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December 16, 2022

VIA ELECTRONIC FILING

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

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

Attention Filing Center:

Attached for filing in the above-captioned docket are the Joint Utilities' Comments Regarding the Group 2 Draft Rules.

Please contact this office with any questions.

Sincerely,

Suzanne Prinsen

Suzanne Prinsen
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 REGARDING THE GROUP 2 DRAFT RULES**

December 16, 2022

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I. INTRODUCTION

Portland General Electric Company (PGE), PacifiCorp dba Pacific Power (PacifiCorp), and Idaho Power Company (Idaho Power) (together, the Joint Utilities) offer these comments regarding the Group 2 Draft Rules in response to the memorandum and proposed draft rules (Draft Rules) provided by the Administrative Hearings Division (AHD) on November 23, 2022. The Draft Rules represent material, substantive changes to the Public Utility Commission of Oregon's (Commission) implementation of the Public Utility Regulatory Policies Act of 1978 (PURPA) standard contracting process and the terms for standard Power Purchase Agreements (PPAs) with Qualifying Facilities (QFs). The Joint Utilities greatly appreciated the opportunity to discuss their latest suggestions and concerns with the Commission, the Administrative Hearings Division (AHD), and other stakeholders at the October 18, 2022 Workshop.

Recognizing that the formal rulemaking phase is nearing its conclusion, the Joint Utilities focus in these comments on only the most important substantive changes that they urge the Commission to make before finalizing the rules. The current Draft Rules are the result of years of discussion and incorporate trade-offs and compromises by both the utilities and QF developers. In many cases, the balance struck in the rules is reasonable, but in other cases, the Joint Utilities continue to advocate for a few important revisions to ensure customer indifference. The Joint Utilities also oppose new changes to the Draft Rules by AHD that represent a significant step backward from the balance Staff attempted to strike at the end of the informal rulemaking period, to the detriment of customers—including the recommendation to wholly remove New Rules #1 (OAR 860-029-0044) and #5 (OAR 860-029-0122), as well as the addition of new caps on damages. If adopted, the new caps on damages would result in significant financial harm to

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customers, and the removal of New Rules #1 and #5 would create a regulatory gap and uncertainty, likely resulting in future disputes.

A recent example of how a defaulting Oregon QF can and does harm utility customers underscores the need to retain and build upon Staff's carefully crafted balance of interests regarding credit requirements, security, and meaningful damages in these rules. PacifiCorp is currently trying to collect approximately $400,000 in delay and termination damages in connection with an Oregon QF that walked away from its 2.7 MW solar project and PPA in 2022.[1] The damages result from the fact that the purchase price under the PPA is materially lower than current costs of power. The developer behind the QF is a sophisticated developer that availed itself of PacifiCorp's current standard PPA. The terms of this contract, based on current Commission policy, allowed the developer to meet minimal credit requirements and enter into the standard PPA without posting any kind of security. Because the QF entity never constructed a facility, it is assumed to have no assets, and PacifiCorp has no meaningful way to recover its damages.

The Joint Utilities are concerned that the latest revisions to the Draft Rules shift Commission policy in a direction that will encourage speculative contracting for projects that will ultimately not be built, causing utilities lost opportunity to lock in power purchases from more reliable sources at then-current prices. Furthermore, when a QF defaults on its obligation to supply power and replacement costs are significant, utility customers will be left bearing the financial burden of that default if caps on damages are hit. To the extent the Commission adopts policies that exempt QFs from reasonable commercial requirements in order to promote QF development,

[1] Note that but for the 24-month limit on termination damages under existing Commission policy, the actual damages PacifiCorp projects it will incur in this case, unless it is able to mitigate for the loss of the QF power under the contracted-for price, is approximately $1.5 million.

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that policy cannot be used to transfer project risk and cost to utility customers unless such risk and cost are quantified and reflected in avoided cost pricing. The Joint Utilities urge the Commission to adopt the Joint Utilities' creditworthiness, security, and damages recommendations to ensure customers are protected.

Finally, based on the understanding that the Draft Rules will undergo clean-up and internal reconciliation before they are finalized, the Joint Utilities are not providing their more minor corrections and clarifications to the Draft Rules in these comments. However, the Joint Utilities note that they have identified a number of edits that will ultimately need to be made to the rules before they are consistent and error-free. The Joint Utilities intend to provide suggested clean-up edits later in the process or to AHD directly. At this time, however, the Joint Utilities offer the following comments in response to AHD's November 23, 2022, memorandum and the revised Draft Rules.

The Joint Utilities have prepared a summary of their positions on key issues, intended as a quick reference guide to these comments for the Commission's convenience. The summary is attached hereto as Attachment A.

II. FINAL COMMENTS ON GROUP 2 RULES

A. OAR 860-029-0044/New Rule #1 — Allocation of Costs Related to Deliveries from Off-System Qualifying Facilities

OAR 860-029-0044, formerly known as New Rule #1, details the process for identifying and allocating transmission-service-related Network Upgrade costs incurred to deliver a QF's output, which in most instances cannot be known with certainty at the time the PPA is executed. In the November 23, 2022, memorandum, AHD stated that they did not make any edits to "proposed New Rule #1 because [they] have chosen to wait pending a decision in docket

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UM 2032."[2] The Joint Utilities disagree that New Rule #1 is dependent on the outcome of docket UM 2032, or that a decision in docket UM 2032 would obviate the need for New Rule #1. The Joint Utilities support retaining New Rule #1 in the Draft Rules because its provisions are critical to maintaining customer indifference, the rule is consistent with Commission precedent,[3] and the rule mirrors provisions that the Commission already approved in the utilities' Community Solar Program (CSP) PPAs.[4]

1. <u>New Rule #1 Should be Retained and Addressed in the Draft Rules Regardless of the Outcome of Docket UM 2032; Failure to Address the Issue Now Will Result in Regulatory Gaps, Uncertainty, and Additional Administrative Process No Matter What the Commission Decides in Docket UM 2032.</u>

AHD apparently deferred addressing New Rule #1 because it agreed with the Community Renewable Energy Association (CREA), the Northwest & Intermountain Power Producers Coalition (NIPPC), and the Renewable Energy Coalition (REC) (collectively, the QF Trade Associations) that the rule addresses issues currently being litigated in docket UM 2032.[5] However, this premise is simply incorrect. Delaying adoption of New Rule #1 pending the outcome of docket UM 2032 is not only unreasonable and unnecessary because the rule addresses

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[2] AHD Memorandum on Request for Comment at 1 (Nov. 23, 2022).
[3] *See In re Blue Marmot V LLC et al. v. Portland General Electric Company,* Docket No. UM 1829, Order No. 19-322 at 19 (Sept. 30, 2019) ("QFs should understand that utilities may manage scarce transmission rights to achieve legitimate management objectives for the benefit of utility customers, subject to our reasonableness review, and that a [Point of Delivery] cannot be unilaterally dictated by a QF to the detriment of a higher system value. If a QF wishes to deliver to a point at which PGE is not otherwise accepting delivery from off-system QFs, PGE and the QF have the option to negotiate a mutually acceptable non-standard contract that adjusts avoided cost values to incorporate additional transmission system costs that PGE cannot reasonably avoid, or allows the QF to fund upgrades to generate the necessary incremental transmission system capacity.").
[4] *See In re Public Utility Commission of Oregon, Community Solar Program Implementation*, Docket No. UM 1930, Order No. 20-122 at 1-2 (Apr. 9, 2020).
[5] *See* Comments of the Community Renewable Energy Association, Northwest & Intermountain Power Producers Coalition, and Renewable Energy Coalition on Staff's Proposed Group 2 Rules at 12-14 (Sept. 16, 2022) [hereinafter, "QF Trade Associations' Initial Group 2 Comments"].

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an issue ***outside the scope of docket UM 2032*** but is also inefficient because stakeholders have spent years commenting on and developing New Rule #1 in this docket. If New Rule #1 is not adopted in this docket, allocation of transmission-service-related Network Upgrade costs will need to be addressed in a different docket, and that alternative docket is not docket UM 2032.

AHD's apparent concern regarding overlap with docket UM 2032 is without merit because docket UM 2032 addresses ***interconnection-related*** Network Upgrades triggered by on-system QFs, whereas New Rule #1 addresses ***transmission-service-related*** Network Upgrades, which can be triggered by both on-system and off-system QFs. At the conclusion of docket UM 2032, the Commission will not have decided *anything* about allocation of Network Upgrade costs revealed in transmission-service studies necessitated by utility purchases of QF power.

Although QF developers argued in their comments and at various workshops that all Network Upgrades are the same, and that the policy decision in docket UM 2032 will somehow set *de facto* policy for a QF's transmission-service-related Network Upgrades,[6] this statement is simply untrue. As a matter of state regulatory policy, not all Network Upgrades are alike.[7] While the Joint Utilities believe QFs should be responsible for the costs of their transmission-service-related Network Upgrades (since transmission constraints can be expensive to address and receipt of QF power could be useless—or even harmful—unless the costs are allocated to QFs), adoption of such a policy is outside the scope of docket UM 2032. Indeed, at the September 23 Workshop, the QF Trade Associations appeared to concede that docket UM 2032

[6] *See* QF Trade Associations' Initial Group 2 Comments at 14.

[7] As the Joint Utilities noted in their briefing in docket UM 2032, state commissions assess various types of Network Upgrades differently, including Network Upgrades for load service, for reliability, needed to add new customers, etc. Moreover, some Network Upgrades are mandated by the Federal Energy Regulatory Commission (FERC), while others may be discretionary. While FERC may not care about these distinctions, state commissions do.

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and New Rule #1 do not address identical issues.

Moreover, New Rule #1 simply creates a ***process*** for allocating transmission-service-related Network Upgrade costs but does not predetermine that allocation. Regardless of what happens in docket UM 2032, this process question will need to be independently addressed. This issue is critical and can only be addressed in *this docket* because of the jurisdictional and timing differences relevant to allocation of ***interconnection-driven*** versus ***transmission-driven*** Network Upgrades. PURPA gives state regulatory authorities the power to allocate directly to QFs any interconnection-driven Network Upgrade costs identified in the QFs' interconnection studies, regardless of when those studies are complete. Docket UM 2032 was opened to address this issue and nothing more. However, timing differences and other key differences—such as the lack of a Commission-jurisdictional interconnection study for off-system QFs—make the process contemplated by docket UM 2032 unworkable for transmission-service-related Network Upgrades.

While transmission-service-related Network Upgrades can be significant, and while the Federal Energy Regulatory Commission (FERC) allows them to be assessed to QFs,[8] transmission-service-related Network Upgrade costs are not ordinarily capable of identification until the QF has signed both a PPA and an interconnection agreement. Thus, the only two tools

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[8] *See, e.g.*, *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215 at P. 38 n. 73 (2013) ("This is not to suggest that the QF is exempt from paying interconnection costs, *see* 18 C.F.R. §§ 292.101(b)(6), 292.306 (2013), which may include transmission or distribution costs directly related to installation and maintenance of the physical facilities necessary to permit interconnected operations. 18 C.F.R. § 292.101(b)(6) (2013). Such permissible interconnection costs do not, however, include any costs included in the calculation of avoided costs. *Id.* Correspondingly, implicit in the Commission's regulations, transmission or distribution costs directly related to installation and maintenance of the physical facilities necessary to permit interconnected operations may be accounted for in the determination of avoided costs if they have not been separately assessed as interconnection costs.").

the Commission currently deploys to ensure customer indifference—the PPA and, for on-system QFs, the interconnection agreement—are likely to be finalized and executed before the transmission-service-related Network Upgrade costs are identified. The process contemplated by New Rule #1 simply ensures that if a QF drives significant transmission-service-related Network Upgrade costs, the Commission retains the legal authority to address allocation of those costs. Absent a workable process that the Commission can use to address transmission-service-related Network Upgrade costs, those costs will fall to customers by default, and the Commission may have few tools to remedy the resulting harm. New Rule #1 is a reasonable and appropriate tool for ensuring the Commission retains the authority to protect retail customers and should be included in these Draft Rules regardless of the outcome of docket UM 2032.

2. New Rule #1 Should Apply to Both On-System and Off-System QFs.

Currently, the cost-allocation process in New Rule #1 applies only to off-system QFs. The Joint Utilities continue to propose that New Rule #1 apply to on-system QFs as well. Regardless of how the Commission resolves docket UM 2032, there will be a gap in the Commission's policy addressing QF-driven costs if New Rule #1 applies only to off-system QFs. Specifically, even if an on-system QF obtains Network Resource Interconnection Service (NRIS) and pays for the resulting Network Upgrades, subsequent transmission service studies may reveal costs not identified by the NRIS studies, as NRIS studies are completed independently from and for a different purpose than transmission studies. New costs could also be identified due to system changes during the time that lapses between completion of an interconnection study and completion of a transmission service study. The Commission currently has no policy for allocating these transmission-service-related Network Upgrade costs for on-system QFs. As discussed above, without a workable process for allocating transmission-service-related Network Upgrade

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costs for both on- and off-system QFs, it appears to the Joint Utilities that these costs would be allocated to retail customers by default with little recourse to the Commission for ensuring customer indifference.

There is substantial precedent for applying the cost-allocation process in New Rule #1 to on-system QFs. First, the Commission required all the Joint Utilities to include a similar provision in both on-system and off-system CSP PPAs.[9] Furthermore, PacifiCorp has executed PPAs with on-system QFs that include this provision, both in Oregon and in other jurisdictions,[10] 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 and 2022 All-Source Requests for Proposals (RFPs).[11] Accordingly, New Rule #1, which reflects market-based and Commission-approved terms and conditions, should apply to *all* QF PPAs to ensure customer indifference. The Commission should revise New Rule #1 to remove language limiting its application to off-system QFs.

3. New Rule #1 Should Not Allow Deferment of the Development Period.

The Commission should revise OAR 860-029-0044 so that the cost-allocation process does not delay the Scheduled Commercial Operation Date (COD) indefinitely—potentially resulting in

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[9] *See* Order No. 20-122 at 1-2 & App. A at 11-15.

[10] For example, PacifiCorp's PPA with non-standard Oregon QF Skysol, LLC, which was executed in 2020 contains a Conditional DNR provision. *See In re PacifiCorp, dba Pacific Power Information Filing of Qualifying Facility Contracts or Summaries Per OAR 860-029-0020(1)*, Docket RE 142, PacifiCorp's Informational Filing on Qualifying Facility Transactions - Skysol, LLC, Attachment A, Section 4.2 (Apr. 24, 2020), *available at* 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 and with QFs in Washington. These PPAs have been approved by the Idaho Public Utilities Commission.

[11] The form PPA for the 2020 All-Source RFP (RFP Appendix E-2) is available here: https://www.pacificorp.com/suppliers/rfps/all-source-rfp/2020-all-source-rfp-docs.html. The form PPA for the 2022 All-Source RFP (RFP Appendix E-2.1) is available here: https://www.pacificorp.com/suppliers/rfps/2022-all-source-rfp/RFP-documents-appendices.html. The Conditional DNR provision is Section 4.2 of both form PPAs.

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the QF receiving very stale avoided cost prices. Specifically, the Joint Utilities urge the Commission to delete subsection (4)(a) in its entirety so that the start of the Development Period cannot be postponed. As context, section (3) provides that a utility may choose to include in its standard PPA a provision specifying the Commission may allocate to the QF the costs of transmission-service-related Network Upgrades necessary to transmit the QF's output. Subsection (4)(a) states that if the utility chooses to include such a provision, then the standard PPA must specify that the Development Period does not commence until the Commission processes to allocate such costs are complete. Unless subsection (4)(a) is removed, the Development Period could be deferred indefinitely, which would be inconsistent with Staff's and AHD's recommendation elsewhere in the Draft Rules that a QF should not be permitted to select a Scheduled COD more than four years from the PPA Effective Date.[12]

Assuming that the Commission makes no changes to the existing NRIS requirement, most QFs will be unlikely to trigger transmission-service-related Network Upgrades; however, some will. As discussed above, in most instances the purchasing utility cannot even begin the process of identifying transmission-service-related Network Upgrades necessitated by an off-system QF until the purchasing utility has signed a PPA with the QF and is able to submit a request for transmission service. That request allows the transmission function to conduct studies needed to identify transmission-service-related Network Upgrades triggered by the QF. Once the purchasing utility requests to designate the QF as a network resource (which occurs immediately after the PPA is executed), if a significant Network Upgrade is required, it is possible that the cost-allocation

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[12] *See* Draft Rules OAR 860-029-0120(5)(e) ("A qualifying facility entering into a standard power purchase agreement may not select a scheduled commercial operation date more than four years from the Effective Date.").

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process could be resolved relatively quickly, but it is also possible that it could require one year or more. For example, the *Blue Marmot* case, which addressed deliverability and cost-allocation issues, took almost two and half years to resolve.[13] If the cost-allocation process under New Rule #1 takes two years and *then* the QF can take an additional four years to achieve Scheduled COD, the avoided cost prices in the PPA would be six years old.

Because a lengthy delay could render the avoided cost prices unacceptably stale, the Commission should not permit indefinite deferral of the Development Period. The removal of subsection (4)(a) would ensure that customers remain indifferent when a QF sites at a constrained location that requires Network Upgrades. However, if the Commission does permit an indefinite deferral of the Development Period, and elects not to remove subsection (4)(a), the Commission should, after resolving allocation of transmission-service-related Network Upgrade Costs, require the QF to either accept updated pricing or terminate the PPA.

4. New Rule #1 Should Clarify that an Off-System QF Must Have Firm Transmission to Deliver Its Output to the Purchasing Utility's System Prior to the Utility Designating the QF as a Network Resource.

OAR 860-029-0044(4)(b) requires the public utility to, no later than 15 business days after the Effective Date of the PPA, submit an application to the appropriate transmission provider requesting designation of the QF as a network resource and requesting network transmission service. The Joint Utilities recommend that the Commission revise subsection (4)(b) to clarify that an off-system QF must have obtained firm transmission to the purchasing utility's system before the utility is required to designate the QF as a network resource. Under the Open Access Transmission Tariff (OATT), an off-system generator must have firm transmission arrangements

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[13] The Blue Marmots filed complaints on April 28, 2017, and the Commission entered a final order in Phase I on September 30, 2019. Order No. 19-322 at 2.

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to the purchasing utility's system in order to become a designated network resource.[14] Off-system QFs are responsible for securing firm transmission from a third-party to deliver their output to the purchasing public utility's system. However, as currently drafted, New Rule #1 lacks any requirement that the QF have arranged for firm delivery, and the requirement that the purchasing public utility request network transmission service from the "appropriate transmission provider" could be read to suggest that the purchasing public utility is responsible for acquiring transmission service for the QF on a third-party's system. Accordingly, the Joint Utilities request the following clarifying revisions to subsection (4)(b):

> (b) No later than 15 business days after the Effective Date of the standard power purchase agreement, <u>provided that if the qualifying facility is off-system, the off-system qualifying facility has obtained firm transmission to the Point of Delivery as of the Effective Date, or no later than 15 business days after the purchasing public utility receives a signed transmission service agreement from the off-system qualifying facility showing that the off-system qualifying facility has obtained firm transmission service to the Point of Delivery,</u> submit an application to the appropriate transmission provider requesting designation of the qualifying facility as a network resource and requesting network transmission service for the purpose of transmitting the power purchased from qualifying facility to the public utility's load.

5. <u>New Rule #1 Should Not Require the Purchasing Utility to Obtain in Advance at PPA Execution Transmission Service for the QF Output More than 90 Days Prior to the Scheduled COD.</u>

The Joint Utilities recommend that the Commission revise OAR 860-029-0044(4)(c) such that the public utility is required to request an effective date for commencement of network

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[14] *See, e.g.*, PGE Pro Forma Open Access Transmission Tariff, Section 30.2 at 128-29 (2022) ("The Network Customer may designate a new Network Resource by providing the Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must be made through the Transmission Provider's OASIS by a request for modification of service pursuant to an Application under Section 29. This request must include a statement that the new network resource satisfies the following conditions: …. The Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load *or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis*, except for purposes of fulfilling obligations under a reserve sharing program….") (emphasis added).

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transmission service for a QF 90 days prior to the Scheduled COD—not 180 days as provided in the Draft Rules. This change is consistent with the Joint Utilities' proposal to revise OAR 860-029-0121(5) (formerly known as New Rule #4) to provide that utilities should not plan in advance, at PPA execution when the utility makes the designated network request, that a QF will commence commercial operation sooner than 90 days before the Scheduled COD and is justified for the reasons explained below in Section II.C.2 discussing New Rule #4.

6. New Rule #1 Should Allow Both Parties to Elect to Proceed with a Contested Case Process.

In their Initial Comments, the QF Trade Associations argued that the cost-allocation process under New Rule #1 should follow contested case procedures "unless waived by the [QF]."[15] The Joint Utilities agreed that contested case procedures may be appropriate but disagreed that only the QF should have the option to determine the process.[16] As both parties agree that a contested case proceeding may be appropriate, the Joint Utilities recommend that the Commission incorporate the following revisions to OAR 860-029-0044(5):

> (5) Upon receipt of a request for a cost allocation determination under subsection (4)(e), the Commission will conduct a proceeding at which the 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-related Network Upgrades. After providing notice and opportunity to comment regarding a request filed under subsection (4)(e), the Commission will issue an order regarding the appropriate allocation of costs of transmission-service-related Network Upgrades. Notwithstanding the notice and opportunity to comment provided under this section, a public utility and qualifying facility both have the right to proceed with a contested case to address transmission-service-related Network Upgrade costs.

[15] QF Trade Associations' Initial Group 2 Comments at 18-20 & Proposed Redlines at 10.
[16] Joint Utilities' Comments in Response to Stakeholders' Comments on the Group 2 Draft Rules at 9 (Oct. 7, 2022) [hereinafter, "Joint Utilities' Group 2 Draft Rules Response Comments"].

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

1. OAR 860-029-0120(12)-(13) – Mechanical Availability Guarantees (MAGs).

Because doing so transfers costs and project risk from the QF to the utility that are not included in avoided cost pricing, as discussed in Section II.E.1 of these comments below, the Joint Utilities oppose AHD's inclusion of a cap at the contract price on damages for failure to meet the MAG and recommend that the Commission remove OAR 860-029-0120(12)(c) from the Draft Rules.

2. OAR 860-029-0120(14)-(15) – Minimum Delivery Guarantees (MDGs).

A MDG is a contractual provision that ensures the QF delivers the output for which the utility has contracted. As currently proposed, the Draft Rules include a MDG for solar, geothermal, biomass, and baseload hydroelectric QFs equal to 90 percent of the QF's expected energy for the year. Furthermore, AHD revised the MDG to clarify that—in addition to reasons of Force Majeure—the 90 percent output guarantee will be reduced on a pro rata basis for any portion of the annual period the QF was prevented from generating or delivering electricity due to: (i) a default by the public utility under the PPA or interconnection agreement; or (ii) any interconnection and transmission curtailment initiated by the purchasing utility or the transmitting utility. Finally, based on the recommendation of the QF Trade Associations, AHD added a cap on damages for a QF's failure to meet the MDG, which limits damages to no more than what the QF would have been paid under the standard PPA for energy it would have delivered to meet the MDG (i.e., the contract price). While the Joint Utilities generally support AHD's revisions to the MDG provision, the Joint Utilities provide further comment on: (a) the appropriateness of a mandatory 90 percent MDG for solar resources; (b) the proper calculation for the MDG; and (c) the Joint Utilities' opposition to a cap on damages for failure to meet the MDG.

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a) A Mandatory 90 Percent MDG is Market, and Reasonable and Appropriate for Solar Resources.

As requested by AHD, the Joint Utilities explain their reasoning and evidence supporting a mandatory 90 percent MDG for solar resources, as well as geothermal, biomass, and baseload hydroelectric resources.[17] Solar resources are regularly able to meet 90 percent generation targets. For instance, Idaho Power has negotiated four non-PURPA solar PV PPAs, totaling 460 MW cumulatively, that each contain a 90 percent monthly output guarantee (i.e., MDG). Similarly, since 2017, PacifiCorp has executed nine non-QF PPAs for solar and wind resources, for system supply, that have included a MDG requirement between 80 and 90 percent, with the majority at the midpoint of that range. Additionally, since 2017, PGE has executed nine negotiated QF and bilateral PPAs for solar resources that have included a MDG requirement between 80 and 90 percent, with approximately half of the contracts at 90 percent.[18] Moreover, under the pro forma Washington QF PPA for PacifiCorp, solar and baseload hydroelectric facilities are subject to a 90 percent output guarantee less any output that is not delivered or accepted by the purchasing utility.[19] Accordingly, a 90 percent MDG is feasible and market for solar resources.

At various workshops and in comments, QF developers have argued that a 70 percent MDG was reasonable because QFs expect year-to-year swings in generation between 20 and 30 percent. The Joint Utilities disagree with this representation. It is unlikely that the types of resources subject to the MDG—rather than the MAG—would experience such significant swings. For example,

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[17] AHD Memorandum on Request for Comment at 1 ("While participants have already advocated for numbers ranging from 70 percent to 90 percent, AHD now particularly seeks any available empirical evidence showing what number would be reasonable to use for solar resources.").
[18] For one of the nine PPAs (non-QF), the MDG was not consistent for the entire term but was within the stated range for the majority of the term.
[19] *In re Pacific Power & Light Company Schedule QF Tariff Revision*, Washington Utilities and Transportation Commission (WUTC) Docket No. UE-190666, Standard Power Purchase Agreement, Attachment A, Exhibit F: Performance Guaranty – Solar & Baseload at 48-49 of 55 (Mar. 1, 2021).

PGE reviewed seven small *solar* facilities and found that the variation in generation ranged between 0 and 11 percent between 2019 and 2020 and between 2020 and 2021.

For the above reasons, the Joint Utilities continue to support a 90 percent MDG for solar, geothermal, biomass, and baseload hydroelectric QFs. However, as discussed at the October 18, 2022 Workshop, the Joint Utilities are not opposed to a MDG at 85 percent in an effort to find common ground while remaining sufficiently protective of customers.

b) The MDG Should Be Measured over a One-Year Period for All Subject Resources, Including Solar QFs.

AHD further requested that parties comment on how the MDG for solar resources should be calculated.[20] As an initial matter, solar resources are sufficiently reliable such that calculation of the MDG for solar resources should be treated the same as other resources subject to the MDG (i.e., geothermal, biomass, and baseload hydroelectric). The Joint Utilities reiterate that an annual time period for measuring the MDG for *all* subject resources is reasonable and appropriate, reflects current utility practice, and should remain in the Draft Rules. For example, in PGE's most recent RFP, the "Performance Measurement Period" for the output guarantee—or MDG—is equal to a *monthly* period commencing on the COD, an even more granular measurement than an annual measurement period. In PGE's nine executed Schedule 202 and bilateral contracts for solar resources that have included a MDG requirement, all MDG measurement periods have been for one year. Under the Washington pro forma QF PPA for PacifiCorp, the output guarantees for both solar and baseload hydroelectric resources are measured on a "rolling period," which is defined as every consecutive *12-month period* commencing on the COD.[21] Furthermore, the Commission

[20] AHD Memorandum on Request for Comment at 1.
[21] WUTC Docket No. UE-190666, Standard Power Purchase Agreement, Attachment A, Section 1: Definitions, Rules of Interpretation at 14 of 55.

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has previously recognized that annual delivery commitments provide QFs sufficient flexibility to manage power deliveries to avoid default.[22]

c) The MDG Damages Provision Should Not Include a Cap at the Contract Price.

Because doing so transfers costs and project risk from the QF to the utility that are not included in avoided cost pricing, as discussed in Section II.E.1 of these comments below, the Joint Utilities oppose AHD's inclusion of a cap at the contract price on damages for failure to meet the MDG. It is appropriate for the QF, which is in the best position to control and mitigate the risk, to assume this risk in its entirety. The Joint Utilities recommend that the Commission remove OAR 860-029-0120(14)(c) from the Draft Rules.

3. <u>OAR 860-029-0120(16) – Incremental Facility Upgrades.</u>

The Draft Rules describe in detail how and when a QF is permitted to increase its Nameplate Capacity Rating or expected annual net output and explain when facility modifications require revised pricing or a new PPA. The Joint Utilities generally support the Incremental Facility Upgrades provision in the Draft Rules, which incorporates many of the recommendations provided by the Joint Utilities. However, the Joint Utilities recommend several important clarifying revisions.

First, the Joint Utilities recommend deleting "Except as expressly permitted in subsection (b)" from subsection (16)(a). Subsection (16)(a) addresses permissible changes during the Development Period—prior to commercial operation, whereas subsection (16)(b) addresses

[22] *In re Public Utility Commission of Oregon, Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Docket No. UM 1129, Order No. 06-538 at 24 (Sept. 20, 2006) ("Our direction, in this order, that standard contracts require annual delivery commitments (instead of monthly commitments) provides QFs with sufficient flexibility, we believe, to manage power deliveries to avoid default.").

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changes after the facility is operational. Therefore, the reference to subsection (16)(b) is not relevant to subsection (16)(a).

Second, subsection (16)(b) provides that the utility *is not required to approve* facility upgrades that would (A) result in an increase to Nameplate Capacity Rating above that specified in the PPA at the time of execution ***or*** (B) cause the expected annual net output specified in the PPA at the time of execution to increase by more than 10 percent. However, if the Commission wishes to allow QFs to pursue facility upgrades that would not increase the Nameplate Capacity Rating, but would likely increase the annual net output by more than 10 percent, *without the utility's consent*, the Joint Utilities recommend that the Commission remove subsections (16)(b)(A)-(B) because they are inconsistent with the language in subsection (16)(b) stating, "except as permitted under subsection (c)…."

Third, the Joint Utilities recommend that the Commission clarify that if a QF elects facility upgrades that would likely increase the annual net output by more than 10 percent, then the QF ***must*** accept repricing and execute an amended PPA under subsection (16)(c)(D). The current phrasing of subsection (16)(c)(D) could be interpreted as permissive rather than mandatory, which is inconsistent with the intent of the provision.

The Joint Utilities provide their recommended changes below.

(16) Incremental Facility Upgrades.

(a) During the development period, the qualifying facility may make reasonable modification to the design and components of its facility from the design and components contained in the power purchase agreement. The qualifying facility is obligated to provide the purchasing public utility an as-built supplement describing the Facility within 90 days after the commercial operation date. ~~Except as expressly permitted under subsection (b) of this section, t~~The Facility as reflected in the as-built supplement may not:

(A) Have a nameplate capacity rating that exceeds the nameplate capacity

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rating in the power purchase agreement at the time it was executed; or

(B) Result in the expected annual net output specified in the power purchase agreement at the time it was executed to increase by more than 10 percent.

(b) During the term of the power purchase agreement, except as permitted under subsection (c) of this section, the facility may not be modified in a manner that materially deviates from the as-built supplement without the purchasing utility's prior written approval. That approval may not unreasonably be withheld, conditioned or delayed.~~, provided that the purchasing utility is not required to approve any modification of the facility that:~~

~~(A) Results in the facility increasing its nameplate capacity rating beyond the nameplate capacity rating specified in the power purchase agreement at the time it was executed; or~~

~~(B) Is reasonably likely to result in the expected annual net output specified in the power purchase agreement at the time it was executed to increase by more than 10 percent.~~

(c) In the event that the qualifying facility seeks to upgrade the facility during the term of the power purchase agreement in a manner that does not increase the nameplate capacity rating of the facility in the power purchase agreement, but which is reasonably expected to exceed 10 percent of expected annual net output in the power purchase agreement, such upgrades may be made without the utility's prior approval under this subsection (c) of this section subject to the following requirements:

(A) The proposed upgrades may not cause the qualifying facility to fail to meet the current eligibility requirements for either the standard power purchase agreement or standard prices, to breach its generation interconnection agreement, or necessitate network upgrades in order to maintain designated network status.

(B) At least six months in advance of the scheduled installation date for the proposed upgrades, the qualifying facility must send written notice to the purchasing utility containing a detailed description of the proposed upgrades and their impact on expected net output and revised 12 x 24 delivery schedule and requesting indicative pricing for the incremental additional net output expected to be generated as a result of the upgrades.

(C) Within 30 days after receiving such a request, the purchasing utility must respond with indicative pricing for the expected incremental

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additional net output to be generated as a result of the upgrades and which exceeds 10 percent of the expected annual net output specified in the power purchase agreement.

(D) Within 30 days after receiving indicative pricing, the qualifying facility ~~may~~ must request a draft amendment to the power purchase agreement to reflect revised pricing for the remaining term of the power purchase agreement, effective upon completion of the upgrades. If it is not reasonably feasible to separately meter the incremental additional net output resulting from the proposed upgrades, the purchasing utility may create a blended rate based on the proportion the expected incremental additional net output bears to the expected total net output following the installation of the upgrades.

(d) Within 90 days after the date on which upgrades are installed under subsections (a), (b), or (c) of this section, the qualifying facility is obligated to provide the purchasing utility an as-built supplement describing in detail the upgraded facility.

(e) A qualifying facility that wishes to install upgrades that would cause the Facility to increase its Nameplate Capacity Rating must terminate its existing power purchase agreement and may choose to enter a new standard or new non-standard power purchase agreement based on the then current avoided cost. In calculating damages resulting from the early termination of the original standard power purchase agreement, if any, the cost to cover will be calculated based on the pricing set forth in the new non-standard pricing agreement notwithstanding any other provision in these rules to the contrary. A qualifying facility that chooses to negotiate a new power purchase agreement under this subsection will not be liable for damages for any default caused by its failure to maintain eligibility for a standard power purchase agreement.

C. OAR 860-029-0121/New Rule #4 – Delivery and Purchase under Standard Power Purchase Agreement

OAR 860-029-0121 (formerly known as New Rule #4) codifies requirements related to the sale and delivery of power under PURPA. The rule is intended to specify the public utility's obligation to purchase energy—including surplus energy and Test Energy—as well as the QF's obligation to sell energy beginning on the QF's COD. The Joint Utilities generally support AHD's revisions to New Rule #4, which incorporate many of the Joint Utilities recommended changes. However, the Joint Utilities recommend that the Commission: (1) remove AHD's new language

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requiring utilities to accept intra-hour scheduling for off-system QFs; (2) revise New Rule #4 such that the rule does not require purchasing utilities to plan or assume, by obtaining designated network status for a QF at the time the PPA is executed, that QFs will come online more than 90 days prior to the Scheduled COD but allows the QF to come online up to 180 days early, i.e., when the project completion date is known, if the utility can modify its network resource designation for the QF at no additional cost; and (3) revise New Rule #4 such that utilities are not required to pay the full Index Rate for Test Energy.

1. <u>New Rule #4 Should Not Require Utilities to Accept Intra-Hour Scheduling for Off-System QFs.</u>

Following the QF Trade Associations' recommendation,[23] AHD added the following requirement to OAR 860-029-0121(1): "For off-system qualifying facilities, the public utility shall offer to receive deliveries made by any form of scheduling offered to the qualifying facility by its transmission provider, including intra-hour scheduling." The Joint Utilities have several substantive concerns with AHD's revision and also object to its addition at this late stage for procedural reasons.

First, allowing QFs to use intra-hourly scheduling would impose additional operational or administrative costs on the purchasing utility that are not accounted for in avoided cost prices. A PPA for hourly scheduling provides predictability that allows the utility to anticipate how it will manage its resources within the hour to ensure it does not incur charges within its balancing area authority and ensure that resources match load in real time. When supply and demand within a balancing authority area are not equal, the balancing authority must take corrective action to balance the system and will charge the generators or load that caused the imbalance. Permitting

[23] QF Trade Associations' Initial Group 2 Comments at 21.

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an off-system QF to engage in intra-hour scheduling shifts the cost of managing the QFs' variable output from the QFs to retail customers. This is problematic from an avoided-cost perspective, as a general matter, and is compounded by the fact that the utility—unlike the QF—has no control or insight into QF project operations that would allow the utility to anticipate how the off-system project might operate within each hour.

Second, even if the avoided cost calculation were adjusted to account for one type of intra-hourly scheduling, the type of scheduling offered by the QF's transmission provider could change in the future, and under AHD's unreasonably broad proposed language, the utility would be required to accept any new form of scheduling offered—even if doing so would impose additional costs.

Third, all of the Joint Utilities are members of the Western Energy Imbalance Market (EIM), and the EIM imposes charges if a generator's or transmission customer's schedule is modified less than 57 minutes before the hour.[24] Thus, even if QFs were permitted to use 15-minute scheduling, they would be imposing additional charges that have not been adequately addressed in the standard PPA or avoided cost prices. Therefore, QFs should not be allowed to change the schedules during the hour. [25]

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[24] *See, e.g.*, PGE's Energy Imbalance Market Business Practice (Dec. 23, 2020), *available at* https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_EIM_BP_v1_(1-1-2021).pdf ("Transmission Customers may modify generation Forecast Data in BSAP until fifty-seven (57) minutes prior to the Operating Hour ("T-57"). At fifty-five (55) minutes prior to each Operating Hour ("T-55"), the generation Forecast Data for the Operating Hour in BSAP will be considered financially binding. Changes by Transmission Customers to their generation Forecast Data after "T-57" will be subject to imbalance charges.").

[25] The Joint Utilities would also note that that the on- and off-peak periods applicable to the QF's monthly netting calculation in the standard QF PPA are outdated and no longer accurately reflect the relative value of energy within the applicable hours. For example, PacifiCorp's standard QF pricing approved effective July 1, 2022 in docket UM 1729 has higher prices in off-peak than in on-peak starting in 2026. The Joint Utilities believe this is primarily an avoided cost issue that should be addressed in docket UM 2000.

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Finally, attempting to add this highly technical but operationally important issue into the rulemaking at this stage is inappropriate. Intra-hour scheduling was not subject to careful study and vetting during the informal rulemaking process, resulting in its exclusion from the Draft Rules prepared by Staff after a comprehensive informal rulemaking process.[26] Moreover, this topic was not included in the scope of issues to be addressed in the formal rulemaking phase when AHD issued its scoping memorandum.[27] The Joint Utilities are very concerned about adopting a requirement to accept intra-hourly scheduling when the Commission does not have a fully developed record about the implications or a well vetted draft rule that takes into account the operational impacts, avoided cost pricing effects, or the current industry standards and trends for scheduling. Accordingly, the Joint Utilities recommend that the Commission remove the new intra-hourly scheduling requirement from the Draft Rules and that the topic be addressed in docket UM 2000 where pricing implications can be fully considered.

2. <u>New Rule #4 Should Prevent QFs from Coming Online More than 90 days Prior to the Scheduled COD.</u>

The Draft Rules currently allow a QF to come online up to 180 days prior to the Scheduled COD, suggesting that Joint Utilities must plan in advance, at PPA execution, to reserve an extra six months of transmission service when submitting a designated network resource request. The Joint Utilities recommend that this provision be revised such that a utility will plan in advance for a QF to come online *up to* 90 days prior to the Scheduled COD instead. One hundred eighty days in advance of Scheduled COD is far too long for utilities to reasonably reserve transmission capacity when there is no evidence that a QF will achieve COD that early. The Joint Utilities

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[26] *See* Staff Report at 10-11 (Oct. 14, 2021) (discussing New Rule #4, but not mentioning intra-hour scheduling or delivery options).
[27] *See* AHD Scoping Memorandum (Dec. 3, 2021).

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propose that QFs may come online up to 180 days early after the QF is reasonably certain of its COD date ***and*** the purchasing utility *is able to modify the facility's network resource designation without incurring any additional cost*.

This approach reasonably accommodates the QF developers' concerns and avoids a number of potential issues for the purchasing utility. Planning for a QF to come online up to 180 days in advance of Scheduled COD as a matter of course would generate uncertainty in utilities' system planning, particularly given, in the Joint Utilities' experience, it is unlikely that most QFs will *actually* come online before Scheduled COD; in fact, the opposite outcome, that a QF will come online *after* Scheduled COD, is more often the case. Moreover, it raises concerns that would need to be vetted about whether utilities reserving transmission capacity so far in advance would face legal risks related to impermissible hoarding of transmission capacity in contravention of FERC policy.[28] In addition, planning for deliveries no more than 90 days early would be consistent with non-QF PPAs and the Oregon utilities' CSP PPAs,[29] which typically allow the generator to

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[28] FERC Order No. 888, 75 FERC ¶ 61,080, 61,238, at 172 (1996) ("We conclude that public utilities may reserve existing transmission capacity needed for native load growth and network transmission customer load growth reasonably forecasted within the utility's current planning horizon. However, any capacity that a public utility reserves for future growth, but is not currently needed, must be posted on the OASIS and made available to others through the capacity reassignment requirements, until such time as it is actually needed and used.").

[29] *See, e.g.*, PacifiCorp Oregon Community Solar Program Power Purchase Agreement, Section 3.3 (June 18, 2021), *available at* https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/community_solar_program/Community_Solar_Program_Purchase_Agreement.pdf ("Subject to Section 3.1 above and unless otherwise provided in this Agreement, commencing on the Commercial Operation Date (except as provided in Section 3.2 for Start-up Test Energy), Project Manager will transmit to PacifiCorp all Net Output and PacifiCorp will accept all Net Output delivered to the Point of Delivery. PacifiCorp will accept Net Output, including Start-up Test Energy, delivered to the Point of Delivery as early as ninety (90) days prior to the Scheduled Commercial Operation Date. If Project Manager desires to begin transmitting Net Output, including Start-up Test Energy, to PacifiCorp at a date earlier than ninety (90) days prior to the Scheduled Commercial Operation Date, PacifiCorp will only be obligated to purchase such Net Output, including Start-up Test Energy, if PacifiCorp is able to modify its network resource designation for the Facility such that the output could be delivered using

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come online up to 90 days early. Finally, the QF Trade Associations' argument that a blanket prohibition on QFs delivering more than 90 days before Scheduled COD is unlawful because it would violate the utilities' must-take obligation is without merit for two reasons.[30] First, the Joint Utilities are not proposing a blanket prohibition. Second, when a QF selling pursuant to a legally enforceable obligation seeks to begin delivering, for example, six months early, PURPA requires the utility to accept the output, but the sale occurs on an as-available basis, rather than pursuant to the standard PPA. For the above reasons, the Joint Utilities propose the following changes to OAR 860-029-0121(5), which mirror provisions already approved by the Commission in the utilities' CSP PPAs:

> (5) A qualifying facility may not commence commercial operation any sooner than ~~180~~ 90 days before the scheduled commercial operation date of the standard power purchase agreement unless the public utility consents to early operation. If a qualifying facility desires to begin transmitting start-up Test Energy to the purchasing public utility at a date earlier than 90 days, but no more than 180 days, prior to the scheduled commercial operation date, the purchasing public utility will be obligated to purchase such net output under the standard power purchase agreement only if the purchasing public utility is able to modify its network resource designation for the Facility such that the output could be delivered using network transmission service at no additional cost or other economic impact to the purchasing public utility. ~~The purchasing public utility may require a qualifying facility to wait to commence commercial operation until no sooner than 90 days prior to the scheduled commercial operation if the purchasing public utility is unable to accept delivery from the qualifying facility but is obligated to undertake~~

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network transmission service as described in Section 3.1 above at no additional cost or other economic impact to PacifiCorp.").

[30] QF Trade Associations' Initial Group 2 Comments at 23. It is worth noting that in docket UM 1930, the QF developers brought up the same "must purchase" arguments, but the Commission approved the utilities' CSP PPAs which prohibited deliveries earlier than 90 days before Scheduled COD, except where the purchasing utility was able to modify its network resources designation for the facility such that the output could be delivered using network transmission service at no additional cost or other economic impact to the purchasing utility. *See supra* note 29.

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~~reasonable efforts to obtain transmission service up to 180 days ahead of the scheduled commercial operation date.~~

3. New Rule #4 Should Not Require Utilities to Pay the Full Index Rate for Test Energy.

The Joint Utilities oppose being required to pay the full Index Rate for Test Energy, which is not consistent with currently approved standard PPAs or the Joint Utilities' negotiated QF and non-QF agreements. For example, under PGE's current standard PPA, PGE pays a discounted as-available rate for Test Energy,[31] and in certain bilateral contracts, PGE pays 50 percent of the contract price. Moreover, PGE's current RFP PPA pays $0 for Test Energy.[32] The Index Rate can significantly exceed the contract price at times—market prices have recently spiked to hundreds or even above one thousand dollars in certain instances. Moreover, if the Test Energy is not delivered as firm energy, accepting the Test Energy could impose *additional* cost on the utility because the utility would be required to hold 1:1 reserves against the Test Energy. Neither AHD nor the QF developers have provided reasonable argument why QFs are entitled to the full Index Rate for Test Energy. For these reasons, the Joint Utilities propose that the purchasing public utility pay the QF the lower of 85 percent of Index Rate or 85 percent of contract price for Test

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[31] Under PGE's Schedule 201, PGE purchases "as-available energy" at the "as-available rate". PGE, Schedule 201: Qualifying Facility 10 MW or Less Avoid Cost Power Purchase Information at 201-19 (July 13, 2022), *available at* https://assets.ctfassets.net/416ywc1laqmd/2dXGX4FvW9bUeyimPsm05X/3d338ae86620e4162898734ee9685efc/UM_1728_Compliance_Filing_Update_2022_Sch_201_OF_Info_Sch_201_Eff_07.13.22.pdf [hereinafter, "PGE Schedule 201"]. "As-available energy" includes "all Net Output delivered prior to the Commercial Operation Date," such as Test Energy. *Id.* at 201-23. The "as-available rate" is equal to "avoided energy cost", which is eighty-two and four tenths percent (82.4%) of the monthly arithmetic average of each day's ICE Mid-C Physical Peak (bilateral) and Mid-C Physical Off-Peak (bilateral) average index prices. *Id.* at 201-19, 201-23.

[32] *In re Portland General Electric Company, Application for Approval of an Independent Evaluator for 2021 All-Source Request for Proposal*, Docket No. UM 2166, Portland General Electric Company's ("PGE") 2021 All-Source RFP – Final Draft, App. A at 5 (Oct. 15, 2021), *available at* https://edocs.puc.state.or.us/efdocs/HAC/um2166hac155830.pdf.

Energy delivered prior to the Scheduled COD. This proposal, which is shown below, is more favorable for QFs than the terms of recent non-QF and RFP PPAs executed by the utilities.

> (6) The purchasing public utility will accept Test Energy delivered to the Point of Delivery as early as 90 days prior to the scheduled commercial operation date, as long as the purchasing public utility has commenced transmission service for the Facility; provided that, in such case, the purchasing public utility's obligation to purchase Test Energy will not exceed a maximum period of 90 days. The purchasing public utility will pay the qualifying facility the lower of 85 percent of Index Rate or 85 percent of Contract Price ~~index rate~~ for Test Energy delivered prior to the scheduled commercial operation date.

D. OAR 860-029-0122/New Rule #5 — Force Majeure

1. Retaining New Rule #5 Would be Efficient and Consistent with the Intent and Scope of this Docket.

In the November 23, 2022 memorandum, AHD states that it intends to "recommend that the Commission delete proposed New Rule 5 on *force majeure* from the draft rules."[33] The Joint Utilities strongly object to this proposed change. The Commission is tasked with adopting a "settled and *uniform* institutional climate" for QFs,[34] and as the Joint Utilities explained in detail in their Response Comments, the purpose of this docket is for the Commission to develop uniform regulatory policy modernizing the terms and conditions of standard QF PPAs, including those contract terms that have common law jurisprudence and reflect basic contractual principles.[35] Stakeholders have spent years in this docket attempting to create standardized PPA terms (including for basic contractual principles such as cure and termination)—there is no reason why Force Majeure should be an exception.[36]

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[33] AHD Memorandum on Request for Comment at 1.
[34] ORS 758.515(3)(b) (emphasis added).
[35] Joint Utilities' Group 2 Draft Rules Response Comments at 31-34.
[36] Note that it is the Joint Utilities' understanding based on comments from the October 18, 2022 Workshop that NewSun Energy LLC (NewSun), at the very least, supports minimum principles enumerating Force Majeure criteria.

Importantly, if the Commission defers addressing Force Majeure in the rules, the utilities' PPAs will still contain Force Majeure provisions. Therefore, it is possible that the Commission may still need to address the same issues raised by New Rule #5 when approving the utilities' compliance filings, which would be less efficient than addressing the issues now by retaining New Rule #5. This docket has already lasted for several years, and the issues have been discussed at length; the Commission should resolve as many issues as possible during this rulemaking for efficiency.

While addressing Force Majeure in this docket will not prevent *all* future disputes, addressing the parameters of Force Majeure in those areas where the Commission has expertise to guide courts and adopting common-sense administrative provisions to prevent abuse of Force Majeure would help avoid and limit future litigation. For example, PGE and numerous developers have had disputes regarding what is and what is not a Force Majeure event; some off-system QF developers have claimed that interconnection issues with other utilities that are not the purchasing utility are Force Majeure events that should extend the Scheduled COD to seven or eight years after execution of the PPA and as long as four years after the original Scheduled COD. The Commission has significant specialized expertise regarding interconnection issues in the West that make it well-positioned to determine whether interconnection delays of this type are truly unforeseeable events (like act-of-God type events such as earthquakes, fires, etc.) that should result in an indefinite extension of long-term PPAs with fixed prices that can become stale and outdated.

Furthermore, the Commission has previously defined what does and does not constitute Force Majeure for standard PPAs, relying on the common legal definition of Force Majeure to determine that "it is unlikely that a Northwest wind or water drought would be considered a force

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majeure event" that excuses a QF's minimum delivery obligations.[37] There is no reason the Commission should not address Force Majeure in this docket where it clearly has expertise to adopt policy that ensures future parties understand their rights and obligations and avoids unnecessary disputes and litigation. If the Commission is wary of assuming jurisdiction over future Force Majeure disputes, one option is to specify in the Draft Rules that the Commission may, or even will under certain circumstances, waive primary jurisdiction over Force Majeure disputes under OAR 860-029-0122.[38]

2. <u>At a Minimum, the Commission Should Retain the New Rule #5 Provisions that Address Issues Within Its Expertise.</u>

Even if the Commission declines to address the parameters of Force Majeure in great detail in these rules, the Joint Utilities recommend that the Commission nevertheless adopt two specific provisions/policies that prevent parties from abusing claims of Force Majeure.

First, the Joint Utilities recommend that the Commission clarify that any delay, alleged breach of contract, or failure by the transmission provider or interconnection provider ***does not*** qualify as an event of Force Majeure unless that delay, breach, or failure is due to a Force Majeure event as defined in any agreement with the transmission provider or interconnection provider. As

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[37] Order No. 06-538 at 24. The QF Trade Associations have acknowledged that such parameters of Force Majeure constitute Commission policy. QF Trade Associations' Initial Group 2 Comments at 32 ("The QF Trade Associations propose one change in Commission policy related to any QFs that rely upon water, which is a motive force that can be impacted by weather related events. In UM 1129, the Commission decided that wind or water droughts should not be defined as force majeure events because….").

[38] At the October 18, 2022 Workshop, the QF Trade Associations argued that the Commission should clarify under what circumstances, if at all, the Commission would assume primary jurisdiction over Force Majeure matters. It is the Joint Utilities' understanding that the QF Trade Associations' position is that the Commission should *never* have primary jurisdiction over Force Majeure disputes; however, it is the Joint Utilities position that the Commission *may* have primary jurisdiction over a Force Majeure-related complaint when: (1) the issue benefits from the Commission's specialized expertise; (2) uniform resolution is preferable; and (3) a judicial resolution could adversely impact agency performance of its regulatory responsibilities. *Portland General Electric Company v. Dayton Solar I LLC et al.*, Docket No. UM 2151, Order No. 21-210 at 8 (June 25, 2021).

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discussed above, the Commission has significant specialized expertise regarding interconnection issues in the West and is well-positioned to determine whether a delay, alleged breach of contract, or failure by a transmission provider or interconnection provider is truly an "an unforeseeable event of superior or irresistible force" qualifying as Force Majeure or if it is within the reasonable risks anticipated by off-system QF developers when selecting such projects and entering into off-system PPAs. The Joint Utilities believe this type of event is the latter, and to prevent abuse of Force Majeure claims, the Commission should clarify that delays and breaches of the PPA caused by the transmission provider or interconnection provider do not qualify as Force Majeure.

Second, if an event of Force Majeure extends beyond 180 days, the Joint Utilities recommend that the party not claiming Force Majeure should have the right to terminate the PPA. Extraordinary events that are not reasonably foreseeable at the time of contracting, and which cannot be overcome by reasonable diligence, provide a basis for temporarily suspending the parties' obligations and performance. However, with changing avoided cost prices and the long-term nature of these contracts, it is unreasonable to permit *indefinite* extensions of the parties' rights and obligations. Such a provision is market[39] and protects both parties. Moreover, limiting the time during which Force Majeure can be claimed does not prevent the parties from re-entering a PPA if the Force Majeure eventually resolves. In addition, placing a time limit on Force Majeure

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[39] For example, *all* of PGE's nine Schedule 202 and bilateral contracts for solar resources executed since 2017 include a time limit for Force Majeure events ranging from 180 days to 365 days. Furthermore, the pro forma Washington QF PPA for PacifiCorp includes a 180-day time limit for Force Majeure events. *See* WUTC Docket No. UE-190666, Standard Power Purchase Agreement, Attachment A, Section 14.5 at 37-38 of 55 ("If a Force Majeure event prevents a Party from substantially performing its obligations under this Agreement for a period exceeding 180 consecutive days, then the Party not affected by the Force Majeure event may terminate this Agreement by giving ten (10) days prior notice to the other Party. Upon such termination, neither Party will have any liability to the other with respect to the period following the effective date of such termination; provided, however, that this Agreement will remain in effect to the extent necessary to facilitate the settlement of all liabilities and obligations arising under this Agreement before the effective date of such termination.").

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events does not expose QF developers to damages claims given that the right to terminate after 180 days is without liability or damages for both parties. Finally, while the Joint Utilities are recommending a 180-day Force Majeure time limit, the Joint Utilities would not oppose a time limit between 180 days and one year. Accordingly, the Joint Utilities propose the following OAR 860-029-0122 as an alternative:

> (1) Every power purchase agreement shall include a Force Majeure provision that is based on the common legal definition of the term and complies with the requirements of this section.
>
> (2) Any delay, alleged breach of contract, or failure by the transmission provider or interconnection provider will not constitute an event of Force Majeure unless due to a Force Majeure event as defined in any agreement with the transmission provider or interconnection provider.
>
> (3) If an event of Force Majeure exceeds [180 days - one year], the party not claiming a Force Majeure defense or delay may terminate the power purchase agreement without liability or damages to either party by providing written notice to the other party.

These provisions address issues well within the Commission's expertise and do not implicate the Commission's concerns that it lacks expertise to define the full parameters of Force Majeure. Therefore, even if the Commission declines to adopt a comprehensive Force Majeure provision for all standard PPAs, the Joint Utilities recommend that the Commission, at the very least, include these two provisions in OAR 860-029-0122.

E. OAR 860-029-0123/New Rule #6 — Default, Damages, and Termination

OAR 860-029-0123 (previously known as New Rule #6) describes events that constitute default, the applicable cure periods and damages calculations, and when and how a standard PPA may be terminated. The Joint Utilities generally support AHD's revisions to this rule, with one significant exception. Specifically, the Commission should remove AHD's new caps for delay, failure to deliver, and termination damages at the contract price, because the caps shift potentially

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significant costs from QFs to customers without basis and contrary to PURPA's customer-indifference requirement. The Joint Utilities also recommend changes to the cure period language in OAR 860-029-0123(4) for clarity and advocate that the Commission add "failure to comply with any material obligation under the power purchase agreement" to the events of defaults for QFs for symmetry. Finally, the Joint Utilities recommend that the notice of default provision, OAR 860-029-0123(2), apply to events of default for *both* QFs and utilities, and that all damages provisions cover both additional transmission costs *and ancillary service costs* for delivery of replacement power.

1. A Cap on Damages Based on the Contract Price Would Harm Customers.

AHD adopted the QF Trade Associations' recommendation that the damages owed to the purchasing public utility by a QF in the event of a default should be capped at the contract price of the energy the QF failed to deliver.[40] This change represents a significant step backward from the balance Staff attempted to strike at the end of the informal rulemaking period, to the detriment of customers. Because this issue was not discussed at length at the October 18, 2022 Workshop, the Joint Utilities assume that AHD's decision was based on the QF Trade Associations' argument that the Commission should retain the policy it adopted in Order No. 06-538 from docket UM 1129.[41] Contrary to the QF Trade Associations' claims, however, Order No. 06-538 does not support retaining the cap on delay damages, much less extending the cap to other types of damages. Even if the Order No. 06-538 decision somehow remained relevant, the Commission should change its policy going forward because damages caps have shifted significant costs from QFs to customers and will likely continue to do so in the future.

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[40] QF Trade Associations' Initial Group 2 Comments at 7.
[41] QF Trade Associations' Initial Group 2 Comments at 7-8 (citing Order No. 06-538 at 5-6, 66-67).

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a) Capping Damages Unreasonably and Illegally Shifts Costs from QFs to Utility Customers.

Capping damages at the contract price does not adequately protect customers and violates the customer indifference principle. A cap based on what the utility would have paid the QF does not keep customers financially whole if the QF breaches when market prices are high, which is increasingly the case under current market conditions. When the QF fails to deliver energy under the PPA, customers bear all costs of the QF's default that exceed the cap. For example, three years ago, QFs under contract with PGE defaulted. Because delay damages were capped at the contract price and the cap was hit, the utility customers bore the resulting costs—approximately $700,000, over a third of the utility's actual damages. While this number by itself is significant, defaults of greater volumes and for longer periods of time in the future could force customers to bear millions of dollars in damages that should have been borne by the defaulting QFs but for the cap.

The QF developers argue that caps for damages are appropriate and do not harm customers because a utility can simply replace power using its own resources at lower-than-market value. This argument is without merit. Utilities pay QFs long-term firm prices that are based on the assumption that the QF is *replacing* other reliable utility resources or purchases. Utilities do not hold resources in reserve to be available at a moment's notice to replace contracted-for power in the event of a breach. If utilities were expected to do so for QFs, it would impact the avoided cost price. Even if the utility had excess (as measured relative to retail load) generation available, it (i) may be committed to sell that power into the wholesale market or (ii) it would incur a significant opportunity cost during periods of high market prices if it used the excess generation to replace QF output rather than selling into the market. Moreover, if the utility provided replacement power using its own resources, it is not clear that it could provide such power at lower-than-market value.

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For example, where gas prices have skyrocketed to \$40/Mmbtu, PGE would still have to pay \$280/MWh to dispatch one of its most efficient gas plants—which is above avoided cost prices.

Furthermore, capping damages at the contract price undermines the value of a firm contract. One of the primary purposes and benefits of a firm contract is that it hedges against high market prices and reduces risks of market-scarcity pricing and volatility that customers bear. If the firm contract does not protect customers when market prices are higher than PPA prices, then the contract is less valuable and avoided cost prices should reflect the risk inherent in the purchase. For this reason, a utility would not voluntarily sign a PPA with the caps proposed by AHD unless the utility received significant concessions elsewhere in the PPA, such as a significant reduction in price, that balanced the risk introduced by such caps on damages. Because the proposed caps on damages leave customers exposed to high market prices during times of need, the PPA and any resulting cost overruns would run the risk of being deemed imprudent by the Commission if signed by the utility voluntarily. If the Commission adopts the damages caps proposed here, it should also make clear that the diminished value and increased risk associated with the PPA should be addressed in docket UM 2000 in the context of a lower avoided cost price.

Moreover, separate from the financial risk to customers, caps on damages may have reliability implications due to perverse incentives. When the contract price and market price diverge significantly, but damages are capped at the contract price, a QF could be incentivized to default, pay the limited damages, and sell its energy into the market at a much higher price. Similarly, QFs may be incentivized to not provide energy and terminate their PPAs when market prices are high if damages are capped at the contract price and also limited to a 24-month period. Under such circumstances, the QF could pay the capped damages, terminate its original contract

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with one utility, and wheel the power to another utility under a new PPA with higher prices. These scenarios represent inappropriate and unreasonable outcomes.

Finally, the 24-month limit on termination damages in proposed OAR 860-029-0123(9) already caps QFs' liability. Although, this 24-month limit is not market, the Joint Utilities have not opposed retaining this Commission policy from Order No. 06-538. But providing additional caps on damages on top of the existing 24-month limit will result in utility customers further, and inappropriately, assuming project risk not incorporated in avoided cost pricing that should be borne by QF developers.

b) The Commission Should Not Rely On or Extend the Contract-Price Cap Decision from Order No. 06-538.

The Commission's 2006 decision, which the QF Trade Associations rely on to support caps on damages, was based on facts and circumstances that are not applicable today. First, the Commission's decision was heavily reliant on testimony that the small-scale energy loan program (SELP), a primary source of funding for QFs with capacity ratings of 10 MW or less, could not finance a QF without a cap.[42] However, there is no evidence that QFs cannot obtain financing without a damages cap today, nor does SELP remain a primary source of financing. Second, the Commission's 2006 order relied on a 2005 market analysis to conclude that customers would not be harmed by the cap because the cap was unlikely to be triggered except in extreme circumstances.[43] That 2005 market analysis is now significantly outdated and wholly irrelevant;

[42] Order No. 06-538 at 66 ("We are also presented with testimony that the SELP, a primary source of funding for QFs with capacity ratings of 10 MW or less, cannot fund a QF unless a cap on potential default losses is instituted.").
[43] Order No. 06-538 at 66 ("In this phase of UM 1129, however, we are presented with empirical evidence that it is unlikely, except in extreme circumstances (such as the effective termination of a standard contract by a QF during a market crisis), that utilities and their ratepayers will need to cover a QF's default losses.").

in reality, as discussed above, caps on damages have been hit, market prices have diverged greatly from PPA contract prices, and customers have indeed been harmed. For example, during the most recent fire season in Oregon, market prices were in the thousands of dollars. Under such circumstances, a cap on damages at the contract price may result in perverse incentives as discussed above.

While the Joint Utilities recommend that the Commission remove all new caps for delay, failure to deliver, and termination damages as such mechanisms unreasonably and inappropriately place the burden of QF default on customers, should the Commission decide to follow Order No. 06-538, it should at the very least remove the new contract price cap for termination damages which is inconsistent with that order. Order No. 06-538 did not apply a contract-price cap to termination damages as the Commission determined such a cap was not necessary.[44] Neither the QF Trade Associations nor AHD have provided persuasive reasoning as to why a cap for termination damages that the Commission previously found unnecessary should now be added in these Draft Rules. Moreover, termination damages are already capped because the Draft Rules contain a 24-month time limit to determine termination damages, which is consistent with PacifiCorp's Washington QF PPA[45] and current Commission policy.[46] An additional cap based on the contract price would be unreasonable and inappropriate, does not reflect market, and further harms customers.

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[44] Order No. 06-538 at 6 ("We conclude that it is not necessary to cap damages for termination.").
[45] *See, e.g.*, WUTC Docket No. UE-190666, Standard Power Purchase Agreement, Attachment A, Section 11.5 at 35 of 55.
[46] Order No. 06-538 at 32.

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2. OAR 860-029-0123(4) Regarding Cure Periods Should be Revised for Clarity Purposes.

OAR 860-029-0123(4), as drafted, is confusing and contains multiple errors. For example, OAR 860-029-0123(4)(c), which is supposed to refer to a QF's failures to meet the MAG and MDG, refers to an incorrect subsection.[47] Furthermore, OAR 860-029-0123(4) fails to incorporate any references to defaults of the utility under the newly drafted OAR 860-029-0123(2). For these reasons, the Joint Utilities propose removing any references to section (1) in OAR 860-029-0123(4) as shown below.

(4) Cure periods:

(a) ~~If a Notice of Default is issued under subsection (1)(a), t~~The qualifying facility has one year from the date of the scheduled commercial operation date in which to cure the default for failure to meet the scheduled commercial operation date.

(b) Except with respect to a failure to meet the Minimum Availability Guarantee or the Minimum Delivery Guarantee, which failures are not capable ~~If a Notice~~ of cure, and as otherwise specified in ~~Default is issued under~~ subsection (4)(a) ~~(1)(b), (1)(c), (1)(d), 1(e), 1(f), or 1(g)~~, ~~the~~ a ~~non-~~defaulting party has 30 days following written notice from the non-defaulting party in which to cure any failure to comply with its obligations under the power purchase agreement.~~in which to cure the event of default~~. This 30-day period shall be extended by ~~an additional~~ no more than 90 days if:

(A) The failure cannot reasonably be cured within the 30-day period ~~despite diligent efforts~~,

(B) The default is reasonably capable of being cured within the additional 90-day period, and

(C) The defaulting ~~P~~party provides to the non-defaulting party a remediation plan within 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 ~~commences the cure within the~~

[47] The provision should refer to subsections (1)(g) and (1)(h), not 1(h) and (1)(i).

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~~original 30-day period and is at all times thereafter diligently and continuously proceeding to cure the failure~~.

~~(c) There is no cure period for a Notice of Default issued under subsection (1)(h) or (1)(i).~~

3. The List of Events of Defaults for QFs Should Include a Symmetrical Failure to Comply with any Material Obligation under the PPA.

The Joint Utilities believe that AHD mistakenly failed to include "failure to comply with any material obligation under the power purchase agreement" to the events of defaults for QFs. AHD included this event of default for utilities as OAR 860-029-0123(2)(d), and there is no reason that these events of default should not be symmetrical. The Joint Utilities recommend that the Commission add "failure to comply with any material obligation under the power purchase agreement" to the events of defaults for QFs as OAR 860-029-0123(1)(j).

4. OAR 860-029-0123(3) Should be Revised to Add a Reference to Section (2) and Remove a Reference to "Excused Delay."

The Joint Utilities recommend that the Commission revise OAR 860-029-0123(3) to also reference OAR 860-029-0123(2), i.e., events of default for utilities, and that the reference to "Excused Delay" be removed as that term is not defined in the Draft Rules. It is critical that "Excused Delay," which is not defined in the Draft Rules and is open to broad interpretation, be removed because retaining it could lead to increased uncertainty and additional disputes. Furthermore, removing the reference to "Excused Delay" in OAR 860-029-0123(3) is consistent with AHD's previous removal of the reference to "Excused Delay" from OAR 860-029-0120(4).

(3) Unless otherwise excused under the standard power purchase agreement by ~~Excused Delay,~~ Force Majeure~~,~~ or otherwise, the non-defaulting party is authorized to issue a Notice of Default upon any of the events described in sections (1) and (2), as applicable.

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5. <u>The Damages Provisions Should Clarify that Damages Include Ancillary Service Costs in Addition to Transmission Costs to Deliver Replacement Power.</u>

The Joint Utilities further recommend that the Commission clarify that delay, MAG, MDG, and termination damages cover both additional transmission costs ***and ancillary service costs*** for delivery of replacement power. Alternatively, the Joint Utilities recommend that the Commission clarify that transmission costs necessarily include ancillary service costs. Such an interpretation would be consistent with the OATT, which defines ancillary service as "[t]hose services that are necessary to support the transmission of capacity and energy[.]"[48]

III. ADDITIONAL COMMENTS ON GROUP 1 RULES

A. OAR 860-029-0005 – Applicability of Rules

Out of an abundance of caution and for the purpose of clarity, the Joint Utilities request that the Commission explicitly state in the order adopting these rules that any changes to these rules or new rules apply only to PPAs executed after the new or revised rules take effect. This is necessary to provide context and demonstrate the intent of this provision of the rules.

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

1. <u>OAR 860-029-0120(5)(b)(A) – Interconnection Study Must Support a Scheduled COD of No More than Four Years from the Effective Date.</u>

In order to prevent speculative contracting and conform to Staff's intended balance of interests, the Commission should clarify that under OAR 860-029-0120(5)(b)(A), the required

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[48] *See, e.g.*, PGE Pro Forma Open Access Transmission Tariff, Section 1.2 at 11 ("Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice."); *see also In re Portland General Electric Company's Request for Clarification of Stipulation Regarding Use of Rate Base Property at the Beaver Generation Plant*, Docket No. UM 1014, Order No. 01-695 at 5 (Aug. 1, 2001) ("[A]ncillary services are classified as 'transmission services' and hence the point could be argued that ancillary services fall under the category of transmission services.").

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interconnection study must show that interconnection can occur more than three years, ***but no more than four years***, from the Effective Date of the PPA. As currently drafted, OAR 860-029-0120(5)(b)(A) could be interpreted as requiring utilities to enter PPAs with QFs selecting a Scheduled COD anytime between three and four years after the Effective Date, even if the interconnection study shows that interconnection cannot occur until, for example, seven years from the Effective Date. Such an interpretation would encourage speculative contracting and does not reflect Staff's intention in balancing customer protection and QF development. Accordingly, the Joint Utilities recommend that the Commission revise OAR 860-029-0120(5)(b)(A) as follows:

> (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~~ can occur more than three years, but no more than four years, after the Effective Date of the standard power purchase agreement; or

2. OAR 860-029-0120(7)-(8) – Remove Duplicate Sections.

Sections (7) and (8) are old drafts and duplicates of sections (4) and (5) in AHD's Draft Rules. The Joint Utilities believe that AHD retained sections (7) and (8) in error and recommend that the Commission remove these sections from the Draft Rules. With respect to sections (5) and (8), in particular, it is extremely important that it is section (5) that is retained in the Draft Rules as that rule represents the balance of interests implemented by Commission Staff in requiring that a QF receive an interconnection-related system impact study report, cluster study report, or facilities study report indicating interconnection will take longer than three years—but no longer than four years—from the Effective Date of the standard PPA should the QF elect to specify a Scheduled COD anytime between three and four years after the Effective Date.

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3. <u>OAR 860-029-0120(18)(c) – Remove Step-In Rights and Senior Liens for Default Security.</u>

The Joint Utilities strongly object to allowing the use of step-in rights and senior liens for Default Security and recommend that these options be removed from the Draft Rules as it is highly unlikely that a qualifying facility's lender would allow the utilities to have meaningful step-in rights or liens senior in priority to the lender's rights. Even if a lender were to allow a utility to hold such rights, these rights would not ensure that the utility will recover sufficient damages to hold customers harmless in the event of a QF default.

As a practical matter, QFs' lenders will always hold a first-priority, senior security interest in the QFs' assets. Thus, in the event of a foreclosure, any proceeds from liquidating the project assets would likely go entirely to making the lender whole, leaving little, if anything, to cover the utility's damages. And if the utility exercises step-in rights, the assets it obtains would likely be encumbered by liens that would ultimately need to be paid off by utility customers.

In addition, even if the utility were to be granted a first-priority security interest in the QFs' project assets, use of senior lien or step-in rights as security remains problematic. In order for the utility to recover its damages, the QF would have to own project assets of value. If those assets existed, the value of those assets would need to be greater than the aggregate transaction costs (including litigation risk and cost) involved in liquidating those assets, taking into account that, because utilities are not in the foreclosure business, these transaction costs could be significant. Furthermore, if the utility exercises step-in rights and takes control of the facility, the cause of the default would then become the utility's problem.

In short, in the case of a defaulting QF, step-in rights and senior liens do not provide meaningful security and improperly shift the burden of the QF's default onto customers.

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Meaningful security is critical to enabling the utility, on behalf of its customers, to recoup damages, maintaining customer indifference.

While step-in rights do not provide meaningful value in the context of a QF default, if the Commission chooses to allow a QF to elect to provide step-in rights as Default Security, the rule must also require the QF to ensure that the purchasing utility is permitted to perfect a ***first-priority security interest in the project through execution of a form of agreement that is either (1) reasonably acceptable to the utility, or (2) approved by the Commission as an attachment to the PPA***.

4. The Joint Utilities' Creditworthiness Criteria Should be Adopted.

In the November 23, 2022 memorandum, AHD requested that parties comment on what credit ratings would be reasonable to use if the Commission should adopt creditworthiness criteria in the Draft Rules, and that AHD would be interested "in other reasonable and specific quantitative approaches."[49] The Joint Utilities continue to support their proposed criteria, which are clear and consistent with market. Specifically, the Joint Utilities continue to support the following creditworthiness criteria provision:

> (X) Creditworthiness requirements under sections (17) and (18)[50] of OAR 860-029-0120 may be satisfied by:
>
> 1. A senior, unsecured long term debt rating (or corporate rating if such debt rating is unavailable) of (a) 'BBB+' or greater from S&P, or (b) 'Baa1' or greater form Moody's; provided that if such ratings are split, the lower of the two ratings must be at least 'BBB+' or 'Baa1' from S&P or Moody's, respectively.
>
> 2. If a rating from S&P or Moody's is not available, the qualifying facility must provide financial documentation that supports an equivalent rating as determined

[49] AHD Memorandum on Request for Comment at 1.
[50] Please note that OAR 860-029-0120(17)-(18) refers to the renumbered Project Development and Default Security provisions in AHD's Draft Rules and these numbers may need to be changed due to the presence of duplicate sections in OAR 860-029-0120 as currently drafted.

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by the purchasing utility through an internal process review and utilizing a proprietary credit scoring model. In such case, the purchasing utility will request audited financial statements for the most recent two full years (including balance sheet, income statement, statement of cash flows, and accompanying footnotes), which information is evaluated considering (a) the type of generation resource, (b) the size of the resource, (c) the expected energy delivery start date, and (d) the term of the power purchase agreement. The internal review process will evaluate, at minimum, certain profitability, cash flow, liquidity, and financial leverage metrics.

3. If the qualifying facility is required to post a letter of credit, the letter of credit must be issued by an institution, not subject to bail-in regulation, with a credit rating on its long-term senior unsecured debt of at least 'A' from S&P and 'A2' from Moody's.[51]

In contrast, the QF Trade Associations' proposal introduces several vague, undefined terms, such as "reasonable credit evaluation" and "net position," which would likely lead to increased litigation.[52] More importantly, the Joint Utilities object to the use of a Dun and Bradstreet credit rating, which the QF Trade Associations claim small QFs can obtain more easily than Moody's or S&P.[53] Specifically, because almost all QFs are LLCs, their balance sheet might only consist of the initial investment and cash at the time of PPA execution; therefore, a Dun and Bradstreet credit rating score would reflect only the payment performance of the LLC itself, which is only one input in a credit evaluation and would not take into account the underlying assets and balance sheet of the QF developer with ultimate responsibility for the project. On the other hand, the Joint Utilities' proposal requires a credit rating from S&P or Moody's, which is tied to rated companies and provides the necessary assurance for covering potentially significant liabilities.

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[51] The Joint Utilities agree to use these creditworthiness requirements for the purposes of sections (17) and (18) of OAR 860-029-0120 *only*. Outside of this context, each utility employs different credit requirements based on utility-specific risk evaluations. *See* Joint Utilities' Group 2 Draft Rules Response Comments at 60-61; Joint Utilities' Final Comments Regarding Group 1 Rules at 22 (May 10, 2022).
[52] QF Trade Associations' Initial Group 2 Comments at 40-41 & Proposed Redlines at 23-24.
[53] QF Trade Associations' Initial Group 2 Comments at 41 n. 64.

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With respect to the QF Trade Associations' continuing concerns regarding the burden of such creditworthiness requirements on small QFs, the Joint Utilities have already proposed an exception for QFs 1 MW and smaller that are owned, directly or indirectly, by persons or entities who hold no other beneficial interests in any other QF. Specifically, these smaller QFs will not be required to adhere to the utility's creditworthiness requirements or to provide Project Development or Default Security if the owner of the QF provides certain representations and warranties regarding the financial condition of the QF and its primary equity owners, subject to verification by the utility based on financial information provided by the QF.[54] This limited exemption from the utility creditworthiness requirements, including the security requirements that are triggered when credit requirements are not met, is intended to both (1) address the financial constraints of truly small, unsophisticated QFs, and (2) limit the utilities' customers' exposure to damages. Finally, these credit and security requirements ensure that project risk not included in avoided cost pricing is not transferred to utility customers when the QF defaults on its obligations.

For the above reasons, the Commission should adopt the Joint Utilities' creditworthiness requirements (including the exception for small QFs).

C. OAR 860-029-0046(2)(c)(F) –12 x 24 Delivery Schedule

The Joint Utilities greatly appreciate AHD's decision to partially adopt their recommendation to include the following language in OAR 860-029-0046(2)(c): "Estimates of the net amount of power to be delivered to the public utility's electric system and the 12 x 24 delivery schedule are subject to revision until the date the qualifying facility commences commercial operation." The Joint Utilities would recommend, however, that the Commission move this

[54] The Joint Utilities' proposed language for this exception is available in their May 10, 2022 comments. *See* Joint Utilities' Final Comments Regarding Group 1 Rules at 23-24.

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language to OAR 860-029-0046(2)(c)(F) and that the section further clarify that a 12 x 24 schedule may be used as a baseline for delivery expectations for the purpose of calculating damages when the QF defaults on its obligation to deliver power. A 12 x 24 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, 12 x 24 schedules, while non-binding, are used to accurately calculate damages under applicable performance guarantees. The Joint Utilities recommend clarifying this point to avoid potential disputes.

> (F) Non-binding estimate of 12 x 24 delivery schedule and 8760 generation profile when practicable<u>, where estimates of the net amount of power to be delivered to the public utility's electric system and the 12 x 24 delivery schedule are subject to revision until the date the qualifying facility commences commercial operation provided that any such revision must be consistent with OAR 860-029-0120(16),[55] and a 12 x 24 delivery schedule may be used by the public utility to calculate damages</u>,

D. OAR 860-029-0046(2)(c)(O) – Interconnection Study Supporting Online COD

The Joint Utilities continue to propose that OAR 860-029-0046(2)(c)(O) be added to the Draft Rules. The proposed provision provides:

> <u>(O) for a qualifying facility selecting a scheduled commercial operation date between three and four years after the Effective Date of the standard power purchase agreement pursuant to OAR 860-029-0120(5)(b)(A), a copy of the interconnection study supporting the scheduled commercial operation date.</u>

AHD did not accept OAR 860-029-0046(2)(c)(O) because the requirement is allegedly "an unnecessary hurdle to interconnection." However, it is unclear how the requirement that the QF provide the public utility ***a copy*** of the interconnection study necessitated under OAR 860-029-0120(5)(b)(A) could affect the interconnection process, and the Joint Utilities are

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[55] This section refers to Incremental Facility Upgrades and may need to be renumbered following revisions to OAR 860-029-0120 which contains duplicate sections.

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aware of no evidence to indicate that the requirement creates a hurdle. The Joint Utilities believe such a requirement simply allows the utilities to implement OAR 860-029-0120(5)(b)(A). That is, just as utilities need to know a facility's capacity in MW in order to determine if the facility is eligible for a standard PPA, utilities also need to know whether the QF actually has an interconnection study that supports a Scheduled COD within four years from contract execution.

IV. CONCLUSION

The Joint Utilities look forward to finalizing terms and conditions for standard PPAs that will implement PURPA consistent with legal requirements and sound public policy, thereby encouraging efficient development of QFs while protecting utility customers. To achieve those ends, additional limited but important revisions to the Draft Rules are necessary. The Joint Utilities request that the Commission adopt the Joint Utilities' recommendations in these comments.

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Attachment A

to

Joint Utilities' Comments Regarding the Group 2 Draft Rules

Summary of the Joint Utilities' Comments Regarding the Group 2 Draft Rules[1]

I. COMMENTS REGARDING GROUP 2 DRAFT RULES

A. OAR 860-029-0044/New Rule #1: Allocation of Costs Related to Deliveries from Off-System Qualifying Facilities

1. The Joint Utilities oppose the Administrative Hearings Division's (AHD) proposal to exclude New Rule #1 until a decision is reached in docket UM 2032 because the rule addresses a different topic than docket UM 2032.[2] Docket UM 2032 is, by virtue of its scope, limited to interconnection costs, so the Commission's decision in that docket will not and cannot be self-implementing here. New Rule #1, which stakeholders have spent years commenting on and developing in this docket, is critical to maintain the integrity of avoided cost prices by ensuring that the Commission has an opportunity to determine whether specific transmission-service-related Network Upgrade costs should be allocated to qualifying facilities (QFs).

2. New Rule #1 should apply to both on-system and off-system QFs because even if an on-system QF obtains Network Resource Interconnection Service (NRIS) and pays for the resulting Network Upgrades, subsequent transmission service studies may reveal costs not identified by the NRIS studies, which are completed independently from and for a different purpose than transmission studies. The process enumerated by New Rule #1 is intended to allocate these costs, which will not be addressed by docket UM 2032, for on-system QFs.

3. New Rule #1 should not allow indefinite deferment of the Development Period as deferral could result in the QF receiving very stale avoided cost prices to the detriment of customers.

4. New Rule #1 should clarify that an off-system QF must have obtained firm transmission to the purchasing utility's system before the utility is required to designate the QF as a network resource.

5. The Joint Utilities recommend that the Commission revise OAR 860-029-0044(4)(c) such that the public utility is required to request an effective date for commencement of network transmission service for a QF 90 days prior to the Scheduled Commercial Operation Date (COD)—not 180 days as provided in the Draft Rules. Requiring the utilities to obtain transmission service 180 days in advance to account for the possibility that a QF may wish to come online early would result in an inefficient use of the transmission system and may interfere with utility planning. QFs have not demonstrated

[1] Note that this Summary addresses only the most substantive topics the Joint Utilities identified as needing clarification or revision. The Joint Utilities intend to submit further comments before the close of the comment period on February 10, 2023 regarding typographical errors and other proposed minor redlines.

[2] Docket UM 2032 addresses ***interconnection-related*** Network Upgrades triggered by on-system QFs, whereas New Rule #1 addresses ***transmission-service-related*** Network Upgrades, which can be triggered by both on-system and off-system QFs.

in this docket a likelihood of coming online early that warrants reserving transmission so far in advance. The Joint Utilities propose that the rule reflect current utility practice of planning at signing for the QF to come online 90 days in advance with the option to come online no more than 180 days in advance with notice to the utility, provided that the utility can obtain designated network resource status without additional cost to the utility.

6. The Joint Utilities recommend that the Commission add a provision to New Rule #1 clarifying that the utility and the QF both have a right to proceed with a contested case.

B. OAR 860-029-0120: Standard Power Purchase Agreements

1. <u>OAR 860-029-0120(12)-(13) – Mechanical Availability Guarantees (MAGs).</u>

   - Because doing so results in transferring costs and project risk from the QF to the utility that are not included in avoided cost pricing, as discussed in Section II.E.1 below, the Joint Utilities oppose AHD's inclusion of a cap at the contract price on damages for failure to meet the MAG and recommend that the Commission remove OAR 860-029-0120(12)(c) from the Draft Rules.

2. <u>OAR 860-029-0120(14)-(15) – Minimum Delivery Guarantees (MDGs).</u>

   - A mandatory 90 percent MDG for solar resources, as well as geothermal, biomass, and baseload hydroelectric resources, is market, and reasonable and appropriate as solar resources are regularly able to meet 90 percent generation targets as demonstrated by the Joint Utilities' past QF and non-QF Power Purchase Agreements (PPAs).

   - Measuring the MDG over a one-year period for all subject resources, including solar, is market and reasonable.

   - Because doing so results in transferring costs and project risk from the QF to the utility that are not included in avoided cost pricing, as discussed in Section II.E.1 below, the Joint Utilities oppose AHD's inclusion of a cap at the contract price on damages for failure to meet the MDG and recommend that the Commission remove OAR 860-029-0120(14)(c) from the Draft Rules.

3. <u>OAR 860-029-0120(16) – Incremental Facility Upgrades.</u>

   - The Joint Utilities recommend deleting "Except as expressly permitted in subsection (b)" from subsection (16)(a). Subsection (16)(a) addresses permissible changes during the development period—prior to commercial operation, whereas subsection (16)(b) addresses changes after the facility is operational. Therefore, the reference to subsection (16)(b) is not relevant to subsection (16)(a) and should be removed.

   - If the Commission wishes to allow QFs to pursue facility upgrades that would not increase the Nameplate Capacity Rating, but would likely increase the annual net output by more than 10 percent, ***without the utility's consent***, the Joint Utilities recommend that the Commission remove subsections (16)(b)(A)-(B) because they are inconsistent with the language in subsection (16)(b) stating, "except as permitted under subsection (c)…."

- The Joint Utilities recommend that the Commission clarify that if a QF elects facility upgrades that would likely increase the annual net output by more than 10 percent, then the QF ***must*** accept repricing and execute an amended PPA under subsection (16)(c)(D).

C. OAR 860-029-0121/New Rule #4: Delivery and Purchase under Standard Power Purchase Agreement

1. New Rule #4 should not require utilities to accept intra-hour scheduling for off-system QFs because allowing QFs to use intra-hourly scheduling would impose additional operational and administrative costs on the purchasing utility that are not accounted for in avoided cost prices, and these cost implications have not been thoroughly vetted in this docket.

2. The Joint Utilities recommend that OAR 860-029-0121(5) be revised such that a utility will plan in advance for a QF to come online only 90 days prior to the Scheduled COD, because 180 days is far too long for utilities to be expected to reserve capacity. As discussed above in Section I.A.5, instead of automatically requiring utilities to reserve capacity 180 days in advance, the Joint Utilities recommend that the public utility be obligated to purchase net output earlier than 90 days, but no more than 180 days, before the Scheduled COD only if the public utility is able to modify its network resource designation for the facility such that the output could be delivered using network transmission service at no additional cost or other economic impact to the purchasing public utility. Such a provision is generally consistent with the Joint Utilities' Community Solar Program PPAs approved by the Commission.

3. New Rule #4 should not require utilities to pay the full Index Rate for Test Energy as such a requirement is not consistent with currently approved standard PPAs or the utilities' negotiated QF and non-QF PPAs. Instead, the Joint Utilities propose that the purchasing public utility pay the QF the lower of 85 percent of the Index Rate or 85 percent of the contract price for Test Energy delivered prior to the Scheduled COD.

D. OAR 860-029-0122/New Rule #5: Force Majeure

1. The Joint Utilities recommend that the Commission retain New Rule #5 in the Draft Rules because retaining it would be efficient and consistent with the intent and the scope of this docket.

2. Even if the Commission declines to address the parameters of Force Majeure in detail in these rules, the Joint Utilities recommend that the Commission at minimum adopt a more limited rule: (1) clarifying that any delay, alleged breach of contract, or failure by the transmission provider or interconnection provider—i.e., entities that are not the purchasing public utility—does not qualify as an event of Force Majeure (as this is project risk not included in avoided cost pricing that should be borne by the QF

developer); and (2) adding a 180-day limit for events of Force Majeure after which time the party not claiming Force Majeure may terminate the PPA. While the Joint Utilities are recommending a 180-day Force Majeure time limit, the Joint Utilities do not oppose a limit between 180 days and one year.

E. OAR 860-029-0123/New Rule #6: Default, Damages, and Termination

1. <u>A Cap on Damages Based on the Contract Price Would Harm Customers.</u>

   - Capping damages unreasonably and illegally shifts costs from QFs to utility customers. When the QF fails to deliver energy under the PPA, customers bear all costs of the QF's default that exceed the cap. Furthermore, separate from the financial risk to customers, caps on damages may have reliability implications due to perverse incentives. When the contract price and market price diverge significantly, but damages are capped at the contract price, a QF could be incentivized to default, pay the limited damages, and sell its energy into the market at a much higher price. Such an outcome would be unreasonable and inappropriate.

   - The 24-month limit on termination damages in proposed OAR 860-029-0123(9) already caps QFs' liability. Although, this 24-month limit is not market, the Joint Utilities have not opposed retaining this Commission policy from Order No. 06-538. But providing additional caps on damages on top of the existing 24-month limit will result in utility customers further, and inappropriately, assuming project risk not incorporated in avoided cost pricing that should be borne by QF developers.

   - Should the Commission decide to follow its damages-cap policy from Order No. 06-538, it should remove the new contract price caps, including for termination damages, which are inconsistent with that order.

2. OAR 860-029-0123(4) regarding cure periods should be revised for clarity. As currently drafted, the cure periods provision is inconsistent with the rest of OAR 860-029-0123.

3. The Joint Utilities note that "failure to comply with any material obligation under the power purchase agreement" should be added to the list of QF events of defaults as a new subsection OAR 860-029-0123(1)(j) because this same language is listed as a public utility default under OAR 860-029-0123(2)(d).

4. The Joint Utilities recommend that the Commission revise OAR 860-029-0123(3) to also reference OAR 860-029-0123(2), i.e., events of default for utilities, and that the reference to "Excused Delay" be removed as that term is not defined in the Draft Rules.

5. The Joint Utilities further recommend that the Commission clarify that delay, MAG, MDG, and termination damages include both additional transmission costs *and ancillary service costs* for delivery of replacement power.

II. COMMENTS REGARDING GROUP 1 DRAFT RULES

A. OAR 860-029-0005 – Applicability of Rules

1. The Joint Utilities request that the Commission explicitly state in the order adopting these rules that any changes to these rules or new rules apply only to PPAs executed after the new or revised rules take effect.

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

1. The Commission should clarify that under OAR 860-029-0120(5)(b)(A), the required interconnection study must show that interconnection can occur more than three years, ***but no more than four years***, from the Effective Date of the PPA. This clarification reflects Staff's intention in balancing customer protection and QF development.

2. The Joint Utilities believe that AHD retained duplicate sections (7) and (8) in error and recommend that the Commission remove these sections from the Draft Rules.

3. The Joint Utilities strongly object to allowing the use of step-in rights and senior liens for Default Security and recommend that these options be removed from the Draft Rules as it is highly unlikely that a qualifying facility's lender would allow the utilities to have step-in rights or liens senior in priority to the lender's rights. Even if a lender were to allow a utility to hold such rights, these rights would not ensure that the utility will recover sufficient damages to hold customers harmless in the event of a QF default. Moreover, utilities are not in the business of foreclosing on projects and the costs and resources needed to administer such foreclosure actions do not make this a realistic remedy for a utility. If the Commission chooses to allow a QF to provide step-in rights as Default Security, the rule must also require the QF to ensure that the purchasing utility is permitted to perfect ***a first priority security interest*** in the project and require the QF to execute and deliver security instruments and financing documents in such form and substance as is acceptable to the utility.

4. The Joint Utilities continue to support their proposed creditworthiness criteria, which are clear and consistent with market. The Joint Utilities object to the use of a Dun and Bradstreet credit rating because a Dun and Bradstreet credit rating score would only reflect payment performance of the LLC itself, which in only one input in a credit evaluation. The Joint Utilities have proposed that smaller QFs, i.e., 1 MW and smaller, that are not able to meet these requirements can provide in lieu of these requirements certain representations and warranties regarding the financial condition of the QF and its primary equity owners, subject to verification by the utility based on financial information provided by the QF. Larger QFs not meeting these requirements would post security. These credit and security requirements ensure that project risk not included in avoided cost pricing is not transferred to utility customers when the QF defaults on its obligations.

C. OAR 860-029-0046(2)(c)(F) –12 x 24 Delivery Schedule

1. The Joint Utilities appreciate that AHD partially adopted their recommendation to include the following language in OAR 860-029-0046(2)(c): "Estimates of the net amount of power to be delivered to the public utility's electric system and the 12 x 24 delivery schedule are subject to revision until the date the qualifying facility commences commercial operation." The Joint Utilities would recommend, however, that the Commission move this language to OAR 860-029-0046(2)(c)(F) and that the section further clarify that a 12 x 24 schedule may be used as a baseline for delivery expectations for the purpose of calculating damages when the QF defaults on its obligation to deliver power.

D. OAR 860-029-0046(2)(c)(O) – Interconnection Study Supporting Online COD

1. The Joint Utilities continue to propose that OAR 860-029-0046(2)(c)(O) be added to the Draft Rules, which would require that the QF provide the public utility ***a copy*** of the interconnection study necessitated under OAR 860-029-0120(5)(b)(A).