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August 12, 2021

VIA ELECTRONIC FILING

Attention: Filing Center
Public Utility Commission of Oregon
P.O. Box 1088
Salem, Oregon 97308-108

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

Attention Filing Center:

Attached for filing in the above-captioned docket are Joint Utilities' Comments in Response to Staff's Draft Rules.

Please contact this office with any questions.

Thank you,

Jennifer Miller
Legal Assistant

Attachment

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' COMMENTS IN RESPONSE TO STAFF'S DRAFT RULES**

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TABLE OF CONTENTS

McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205

McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205

I. INTRODUCTION

Portland General Electric Company (PGE), PacifiCorp dba Pacific Power (PacifiCorp), and Idaho Power Company (together, the Joint Utilities) respectfully submit these comments in response to Staff's draft rules circulated on August 3, 2021[1] (hereinafter, Draft Rules) for changes to the Public Utility Commission of Oregon's (the Commission) implementation of the Public Utility Regulatory Policies Act of 1978 (PURPA) contracting process and the terms for standard Power Purchase Agreements (PPAs) with Qualifying Facilities (QFs).

The Joint Utilities applaud Staff's efforts in the latest Draft Rules to better balance the interests of utility customers and QFs, and appreciate the opportunity to provide these written comments to help ensure that the outcome of this docket is consistent with PURPA's customer-indifference standard, which *requires* state regulatory commissions to implement PURPA consistent with PURPA's requirements, including its mandate that utility customers remain financially indifferent to QF development.[2]

However, while the Joint Utilities generally support many of the policies embodied in the Draft Rules, additional work is required to fine-tune them and better develop the details and wording in these rules to ensure they are clear and consistent and ready to be moved into the formal phase of this rulemaking. To that end, the Joint Utilities suggest that Staff recommend that the Commission delay the start of the formal rulemaking process to allow one additional round of written comments. This additional process will ensure that the Draft Rules are better developed

[1] Staff's Draft Rules (Aug. 3, 2021).

[2] *See, e.g.*, *In the Matter of Portland Gen. Elec. Co.*, 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."); *In the Matter of Staff's Investigation Relating to Electric Utility 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 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).

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before the formal rulemaking process begins. The Joint Utilities recognize that Staff is under instructions to submit these rules to the Commission as soon as possible, and that Staff's timing has been responsive to concerns previously expressed by the Joint Utilities. However, based on present circumstances, the Joint Utilities believe an additional round of comments would benefit Staff, stakeholders, and the Commission in their efforts to modernize and update the QF PPA process and terms and conditions.

Importantly, given the timing constraints associated with responding to Staff's Draft Rules, the Joint Utilities note that this set of comments is intended to highlight key issues of concern prompted by Staff's current round of revisions and *does not* represent the Joint Utilities' final redline of the Draft Rules.

II. DISCUSSION

A. The Rules Must Be Consistent with PURPA's Customer Indifference Standard.

The Commission has long recognized that its obligation when implementing PURPA is to ensure that customers remain indifferent to a QF transaction, *i.e.*, customers are no worse off because the utility transacts with the QF rather than transacting with a non-QF or generating the equivalent electricity itself.[3] The customer indifference requirement is most often associated with the avoided cost prices paid to QFs. As the Commission has noted, however, the standard must *also* extend to all the terms and conditions in the QF PPA, including those that govern how those avoided cost prices are paid and the protections afforded to customers in the QF PPA.[4] Therefore, in order to ensure that customers are no worse off because of a QF transaction, the Joint Utilities

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[3] *See, e.g.*, *In the Matter of Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Docket No. 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).").

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

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419 SW 11th Avenue, Suite 400
Portland, OR 97205

reiterate that: (1) state rules implementing PURPA must be consistent with the federal statute; (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).

First, 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."[5] States, therefore, in choosing to participate in the regulation of retail sales by electricity and gas utilities and in the regulation of transactions between such utilities and cogenerators, must consider and comply with PURPA's standards.[6] In this manner, PURPA pre-empts conflicting state laws and enactments.[7] Accordingly, Oregon laws implementing PURPA *must* remain consistent with the customer indifference standard, and may not attribute additional protections to QF developers that violate that standard.[8] To that effect, there is nothing in Oregon's PURPA statute that conflicts with the customer indifference standard or would suggest additional protections for QF developers above and beyond other market participants.[9]

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[5] *Federal Energy Regulatory Commission v. Mississippi*, 456 U.S. 742, 759 (1982).
[6] *See id.* at 759-61.
[7] *Id.* at 759.
[8] 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.*, *Southern California Edison Co.*, 71 FERC ¶ 61,269, 62,079-62,081 (June 2, 1995). 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.
[9] *See, 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.").

McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205

Second, customer indifference requires that customers be no worse off if the utility purchases electricity from a QF rather than a non-QF resource. While this indifference requirement most clearly applies to avoided cost pricing, it necessarily extends to the terms and conditions included in the QF PPA because those terms and conditions allocate risk of financial harm between the QF and utility 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 transactions. Customers are therefore no longer indifferent; they are worse off. The principle that contract terms and conditions allocate real, financial risk with respect to which utility customers should remain indifferent has long been recognized by the Commission. For example, the market-based terms of non-QF PPAs are negotiated to protect customers from the shifting of risk—and thus costs—from project developers, thereby avoiding customer subsidization of project development.[10] Indeed, both Federal Energy Regulatory Commission (FERC) Order No. 872 and the Commission's own statutory duties make clear that a QF must be responsible for assuming the reasonable financial and operational risk of developing its own project and assuming the risk involved with project commitment along the way, even if the project ultimately proves financially unviable. If the rules do not allow utilities to obtain contractual protections that are consistent with market norms, the only way to ensure customer indifference would be to modify the applicable avoided cost pricing—which under current methodologies does not account for financial costs and

[10] *See*, *e.g., In re PacifiCorp, dba Pacific Power Request for Approval of Draft 2009R Request for Proposals for New Renewable Resources,* Docket No. 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").

risk associated with contract terms—by applying a discount to account for the additional risk that customers would be assuming under the rules.

Throughout this rulemaking process, the Joint Utilities have advocated for updating the standard PPA terms and conditions to conform to current market practices in order to better ensure that customers remain indifferent and receive the same contractual protections when the utility executes a QF PPA. Because the rules controlling PPA terms, conditions, and processes necessarily allocate risks and financial burdens between customers and developers, the rules must be consistent with prevailing market practices to reasonably ensure customer indifference.

Non-market-based PPA terms and conditions not only impose risks on customers that leave them worse off and, by doing so, call into question the integrity of avoided cost pricing, but such preferential terms and conditions for QFs are also an improper subsidization of QFs that relieves them of the risks associated with project finance, design, and construction—risks that would be allocated to any other market participant—to utility customers.[11] Accordingly, contracting rules that favor QF development above and beyond market result in an impermissible subsidy for such development at the expense of the utility customer.[12] For example, Staff's proposed rules lengthening the scheduled Commercial Operation Date (COD) from three to four years could cause utility customers to pay above market prices for net output of projects that could have been

[11] *See, e.g.*, Docket No. UM 1429, Order No. 09-272, Appendix A at 46 of 71 (in which IE notes that, for PPAs that are bid into a utility's RFP, "[m]ost risks are shifted to the seller, including capital cost risk (i.e. the risk of cost overruns) and operating cost risk"); *see also* FERC Order No. 872, 172 FERC ¶ 61,041, at 197 ¶ 344 (July 19, 2020) ("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."). The Commission has also declined to unnecessarily shift risk to customers in any number of contexts, including utility cost recovery mechanisms, direct access programs, wildfire mechanisms, and so forth.

[12] *Id.*; *see also* H.R. Rep. No. 95-1750, at 98 (1978) ("The provisions of [section 210(b) of PURPA] are not intended to require the rate payers of a utility to subsidize cogenerators or small power produc[er]s.").

McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205

financially viable under a three-year COD, but also subsidize development of QF projects that could have otherwise been uneconomic.[13] Such increased costs to utility customers are clearly a violation of the customer indifference standard under PURPA.

The Joint Utilities appreciate Staff's most recent efforts to take the customer indifference standard into consideration when drafting the revised Draft Rules and offer recommendations to further ensure that customers are not left bearing the risk of imprudent or non-competitive PPA terms and conditions that effectively subsidize QF development. While the Joint Utilities acknowledge that the revised Draft Rules are greatly improved from the prior version Staff circulated, the Joint Utilities nevertheless believe that the proposed rules would benefit from further evaluation by stakeholders to improve both the substance of the rules to better protect customers by adhering to the customer indifference standard as well as enhance the clarity and technical quality of the proposed rules.

B. The Draft Rules Must Discourage Speculative QF Contracting.

Through this rulemaking process, the Joint Utilities have recommended that the PPA process, terms and conditions should be designed to ensure that QF developers perform reasonable due diligence before executing a standard QF 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 and its financial commitment to moving the project forward. 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.[14] Indeed, requiring a QF to demonstrate commercial viability and financial commitment is

[13] Staff's Draft Rules at 30.
[14] FERC Order No. 872, 172 FERC ¶ 61,041, at 376 ¶ 688.

McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205

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."[15]

Moreover, executing PPAs with QFs that have little chance of achieving commercial operation—or with QFs that have not performed reasonable due diligence to identify potentially significant projects costs (*e.g.*, interconnection costs)—increases the likelihood of litigation, impacts avoided cost prices, and frustrates utility resource planning processes to the extent utilities are required to assume QF development that may never materialize. Although the Draft Rules do not incorporate all the Joint Utilities' recommendations for deterring speculative contracting, the Draft Rules include some critical customer protections. For example, the Draft Rules include security requirements that take away the "free option" for a QF to execute a PPA without any repercussions if it later chooses to terminate the agreement. The Draft Rules further require an interconnection study reasonably supporting the proposed COD, but only if the COD is beyond three years out. Although the Joint Utilities strongly object to any extension of the COD beyond three years from execution, the Joint Utilities appreciate Staff's inclusion of these critical customer protections in the Draft Rules and continue to support reasonable customer protections that deter speculative contracting.

[15] FERC Order No. 872, 172 FERC ¶ 61,041, at 376 ¶ 688. 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.,* FERC Order No. 872, 172 FERC ¶ 61,041, at 31 ¶ 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.).

C. The Draft Rules Should Not Retroactively Impact Current PPAs or Otherwise Interfere with Current Commission Orders and Utility Contracting Practices Not Addressed by the Rules.

The Joint Utilities recommend that Staff further clarify in OAR 860-029-0005 that the Draft Rules do not retroactively apply to standard QF PPAs executed prior to the effective date of the rules. The following proposed language captures this recommendation:

> (1) These rules apply to all interconnection, purchase, and sale arrangements between a public utility and qualifying facilities as defined herein. Provisions of these rules do not supersede contracts existing before the effective date of this rule as amended on [Insert Effective Date]. At the expiration of such an existing contract between a public utility and a cogenerator or small power producer, any contract extension or new contract must comply with these rules.
>
> (2) Nothing in these rules limits, impacts, supersedes, or otherwise interferes with the authority of a public utility or a qualifying facility to agree to a rate, terms, or conditions relating to any purchase, which differ from the rate or terms or conditions that would otherwise be provided by these rules, provided such rate, terms, or conditions do not burden the public utility's customers.

In addition, the Joint Utilities recommend that Staff and the Commission make clear that the Draft Rules do not impact, supersede, or otherwise interfere with Commission orders or prohibit utility contracting terms and conditions not addressed by, or otherwise not inconsistent with these rules. Because the Draft Rules are not comprehensive and do not provide precise contract language, it would be beneficial for all stakeholders to clearly understand that relevant Commission precedent and contracting practices continue to control QF PPA terms and conditions unless otherwise stated in the rules.

Relatedly, the Joint Utilities also request that Staff clarify their intent regarding delay damages (damages that are owed by the developer to the utility if the project fails to meet its scheduled COD and the cost of replacement power is greater than the contract price) and waiver of consequential damages, which are not specifically addressed by these Draft Rules. If Staff does

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Portland, OR 97205

intend to address these issues, the Joint Utilities would reserve their rights to include these provisions in their standard QF PPAs to the extent the Draft Rules do not prohibit standard QF PPAs from including contracting terms and conditions not addressed by, or otherwise not inconsistent with, these rules.

D. New Rule #1—Obligation for Costs to Accept Deliveries from Off-System Qualifying Facilities

While Staff greatly improved New Rule #1 in the Draft Rules by removing technical details that were inconsistent with FERC transmission tariffs, the rule should: (1) apply to both on-system and off-system QFs; and (2) incorporate language clarifying that a utility may, in specific instances, prior to final execution of a PPA, inform an off-system QF that its chosen Point of Delivery (POD) is not available because of lack of transmission capacity.

1. <u>New Rule #1 Should Apply to On-System and Off-System QFs.</u>

The Joint Utilities propose that New Rule #1 apply to both on-system and off-system QFs. During past discussions regarding the Conditional Designation of Network Resource (DNR) provision, Staff stated that while the provision may be appropriate for off-system QFs, Staff did not support this provision for on-system QFs, in part because the Commission currently requires Network Resource Interconnection Service (NRIS) for QFs, although Staff acknowledged interconnection policies are subject to litigation in docket UM 2032. Staff's position, as the Joint Utilities understand it, is that because the Commission's current policies allocate the cost of NRIS to QFs, there is little or need for the protection of a Conditional Designation of Network Resource (DNR) provision because the upgrades needed for delivery of QF power to load in a constrained area will, by virtue of that policy, have been paid for by QFs. Assuming this is the basis for Staff's position, it ignores various contingencies and leaves customers exposed to meaningful risk. A Conditional DNR provision remains important for on-system QFs. The provision is also a critical safety valve in the event the Commission modifies its QF interconnection cost-allocation policies and is faced with unexpected costs.[16]

First, in the event the Commission modifies its QF interconnection cost-allocation policies in docket UM 2032 by eliminating the requirement for QFs to obtain—and pay for—NRIS, a QF may trigger significant upgrade costs that may not be captured in either the QF's PPA or its interconnection studies. Without a Conditional DNR provision, the vast majority of the delivery costs triggered by the QF's siting choice would be paid for by utility customers, whether those costs were $2 million or $200 million.[17] In the event of a change in QF interconnection policy, a Conditional DNR provision would protect customers against extreme outcomes by providing a safety valve in the PPA that would allow the Commission to review delivery costs that are patently imprudent before blindly passing them on to customers.

Second, even if the Commission retains its existing QF interconnection cost-allocation policies, a Conditional DNR provision would nevertheless provide a meaningful and valuable safety valve that is important to customer indifference, particularly for utilities with constrained transmission systems. The Joint Utilities continue to disagree that such a provision is only necessary for "off-system" QFs. On the contrary, this provision is critical to maintaining the

[16] The Joint Utilities note, however, that interconnection "deliverability" costs *should* be the responsibility of the QF. *See, e.g.*, FERC Order re Pioneer Wind Park I, LLC, 145 FERC ¶ 61,215, at 20 n. 73 (Dec. 19, 2013) (noting that the QF is not "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") (internal citations omitted).

[17] If imprudent upgrade costs associated with QF power delivery are not identified in a QF's interconnection study, a Conditional DNR provision is a critical safety valve for customers. As the Commission noted in its *Blue Marmots* decision: "[W]e conclude that we cannot alter the avoided costs established in the Blue Marmots' LEOs to incorporate additional direct or indirect transmission-related costs, given that our interconnection process for QFs does not identify and capture the transmission-related costs that an off-system QF's delivery to a POD constrained by a transmission management decision may cause." *Blue Marmots*, Docket No. UM 1829, Order No. 19-322, at 8 (Sept. 30, 2019). While the *Blue Marmots* decision applied to off-system QFs, the same rationale applies to on-system QFs. If there is a significant (potentially extraordinary) cost associated with QF power delivery, that costs will be blindly passed through to customers unless the Commission retains its existing QF interconnection policies or adopts a Conditional DNR provision.

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419 SW 11th Avenue, Suite 400
Portland, OR 97205

customer indifference principles of PURPA, regardless of whether a proposed QF resource directly interconnects to the purchasing utility's system (*i.e.*, on-system) or interconnects to a third-party transmission system (*i.e.*, off-system). Because the administratively determined long-term fixed "avoided cost" QF PPA price does not take into account the associated transmission costs that could be incurred by the purchasing utility's retail customers associated with transmitting the QF power, the purchasing utility's QF PPA should reasonably include such a "safety valve" provision that at least ensures that this Commission is able to determine the appropriate allocation for such transmission costs between the QF and retail customers.

While an NRIS study will identify certain "aggregate-level" deliverability issues associated with the need to deliver QF power to customers, the utility's subsequent request for transmission service needed to deliver QF power to load will trigger more detailed studies that may identify additional costs associated with delivery from the QF's chosen location. In other words, additional network upgrades can be identified during the transmission service study process over and above the network upgrades identified in the interconnection study process, even if the QF receives NRIS. While the Commission's current NRIS requirement reduces the likelihood that significant and costly additional upgrades will be identified in the transmission service study process, it does not eliminate that possibility, given the differing nature (and timing) of the studies themselves. Put simply, the outcome of docket UM 2032 in Oregon would not change the Joint Utilities' recommendation to retain an on-system Conditional DNR provision in its form of Standard QF PPA. Rather, the outcome of docket UM 2032 would only impact the *likelihood* (*i.e.*, not the *possibility*) of significant network upgrades being identified in the transmission service study

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419 SW 11th Avenue, Suite 400
Portland, OR 97205

process.[18] Extending this provision to NRIS on-system QFs is also critical to ensuring customer indifference because this provision is included in market-based, non-QF contracts. For example, PacifiCorp executed non-QF PPAs since 2018 that contain the Conditional DNR provision, and this provision was also included in the uncontested version of PacifiCorp's standard QF PPA filed in Washington.

Finally, it is important to note that the Commission has approved including this provision in all three utility's Community Solar Program PPAs and PacifiCorp has executed PPAs with on-system QFs that include this provision, both in Oregon and other jurisdictions,[19] and provisions similar to this have been included in PacifiCorp's non-standard QF and non-QF PPAs, including the form of PPA included in its recent 2020 All-Source Request for Proposals (RFPs).[20] Accordingly, such a provision is market for both on-system QFs as well as off-system QFs.

If Staff chooses to retain the Conditional DNR provision for off-system QFs, but not for on-system QFs, the rule should be amended to indicate that, in the event applicable regulations or any determination of the Commission were to permit on-system QFs to interconnect using energy

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[18] It is important to emphasize that this PPA provision addresses how the purchasing utility designates the QF PPA as a network resource of the utility, and therefore its eligibility to receive firm network integration transmission service. Such *transmission service*, including the costs and timing issues associated, can be wholly distinct from the costs and timing considerations associated with *interconnection service*. Furthermore, and importantly, while a QF's *interconnection* process is generally subject to the rules of this Commission, the process for arranging *transmission* service is subject to the rules and orders issued by FERC in its implementation of the Federal Power Act. Under FERC's pro forma Open Access Transmission Tariff (OATT), transmission service requests are submitted and studied separately from interconnection service requests, and additional facilities or upgrades (beyond those identified in the interconnection studies and agreements) could be required for transmission service to be granted. Under the OATT's requirements, the transmission customer cannot submit its request to designate the new resource as eligible for network transmission service until the agreement is fully executed or the only condition of execution is the availability of transmission service. *See, e.g.*, PacifiCorp OATT, Section 29.2(viii).

[19] For example, PacifiCorp's PPA with (non-standard Oregon QF) Skysol, LLC, which was executed in 2020 contains a Conditional DNR provision. *See* Docket No. RE-142, Informational Filing on Qualifying Facility Transactions, Attachment A, Section 4.2 (Apr. 24, 2020), https://edocs.puc.state.or.us/efdocs/HAQ/re142haq13018.pdf. In addition, PacifiCorp recently has entered into a number of PPAs that contain this provision with small QFs in Idaho. These PPAs have been approved by the Idaho Public Utilities Commission.

[20] The form PPA is available here: https://www.pacificorp.com/suppliers/rfps/all-source-rfp/2020-all-source-rfp-docs.html.

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419 SW 11th Avenue, Suite 400
Portland, OR 97205

resource interconnection service (ERIS), such ERIS on-system QFs contracts also should contain the Conditional DNR provision.

2. New Rule #1 Should Include Language Clarifying the Ability of a Utility to Inform a QF that Its Chosen POD is Unavailable Due to Lack of Capacity.

The Joint Utilities further propose that New Rule #1 incorporate upfront language clarifying the ability of a purchasing public utility, prior to final execution of a PPA, to inform a QF that certain PODs are unavailable due to transmission capacity constraints and other legitimate competing uses. Under this Commission's decision in *Blue Marmot*, the Commission determined that:

> neither FERC precedent nor Oregon law require a utility to accept an off-system QF's unilateral choice of delivery point, regardless of transmission constraints and legitimate competing uses of reserved transmission. In doing so, [the Commission found] that holding a reasonable amount of transmission capacity to accomplish transfers into the EIM and secure the customer benefits of participation is a legitimate justification to decline to accept delivery from QFs at a constrained delivery point.[21]

Accordingly, where a utility is able to determine early on in the QF contracting process that there is a lack of transmission capacity at a QF's chosen POD, the utility may inform the QF that its preferred POD is unavailable even after a Legally Enforceable Obligation (LEO) is formed.[22] This option is intended to be applicable where such information is readily obtainable and reasonably reliable, which is not possible in all circumstances. Moreover, it is not intended to require a utility to fundamentally change its existing study process, which in many instances would be costly and/or inconsistent with its FERC study processes. However, where the utility believes it may

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[21] Docket No. UM 1829, Order No. 19-322, at 7, 12-15.

[22] *Id.* at 7-10 ("We first reject the Blue Marmots' assertion that establishing a LEO carries with it the unilateral right to deliver at the QFs' preferred POD. We conclude that although a LEO must include some project details and contract terms in order to be meaningful, such terms do not extend to delivery arrangements."). Note that early information about transmission constraints may not be available until after the purchasing utility submits a Transmission Service Request (TSR), which does not occur until *after* a PPA is signed. Thus, the need for a Conditional DNR provision remains critical.

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419 SW 11th Avenue, Suite 400
Portland, OR 97205

have early and reliable access to such information, the utility may offer to engage in a cost identification process to determine whether receiving electricity from the QF will require the purchasing utility to incur costs for transmission-service related Network Upgrades. Accordingly, the Joint Utilities offer the following revisions to New Rule # 1 below that are intended to conform the rule with Staff's proposed provision in OAR 860-029-0120(9), which states that the "purchasing public utility must agree to the Point of Delivery before it is included in the power purchase agreement."

860-029-00XX [New Rule #1]

Obligation for Costs to Accept Deliveries from ~~Off-System~~[23] Qualifying Facilities

(1) The standard power purchase agreement for ~~off-system~~ qualifying facilities must include a provision under which parties are required to amend the executed agreement if the Commission issues an order allocating costs to construct transmission-service related Network Upgrade costs to the qualifying facility after the process described in this rule. [The requirements set forth in this 860-029-00XX will also apply to any on-system qualifying facilities to the extent that rules or any determination of the Commission permit such on-system qualifying facilities to interconnect using energy resource interconnection service (ERIS).][24]

(2) Following execution of the standard power purchase agreement, the purchasing public utility may engage in cost identification process to determine whether receiving electricity from the qualifying facility will require the purchasing public utility to incur costs for transmission-service related Network Upgrades. If the purchasing public utility discovers that receiving electricity from the qualifying facility will cause the purchasing public utility to incur costs for transmission service-related Network Upgrades it may request through an application that the Commission issue an order allocating some or all of the costs of the transmission-service related upgrades to the qualifying facility.

[23] The Joint Utilities have deleted "off-system" from New Rule #1 but understand that further revisions may need to be made in order to harmonize the various provisions and make sure it is clear that some of the subsections do not apply to on-system QFs.

[24] The bracketed language should only be included if Staff limits the application of this rule to off-system qualifying facilities.

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Portland, OR 97205

(3) In the event the purchasing public utility has access to information prior to the execution of the standard power purchase agreement that indicates that the qualifying facility's preferred Point of Delivery is unavailable due to transmission capacity constraints or legitimate competing uses of reserved transmission, the purchasing public utility may inform the qualifying facility that its chosen Point of Delivery is unavailable. The purchasing public utility must act reasonably and without discrimination in refusing the qualifying facility's chosen Point of Delivery. Nothing in this subsection prevents the purchasing public utility from offering the qualifying facility a substitute Point of Delivery or requires the purchasing public utility to undertake informational or other studies, or to change its standard study processes to seek information not reasonably in its possession during the contracting process.

~~(3)~~ (4) If the purchasing public utility submits an application to the Commission under subsection (2), the purchasing public utility and qualifying facility will each have opportunity to present their respective positions to the Commission as to the proper allocation of the costs of transmission service Network Upgrades.

~~(4)~~ (5) After providing notice and opportunity to comment regarding an application filed under subsection ~~(2)(a)~~ (2), the Commission will issue an order regarding the appropriate allocation of costs related to accepting the qualifying facility's net output at the Point of Delivery.

~~(5)~~ (6) Notwithstanding subsection (1), the qualifying facility may terminate the power purchase agreement upon written notice to the public utility if the notice is provided within 14 days of the Commission order allocating transmission service related Network Upgrades to the qualifying facility. The qualifying facility's timely termination of the standard power purchase agreement will not be an event of default, and no damages or other liabilities under the power purchase agreement will be owed by or to either party.

~~(6)~~ (7) Notwithstanding the other subsections in this rule, nothing prevents the purchasing public utility and qualifying facility from agreeing to amend a power purchase agreement to address transmission-related Network Upgrade costs or to substitute a new Point of Delivery.

E. New Rule #2—Eligibility for Standard Avoided Cost Prices and Purchase Agreements

The Joint Utilities recommend for New Rule #2 that Staff: (1) remove "[u]nless otherwise ordered by the Commission" from the beginning of subsections (2) and (3) absent clarification regarding Staff's intent in adding this language; (2) revise the definition of "affiliate" to encompass

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419 SW 11th Avenue, Suite 400
Portland, OR 97205

wholly owned subsidiaries that do not have "common ownership"; and (3) add a provision clarifying the entity which has authority to review eligibility under this rule, particularly as it applies to family owned and community based projects.

1. Subsections (2) and (3) Should be Revised to Exclude the Newly Added Language Absent Clarification from Staff.

As mentioned above, the Joint Utilities request that Staff provide further explanation on their assumptions and intentions in revising the new Draft Rules. For New Rule #2, in particular, the Joint Utilities request that Staff remove "[u]nless otherwise ordered by the Commission" from the beginning of subsections (2) and (3) absent clarification regarding Staff's intent in adding this language. This added language appears unnecessary given that OAR 860-001-000(2) allows the Commission to waive any of its rules "for good cause shown," and may invite uncertainty. The Joint Utilities' recommendations regarding subsections (2) and (3) are shown in the redline for New Rule #2 below.

> (2) ~~Unless otherwise ordered by the Commission, a~~All qualifying facilities with a nameplate capacity of ten (10) MW and less are eligible to enter into a standard power purchase agreement.
>
> (3) ~~Unless otherwise ordered by the Commission,~~ Renewable qualifying facilities that satisfy the criteria of subsection (1) are eligible to select the purchasing public utility's standard renewable avoided cost prices. A renewable qualifying facility choosing the standard renewable avoided cost prices must cede all RECs generated by the Facility to the purchasing public utility while the qualifying facility is receiving deficiency-period pricing from the purchasing public utility and during the non-fixed price term of the power purchase agreement.

2. The Definition of "Affiliate" Should be Revised.

The Joint Utilities further propose that Staff revise the definition of "affiliate" in the new Draft Rules as the definition is too narrow. Specifically, the definition of "affiliate" as written would fail to encompass wholly owned subsidiaries that do not have "common ownership," but

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Portland, OR 97205

nevertheless should be considered as affiliates for the purpose of the same site rule. The Joint Utilities therefore recommend the following definition of "affiliate" adopted from PacifiCorp's Washington standard QF PPA approved by the Washington Utilities and Transportation Commission (WUTC) (WUTC PAC PPA).[25]

> (4)(b)(B) Affiliate(s) are persons that directly or indirectly control, are controlled by, or are under common control with, another person or legal entity, with "control" meaning the possession, directly or indirectly, of the power to direct management and policies, whether through the ownership of voting securities or by contract or otherwise. ~~sharing common ownership or management, acting jointly or in concert with, or exercising influence over, the policies of another person or entity.~~

3. <u>New Rule #2 Should Require the QF to Demonstrate Eligibility and Identify an Entity Responsible for Resolving Disputes.</u>

New Rule #2 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. The Joint Utilities also recommend that the purchasing utility be provided with information to support QF eligibility as part of the indicative pricing request, and that such information should be considered eligible for inclusion in the informational requirements permitted under New Rule #3, as discussed in Section F.2. below. While FERC is the ultimate arbiter of QF status, and the Commission is the ultimate arbiter of standard PPA and standard pricing eligibility, the purchasing utility should be permitted to review all relevant eligibility information as part of its contracting due diligence. The Joint Utilities therefore recommend that Staff add a provision to New Rule #2 taking into consideration the above-mentioned concepts.

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[25] *See* WUTC, 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 at 7 (Mar. 1, 2021) [hereinafter, "WUTC PAC PPA"].

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Portland, OR 97205

F. New Rule # 3—Process for Procuring Standard Power Purchase Agreement

As an initial matter, the Joint Utilities note that Staff limited the requirement that the QFs support their proposed CODs with an interconnection study to proposed CODs occurring between three and four years from the effective date of the PPA. To the extent the new rules require commercially appropriate indications of financial and operational commitment from QFs that meaningfully address the issue of speculative contracting (and continue to apply the requirement to QFs desiring a three- to four-year construction period), the Joint Utilities do not object to Staff's proposal. However, the Joint Utilities retain the right to raise the interconnection study requirement again in the event the rules under development are altered in any way that fails to adequately protect retail customers from speculative contracting.

In addition, the Joint Utilities greatly appreciate Staff's addition of the catch-all provision to the informational requirements in New Rule #3 that would allow utilities flexibility in requesting information according to their unique resource planning needs when determining eligibility for a draft PPA.[26] The Joint Utilities further recommend that Staff should: (1) clarify the acceptable forms of evidence that would satisfy the site control requirement in subsection (2)(b); (2) replace "schedule of monthly power deliveries" with "a 12x24 power delivery schedule" and include informational support to demonstrate the qualifying facility meets the eligibility requirements under the same site rule set forth in New Rule #2 in the informational requirements list under subsection (2)(c) ; and (3) retain the fifteen (15) turnaround period for a utility to provide a revised executable standard PPA to a QF.

[26] Staff's AR 631 Rule Revision Matrix at 4 (Aug. 3, 2021).

McDowell Rackner Gibson PC
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Portland, OR 97205

1. <u>The Site Control Requirement Should Better Clarify Acceptable Forms of Evidence.</u>

As a general matter, the Joint Utilities support rules that require QFs to demonstrate substantial due diligence toward developing their projects before they are entitled to a draft PPA. Because obtaining site control is a fundamental initial step in the development process, the Joint Utilities believe that it is an appropriate requirement for determining eligibility for a draft PPA. That said, the Joint Utilities support a proposal to scale back the site control requirement so long as developers are required to submit *unambiguous* documentary evidence of meaningful steps towards obtaining site control. While the Joint Utilities appreciate Staff's inclusion of a more meaningful site control requirement in New Rule #3, the Joint Utilities believe that subsection (2)(b) should better clarify the types of documentation that are acceptable as evidence as well as those non-binding documents that fail to comply with the site control requirement. The Joint Utilities recommend the following revisions:

> (2)(b) Documentary evidence that the qualifying facility has taken meaningful steps to seek site control of the proposed location of the qualifying facility including, but not limited to, documentation demonstrating:
>
> (A) an ownership of, a leasehold interest in, or a right to develop a site of sufficient size to construct and operate the qualifying facility;
> (B) an option to purchase or acquire a leasehold interest in a site of sufficient size to construct and operate the qualifying facility; or
> (C) another document that clearly demonstrates the commitment of the grantor to convey sufficient rights to the developer to exclusively occupy a site of sufficient size to construct and operate the qualifying facility, such as an executed exclusivity agreement to negotiate an option to lease or purchase the site.
>
> <u>The provision of a letter of intent or other non-binding documentation of site control, such as an indication of interest to lease, or a qualitative description of the state of site control development, in and of themselves or together, are not sufficient to satisfy this required site control evidence.</u> ~~Evidence that the qualifying facility has taken meaningful steps to seek site control of the proposed location of the qualifying facility, including, but not limited to, an~~

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Portland, OR 97205

~~option to lease or purchase the site or an executed letter of intent or exclusivity agreement to negotiate an option to lease or purchase the site.~~

The provision by a QF developer of such eligible, binding 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. Accordingly, clarifying the types of eligible documentation in subsection (2)(b) will not only be consistent with PURPA's customer indifference principle, but will also decrease the risks of disputes and complaints before the Commission.

2. <u>The Informational Requirements List Should be Revised to Replace "Schedule of Monthly Power Deliveries" with "a 12x24 Power Delivery Schedule" and Include Information that Supports Standard PPA and Standard Pricing Eligibility.</u>

Staff did not include in its revised Draft Rules the Joint Utilities' recommendation to change the "schedule of monthly power deliveries" to "a 12x24 power delivery schedule."[27] The Joint Utilities urge Staff to reconsider this recommendation as a 12x24 schedule is necessary for typical utility resource and system balancing and planning, particularly with respect to understanding assumptions for daily dispatch and allowing utilities to accurately assess remaining capacity needs after successful contract execution. Moreover, 12x24 schedules are used to accurately calculate damages under applicable performance guarantees. For these reasons, 12x24 power delivery schedules are often incorporated into the PPA as an exhibit.[28]

Importantly, a 12x24 power delivery schedule requirement is also a reasonable market-based term that, in addition to being included in utilities' market-based PPAs, has been incorporated into certain of PacifiCorp's QF tariffs. For example, under PacifiCorp's Non-Standard Avoided Cost Rates in Oregon, QFs must provide documentation of "quantity, firmness,

[27] Joint Utilities' Response Comments at 13-14 (June 9, 2021); Joint Utilities' Initial Comments at 6 (Mar. 30, 2021).
[28] Information provided from a 12x24 schedule is also important in populating and syncing information in Exhibit A of the WUTC PAC PPA.

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419 SW 11th Avenue, Suite 400
Portland, OR 97205

and timing of daily and monthly power deliveries (including project ability to respond to dispatch orders from the Company and maintenance schedule)."[29] Furthermore, in PacifiCorp's Washington Avoided Cost Purchase and Procedures for Qualifying Facilities, both Washington's standard and non-standard QFs are required to "[p]rovide monthly volume of energy (MWh) and 12 X 24 or hourly energy profiles" electronically in a spreadsheet, and if applicable, include the initial year's maintenance plan.[30] Most developers will have completed a 12x24 schedule profile for their own purposes to compare facility development costs to PPA contract prices received for both on-peak and off-peak hours of the day; therefore, this requirement will likely not result in additional work for QFs in most cases and should not be burdensome. For these reasons, the Joint Utilities again propose that a 12x24 power delivery schedule be incorporated into the informational requirements.

As discussed in Section E.3. above, as part of purchasing utilities' due diligence, qualifying facilities should provide information that supports their eligibility for a standard PPA and standard pricing, consistent with the same site rule set forth in New Rule #2. Accordingly, the Joint Utilities' proposed revisions to subsection (2)(c) are shown below.

(2)(c) The following information regarding the proposed qualifying facility:

(A) demonstration of ability to obtain certified qualifying facility status prior to commercial operation and eligibility for standard power purchase agreement and standard qualifying facility pricing under OAR 860-029-XXX,

(B) design capacity (MW),

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[29] PacifiCorp Oregon Non-Standard Avoided Cost Rates, at 3 (effective Feb. 26, 2020), https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/purpa/Non_Standard_Avoided_Cost_Rates_Avoided_Cost_Purchases_From_Eligible_Qualifying_Facilities.pdf.

[30] PacifiCorp Washington Avoided Cost Purchase and Procedures for Qualifying Facilities, Section I.B., Table 1 at 3, and Table 2 at 5 (effective Jan. 1, 2021), https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates--regulation/washington/rates/QF_Avoided_Cost_Purchases_and_Procedures_for_Qualifying_Facilities.pdf.

McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205

(C) station service requirements and net amount of power to be delivered to public utility's electric system,

(D) generation technology and other related technology applicable to the site,

(E) a 12x24 power delivery schedule ~~schedule of monthly power deliveries~~,

(F) calculation or determination of minimum and maximum annual deliveries,

(G) motive force or fuel plan,

(H) proposed on-line date and other significant dates required to complete the milestones,

(I) 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,

(J) proposed contract term,

(K) proposed pricing provisions,

(L) Point of delivery or interconnection,

(M) latitude and longitude of proposed facility and site layout,

(N) for a qualifying facility with battery storage system, description of the storage design capacity, description of technology used by battery storage system, storage system duration, and net power output, and

(O) other information specified in the utility's avoided cost rates schedule or standard power purchase agreement approved by the Commission.[31]

3. <u>The Turnaround Period for an Executable Standard PPA Should Continue to be Fifteen (15) Days.</u>

In the New Rule #3, Staff continues to include a ten (10) business day turnaround requirement for a utility to provide a revised executable PPA to a QF because Staff "intend[s] to shorten turnaround time for public utilities after [the] initial draft [of the] PPA [is] provided."[32] The Joint Utilities disagree with Staff's proposal for a ten (10) business day turnaround, not because they wish to delay the process, but because the ability to turn around a PPA in this time period is not always within the utility's control. For example, this is frequently the case if the QF

[31] Please note that the Joint Utilities' additional revisions to subsection (2)(c) are to better conform the informational requirements to PacifiCorp's Schedule 37 for Oregon Standard Avoided Cost Rates Tariff (PacifiCorp's Schedule 37 tariff), which Staff used as a template for its updated proposal. *See* Updated Staff Proposal at 2-3 (Apr. 29, 2021); *see also* PacifiCorp's Schedule 37 Standard Avoided Cost Rates Tariff, Section I.B.2., Qualifying Facilities Contracting Procedure; Process for Completing a Power Purchase Agreement, at 11 (Effective for service on and after February 26, 2020), https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/purpa/Standard_Avoided_Cost_Rates_Avoided_Cost_Purchases_From_Eligible_Qualifying_Facilities.pdf. The Joint Utilities request that Staff provide an explanation for removing "calculation or determination of minimum and maximum annual deliveries" and "other significant dates required to complete the milestones" from the informational requirements list.

[32] Staff's AR 631 Rule Revision Matrix at 4.

McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205

submits comments to the public utility or asks for revisions to the draft PPA in connection with the request for an executable PPA. In the Joint Utilities' collective experience, fifteen (15) business days represents standard industry practices and is a reasonable and necessary timeline for preparing and reviewing an executable 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.[33] Conversely, there is no evidence on the record of this or any other proceeding suggesting that a fifteen (15) business day interval is either unreasonable or causes any harm to the QFs. Because the fifteen (15) business day interval is reasonable and there is no evidence of harm to QFs from the existing deadline, the current fifteen (15) business day turnaround time should be retained. The Joint Utilities offer the following revisions below.

> (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.

If Staff continues to recommend a ten (10) business day turnaround, at a minimum the Joint Utilities request that a longer response period be allowed under certain circumstances where additional care is required to ensure the completeness and accuracy of the PPA. Specifically, the Joint Utilities recommend that a fifteen (15) business day period, instead of a ten (10) business day period, apply in the event material changes to the initial draft PPA are required, such as: (1) a change in electrical generating equipment that increases power production capacity by the greater of 1 MW or five (5) percent of the previously certified capacity of the QF;[34] (2) a change in ownership in which an owner increases its equity interest by at least ten (10) percent from the

[33] This can be particularly true during times when multiple requests from qualifying facilities are pending.
[34] FERC Order No. 872, 172 FERC ¶ 61,041, at 309 ¶ 550.

McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205

equity interest previously reported;[35] (3) an addition or change in the battery system of a project; (4) 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 the case of clause (4), the utility should not be required to issue a revised draft PPA until the later of the expiration of the fifteen (15) business day period following the developer's request for an executable PPA and the fifteenth (15th) 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 (5) 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 qualifying facility still meets the eligibility requirements for a standard contract, which may be impossible to complete in ten (10) business days. In light of the burden the ten (10) business day turnaround period would place on utilities, as well as the corresponding lack of harm to QFs, the Joint Utilities offer the following alternative below.

> (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) 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.
>
> (6) Notwithstanding subsection (5), the public utility has fifteen (15) business days to provide the qualifying facility a revised draft purchase power agreement if:
>
> (a) the qualifying facility makes a change in electrical generating equipment that increases power production capacity by the greater of 1 MW or five (5) percent of the previously certified capacity of the qualifying facility.
>
> (b) the qualifying facility makes a change in ownership in which an owner increases its equity interest by at least ten (10) percent from the equity interest previously reported.

[35] *See id.*

McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205

(c) the qualifying facility makes an addition or change in the battery system of a project.

(d) there is any other change with respect to the qualifying facility that triggers a requirement under applicable FERC rules that the qualifying facility amend the FERC Form 556 on which the qualifying facility relies for eligibility, provided that in the case of subsection (d), the utility should not be required to issue a revised draft power purchase agreement until the later of the expiration of the fifteen (15) business day period following the qualifying facility's request for an executable purchase power agreement and the fifteenth (15th) business day following the date on which the qualifying facility delivers to the public utility an amended FERC Form 556 that corrects the applicable non-conformities.

(7) Notwithstanding subsection (5), the public utility has fifteen (15) business days to provide the qualifying facility a revised draft purchase power agreement in the event of a change in avoided cost pricing or any other change in circumstances outside the utility's control that requires a substantive modification to the standard power purchase agreement.

G. OAR 860-029-0120—Standard Power Purchase Agreements

While the Joint Utilities believe that Staff has greatly improved the provisions in OAR 860-029-0120 to better mitigate stale pricing and reflect market practices, the Joint Utilities strongly urge Staff and the Commission to go further and note that certain revisions are necessary to comply with the customer indifference standard.

First, the Joint Utilities recommend that Staff retain the three-year interval between contract execution and the scheduled COD to prevent stale pricing which harms utility customers and violates the customer indifference standard. Moreover, in the context of both QF PPAs and non-QF PPAs, a maximum of a three-year construction period has been the industry standard across utilities and jurisdictions.

Second, if Staff decides to retain the maximum four-year COD period, then the Joint Utilities further suggest that Staff clarify that when a QF chooses to modify the scheduled COD under subsection (8)(a), it may not select a new scheduled COD more than three years from

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419 SW 11th Avenue, Suite 400
Portland, OR 97205

contract execution without an interconnection study affirming the feasibility of that project coming online within that time.

Third, the Joint Utilities continue to urge Staff to include a minimum delivery guarantee, instead of a minimum availability guarantee, for solar and baseload hydro resources. Solar and hydro resources are predictable enough that QFs can provide minimum delivery guarantees and, indeed, sellers of generation from solar and hydro resources currently provide delivery guarantees as a matter of course, consistent with market practices.

Fourth, the Joint Utilities recommend that Staff clarify the deadline for QFs to provide Project Development Security to mitigate speculative contracting or harm to utility customers. Finally, the Joint Utilities recommend that the insurance provision reflect market terms by requiring at least an A- rating, with general commercial liability insurance of $1,000,000 and umbrella coverage of $5,000,000.

1. Scheduled COD Should be No More than Three Years from Contract Execution.

The Joint Utilities continue to strongly disagree that it is appropriate to allow QFs to lock in avoided cost prices a full four years before deliveries commence. Any rule that allows them to do so 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.[36] Instead, a QF should be allowed to select a COD no more than three years from contract execution. This approach is consistent with existing QF and non-QF PPA contracting

[36] PURPA Section 210(b) (16 U.S.C. § 824a-3(b)); OAR 860-029-0040(1)(a); *see also, e.g.*, *In the Matter of Portland Gen. Elec. Co.*, 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."); *In the Matter of Staff's Investigation Relating to Electric Utility 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 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).

McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205

practices [37] and consistent with QF requirements in Idaho, Wyoming, and Utah where the COD must be within thirty (30) months of the PPA execution date, as well as under the approved WUTC PAC PPA where the scheduled COD must be within three (3) years of PPA execution.[38]

For QFs that estimate construction will take more than three years because of interconnection or other design hurdles, such QFs should continue advancing their early-stage development activities, including activities related to project siting due diligence and interconnection, and only execute a PPA when they are able to commit to a COD within three years of contract execution. In this way, projects will either remain financially viable with the avoided cost prices effective at contract execution (*i.e.*, three years before scheduled COD) or become uneconomic, in which case construction will not proceed. To the extent a delay is caused by a QF's decision to interconnect in a crowded or transmission-constrained location, delays may be caused by the need to construct significant upgrades to facilitate the request, or, in the case of serial interconnection studies, because of the need to conduct interconnection re-studies when other projects ahead of the QF withdraw from the interconnection queue. Because such delays are not the fault of the purchasing utility and apply equally, on a non-discriminatory basis to non-QF projects that are similarly sited (the developers of which bear this risk), there is little justification to provide QFs with a longer time to construct period. Indeed, many non-QF developers face this same issue, and many receive interconnection studies that show they will not be online well beyond a three-year window due to the need for significant upgrades in their location. In such an instance, project viability is limited until such constraints are resolved and, often, developers will focus on advancing other projects that are more favorably positioned with regard to transmission

[37] For example, for PGE's on-system QF projects from 2010 to 2019, the average time for the QF projects to come online from the date of contract execution was 2.6 years. *See* Attachment A.
[38] *See* Section 2.1 of the WUTC PAC PPA.

constraints. Such an outcome should be no different for QFs that are similarly facing the challenges of siting projects in a constrained area.

Staff's proposal to lengthen the COD from three to four years will have a number of impacts, all of which harm utility customers and violate the customer indifference principle. For projects that would have been financially viable under a three-year scheduled COD, customers will be paying higher than market prices for net output for the entirety of the 14-year fixed priced period. In such cases, QFs will be receiving a subsidy or premium that is unnecessary for the viability of the project. Similarly, for projects that would have been uneconomic under a three-year scheduled COD, such projects would be constructed *only because* they are receiving a subsidy at the utility customer's expense.

In both cases, retail utility customers will be paying above market prices for net output and effectively subsidizing QF development. The amount of this premium can be substantial and reflects the difference in avoided cost prices at four years before COD versus three years before COD applied to all net output received during the fixed price period. This 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.

Moreover, as the Joint Utilities discussed in previous comments, Staff's proposal is also flawed because it appears to be based on the assumption that the harm to customers due to stale prices is equal to the customer savings resulting from reduction of the fixed-price term, but this is not necessarily true. 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

McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205

resource.[39] For example, as shown in Attachment B to these Comments, the net present value of the amount PacifiCorp would have paid for 1 MW of 14.5 years of power from a tracking solar 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 1 MW of 15 years 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. Staff's assumption that harm to customers due to stale prices is equal to customer savings resulting from a reduction of the fixed-price term is therefore inaccurate. Moreover, 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. The Joint Utilities provide their recommended changes below.

> (6) A qualifying facility may specify a scheduled commercial on-line date for a standard power purchase agreement anytime within three years from the date of agreement execution. ~~subject to the following limitations:~~
>
> ~~(a) Anytime within three years from the date of agreement execution; or~~
>
> ~~(b) Anytime between three years and four years after the Effective Date of the standard power purchase agreement if:~~
>
> ~~(A)The qualifying facility has received an interconnection related system impact study report, cluster study report, or facilities study report indicating interconnection will take longer than three years from the Effective Date of the standard power purchase agreement, or~~

[39] The Joint Utilities use the example of 14.5 years to mirror Staff's example that they have used since their initial proposal: "For every month in the interval between PPA execution and scheduled on-line date that is after three years, the fixed-price term will be shortened. For example, if the scheduled COD is 3 years and six months after PPA execution, the fixed price term for the PPA will be 14 years and 6 months (15 years – 6 months)." Staff's Initial Proposal at 5 (Jan. 15, 2021).

McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205

> ~~(B) The qualifying facility demonstrates to the public utility it cannot reasonably be expected to achieve commercial operation in three years or less from the Effective Date and the utility consents to a scheduled commercial operation date more than three years from the Effective Date.~~

If Staff nevertheless wishes to recommend that QFs may select a COD up to four years from PPA execution, the Joint Utilities appreciate and approve of Staff's intention to "minimize cost risk[s] to ratepayers associated with stale prices" by requiring an interconnection study supporting a COD between three and four years from contract execution under subsection (6)(b).[40]

2. Extension of the Scheduled COD More than Three Years from Contract Execution Should Require Receipt of an Interconnection Study Supporting the New COD.

In light of Staff's revisions in subsection (6)(b) regarding the interconnection study requirement, the Joint Utilities urge Staff to clarify that *any* extension of the scheduled COD more than three years from contract execution under subsection (8)(b) similarly requires proof of feasibility. The Joint Utilities therefore propose the following revisions below to ensure that subsection (6)(b) and subsection (8)(b) are consistent.

> (8)(b) A qualifying facility that chooses to modify the scheduled commercial on-line date under subsection (8)(a) ~~(1)(a)~~ may not select a new scheduled commercial on-line date more than four years from the date the standard power purchase agreement was executed. If the qualifying facility chooses to modify the scheduled commercial on-line date under subsection 8(a) to anytime between three (3) years and four (4) years after the Effective Date of the standard power purchase agreement, the qualifying facility must comply with the requirements under subsection (6)(b) with respect to receiving an interconnection study that supports a commercial on-line date within three (3) to four (4) years of the Effective Date.

3. OAR 860-029-0120 Should Allow Utilities to Require a Minimum Delivery Guarantee for Solar Resources.

While Staff did not include a minimum delivery guarantee for solar and baseload hydro resources in the revised Draft Rules, the Joint Utilities note that Staff seemingly intended to do so

[40] Staff's AR 631 Rule Revision Matrix at 4-5.

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by drafting subsection (1)(h) of New Rule #6, which lists "failure to satisfy applicable Minimum Delivery Guarantee for three (3) consecutive years" as an event of default. The Joint Utilities support the addition of a minimum delivery guarantee for solar and baseload hydro resources, and request that Staff clarify the provision which allows for such a guarantee in OAR 860-029-0120.

While the Joint Utilities and QF developers have been able to negotiate reasonable and achievable minimum delivery guarantees for solar, wind, and hydro resources in non-standard QF and non-QF contracts,[41] the Joint Utilities are willing to accept minimum availability guarantees (MAG) in lieu of minimum delivery guarantees for *wind* resources for purposes of standard QF PPAs. In the case of solar and baseload hydro resources, however, a minimum delivery guarantee is *both* feasible and important to protect utility customers to ensure PURPA's customer indifference standard is met. Therefore, the Joint Utilities continue to advocate for a minimum delivery guarantee.

Minimum delivery guarantees, also referred to as output guarantees, such as the agreed upon performance guarantee for solar and baseload hydro set forth in the WUTC PAC PPA, are feasible because the net output of solar resources can be reliably estimated based on the size and location of the project. These guarantees provide important price protections for utility customers for under deliveries (*i.e.*, having to buy energy at market price) and are therefore required to hold utility customers harmless. Importantly, the avoided cost prices paid to QFs include compensation for both capacity and energy. Without a minimum delivery guarantee, utility customers pay for an assumed capacity performance that they may or may not receive. If utility customers pay for an assumed capacity performance that they do not receive, PURPA's customer indifference

[41] For example, PGE has executed ten (10) negotiated PPAs since 2017 for solar, wind and hydro resources that have included a minimum delivery requirement.

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Portland, OR 97205

principle is violated unless there is a delivery or output guarantee to remedy such non-performance. Customer indifference is particularly an issue because utilities customarily obtain minimum delivery guarantees from non-standard QF and non-QF solar, wind, and hydro projects.[42]

In order to better ensure compliance with PURPA's customer indifference standard, the Joint Utilities recommend the following provision, with the understanding that additional revisions may still need to be made regarding calculation of damages and relief of the QF in the event of Force Majeure:[43]

> (12) Notwithstanding subsection (10), the standard power purchase agreement may include a minimum delivery guarantee (MDG) for solar and baseload hydro qualifying facilities as an alternative to a MAG for such facilities.
>
> (13) A public utility may issue a Notice of Default, and subsequently terminate a standard power purchase agreement pursuant to its terms and limitations, for failure to meet the MDG if the solar or baseload hydro qualifying facility does not meet the MDG for three consecutive years if such failure is not otherwise excused by the power purchase agreement.

4. QFs Must Post Project Development Security Upon Execution of the PPA Consistent with Market Requirements.

The Joint Utilities urge Staff to clarify in the Draft Rules that Project Development Security is due upon execution of the PPA, or in the alternative, within thirty (30) days of execution of the PPA. In the matrix explaining Staff's intent, Staff states that the revised Draft Rules require "all QFs to post Development Security *at execution* of [the] PPA because of recent history that reflects a high percentage of QFs that execute PPAs do not come online."[44] The Joint Utilities agree that without clarification of when Project Development Security should be posted, the utilities are left vulnerable to bearing significant financial risks should a QF default before such security is assured.

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[42] For example, *see* Footnote 41 above.

[43] Alternatively, these provisions may be more appropriately developed on a utility-specific basis in each utility's Commission approved standard QF PPA.

[44] Staff's AR 631 Rule Revision Matrix at 5 (emphasis added).

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Portland, OR 97205

Accordingly, the Joint Utilities recommend the following changes below to conform the Draft Rules with Staff's stated intent.

> (14) ~~(13)~~ Project Development Security. A qualifying facility entering into a standard power purchase agreement must post Project Development Security upon execution of the standard power purchase agreement for the public utility's benefit in the event of default by the qualifying facility prior to the scheduled commercial online date or termination under subsection (8). The amount of required Project Development Security will set forth in the purchasing public utility's form of standard power purchase agreement approved by the Commission and the obligation to maintain the Project Development Security will expire once the qualifying facility commences commercial operation. The qualifying facility may use either of the following options to post Project Development Security:

5. <u>Insurance Requirements Should Reflect Market Practices to Ensure Customer Indifference.</u>

The Joint Utilities continue to assert that a minimum rating of A- is industry standard, and QFs should be required to obtain umbrella coverage of $5,000,000 in addition to $1,000,000 in general commercial liability coverage. The Joint Utilities remain concerned that acceptance of insurance coverage from an insurer rated below the A- industry standard rating, a minimum rating that is met by most major, national insurers, creates an unacceptable, preventable, and unnecessary risk that utility customers will be responsible for any loss that is not covered by a QF's carrier. In order to protect utility customers, the Commission should require QFs to provide insurance on a basis that is comparable to market. PacifiCorp has required, without objection from any QFs, at least an A- insurance rating in all of its recent PURPA contracts and generally requires QFs to carry at least $1,000,000 in commercial general liability coverage and $5,000,000 in umbrella coverage.[45] PGE's negotiated PURPA PPAs routinely require the QF to carry at least $2 million in commercial general liability coverage from an insurer with a rating of at least A-. Similarly, all

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[45] For example, such insurance requirements were included in Exhibit I of PacifiCorp's PPA with Skysol, LLC, which was executed in 2020. *See* Docket No. RE-142, Informational Filing on Qualifying Facility Transactions, Attachment A, Exhibit I, Section 1.1.

of Idaho Power's PURPA PPAs in Idaho and its PPA for the Oregon Solar Photovoltaic Pilot Program require at least $1 million in commercial general liability coverage from an insurer with a rating of at least A-.[46]

In the Joint Utilities' experience, the above-described minimum rating requirement and the minimum insurance limits are consistent with market-based terms and conditions. With the exception of certain very small "Mom and Pop" QFs in other states where PacifiCorp has agreed to lower the minimum required umbrella coverage below the $5,000,000 minimum requirement, the Joint Utilities are unaware of any concerns raised by QF developers in negotiations or on the record of this or any other proceeding that either the A- minimum rating or the Joint Utilities' insurance coverage requirements exceed industry standard or are otherwise overly burdensome to meet. To address stakeholder concerns for smaller "Mom and Pop" QFs under 200 kW, PacifiCorp would propose retaining the above general commercial liability insurance requirement but lowering the minimum requirement for umbrella insurance requirement to $2,000,000.

Accordingly, the Joint Utilities recommend the following revisions to the insurance requirement below.

> (16) ~~(14)~~ Insurance requirements. A qualifying facility ~~with a nameplate capacity rating greater than 200 kW~~ must secure and maintain ~~general liability~~ insurance coverage that complies with the following:
>
> (a) The insurance provider must have a rating no lower than "A-" ~~"B+"~~ by A.M. Best Company.
>
> (b) ~~The coverage will be for both~~ Insurance coverage will include:
>
> (A) general commercial liability insurance covering bodily injury and property damage in the amount of $1,000,000 each occurrence combined single limit, or greater if desired by the qualifying facility.

[46] 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 Jul. 1, 2010).

McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205

(B) umbrella insurance in the amount of $5,000,000, or greater if desired by the qualifying facility; provided that this amount is reduced to $2,000,000 for qualifying facilities having a nameplate capacity rating of less than 200 kW.

H. New Rule #4—Delivery and Purchase

The Joint Utilities recommend that Staff clarify undefined terms and the underlying intent behind New Rule #4. Furthermore, Staff must revise New Rule #4 such that it complies with Order No. 07-360 where the Commission recognized that it could not force a utility to purchase non-QF imbalance energy.

1. Clarification is Required for New Rule #4.

The Joint Utilities request that Staff clarify "non-firm deliveries of Net Output" in subsection (2) of New Rule #4 and their overall intent for this rule, which has not been previously discussed by stakeholders. First, "non-firm deliveries of Net Output" is an undefined term. Second, if net output exceeds scheduled firm energy, then it is not delivered by definition, and utilities cannot be required to pay for such energy. Absent further explanation, the Joint Utilities believe that Staff is actually concerned with scheduled firm energy that exceeds net output, where the question becomes whether utilities must pay for imbalance energy from the balancing authority in which the QF is located and if so, at what price. In such case, the Commission has already indicated that such a requirement is impermissible where the imbalance energy was not generated by the QF.

To the extent Staff is attempting to draft a rule that would require a purchasing utility to purchase incremental additional output as a result of modifications to a QF (*e.g.*, repowering) that increase the facility's ability to generated energy as a result of efficiencies or additional capacity, the rule should provide that the incremental additional generation resulting from such changes (i) must not cause the QF to become ineligible for standard rates or otherwise result in a breach of the QF's PPA or interconnection agreement; and (ii) is subject to payment at then-current standard rates.

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Portland, OR 97205

2. Purchasing Utilities May Not be Required to Purchase Imbalance Energy.

Under subsection (3) of New Rule #4, the purchasing public utility *must* "receive and purchase, imbalance energy delivered at the Point of Delivery," subject to certain conditions. Where Staff's proposal would require the utility to purchase output from the QF that is not generated by the QF, *i.e.*, imbalance energy provided by the transmission provider, the Commission has already determined that such a requirement is impermissible. Specifically, under Order No. 07-360, the Commission recognized that "[r]egarding energy in excess of net output that is not offset during the settlement period, …the utilities have no obligation to purchase that energy under PURPA."[47] However, the Commission allowed that "[t]he parties may negotiate the price that would apply to any such sales."[48] As stakeholders have not had the opportunity to previously discuss these issues, the Joint Utilities recommend that Staff revise New Rule #4 to be consistent with such standards and provide further explanation on the proposed language and terms within the rule. Absent further clarification from Staff regarding what is intended or what alternatives Staff is asking for feedback on, the Joint Utilities are not currently in a position to offer revisions, or comment on the correct price for imbalance energy or purchasing limits.

I. New Rule #6—Default, Damages and Termination

The Joint Utilities recommend that Staff revise the cure periods in New Rule #6 to reflect standard market terms and provisions. The Joint Utilities continue to propose that the cure period for failure to timely achieve scheduled COD should be reduced to ninety (90) days. The current one-year cure period is 9-12 months longer than most negotiated cure periods in market-based PPAs and significantly longer than the cure periods applicable to QF standard PPAs in other

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[47] Docket No. UM 1129, Order No. 07-360 at 38.
[48] *Id.*

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states.[49] Any adjustments to the one-year cure period should serve to more closely align PURPA standard PPAs with market-based contract terms. To achieve this result, the cure period should be reduced to ninety (90) days. This period is both reasonable and appropriate, particularly if Staff's final proposed rules allow QFs to select a scheduled COD up to four years after the effective date of the PPA. Any project that requires more time is unnecessarily speculative and puts customers at undue risk of paying prices that are stale and not reflective of actual avoided costs. This is not a theoretical problem. As discussed in previous comments, of the 22 standard PPAs executed by PacifiCorp within the last ten years, 32 percent achieved COD more than three and a half years after PPA execution. For standard PPAs executed by PGE since 2010, 24 percent of the projects that achieved COD did so more than three and a half years after PPA execution.[50] Due to the one-year cure period, the utilities were not able to refresh pricing for these QFs.

Furthermore, the Joint Utilities recommend shortening the cure period for events of default other than failure to reach COD to an initial 30-day period. Staff has neither explained its reasoning for lengthening the cure period from a minimum of thirty (30) days in its initial proposal to ninety (90) days in the revised Draft Rules, nor have QFs argued that an initial 30-day cure period causes harm to the QFs. The minimum 30-day cure period is a more accurate reflection of what is "market". For example, a 30-day cure period is included in the WUTC PAC PPA. Accordingly, to prevent unnecessarily shifting developer risk to utility customers, the Joint Utilities recommend the following revisions to subsection (3) below.

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[49] For example, the standard PPA for PacifiCorp's Washington QFs provides for a cure period of up to 180 days but not to exceed the third anniversary of the execution date for the PPA and only so long as the QF complies with a detailed schedule recovery plan approved by PacifiCorp; provided, however, if the QF does not comply with the schedule recovery plan, the QF has 30 days to cure its default. Also, in Utah, PacifiCorp has entered into standard PPAs that provide for a 15-day cure period, and in Wyoming, PacifiCorp has entered into standard PPAs that provide for a 90-day cure period.

[50] This percentage includes both on-system and off-system QFs. For standard PPAs executed by PGE since 2010 for on-system QFs alone, 14 percent of the projects that achieved COD did so more than three and a half years after PPA execution.

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419 SW 11th Avenue, Suite 400
Portland, OR 97205

(3) Cure periods

(a) If a Notice of Default is issued under subsection (1)(a), the qualifying facility has ninety (90) days ~~one year~~ in which to cure the default for failure to meet the scheduled commercial on-line date.
(b) If a Notice of Default is issued under subsection (1)(b), (1)(c), (1)(d), 1(e), 1(f), or 1(i), the ~~non-~~defaulting party has thirty (30) ~~ninety (90)~~ days in which to cure the event of default~~.~~, provided, however, that if such default is not reasonably capable of being cured within the thirty (30) day cure period but is reasonably capable of being cured within ninety (90) days, the defaulting party will have an additional reasonable time to cure the default, not to exceed ninety (90) days following the date of notice of the default by the non-defaulting party, if the defaulting party provides to the non-defaulting Party a remediation plan within fifteen (15) days following the date of notice of the default by the non-defaulting party, the non-defaulting party approves such remediation plan, and the defaulting party promptly commences and diligently pursues the remediation plan.

J. Excused Delay

The Joint Utilities appreciate Staff's revision to the definition of "Excused Delay" in order to protect utility customers from stale pricing, which uses the WUCT PAC PPA definition as a template.[51] However, the Joint Utilities remain concerned that the definition of "Excused Delay", as is, may not account for situations where delay is not caused by the utility. For example, in the interconnection process with the transmission provider, the transmission provider may need to revise the in-service date for a variety of reasons beyond its control. The timing of the interconnection process is driven by FERC's study requirements, the engineering realities that drive the need for upgrades, and, in the case of serial-queue studies, the requirements of other interconnection customers who have vested rights in the federally regulated process. Such revision to the in-service date under the interconnection agreement should not be considered an excused delay as it is not the result of a default or violation of a Commission rule. Accordingly, the Joint

[51] Staff's AR 631 Rule Revision Matrix at 1; *see also* WUCT PAC PPA at Section 1.1.

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Utilities support the definition of "Excused Delay" as proposed by Staff, and suggest some minor clarifying language, which would read as follows:

> (x) "Excused Delay" means the failure of the qualifying facility to achieve Commercial Operation on or before the Scheduled Commercial Operation Date, but only to the extent such failure is caused by an event of Force Majeure or an Event of Default by the purchasing public utility, a default by the purchasing public utility under the Generation Interconnection Agreement or related interconnection study agreement(s) for the Facility, including a default resulting from any breach by the purchasing public utility of any obligation to meet a material deadline included in such agreement(s), or the purchasing public utility's violation of applicable tariff provisions governing the interconnection of the Facility; provided that the duration of any Excused Delay shall not extend to any period of delay that could have been prevented had the qualifying facility taken mitigating actions using commercially reasonable efforts or that, in the case of any default by the purchasing utility, results from any circumstances beyond the purchasing utility's reasonable control.

K. Other Definitions

The Joint Utilities recommend that Staff add the following definitions to the Draft Rules:

- "Forced Outage" means NERC Event Types U1, U2 and U3, and specifically excludes any Maintenance Outage or Planned Outage.
- "Interconnection Provider" or Transmission Provider" means an entity that owns, operates or controls facilities for the purpose of transmitting or transporting electric energy on behalf of the qualifying facility to or from the Point of Interconnection or Point of Delivery, as specified by the Generation Interconnection Agreement.
- "Maintenance Outage" means NERC Event Type MO includes any outage involving ten percent (10%) of the Facility's Net Output that is not a Forced Outage or a Planned Outage.
- "NERC" means the North American Electric Reliability Corporation.
- "Network Upgrades" means an addition, modification, or upgrade to the transmission system of a transmission provider required at or beyond the point at which the generator interconnects to the transmission system of the transmission provider to accommodate the interconnection of one (1) or more generation facilities to the transmission system of the transmission provider.
- "Planned Outage" or "Scheduled Outage" means NERC Event Type PO and specifically excludes any Maintenance Outage or Forced Outage.

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III. CONCLUSION

The Joint Utilities support many provisions of the Draft Rules and believe that they reflect policies that strike a reasonable balance between customers and developers. However, given that the Draft Rules were provided to stakeholders on August 3, 2021, and these comments are due August 12, 2021, the Joint Utilities believe that the necessarily expedited review hinders stakeholder's ability to provide robust and comprehensive comments on the Draft Rules and could also hinder Staff's ability to incorporate stakeholder feedback into the Draft Rules before presenting the rules to the Commission on August 24, 2021. Therefore, the Joint Utilities recommend an additional round of comments before moving into the formal rulemaking process, which should be scheduled to allow Staff sufficient time to incorporate stakeholder feedback from the present comments and then allow stakeholders an additional opportunity to comment on any proposed revisions to the revised Draft Rules arising from the submission of these comments.

This additional written process will better ensure that the rules presented to the Commission will be comprehensive, consistent, clear, and address with more specificity issues that are important for reaching thoughtful and durable decisions in this docket. While this additional process may delay the formal rulemaking process by a month or so, the Joint Utilities believe that the improved quality of the Draft Rules will far outweigh the downside of a one-month delay. Alternatively, should Staff recommend that the Commission start the formal rulemaking process, the Joint Utilities suggest that Staff also recommend a longer formal rulemaking process than customary, with multiple opportunities to comment on and refine the draft rules, to ensure that the above-mentioned goals are met.

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ATTACHMENT A

to

Joint Utilities' Comments
in Response to Staff's Draft Rules

Year of PPA Execution	Average Time Between PPA Execution and Initial Delivery for On-System QFs (Years)
2010	0.2
2014	2.0
2015	2.5
2016	3.3
2017	2.5
2018	2.5
2019	1.2
Total Average	2.6

ATTACHMENT B

to

Joint Utilities' Comments
in Response to Staff's Draft Rules

	Tracking Solar Standard Renewable Price		PPA MWh (1MW Tracking Solar)			PPA $, 15 years		PPA $, 14.5 years		
	8/25/2020	8/26/2020	15 year	14.5 year		8/25/2020	8/26/2020	8/25/2020	8/26/2020	
2024	$44.78	$23.35	2566	1283		$114,890	$59,906	$57,445	$29,953	
2025	$45.85	$23.99	2553	2559		$117,060	$61,243	$117,354	$61,397	
2026	$46.99	$24.61	2540	2547		$119,367	$62,514	$119,667	$62,671	
2027	$48.14	$25.34	2527	2534		$121,680	$64,044	$121,986	$64,205	
2028	$49.09	$25.84	2515	2521		$123,459	$64,988	$123,770	$65,151	
2029	$50.20	$26.53	2502	2509		$125,613	$66,384	$125,928	$66,550	
2030	$51.34	$27.24	2490	2496		$127,821	$67,812	$128,142	$67,982	
2031	$52.46	$27.89	2477	2484		$129,950	$69,095	$130,276	$69,268	
2032	$53.36	$28.33	2465	2471		$131,532	$69,821	$131,862	$69,996	
2033	$54.33	$28.82	2453	2459		$133,244	$70,693	$133,579	$70,871	
2034	$55.34	$29.34	2440	2446		$135,049	$71,609	$135,388	$71,789	
2035	$56.37	$29.86	2428	2434		$136,880	$72,510	$137,224	$72,692	
2036	$57.52	$30.53	2416	2422		$138,975	$73,759	$139,325	$73,945	
2037	$58.63	$31.17	2404	2410		$140,952	$74,938	$141,306	$75,126	
2038	$59.77	$31.83	2392	2398		$142,951	$76,139	$143,311	$76,331	
NPV at 6.92%			22823	21674	$	$1,161,309	$613,010	$1,110,230	$586,395	
NPV % change, ($) 14.5 years @ old pricing vs 15 years @ updated pricing NPV										**-44.8%**
Levelized Price					$/MWh	$50.88	$26.86	$51.22	$27.06	