk associated with their projects by being paid no more than the purchasing utility's avoided cost, thereby preventing utility retail customers from subsidizing QFs."); ORS 758.515(2)(b).

In addition to the preservation of customer indifference, incorporation of market terms and conditions is also necessary to the goals of promoting healthy competition and avoiding distortion of the renewable generation market. Conversely, adopting terms and conditions unduly preferential to QFs, to the disadvantage of non-QF power producers, will encourage developers to opt for PURPA-eligible projects by parsing their large projects into the many smaller projects, thereby distorting market signals and leading to inefficient project development. Specifically, as further described below, rules that render QF PPAs more attractive to developers than non-QF PPAs, can be expected to lead to lower participation in competitive processes and increase costs of power at the expense of utility customers. Accordingly, the Commission should adopt rules that incorporate market terms and conditions, which can be subject to, as discussed below, carve-outs or reduction in certain requirements for the truly smaller, less sophisticated developers.

As an initial matter, in terms of size and financial strength, the developers that have executed QF contracts over the past several years are similar to, and in some cases the same as, those that have bid into utility requests for proposals (RFPs). The significant majority of the QFs executing PPAs are owned by sophisticated developers that have constructed numerous generation projects and that have the business savvy and financial wherewithal to comply with the terms and conditions that characterize a market contract.

For instance, PGE entered into a total of 82 Standard QF PPAs over the three-year period from January 1, 2019, through December 31, 2021, for a total of 242 MW of renewable generation. In addition, PGE entered into a total of 6 non-standard QF PPAs for 344 MW during the same three-year period, for a total of 88 QF contracts and 586 MW. These 88 QFs were owned by 21 developers, and PGE was able to obtain detailed information on 13 of the 21 developers from their websites. While these 13 developers vary in size, they are all large operations with the ability to commit to market terms. Specifically:

- two of the developers have developed more than 8 GW of projects;
- seven of the developers have developed more than 1 GW of projects;
- five of the developers have developed more than 200 MW of projects; and
- the remaining developer for whom information was publicly available has developed more than 20 3-MW projects.[12]

The remaining eight of the 21 developers do not provide public information about their organizations online. For these developers it is nevertheless helpful to consider that five of the developers have each executed multiple QF PPAs totaling more than 10 MW with PGE alone.[13] This group of developers may be smaller than those with websites, discussed above, but given the number of projects they have developed with PGE alone, they clearly are not the "mom and pop, run of river hydro" QFs that many of the Commission's policies related to standard PPAs were designed to protect. Only three of the 21 developers that executed PPAs with PGE over the last three years appear to be much smaller, with only one project of 5 MW or less executed with PGE.

PURPA terms and conditions should not incentivize inefficient resource development to the detriment of utility customers. Developers of similar size and sophistication are competing with one another to serve the same utility needs. These developers can either bid larger projects into RFPs or reduce the size of their projects to allow them to obtain QF PPAs. PURPA allows them this choice, and the Joint Utilities welcome all approaches to meeting the significant need they are facing. However, larger projects generally enjoy economies of scale, which include, but

[12] *See* Appendix A, attached.
[13] SmartPower Innovation has signed 5 PPAs with PGE for a total of 12 MW; Enerparc has signed 11 PPAs with PGE for a total of 30 MW; Conifer Energy Partners has signed 11 PPAs with PGE for a total of 26 MW; Thor Solar signed 5 PPAs with PGE for a total of 12 MW; and TLS Capital signed 8 PPAs with PGE for a total of 17 MW.

are not limited to: shared points of interconnection, shared interconnection facilities, and shared internal collection systems and infrastructure. When a larger project enjoying such efficiencies bids into a utility RFP, utility customers will ultimately enjoy those savings.

However, if more favorable terms and conditions are available for a developer that disaggregates what would otherwise be a larger project into several smaller projects, less efficient development is incentivized. In fact, developers regularly appear to disaggregate a larger project into multiple smaller projects to render them eligible for a Standard PPA, standard avoided cost pricing, or a negotiated PPA. The following examples, all from 2019, illustrate this point:

- In 2019, Sulus Solar executed 18 PPAs with PGE for a total of 40 MW, most of them located in clusters located in Clackamas County apparently to gain access to standard avoided cost pricing and standard PPAs.

- In 2019 EDP Renewables executed 5 PPAs for 10 MW each with PGE, all located in Lake County five miles apart, apparently to qualify for standard PPAs.

- In a period of approximately 16 months, Energy of Utah signed negotiated PPAs with PGE for two projects less than five miles apart in Morrow County and one project in nearby Jefferson County—all sized between 50 and 80 MW, presumably in order to qualify as QFs.

The Joint Utilities do not have access to the data that would allow them to prove that each of these projects would have been more efficient if it had *not* been sized to come in under a particular threshold. However, basic economic principles would suggest that these disaggregated projects are indeed a more expensive approach to energy generation. It appears clear that QF developers are incentivized to trade economies of scale for the more favorable pricing and terms and conditions generally granted QFs in this state. Commission policies should not encourage such inefficiency. In fact, the encouragement of efficient projects is of particular importance at this time when the utilities are planning very significant renewable energy acquisitions on an accelerated basis to meet state policy mandates to reduce emissions,[14] exit from coal generation,[15] and maintain resource adequacy.[16] PGE is seeking 650 MW of renewable energy by 2030 to comply with these state policies.[17] Idaho Power is seeking 1,800 MW of renewable energy by 2030. And in its currently planned RFP, PacifiCorp is pursuing up to 1,345 MW of new wind and solar resources for commercial operation by the end of 2026.

Finally, the predominance of large, sophisticated QF developers demonstrates that it is reasonable to require market terms in QF PPAs. The Joint Utilities agree that there remain a few very small developers that may find it difficult to comply with some of the terms and conditions contained in a market-based contract (e.g., insurance provisions, for example), but the existence of a handful of small developers does not require that retail customers should be denied the protections that market terms afford for all QF PPAs. Instead, to the extent the Commission seeks to protect these smaller developers from market-based terms and conditions, the most effective way to do so is to establish a rule for identifying these developers and softening the specific requirements. This approach avoids watering down terms and conditions that should otherwise be applicable to the majority of QF developers, as they are well-established and have the wherewithal to comply with market terms and conditions.

In support of this approach, the Joint Utilities have offered in the past and remain open to exempting the smallest QFs from certain terms and conditions. For example, the Joint Utilities offered in this docket to reduce the insurance requirement for QFs with a nameplate capacity rating of less than 200 kW. The 200 kW "threshold" was intended to serve as a proxy for identifying the

[14] Office of the Governor, State of Oregon, Executive Order 20-04, available at: https://www.oregon.gov/gov/Documents/executive_orders/eo_20-04.pdf.
[15] ORS 469A.280.
[16] *See generally In re Pub. Util. Comm'n of Or., Investigation Into Resource Adequacy in Or.,* Docket UM 2143.
[17] Portland General Electric, 2021 All-Source RFP – Final Draft at 5. Available at: https://portlandgeneralrfp2021.com/wp-content/uploads/2021/12/2021-All-Source-RFP-Main-Document_12.16.2021.pdf.

smaller, less sophisticated developers. Specifically, the Joint Utilities offered to reduce the umbrella insurance requirement from $5,000,000 to $2,000,000 for these QFs. The Draft Rules go much further in allocating risk to utility customers by removing the insurance requirements entirely for QFs under 200 kW.[18]

C. Out of market terms that allow QFs to enter into PPAs before performing due diligence harm utility customers.

The Joint Utilities recommend that the standard PPA process, terms, and conditions should be designed to ensure that QF developers perform reasonable due diligence before executing a standard PPA. As FERC recently noted in Order No. 872, although a QF may force utility customers to purchase its power, a critical trade-off associated with that statutory benefit is the QF's obligation to demonstrate the commercial viability of its project, its financial commitment to moving the project forward, and its ability to operate and maintain its performance obligations through the term.[19] FERC acknowledged that requiring QFs to make such a demonstration might prove to be a barrier for "speculative" QFs, but made clear that PURPA is not intended to encourage speculative or inefficient QF development.[20] Indeed, requiring a QF to demonstrate commercial viability and financial commitment is appropriate because, as FERC noted, such a demonstration poses no barrier to the types of project developers PURPA was meant to encourage: namely, "financially committed developers seeking to develop commercially viable QFs."[21]

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[18] Docket AR 631, Joint Utilities' Comments in Response to Staff's Draft Rules at 37 (Aug. 12, 2021).
[19] Order No. 872 at P 688.
[20] *Id.*
[21] *Id.* Despite decades of QF advocacy to the contrary, FERC has long held that PURPA's "encouragement" of QF development is not a guarantee that inefficient or uneconomical QF projects will be developed. *See, e.g., id.* at P 41 ("Guaranteeing QFs cost recovery is fundamentally inconsistent with PURPA, which sets the rate the QF is paid at the purchasing electric utility's avoided cost, not at the QF's cost."); FERC Order No. 69, 85 Fed. Reg. 12214, 12222 (Feb. 25, 1980) (noting that the only time the payment of avoided costs will provide economic benefits to a cogenerator or small power producer is when the cost to the qualifying facility of producing energy capacity is lower than the utility's avoided cost.).

Despite this clear policy guidance, many QFs that execute speculative projects insofar as they have not performed reasonable due diligence to identify potentially significant project costs or have not secured permits required to move the project forward. Because avoided cost prices have steadily declined in recent years, developers are motivated to execute PPAs as early as possible in order to lock in the most advantageous avoided cost pricing before conducting due diligence or settling on some of the most basic details of their projects, including size, point of interconnection, and even technology (*e.g.,* the inclusion of battery storage combined with solar projects). This problem is best illustrated by the fact that Oregon QFs typically sign PPAs before they receive even a single interconnection study. This means that QFs are committing themselves to developing projects with a key cost unknown—despite the fact that the estimated interconnection costs ultimately may render the project uneconomic. Policies that allow them to engage in this type of speculative contracting harm utility customers several ways.

First, customers are harmed by allowing QFs to lock in avoided cost pricing earlier than what would be possible if QFs were required to complete their due diligence before signing the PPA. Second, developers who sign a PPA only to later learn that their project is uneconomic may simply default on their PPAs, while others turn to litigation in an effort maintain the viability of a 20-year contract that is worth millions of dollars. Both approaches harm customers. Litigation imposes significant costs and requires significant time and attention. Importantly, the costs borne by utilities are ultimately borne by their customers through rates.

Second, QF defaults further burden utilities and their customers in that they undermine resource planning processes. Importantly, a full 50 percent of QFs that have executed contracts with PGE over the past 12 years have failed to reach commercial operation. And yet, once a QF contract is signed, the utility must rely on that resource in its planning efforts, which can cause real error, depending on what stage of the planning process the utility is in. When QFs default, a utility may be required to find replacement power to serve load, at disadvantageous replacement prices or with fewer options because now the planning horizon is much shorter to find that replacement. This issue is particularly problematic at a time where accurate resource planning is key to the utilities' ability to meet mandated renewable and clean energy targets.

III. COMMENTS ON GROUP 1 RULES

A. New Rule #2 – Eligibility for Standard Avoided Cost Prices and Purchase Agreements

The Joint Utilities generally support the provisions of New Rule #2 and recommend one revision: The rule should include a subsection that identifies the Commission as the entity responsible for reviewing project eligibility disputes and other related questions that arise during the PPA contracting process, such as whether the QF at issue qualifies as family-owned or community-based for purposes of the same site rule. While FERC is the ultimate arbiter of QF status, the Commission is the ultimate arbiter of standard PPA and standard pricing eligibility.

B. New Rule # 3 – Process for Procuring Standard Power Purchase Agreement

The Joint Utilities generally support the provisions of New Rule #3, many of which incorporate recommendations provided by the Joint Utilities in the informal phase of this rulemaking. However, the Joint Utilities recommend several revisions.

1. To the extent the Commission adopts rules that allow developers to choose a Scheduled COD that occurs between three and four years from the execution date of the PPA, the list of information a QF must provide in New Rule #3(2)(c) should include:

> An interconnection study supporting any proposed on-line date occurring between the third and fourth anniversary of the Effective Date of the standard power purchase agreement.

This information is necessary to implement the rule, discussed in Section III.C.1 below, allowing QFs additional time to achieve commercial operation if supported by an interconnection study to guard against speculative contracting.

2. The Commission should revise New Rule #3 to retain the 15-business-day turnaround period for a utility to provide a revised draft standard PPA to a QF in all circumstances—not just when the QF requests a change to the Point of Delivery. Specifically, the Joint Utilities suggest the following revisions:

> (5) If the qualifying facility submits comments to the public utility or asks for revisions to the draft purchase agreement, in writing, the public utility has ~~ten (10)~~ fifteen (15) business days to (i) notify the qualifying facility it cannot make the requested changes, (ii) notify the qualifying facility it does not understand the requested changes or requires additional information, or (iii) provide a revised draft power purchase agreement. ~~However, the public utility will have fifteen (15) business days to respond or provide a revised draft standard power purchase agreement when the qualifying facility requests a change to the Point of Delivery.~~[22]

Currently, utilities have 15 business days to provide a draft PPA when a QF requests changes. In the Joint Utilities' collective experience, 15 business days represents standard industry practices and is a reasonable and necessary timeline for preparing and reviewing a draft standard PPA, collecting any missing data for PPA exhibits, and performing a final check to confirm that all the QF's documents are complete and accurate.[23] Conversely, there is no evidence on the record of this or any other proceeding suggesting that a 15-business-day interval is either unreasonable or causes any harm to the QFs. Because the 15-business-day interval is reasonable and there is no evidence of harm to QFs from the existing deadline, the current 15-business-day turnaround time should be retained.

[22] Note that if the Commission elects to retain the 10-business-day timeline, then the Joint Utilities support retaining the current exception for when the QF requests to change the Point of Delivery.

[23] This can be particularly true during times when multiple requests from qualifying facilities are pending.

For clarity and simplicity, the Joint Utilities strongly support a consistent 15-business-day timeline. However, if the Commission ultimately decides to adopt a 10-business-day turnaround in general, the Joint Utilities request that, at a minimum, a longer response period be allowed under circumstances where additional care is required to ensure the completeness and accuracy of the PPA. Specifically, the Joint Utilities recommend that a 15-business-day period apply in the event material changes to a draft PPA are required, such as:

- A change in electrical generating equipment that increases power production capacity by the greater of 1 MW or five percent of the previously certified capacity of the QF;[24]
- A change in ownership in which an owner increases its equity interest by at least 10 percent from the equity interest previously reported;[25]
- An addition or change in the battery system of a project;
- Any change that triggers a legal requirement for the developer to amend the FERC Form 556 on which the QF relies for QF eligibility, provided that in this scenario, the utility should not be required to issue a revised draft PPA until the later of the expiration of the fifteen business day period following the developer's request for an executable PPA and the fifteenth business day following the date on which the QF delivers to the utility an amended FERC Form 556 that corrects the applicable non-conformities; or
- Any change to avoided cost pricing or any other circumstances outside the utility's control that require a substantive modification be made to the PPA.

Any of these changes would require significant time for utility review and revision to ensure that the QF still meets the eligibility requirements for a standard PPA, which may be impossible to complete in 10 business days.

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[24] Order No. 872 at P 550.
[25] *See id.*

3. For many of the same reasons that a 15-business-day timeline is reasonable and necessary for providing a revised draft PPA, the same timeline should be provided in New Rule #3(7) for providing a final executable PPA. QF PPAs are long-term agreements worth millions of dollars, and under the Commission's policies, a QF establishes a legally enforceable obligation when it signs a final executable PPA. Therefore, it is important that the purchasing utility be allowed adequate time to fully review and finalize the final executable PPA.

Similarly, the Joint Utilities support including a 15-business-day turnaround in New Rule #3(8) for the utility to countersign a PPA that the QF has already signed. The utility signature process involves several steps and approval processes prior to final signature. This process takes time. As noted above, since the QF has already established a legally enforceable obligation by executing the PPA, there is no reason that the utility's signature must occur within 5 business days. The Commission should revise the timelines in New Rule #3 to provide utilities with adequate time to prepare, review, and finalize the long-term agreements

4. The Joint Utilities support the inclusion of the requirement that a QF provide "a 12 x 24 power delivery schedule." A 12 x 24 schedule is necessary for typical utility resource and system balancing and planning and is used to accurately calculate damages under applicable performance guarantees. For these reasons, 12 x 24 power delivery schedules are often incorporated into PPAs as an exhibit and are typically required in market-based PPAs. However, the Draft Rules allow the 12 x 24 delivery schedule and the "net amount of power to be delivered" to be revised until the QF commences commercial operation, which is potentially problematic. This provision should be modified to make clear that any changes in output must be consistent with OAR 860-029-0120(15) regarding incremental upgrades, which will be discussed in Group 2.

Subject to the foregoing requested revisions, as indicated above, the Joint Utilities support the inclusion in the Draft Rules of several provisions they identified in the informal phase. While the Joint Utilities will not address these provisions at length, a brief overview follows.

1. The Joint Utilities believe the inclusion of the catch-all, New Rule #3(2)(c)(N), which would allow utilities flexibility in requesting information according to their unique resource planning needs when determining eligibility for a draft PPA, is particularly critical.

2. Equally important is the inclusion of New Rule #3(2)(c)(B), which ensures that utilities have the information necessary to determine whether the QF meets eligibility requirements.

3. Lastly, Joint Utilities support the requirement in New Rule #3(2)(b) that a QF provide evidence of site control and the clear criteria in subsections (A)-(C) regarding the required evidence. Obtaining site control is a fundamental initial step in the development process, and the provision of such documentation will help demonstrate to a utility the non-speculative nature of the proposed project, thereby decreasing the risk of withdrawn projects and defaults, as well as the associated costs to retail customers.

C. OAR 860-029-0120 – Standard Power Purchase Agreements

The Draft Rules have greatly improved the provisions in OAR 860-029-0120 to better mitigate stale pricing and reflect market practices. The Joint Utilities generally support the provisions of OAR 860-029-0120 with a few important exceptions discussed below.

1. OAR 860-029-0120(4) – Development Period

Subsection (4) provides that the development period—the period between execution of the PPA and Scheduled COD—does not begin until after the Network Upgrade cost-allocation process set forth in New Rule #1 has been resolved. The Joint Utilities object to delaying the start of the development period—and therefore the Scheduled COD—for this process. The Network Upgrade cost-allocation process addresses potential costs caused by the QF's siting decision. Therefore, the QF—and not the utility's customers—should bear the risk that the QF's siting decision causes delays. The Network Upgrade cost-allocation process certainly should not be used to delay the Scheduled COD beyond three years because doing so would be inconsistent with market terms and would harm customers, as discussed in detail in Section III.C.2 below. Instead of providing for an automatic extension in the rules and, given the fact specific nature of any Network Upgrade cost-allocation process, the Joint Utilities recommend that, at most, the developer may be permitted to petition the Commission to have the Scheduled COD modified following or in connection with the Network Upgrade cost-allocation process. However, such modification should be subject to an outside limit on how far out the Scheduled COD can be extended, and in any event should not extend the overall term of the PPA. The Joint Utilities understand that New Rule #1 will be addressed in Group 2 and recognize that it may make sense to address the relationship between OAR 860-029-0120(4) and New Rule #1 in Group 2.

2. OAR 860-029-0120(6) – Scheduled Commercial Operation Date

The Draft Rules allow a QF to select a Scheduled COD up to four years after executing a Standard PPA if, pursuant to subsection 6(b)A, the QF has received an interconnection study indicating that it will take longer than three years to interconnect, or if, pursuant to subsection 6(b)(A) the QF demonstrates that it cannot reasonably be expected to achieve commercial operation within three years and the utility consents, which consent shall not be unreasonably withheld. When the Scheduled COD is more than three years from the Effective Date, the fixed-price term of the PPA is reduced commensurately.

The Joint Utilities appreciate that OAR 860-029-0120(6)(d) makes clear that the Scheduled COD may not be more than four years from the Effective Date under any circumstances. The Joint Utilities also appreciate the interconnection study requirement in OAR 860-029-0120(6)(b)(A), which will help ensure that QFs that have no chance of interconnecting within four years do not enter speculative PPAs. However, the Joint Utilities strongly urge the Commission to cap the interval between PPA execution and Scheduled COD at three years, without exception. Allowing a four-year development and construction period is inconsistent with market PPAs, will harm utility customers, and is not necessary to allow viable projects to succeed for the following reasons.

First, a maximum three-year development and construction period is standard industry practice for both QF and non-QF PPAs. This approach is consistent with current Oregon QF requirements and QF requirements in Idaho, Wyoming, and Utah where the scheduled COD must be within 30 months of the PPA execution date, as well as the approved PacifiCorp Washington standard form of PPA where the scheduled COD must be within three years of PPA execution.[26]

Second, allowing the QF up to four years to achieve commercial operation will harm customers and violate the customer indifference standard. Any rule that allows QFs to lock in avoided cost prices a full four years before deliveries commence, particularly when combined with an extended cure period, effectively extending the period beyond four years, ensures that some QFs will be paid stale prices, which risks significant overpayment by utility customers in violation of the "just and reasonable" requirement and PURPA's customer indifference principle.[27]

[26] *See* WUTC, *In re Pac. Power & Light Co., Schedule QF Tariff Revision*, Docket UE 190666, https://www.utc.wa.gov/casedocket/2019/190666; Form of Standard QF PPA (5MW or Less)—On System New Small Power Production Facility – Firm, Attachment A to Washington Schedule QF, Section 1.1 (Mar. 1, 2021) (defining "Scheduled Commercial Operation Date").

[27] PURPA Section 210(b) (16 U.S.C. § 824a-3(b)); OAR 860-029-0040(1)(a); *see also, e.g.*, Docket UM 1894, Order No. 18-025 at 7 ("[O]ne critical feature of our implementation of PURPA, including (but not limited to) the terms and conditions of our regulated PURPA contracts, is the need to ensure that ratepayers remain financially indifferent to QF development."); *In re Staff's Investigation Relating to Elec. Util. Purchases from Qualifying Facilities*, Docket UM 1129, Order No. 05-584 at (May 13, 2005) ("We seek to provide maximum incentives for the development of

Importantly, since PacifiCorp and PGE began offering renewable avoided cost prices, such prices have declined year over year, with few exceptions. As a result, stale prices are likely to be higher prices. For this reason, Oregon's current rule limiting the development period to three years is good policy that the Draft Rules, which would extend such period, would upset. Under the existing rule, when a QF receives an interconnection study indicating that it will need more than three years to commence operations, the QF may not enter into a PPA immediately, but is free to begin the development and interconnection process. The QF can then sign a PPA when it can achieve commercial operation within three years. This is precisely the approach non-QFs must take. However, allowing a QF to sign a PPA four years ahead of time, locking in the higher avoided cost stream in place at the time, particularly when combined with a generous cure period, allows the QF a significant advantage not enjoyed elsewhere in the market. Providing such an unambiguous, significant advantage to QFs in the Commission rules is a clear violation of the customer indifference standard that will cause utility customers to pay QFs substantial subsidies that are neither justified nor necessary to support QF or renewable resource development.

While Joint Utilities recognize that the Draft Rules' proposal to impose a commensurate reduction in the fixed-price term is intended to mitigate the harm of stale pricing, this approach is inadequate to protect customers because the harm to customers due to stale prices does not necessarily equal the customer savings resulting from reduction of the fixed-price term. Fourteen years and six months of stale pricing could be far worse for customers than 15 years of accurate, current pricing that reflects the up-to-date cost of the avoided resource. For example, as shown in Attachment B to the Joint Utilities' August 12, 2021, Comments, the net present value of the amount PacifiCorp would have paid for 14.5 years of 1 MW of power from a tracking solar

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QFs of *all* sizes, *while ensuring* that ratepayers remain indifferent to QF power by having utilities pay no more than their avoided costs.") (emphasis added).

resource at PacifiCorp's 2020 standard avoided cost prices in effect before its August 26, 2020 post-IRP update is $1.1 million. The net present value of the amount PacifiCorp would have paid for 15 years of 1 MW of power from the same tracking solar resource at PacifiCorp's 2020 refreshed standard avoided cost prices in effect after PacifiCorp's August 26, 2020 post-IRP update is $0.6 million. In other words, 15 years of refreshed pricing represents a *45 percent reduction* in the cost per MW to PacifiCorp's customers, as compared to 14.5 years of stale pricing that reflects out-of-date avoided cost pricing. This example clearly demonstrates how stale pricing, resulting from off-market contract terms, can result in payments to QFs that do not accurately reflect the utility's avoided costs and violate PURPA's customer indifference standard.

Third, allowing a QF four years to achieve commercial operation is not necessary because QFs that elect to site their projects in relatively unconstrained locations will have few problems meeting an online date of three years from execution. QFs signing PPAs with PGE, for instance, average approximately 2.5 years from execution to commercial operation.[28] QFs that estimate construction will take more than three years because of interconnection or other design hurdles should continue advancing their early-stage development activities, including activities related to project siting due diligence and interconnection, and execute a PPA only when they are able to commit to a Scheduled COD within three years of contract execution.

To the extent a QF's interconnection is delayed because of its siting choice—delays may be caused by the need to construct significant upgrades to facilitate the request, or, in the case of

[28] In recent years PacifiCorp was faced with an extremely high volume of interconnection requests leading to a backlog. By February 2020, PacifiCorp had over 219 interconnection requests in its queue, equaling approximately 39,500 MW of generation. In response, PacifiCorp sought and received FERC approval to reform its queue process and conduct annual Cluster Studies under standardized study windows that increase the certainty and speed of interconnection study timelines, such that studies will be complete, or near complete, within a year. PacifiCorp received Commission approval of its queue reform process on August 3, 2020. *See In re PacifiCorp, dba Pac. Power, Application for an Order Approving Queue Reform Proposal,* Docket No. UM 2108, Order No. 20-268 (Aug. 19, 2020).

serial interconnection studies, because of the need to conduct interconnection re-studies when other projects ahead of the QF withdraw from the interconnection queue—such delays are not the fault of the purchasing utility. Because such delays apply equally, on a non-discriminatory basis to non-QF projects that are similarly sited (the developers of which bear this risk), there is no justification for providing QFs that face the challenges of siting projects in a constrained area with a longer time to construct. Indeed, many non-QF developers receive interconnection studies that show they will not be online within a three-year window due to the need for significant upgrades in their location, so the developer shifts its focus to advancing other, more viable projects instead.

Finally, the exception from the three-year limit contained in subsection 6(b)(B) is even more problematic than contemplated in subsection (A). This subsection allows the QF to receive a COD up to four years from execution of the PPA if it "demonstrates to the public utility it cannot reasonably be expected to achieve commercial operation within three years . . . and the utility consents. . . which consent shall not be unreasonably withheld." The Joint Utilities urge the Commission to reject this provision, as it would establish a standard that is overly broad and vague and would almost certainly lead to litigation.

Any number of circumstances might lead a developer to expect that a project "cannot reasonably be expected" to be completed in three years: permitting challenges, technology challenges, supply chain issues, higher priority projects in the developer's queue of projects, etc. Moreover, the rule language is so broad that it could encompass circumstances either personal or business, circumstances of the QF's own making or beyond the QF's control. Importantly, the draft rule gives no standard or indication about how the utility or the developer should assess whether these circumstances suggest that a decision by the utility to withhold consent would be deemed "unreasonable." While the Joint Utilities object to any grounds for permitting the election of a scheduled COD more than three years from the Effective Date, at minimum the Commission rules should limit such elections to the narrow set of circumstances in which a qualifying facility has received an interconnection study supporting such a request.

For these reasons the Commission should revise OAR 860-029-0120(6) to require all QFs to select a Scheduled COD within three years of the PPA execution date, without exception. If the Commission decides to permit the election of a development period in excess of three years, it should permit such an election only under the circumstances set forth under subsection 6(b)(a) and delete subsection 6(b)(B) entirely.

3. OAR 860-029-0120(7) – Modification of Scheduled Commercial Operation Date or Termination

The Draft Rules allow a QF to terminate a Standard PPA within six months of execution if the QF receives an interconnection study with a cost estimate that renders the project uneconomic or an estimate of the time required to interconnect that is longer than the Standard PPA allows. If the QF terminates the PPA, it is liable for damages. The QF may also choose to extend the Scheduled COD in the executed PPA up to four years from the PPA execution date, if the interconnection study indicates that a longer time is required. As explained in Section III.C.2 above, the Joint Utilities strongly oppose allowing a QF to select a Scheduled COD more than three years after PPA execution under any circumstances.

The Joint Utilities also oppose the provisions allowing a QF to terminate its PPA within six months after it obtains more information about its ability to interconnect. These provisions are unnecessary because a QF always has the ability to terminate the PPA and pay damages. Moreover, this free option flies in the face of the requirements necessary for QFs to establish a legally enforceable obligation necessary to obtain the current avoided cost prices. These provisions also encourage speculative contracting by including an explicit invitation for QFs to lock in avoided cost pricing before performing basic due diligence and then revise their PPAs once they obtain more information. Speculative PPAs harm customers by absorbing utility resources that could be devoted to other important priorities and frequently causing litigation, and FERC has recognized that PURPA is not intended to encourage speculative QF development.[29] Therefore, the Commission should remove the sections of OAR 860-029-0120(7) that allow a QF to terminate its PPA after obtaining more accurate interconnection information.

Finally, the Joint Utilities oppose OAR 860-029-0120(7)(d) to the extent that it allows an unlimited extension of the Scheduled COD caused by an event of Force Majeure. While an event of Force Majeure is outside the QF's control, it is similarly outside the purchasing utility's control. Therefore, there is no basis for requiring customers to solely bear the risk that a Force Majeure event will delay commercial operation and require customers to pay stale prices to a QF as a result. While a limited extension of the Scheduled COD due to an event of Force Majeure is appropriate, the QF should not be permitted to extend its Scheduled COD or extend any cure period related to meeting the Scheduled COD more than 180 days due to a Force Majeure event. In addition, any delay in the Scheduled COD beyond three years should be accompanied by a reduction of the fixed-price term to help offset the harm to customers. The Joint Utilities understand that New Rule #5 addressing Force Majeure will be discussed in Group 2 and that this provision may need to be updated following that discussion.

4. OAR 860-029-0120(8)-(9) – Default, Damages, and Termination for failure to meet Scheduled COD

The Joint Utilities understand that cure periods will be addressed in Group 2 during the discussion of New Rule #6. However, in response to OAR 860-029-0120(8)-(9), the Joint Utilities note that they oppose the one-year cure period, which is not consistent with market, and that the

[29] Order No. 872 at P 688.

language of these rules may need to be updated once the appropriate cure period is addressed in Group 2. Also, the cross-reference to "section (5)" in OAR 860-029-0120(9) should be updated to "section (8)."

5. OAR 860-029-0120(16)-(17) – Project Development and Default Security

The Joint Utilities support the security requirements in the Draft Rules, which provide an important customer protection. In particular, the requirement in OAR 860-029-0120(16) that QFs must post project development security within 30 days after executing the PPA ensures that security is available if a non-creditworthy QF defaults after executing a PPA and before achieving commercial operation. And the requirement in OAR 860-029-0120(17) that QFs post Default Security in the form of Cash Escrow or a Letter of Credit provides important protections in the event a QF defaults after achieving commercial operation.

However, the rules should specify the *amount* of Project Development and Default Security that a QF PPA can require, rather than leaving this issue to be addressed in the compliance phase. Security provisions serve to protect customers only if the amount of security is sufficient, meaning that the security amount is a key provision of the rules. Due to a number of circumstances, the AR 631 docket and been quite protracted, commencing just less than three years ago. Deferring the Commission's consideration of the appropriate amount of security will further delay implementation of revised standard power purchase agreements that are long overdue. Specifically, the Joint Utilities propose that the rules allow Standard PPAs to require Project Development Security of up to $150 per kilowatt-hour (kWh) and Default Security of up to $50 per kWh. In the Joint Utilities' experience, these values are within the range of security amounts required by market PPAs.

6. OAR 860-029-0120(18) Insurance Requirements

The Joint Utilities generally support the insurance requirements in the Draft Rules, which are consistent with industry standards and with the Joint Utilities' PURPA PPAs.[30] The Joint Utilities do not, however, support the Draft Rules' provision exempting QFs under 200 kW from insurance requirements altogether. Doing so would inappropriately shift all risks related to an under-insured developer to utility customers. Instead, the Joint Utilities recommend that QFs smaller than 200 kW be required to maintain insurance, but in smaller amounts, specifically a reduction of $5 million applicable to the larger QFs to $2 million.[31]

7. OAR 860-029-0120(19)-(20) – Changes to Ownership and Jurisdiction Language

The Joint Utilities propose revisions to OAR 860-029-0120(20). The text of this rule is outdated and should be updated to reflect recent Commission orders regarding the Commission's jurisdiction.[32] Specifically, the Joint Utilities propose:

> (20) All standard power purchase agreements between a qualifying facility and a public utility for energy, or energy and capacity, must include language that substantially conforms to the following: The Commission shall have jurisdiction to resolve any action or claim relating to this Agreement. The Commission may elect to decline to hear an action or claim relating to this Agreement. The Commission's jurisdiction to resolve actions or claims relating to this Agreement shall not be exclusive. ~~This agreement is subject to the jurisdiction of those governmental agencies and courts having control over either party or this agreement. The public utility's compliance with the terms of this contract is conditioned on the qualifying facility submitting to the public utility and to the Public Utility Commission of Oregon, before the date of initial operation, certified copies of all local, state, and federal licenses, permits, and other approvals required by law.~~

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[30] Idaho Power Company Advice No. 10-11, Requesting Approval of Tariffs and Applications Necessary to Implement a Volumetric Inventive Rate Pilot Program for Solar Photovoltaic Energy Systems (filed June 22, 2010, effective July 1, 2010).

[31] Docket AR 631, Joint Utilities' Comments in Response to Staff's Draft Rules at 37 (Aug. 12, 2021).

[32] *See, e.g.*, *Portland Gen. Elec. Co. v. Dayton Solar I LLC, et al.*, Docket UM 2151, Order No. 21-210 (June 25, 2021).

IV. CONCLUSION

The Joint Utilities look forward to continuing to work with Staff and the parties to develop terms and conditions for standard PPAs that will implement PURPA consistent with legal requirements and sound public policy, thereby protecting utility customers.

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APPENDIX A

to

Joint Utilities' Initial Comments

Appendix A: Developer Information from Websites

- *BNRG Renewables* – has developed 183 renewable energy projects with a total nameplate capacity of 2.8 gigawatts (GW).[1]

- *Covanta* – has developed 46 facilities with a total of 1,878 megawatts (MW) of generation capacity.[2]

- *Cypress Creek Renewables* – has developed more than 8 GW of solar, with more than 2.5 GW under management.[3]

- *Ecoplexus* – is a global corporation with solar developments (proposed or constructed) totaling at least 2250 MW with $521 million in assets.[4]

- *EDP Renewables* – EDP Renewables' parent, EDPR NA, is a global corporation that has developed more than 8,800 MW, including 58 wind farms and 9 solar parks.[5]

- *Energy of Utah* – is a regional corporation, with renewable projects in 5 states with almost 2000 MW of constructed or proposed projects.[6]

- *GreenKey Solar* – boasts more than 15 years of industry experience and 200 MW of solar development.[7]

- *Heelstone Energy* – has achieved commercial operation on more than 60 solar projects with an aggregate generating capacity in excess of 500 MW.[8]

- *Obsidian Renewables* – is the largest locally based developer of utility-scale solar photovoltaic facilities in the Pacific Northwest, with approximately 500 MW developed or proposed (not including its newly proposed hydrogen hub, to be located in Hermiston, Oregon, with distribution into Washington and Idaho).[9]

- *OneEnergy Renewables* – has developed 70 solar projects totaling more than 700 MW.[10]

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[1] Available at: https://bnrg.ie/portfolio/.
[2] *See* "Operations Performance" table, available at: https://covanta-csr.com/data-pages/performance-tables/.
[3] Available at:
https://ccrenew.com/#:~:text=Led%20by%20an%20experienced%20management,leading%20solar%20and%20storage%20companies.
[4] Available at: https://www.ecoplexus.com/about-us.
[5] Available at: https://www.edpr.com/north-america/sites/edprna/files/2022-02/About%20Us%20February%202022_0.pdf.
[6] Available at: https://www.energyofutah.com/.
[7] Available at: https://www.greenkeysolar.com/about-us.
[8] Available at: https://heelstoneenergy.com/.
[9] Available at: https://www.obsidianrenewables.com/projects1.html.
[10] Available at: https://www.oneenergyrenewables.com/about-us.

- *Pacific Northwest Solar* – has developed more than 485 MW of solar facilities throughout the United States.[11]

- *Pinegate Renewables* – operates more than 100 solar projects totaling more than 1 GW and has more than 15 GW in active development.[12]

- *Sulus Solar* – specializes in smaller projects, generally 3 MW, and has constructed 20 solar facilities across: Clackamas, Marion, Polk, Washington, Linn, Douglas, and Jackson counties.[13]

[11] Available at: http://www.pnw-solar.com/who-we-are.php.
[12] Available at: https://pinegaterenewables.com/.
[13] *See* https://www.sulus-solar.com/who-we-are/.