BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

AR 631

In the Matter of Rulemaking to Address Procedures, Terms, and Conditions Associated with Qualifying Facilities (QF) Standard Contracts	COMMENTS OF THE COMMUNITY RENEWABLE ENERGY ASSOCIATION, NORTHWEST & INTERMOUNTAIN POWER PRODUCERS COALITION, AND RENEWABLE ENERGY COALITION ON STAFF'S PROPOSED GROUP 2 RULES

I. INTRODUCTION

The Community Renewable Energy Association ("CREA"), the Northwest & Intermountain Power Producers Coalition ("NIPPC"), and the Renewable Energy Coalition (the "Coalition") (collectively the "QF Trade Associations") respectfully submit these Comments on Group 2 Issues. These Comments address the proposed Group 2 rules and issues agreed upon earlier in this docket.[1]

II. GROUP 2 COMMENTS

A. New Rule #5 Force Majeure

1. The Commission Should Not Codify Normal Contract Provisions Like Force Majeure

The QF Trade Associations recommend removing the specific force majeure contractual language in Staff's Proposed Rules and replacing it with a general principle that a force majeure

[1] ALJ Ruling at 1-2 (Jan. 21, 2022).

provision, "consistent with the common legal" term,[2] should be included in every PPA. Staff's Proposed Rules include a new rule that requires every PPA to include a Force Majeure provision and details the specifics of that Force Majeure provision.[3] The QF Trade Associations oppose this Staff Proposed Rule as it is overly detailed by including contract-like language in rules and contractual provisions like force majeure that should not be adjudicated at the Commission. In addition, legal concepts like force majeure evolve and are continually being reviewed and interpreted by the common law courts. The Commission should not calcify one specific definition in an administrative rule that is difficult to modify, but instead allow Force Majeure provisions to be updated more easily through utility contract filings.

The QF Trade Associations maintain their general opposition to the Commission's unprecedented assertion of jurisdiction over post-execution contract disputes.[4] While Oregon's appellate courts have not yet resolved the question of whether the Commission's actions are lawful, even the Commission has agreed it is inappropriate for the Commission to exercise jurisdiction over common-law contract disputes such as force majeure.[5] In *PGE v. Dayton Solar I LLC*, the Commission granted a motion to dismiss regarding a force majeure dispute.[6] The

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2 *In re Commission Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Docket No. UM 1129, Order No. 06-538 at 24 (Sept. 20, 2006).

3 Order No. 21-353, Attachment A, Staff's Proposed Rules at OAR 860-029-XXXX [New Rule #5] (Oct. 26, 2021) [hereinafter "Staff's Proposed Rules"].

4 *E.g.*, NIPPC-Renewable Energy Coalition-CREA Comments for AR 631, UM 2000, UM 2151 at 1-4.

5 *PGE v. Dayton Solar I LLC*, Docket No. UM 2151, Order No. 21-210 at 9-10 (June 25, 2021).

6 Docket No. UM 2151, Order No. 21-210 at 9-10 (June 25, 2021).

Commission stated "we do not have significant expertise with the jurisprudence of force majeure, and that the factual applications are so specific as to not pose a larger influence on future contracts or policy" and that the Commission's "legal understanding of the term, force majeure, was informed by common law and not specialized regulatory policy."[7] Thus, the Commission deferred such disputes to the court system.

Since the Commission already agreed that the courts, and not the Commission, will adjudicate any dispute involving force majeure provisions, the Commission's rules should not complicate those disputes by providing specific contract language. Any contractual dispute should be resolved by a court applying the ordinary tools of contract interpretation and not seeking to interpret rulemaking provisions.

Thus, the QF Trade Associations recommend removing the specific force majeure contractual language in the proposed rules and replacing it with a general principle that a force majeure provision should be included in every PPA. To the extent that Staff's proposed Force Majeure provision remains in the rules, it should be clarified whether that particular language must be in all PPAs or just standard PPAs.

2. If Included in the Rules, the Proposed Definition of Force Majeure Should be Revised

The definition of Force Majeure in Proposed Rule #5 is far more narrow than is normally included in power purchase agreements, and certainly much more narrow and much more generous to the purchasing utility than the force majeure provisions in each of the Oregon

[7] Docket No. UM 2151, Order No. 21-210 at 9.

utilities' currently approved standard contracts in Oregon. In the QF Trade Associations' view, the currently proposed definition is very problematic. If the final rules include a definition, revisions should be made to prevent unreasonable obstacles to development of small-scale renewable facilities under the Commission's standard contract.

The general concept of a force majeure clause is that a party's obligation to perform should be suspended when performance is rendered impractical due to circumstances that are beyond the party's control. Despite the moniker, the force majeure concept provides relief in more circumstances than a traditional "Act of God" circumstance: "most courts have recognized that this expression [i.e., 'force majeure'] refers to circumstances outside of a party's control, which is a more expansive concept than that of an Act of God."[8] Force majeure clauses are rooted in the contractual doctrine of temporary impracticality.[9] As the Restatement of Contracts explains, "the affected party's duty is at least suspended" and "[w]hen the circumstances giving rise to the impracticability or frustration cease to exist, he must then perform. He is usually expected to perform in full and is entitled to an appropriate extension of time for performance."[10] While parties of equal bargaining power can of course negotiate for a more precise set of circumstances temporarily excusing performance in a force majeure clause, the issue here is whether the Commission should significantly narrow the otherwise applicable circumstances that

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8 1 Am Jur 2d, *Acts of God*, § 2 (2022).
9 *Restatement 2d of Contracts*, § 269 (1981).
10 *Restatement 2d of Contracts*, § 269, comment a.

would normally be excused through a narrow definition of force majeure in its administrative rules.[11]

The QF Trade Associations submit that the Commission should not unreasonably narrow the circumstances under which a QF's performance obligation is suspended because the entire purpose of the PURPA rules is to *encourage* development of qualifying facilities ("QFs"). Imposing contractual burdens more onerous than normally applicable contract law does not encourage QFs; to the contrary, it discourages QFs. The currently proposed Rule #5 contains the stock general definition of "force majeure" in subsections (2) and (3), but then it unreasonably includes an expansive and overbroad list of specifically excluded categories of events in subsection (4). Thus, the QF Trade Associations recommend revisions to subsection (4).

First, subsection (4)(b)— which excludes "the cost or availability of fuel or motive force to operate the Facility"— should include the qualifier "unless due to a Force Majeure event." All parties will agree that a reasonably anticipated increase in the cost of fuel is not a force majeure event. But if the lack of *availability* of fuel was itself caused by an event of force majeure, the QF's performance obligation should be suspended. For example, a cogeneration QF's fuel would be its steam, which could easily be rendered unavailable for a legitimate force majeure event that caused its host facility to shut down, such as an earthquake that delays

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11 *See Perlman v. Pioneer Partnership*, 918 F2d 1244, 1248 n5 (5th Cir. 1990) ("Force majeure is a phrase coined primarily for the convenience of contracting parties wishing to describe the facts that create a contractual impossibility due to an 'Act of God'" but courts "look to the language that the parties specifically bargained for in the contract to determine the parties' intent concerning whether the event complained of excuses performance").

delivery of critical supplies to the plant. Or a solar QF could suffer from lack of availability of motive force, sunlight, on account of a volcanic eruption. These type of climate-related effects on motive force are beyond the QFs control and the QF should not penalized for climate events it cannot control. These examples should help illustrate why the Commission should be careful before adopting wholesale exclusions from force majeure that the utilities will propose.

Second, the Commission should delete entirely subsections (g) through (j), which provide wholesale exclusion of major categories of circumstances beyond the QF's control as follows:

> (g) any delay, alleged breach of contract, or failure by the transmission provider or interconnection provider unless due to a Force Majeure event as defined in any agreement with the transmission provider or interconnection provider,
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> (h) maintenance upgrade(s) or repair(s) of any facilities or right of way corridors constituting part of or involving the interconnection facilities, whether performed by or for the qualifying facility, or other third parties (except for repairs made necessary as a result of an event of Force Majeure);
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> (i) the qualifying facility's failure to obtain, or perform under the Generation Interconnection Agreements, or its other contracts and obligations to transmission owner, transmission provider or interconnection provider, unless due to a Force Majeure event; or
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> (j) any event attributable to the use of interconnection facilities for deliveries of Net Output to any party other than the purchasing public utility.

None of the above exclusions ((g) through (j)) exist in any of the Oregon utilities' currently effective standard contracts approved by this Commission, and their inclusion in administrative rules would constitute a major, detrimental change for renewable energy development. Further, in some cases, the delay caused by these circumstances could be caused by the purchasing utility itself, and depending on the duty at issue, there may be no other excuse in the power purchase agreement for the QF's failure to perform. For example, if the purchasing or transmitting utility elects to conduct maintenance on its system that de-energizes the point of interconnection, the QF has no control over that and should not have its power purchase agreement terminated if such maintenance activity causes it to miss its scheduled commercial operation date. Essentially, a utility could be allowed to terminate a QF's power purchase agreement when the utility itself is the cause of the QF's inability to deliver its net output. Adopting administrative rules that bless this result fail to encourage the development of QFs, as Oregon law requires.

B. New Rule #6 Default, Damages, and Termination

1. Damages

The damages provisions of the rules should undergo significant revisions because they are very one-sided in favor of the utility and include significant changes to current damages provisions in some of the standard contracts that require careful consideration.

First, the QF Trade Associations recommend that the damages owed to the 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. A cap of the contract price will provide upfront certainty for a QF to secure financing, while posing minimal risk to the utility's ratepayers. In UM 1129, the Commission held an identical cap on damages owed by QFs to utilities in the event of a default was reasonable.[12] The Commission directed the utilities to revise their standard contracts to insert a cap on damages at "100% of the QF contract price multiplied by the amount of energy the QF failed to deliver."[13]

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12 Docket No. UM 1129, Order No. 06-538 at 66-67 (Sept. 20, 2006).
13 *Id.* at 5-6.

The Commission reasoned that this cap on damages would "facilitate the development of QFs of all sizes, while keeping ratepayers indifferent to the development of QF power, versus other power sources."[14] Thus, the QF Trade Associations recommend changing Staff's Proposed Rules to account for a cap at the contract price, consistent with the Commission's prior decision.

Second, even worse than no cap on damages, at least one provision appears to include duplicative damages. Apparently in response to Joint Utilities' comments, Staff's Proposed Rule OAR 860-029-0120(13) includes duplicative (and uncapped) replacement price damages for violations of the minimum delivery guarantee in the PPA. Specifically, it first requires the QF to pay liquidated damages based on a formula for replacement price damages for the "cost to cover," which is undefined but generally understood to mean the cost of replacement power, and then *in addition*, it further requires the QF to pay the cost of the replacement energy "procured" by the utility.[15] This may be an oversight in the drafting process, but if not, it is hard to

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[14] *Id.* at 66.

[15] Staff's Proposed Rules at OAR 860-029-0120(13) states, in pertinent part:

> (13) The standard purchase agreement will include an annual minimum delivery guarantee (MDG) for solar, geothermal, biomass, and baseload hydro qualifying facilities equal to 90 percent of the qualifying facility's expected energy for the year.
> (a) The qualifying facility will owe damages for failure to meet the MDG equal to:
> (A) the product of the deficiency for such period and the utility's cost to cover;
> (B) the cost of any replacement energy procured by the utility as a result of the qualifying facility's failure to meet the MDG and any resulting incremental ancillary services and transmission costs; and
> (C) the cost of replacement Renewable Energy Credits.

understand how such duplicative damages could possibly be lawful or reasonable. It should be corrected.

Third, the QF Trade Associations recommend that the termination damages owed to the utility by the QF in the event of termination also be capped at the contract price of the energy. Currently, Staff's Proposed New Rule #6(8) calculates termination damages by the positive difference between market replacement price and the contract price for the 24 months after termination. In previous comments in this docket, the QF Trade Associations were concerned about the liquidated damages as termination damages because of the uncertain rule language and potential for unlawful penalties.[16] While the QF Trade Associations appreciate Staff's effort to provide clarity regarding liquidated damages, the QF Trade Associations are still apprehensive that the current termination damages could result in an unlawful penalty.

Generally, liquidated damages are only lawful when actual damages are difficult to estimate and the liquidated damages are "a reasonable forecast of just compensation for the harm that is caused by the breach."[17] Further, the provision cannot be a penalty designed to deter non-performance.[18] The QF Trade Associations do not agree that an uncapped market replacement price would necessarily be an accurate estimate of harm to the utility. However, termination damages at the capped contract price would be a better estimate of harm while providing certainty and clarity to the QFs. Thus, the QF Trade Associations recommend changing all of

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16 Joint Comments of CREA/REC/NIPPC on Staff's Initial Proposal at 26 (Mar. 30, 2021).

17 *State Highway Comm'n v. De Long Corp.*, 9 Or App 550, 574, 495 P2d 1215, 1227 (1972) (internal quotes omitted).

18 *Id.*

the liquidated damages formulas in the proposed rules to include a cap at the contract price and have proposed edits in the attached mark-up of the draft rules on that point.

2. Termination Provisions

The QF Trade Associations have concerns with two aspects of Staff's Proposed Rules regarding PPA termination. First, Staff has deleted New Rule #8 from earlier in the informal process, which specified certain events that specifically do not justify PPA termination. The list of items that specifically do not justify termination was clarifying, and the QF Trade Associations recommend that the concept be re-inserted into the rules. The QF Trade Associations also recommend that Staff clarify that the list is non-exhaustive, as there may be many other events that do not justify PPA termination.

Clarifying that certain contractual breaches will not result in termination is consistent with contract law, which generally requires that non-material breaches may not result in termination of a contract.[19] To be material and justify termination if uncured, a breach "must relate to a matter of vital importance, go the essence of the contract, or defeat an essential purpose of the contract."[20] The circumstances, especially the breaching party's prior performance and reliance on the contract, are significant; as the Restatement explains: "failure is less likely to be regarded as material if it occurs late, after substantial preparation or

19 *Restatement 2d of Contracts*, § 237 (explaining, "it is a condition of each party's remaining duties to render performances to be exchanged under an exchange of promises that there be no uncured material failure by the other party to render any such performance due at an earlier time").

20 17A Am Jur 2d, *Contracts*, § 706 (2004) (footnotes omitted).

performance, and more likely to be regarded as material if it occurs early, before such reliance."[21] However, "[e]ven if not material, the failure may be a breach and give rise to a claim for damages for partial breach."[22] The Commission's rules should reflect these basic contractual principles through inclusion of a non-exhaustive list of contractual violations that will not result in termination.

3. The QF Trade Associations' Edits to the Default, Damages, and Termination Provisions Should be Adopted

The QF Trade Associations have also submitted in the attached mark-up of the proposed rules a handful of clarifying edits to default, damages, and termination provisions in Proposed New Rule #6 that should be adopted. First, New Rule #6(1)(d) should be revised to clarify that delivery of less than all net output is not to be a breach unless it is a PURPA contract that requires delivery of all of the QF's net output. Certain QFs may contract to sell less than all of their net output for various reasons, such as use of some portion of their net output to serve an onsite load not associated with the power production process. New Rule #6(4)(a) is also

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[21] *Restatement 2d of Contracts*, § 241, comment d; *see also Restatement 2d of Contracts*, § 241 (stating the rule as follows: "In determining whether a failure to render or to offer performance is material, the following circumstances are significant: (a) the extent to which the injured party will be deprived of the benefit which he reasonably expected; (b) the extent to which the injured party can be adequately compensated for the part of that benefit of which he will be deprived; (c) the extent to which the party failing to perform or to offer to perform will suffer forfeiture; (d) the likelihood that the party failing to perform or to offer to perform will cure his failure, taking account of all the circumstances including any reasonable assurances; (e) the extent to which the behavior of the party failing to perform or to offer to perform comports with standards of good faith and fair dealing.").

[22] *Restatement 2d of Contracts*, § 241, comment a.

problematic as currently drafted. It states: "The public utility may impose damages after issuing a Notice of Default under subsection (l)(a) or (l)(d) as specified in OAR 860-029-0120(7)." The utility does not have authority to "impose" damages. A court awards damages. Additionally, the inclusion of a 30-day due date to pay such damages should be triggered only if the amount owing is not subject to a good faith dispute, as other provisions of the rules specify for other amounts owed by one party to the other. Thus, in addition to the cap on liquidated damages at the contract price, we have proposed an edit to avoid a misunderstanding that the utility has sole discretion to deem itself lawfully entitled to payment of damages. Finally, as discussed above, we have included within Proposed New Rule #6(5) the substance of the former New Rule #8 that provides a non-exhaustive list of defaults that do not result in termination and clarifies that other non-material violations of the terms and conditions of the power purchase agreement will not result in termination.

C. New Rule #1 Obligation for Costs to Accept Deliveries from Off-System QFs

1. Conditional Network Resource Status: Staff's Proposed New Rule #1 Should Be Removed or Significantly Revised Because It Is an Unreasonable Contract Reopener

Staff's proposed New Rule #1 would allow the purchasing utility to reopen any off-system QF's PPA after execution to litigate whether costs related to network transmission should be allocated to the QF through an avoided cost rate reduction or otherwise. The QF Trade Associations oppose this proposed rule and recommend that it be removed from the rules. In the alternative, if the Commission determines to retain this new rule, the proposal should be significantly revised to limit the harm that would be caused by this contract reopener.

Under Oregon's implementation of PURPA, the Commission must require the utility to offer each QF "projected avoided costs calculated at the time the legal obligation to purchase energy or energy and capacity is incurred."[23] When the QF elects to sell at such forecasted avoided cost rates, PURPA and related state law bar contract reopeners that would recalculate the rates.[24] For example, in *Smith Cogeneration Mgmt. v. Corp. Comm'n & Pub. Serv. Co.*, 863 P2d 1227, 1241 (Ok 1993), the state commission promulgated a rule that required all QF PPAs to contain a provision stating the contract terms could be reopened by the state commission.[25] The Oklahoma Supreme Court held that such rule was inconsistent with PURPA's requirement for long-term fixed-price PPAs and thus unlawful. The *Smith* court explained that "[s]uch a requirement makes it impossible to comply with PURPA and FERC regulations requiring established rate certainty for the duration of long term contracts for qualifying facilities that have incurred an obligation to deliver power."[26] "Once avoided costs are set, the Corporation Commission cannot later review the contract to reconsider the avoided costs."[27] The court correctly recognized that such a risk of reopening a fixed-price PPA "prevents cogenerators from

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23 ORS 758.525(2)(b).

24 *Oregon Trail Electric Consumers Cooperative, Inc. v. Co-Gen Company*, 168 Or App 466, 482, 7 P3d 594 (2000).

25 The *Smith* court described the rule as follows: "Rule 58(h) requires utilities and cogenerators to include in each contract a notice provision that allows the Corporation Commission to change the terms and otherwise finalize experimental purchase tariffs of a power sales agreement throughout the duration of the contract." *Smith Cogeneration Mgmt.*, 863 P2d at 1237 n 35.

26 *Smith Cogeneration Mgmt.*, 863 P2d at 1241.

27 *Id.*

obtaining the necessary financing to develop a facility" and thus "stands as an obstacle to the accomplishment of PURPA and FERC regulations."[28]

Staff's Proposed New Rule #1 is a classic case of an unlawful contract reopener. It frustrates the QF's right to rely on the forecasted and fixed prices in the PPA from the time that the PPA is executed for purposes of financing. Instead, this new rule would require inclusion in the PPA of a right of the purchasing utility to petition the Commission to examine whether the prices in the contract should change on account of costs of "transmission service-related Network Upgrades" and it expressly allows the utility to file such petition *after* the PPA is executed. Because this proposal is unlawful, Proposed Rule #1 should not be adopted as part of the administrative rules.

Further, the issue of whether QFs should be obligated to pay for costs related to transmission-level network upgrades is currently being litigated in UM 2032. That docket asks the Commission to decide the cost responsibility for such upgrades in the interconnection process and whether QFs should be required to take Network Resource Interconnection Service. Although Staff's Proposed New Rule #1 regards off-system QFs, it addresses the same type of network upgrade cost allocation issue as in UM 2032. Therefore, approving Proposed New Rule #1 could pre-judge the outcome of UM 2032, and it should not be addressed in the rules until resolution of UM 2032.

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28 *Id.*

Even if this type of contract reopener could somehow be lawfully implemented, it would need to be significantly revised and very narrowly limited in its application to prevent it from frustrating financing of QFs. While the QF Trade Associations oppose this provision altogether, we also urge the Commission to require very stringent restrictions on the use of such a provision if the Commission is inclined to adopt such a provision. In the attached mark-up of the proposed rules, the QF Trade Associations have offered several edits consistent with the points discussed below.

First, if the utility exercises the right to reopen the PPA before the Commission under this provision, the QF must be provided with the option to extend the PPA's scheduled commercial operation date on a day-for-day basis for each day until the final order in such proceeding is issued and any amendments to the PPA executed. As with any contested proceeding before the Commission, the proceeding to evaluate the utility's claimed network transmission costs will take months or more than a year before resolution. As noted above, the effect of this provision is to repeal the QF's contractual right to price certainty and to potentially require the QF to enter into a new contract with materially lower rates. In effect, the standard right to a three-year development period should be restarted upon execution of the new PPA that allocates newly identified network upgrade costs to the QF. This would be consistent with this and other commission decisions in prior cases in which the contract length and terms were ultimately revised to account for the time in litigation.[29] Otherwise, the QF will lose the price certainty needed during the three-year development period to successfully complete development and bring the facility online.

However, it is not clear that Staff's Proposed Rule would require the utility to agree to update the scheduled commercial operation date in the PPA after conclusion of the Commission process because it only states the PPA must state the "development period . . . does not commence" until after the Commission process ends.[30] The rule should unambiguously declare that the scheduled commercial operation date and the commencement of the fixed-price period shall be tolled pending resolution of the network upgrade cost allocation dispute.

Second, the QF Trade Associations are concerned with an apparent loophole in Proposed Rule #1 wherein a utility could substantially delay the QF contracting process by repeatedly: 1) declining an off-system QF's proposed point of delivery ("POD"); and 2) refusing to provide information about any alternative POD(s). Proposed Rule #1 requires utilities to consider a QF's proposed POD and allows utilities to decline a QF's proposed POD; if the utility declines the

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[29] *West Penn Power Co.*, 71 FERC ¶ 61,153 (1995) (declining to disturb state Commission findings that certain milestones of a QFs contract could be modified for litigation delay); *see Blue Marmot V LLC et al. v. PGE*, Docket No. UM 1829, Order No. 19-322 (Sept. 30, 2019) (the Commission allowed QFs an opportunity to demonstrate that a later COD should be allowed); *compare Kootenai Elec. Coop., Inc. v. Idaho Power*, Docket No. UM 1572, Complaint Exhibit 103 at 55 ("Seller has selected May 1, 2012 as the estimated Schedule Operation Date") (Jan. 3, 2012), *with Idaho Power Co. – QF Contracts*, Docket No. RE 141, OAR Compliance Filing Kootenai Elec. Coop., Inc. Oregon Standard Energy Sales Agreement, Appendix B at 36 ("Seller has selected April 1, 2014 as the estimated Schedule Operation date") (Mar. 11, 2014).

[30] Staff's Proposed Rules at OAR 860-029-00XX(4)(a) [New Rule #1].

POD, the QF may submit an alternative POD for the utility to consider.[31] The utility may not unreasonably withhold its agreement.[32] However, Proposed Rule #1 does not require utilities to study or even provide information already in the utility's possession about any alternative PODs.[33] This is a problem.

Any QF faced with repeated denials of its proposed PODs would have little recourse but to file a complaint asking the Commission to require the utility to negotiate in good faith by agreeing to a proposed POD or, as necessary, sharing information and potentially studying alternative PODs. In the absence of a requirement to do so in the rules, the utility may argue it has no responsibility to investigate or otherwise supply the QF with a viable alternative POD. To avoid needless litigation, the QF Trade Associations recommend that the Commission's rules simply require utilities to either accept a QF's proposed POD or, if the utility has a reasonable basis not to accept the POD, then the utility should be required to provide the QF with the evidence demonstrating that the proposed POD lacks adequate capacity to accommodate QF delivery, to reasonably study alternative PODs, and to promptly inform the QF of viable alternative PODs, including providing all evidence related to the study and conclusion that an alternative POD is viable.

Third, the Commission's final rules should provide a reasonable opportunity for the QF to change its POD after contract execution. Staff's Proposed Rules are silent on this issue. They

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31 Staff's Proposed Rules at OAR 860-029-00XX(1), (2) [New Rule #1].

32 Staff's Proposed Rules at OAR 860-029-0120(10).

33 Staff's Proposed Rules at OAR 860-029-00XX [New Rule #1] (specifying that the rule does *not* require utilities to do so).

should explicitly recognize that the QF may propose a different POD after contract execution, and the utility should *still* be required demonstrate that inadequate transfer capability is available or that there are competing uses of transmission, and to document its conclusion, before denying access to the new POD. In other words, the same standard should apply for changes to a POD both before and after contract execution. A change to the POD during the purchase period of the PPA could be necessary if the original transmission path develops impediments to delivering the QFs' net output, such as an extended outage to rebuild a line five or 10 years into the PPA. Without clarity in the rules, the purchasing utility may unreasonably refuse to accommodate a more suitable delivery point when such circumstances arise. Thus, the QF Trade Associations recommend adding language to Staff's Proposed Rules that clarify that a QF may propose a new POD after PPA execution, and the utility may not unreasonably withhold agreement to the new POD.

Fourth, the QF Trade Associations recommend that Staff's Proposed Rules recognize that QFs may elect to have any challenge to the proper allocation of the costs of transmission service Network Upgrades be conducted as a contested case proceeding. Staff's Proposed Rules provide that upon the Commission's receipt of a request for cost allocation of Network Upgrade costs, the utility and QF will have the opportunity to present their respective arguments to the Commission, and the Commission will issue an order resolving the dispute after "providing notice and opportunity to comment" (which is undefined).[34]

Under the Oregon Administrative Procedures Act ("APA"), a contested case proceeding is required under specific circumstances or where the Commission requires a contested case proceeding by rule.[35] Among other things, a "contested case" includes a proceeding where "the agency has discretion to suspend or revoke a right or privilege of a person."[36] "The starting point for determining whether an interest amounts to a 'right' or 'privilege' for purposes of ORS 183.310 is the defining source, not ORS 183.310 itself."[37] For example, the Oregon Court of Appeals has found that a petitioner's interest in a probationary apprenticeship terminated by an agency did not rise to the level of either a right or a privilege when it was "terminable without cause[.]"[38] But an interest in a non-probationary apprenticeship is a right or privilege where it is terminable only for "good cause."[39] Likewise, a proceeding to revoke a student's privilege to attend a university is considered a contested case under ORS 183.310(2)(a)(B).[40]

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34 Staff's Proposed Rules at 860-029-00XX(5) [New Rule #1].

35 ORS 183.310(2)(a).

36 ORS 183.310(2)(a)(B).

37 *Berry v. Metro Elec. Joint Apprenticeship & Training Comm.*, 155 Or App 26, 30, 963 P2d 712 (1998).

38 *Id.* at 30-31.

39 *Id.* at 31 (citing *Fairbanks v. Bureau of Labor and Indus.*, 323 Or 88, 913 P2d 703 (1996)).

40 *Morrison v. Univ. of Or. Health Sciences Cent.*, 68 Or App 870, 872, 685 P2d 439 (1984).

Here, the Commission would be exercising discretion to alter "rights" or "privileges" within the meaning of ORS 183.310(2)(a)(B). A Commission decision allocating Network Upgrade costs to the QF and utility alters the rights or privileges of the QF or utility and will result in modification or termination of an executed PPA. A fully executed PPA is unquestionably a "right" or "privilege" within the meaning of Oregon's APA. In Staff's Proposed Rules, a standard PPA may include a provision allocating Network Upgrade costs to the QF.[41] Thus, a utility has the right to allocate Network Upgrade costs to the QF, and the QF has the right to ensure costs allocated to it are reasonable per the Commission's decision. Thus, the appropriate proceeding for a decision regarding cost allocation would be a contested case.

Indeed, as we previously explained, a long-term PURPA PPA should not be subjected to modification or revocation in any event because PURPA proscribes such contract reopeners and preempts modification of long-term PPAs. But if the Commission is going to implement a process to modify or revoke PPAs, it should at a bare minimum provide the QF with basic contested case protections such as discovery and the right to challenge the utility's factual assertions in an evidentiary hearing.

Staff's Proposed Rules should be amended to specify that the proceeding for cost allocation of Network Upgrade costs will follow contested case procedures.

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[41] Staff's Proposed Rules at 860-029-00XX(3) [New Rule #1].

D. New Rule #4 Delivery and Purchase

1. Staff's Proposed Monthly Netting, Price Paid for Excess Energy, and Imbalance Rules Require Clarifying Edits

Staff's Proposed New Rule #4(2)(b) addresses imbalance and scheduling provisions for off-system QFs, but it fails to provide necessary clarity and unreasonably allows the utility to receive energy without paying for it. For purposes of off-system scheduling, the QF Trade Associations generally support the provisions governing monthly netting contained in PacifiCorp's Addendum W of its currently effective Commission-approved standard contract, with two clarifications.

First, the Addendum W provisions should be modified to include a requirement that the utility must pay the QF for any surplus energy in excess of the QF's monthly net output that the utility receives over the course of the month. Modest amounts of such overscheduled surplus energy (referred to by Staff's Proposed Rule as "Excess Energy") should be the expected result of the QF's efforts to ensure delivery of all of its net output (measured in kWh) through the transmission provider's scheduling protocols that utilize whole MW increments.

Second, any off-system-specific PPA should expressly allow use of commonly available intra-hour scheduling methods (e.g., FERC-mandated 15-minute scheduling) and not mandate the use of the hourly block scheduling. In Order No. 764, FERC required transmission providers to offer 15-minute scheduling after finding that hourly block scheduling imposes unjust and unreasonable imbalance charges on intermittent generators.[42] It would be unreasonable to deny use of that option to small Oregon QFs. The QF Trade Associations previously attached a proposed mark-up of the existing Addendum W along with our informal comments filed on June 9, 2021, which we continue to support. Staff currently proposes no payment by the utility for the "excess energy" delivered each month. However, the QF Trade Associations submit that the lesser of the contract price or the market index price is a reasonable price for such Excess Energy, and that the rule would ideally require use a market index price reasonably reflective of index pricing used by transmission providers' generator imbalance services.[43] Additionally, the QF Trade Associations do not believe it is necessary to limit the amount of Excess Energy purchased by the utility because the QF should have no incentive to deliver more Excess Energy than necessary to ensure delivery of all of its net output if it is only paid the market index price for such energy supplied by the transmission provider as imbalance energy.

Accordingly, the QF Trade Associations have proposed edits consistent with the points above to the scheduling and excess energy provisions of the proposed rules in the attached mark-up of the proposed rules.

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42 *Integration of Variable Energy Resources*, Order No. 764, FERC Stats. & Regs. ¶ 31,331, at PP. 20-22, 77 Fed. Reg. 41,482 (July 13, 2012) (stating that the "hourly scheduling protocols can expose transmission customers to excessive or unduly discriminatory generator imbalance charges").

43 For example, the Bonneville Power Administration ("BPA") currently uses the Powerdex Mid-Columbia Hourly Index as the price for settlement of imbalance energy, but may soon be joining the EIM and using an EIM price. *See Generation Imbalance Service: BPA Transmission Business Practice,* Bonneville Power Administration, https://www.bpa.gov/transmission/Doing%20Business/bp/tbp/Generation-Imbalance-Service-BP.pdf (Oct. 25, 2019).

2. Ability to Come Online Prior to Scheduled COD (Proposed New Rule #4(4))

The QF Trade Associations stand by their position stated in their previous comments. Under PURPA, utilities are required to accept all net output of a QF as PURPA requires that utilities "purchase all energy made available … [and] the price paid must not be less than the utility's avoided costs."[44] If the energy is made available, the utility must purchase it and pay no less than avoided costs. The QF Trade Associations therefore believe a blanket prohibition on QFs from delivering power more than 90 days before scheduled COD is unwarranted and unlawful as it is inconsistent with PURPA's must-purchase obligation.

Staff's Proposed Rules contain an unreasonable 90-day limitation on achieving commercial operation earlier than forecasted absent utility agreement.[45] Staff's Proposed Rule would allow the utility to refuse to allow commercial operation more than 90 days early in its sole discretion if the utility is "unable" to accept delivery from the QF, even if withholding such consent is not reasonable or based on any impediment to allowing such early operation. The QF Trade Associations recommend that the rules allow for more flexibility to the QF.

Staff bases its proposal upon on the need for utilities to plan and to forecast power costs, and the Joint Utilities' support Staff's proposal on the basis that "a utility typically needs at least 90 days advance written notice to arrange for transmission services."[46] If the utilities have

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[44] *Snow Mountain Pine Co. v. Maudlin*, 84 Or App 590, 595 (1987) (internal citations omitted) (internal quotations omitted); *see also* ORS 758.525; 18 CFR 292.304.

[45] *See* Staff's Proposed Rules at OAR 860-029-XXXX(4) [New Rule #4].

[46] Joint Utilities' Initial Comments at 22 (Mar. 30, 2021).

concerns regarding lack of transmission capacity or lack of communication,[47] then those should be addressed separately. To date, the utilities' vague claims have not been supported with actual facts and the utilities have not provided any proof that there are any such restrictions, additional costs, or harms. The answer is not to allow the utilities to refuse to accept the QF's power.

If there is a notice requirement, then the QF Trade Associations cannot respond to whether 90 or 365 days is appropriate given the lack of information. The Joint Utilities' comments implicitly acknowledge that less than 90 days' notice is sufficient in at least some cases.[48] The Joint Utilities should clarify what notice they would need to mitigate potential costs and allow QFs to come online ahead of schedule so long as they provide the specified notice. Only after the utilities provide detailed information can Staff and the QF Trade Associations properly evaluate any specific notice requirement.

It is difficult to precisely time the date on which the facility will achieve commercial operation, and in cases where the utility is not harmed by the QF achieving commercial operation early, the QF should be allowed to do so without arbitrary limits. We propose that QFs be permitted to achieve commercial operation and commence receiving payment at the full contract prices up to 180 days in advance of the scheduled commercial operation date, with notice to the utility, and at an earlier time if the utility consents with such consent not to be unreasonably withheld. The QF Trade Associations note for comparative purposes that at least PGE and PacifiCorp allow Community Solar projects to come online more than 90 days in advance of

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[47] Concerns raised by PGE and PacifiCorp at the Mar. 2, 2021 Workshop.
[48] *See id.*

Scheduled COD if the utility is able to make transmission arrangements at no added cost.[49] PacifiCorp's recent non-standard PPA with SkySol Solar (a 55 MW project) provides similar flexibility.[50] The QF Trade Associations assert any potential cost could be avoided so long as the QF provides adequate notice. The QF Trade Associations are not certain how much notice the Joint Utilities would consider to be necessary and cannot make any specific recommendation until the utilities provide more information.

Additionally, it is inconsistent with PURPA's must-purchase obligation to refuse to purchase a QF's power regardless of when the QF provides that power. If the Commission is concerned about stale prices at the end of fixed-price term, there is no reason to make it unreasonably difficult for a QF to come online sooner and commence its fixed-price term earlier. The QF Trade Associations also note that, generally speaking, QFs are more likely to be late than early. As noted above, the interconnection process and its delays have been a consistent and continuing factor in delaying commercial operations that makes it difficult to pin down a precise

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49 *In re Community Solar Program Implementation*, Docket No. UM 1930, PGE's Community Solar PPA at Section 3.2 (filed Jan. 25, 2021 and approved by Order No. 21-192) ("If Project Manager desires to begin transmitting Start-up Test Energy to PGE at a date earlier than ninety (90) days prior to the Scheduled Commercial Operation Date, PGE will only be obligated to purchase such Net Output if PGE is able to modify its network resource designation for the Facility such that the output could be delivered using network transmission service as described in Section 3.1 above at no additional cost or other economic impact to PGE"); Docket No. UM 1930, PacifiCorp's Community Solar PPA at Section 3.2 (filed Jan. 27, 2021 and approved by Order No. 21-192) (containing identical language). Idaho Power's contract does not appear to impose any restriction on early deliveries. *See Idaho Power Advice No. 20-12 Community Solar Interconnection and PPA,* Docket No. ADV 1205, Idaho Power Community Solar PPA.

50 *See in re Pacific Power – Qualifying Facility Contracts,* Docket No. RE 142, SkySol Solar PPA at Section 5.1.1.

date.

Accordingly, the QF Trade Associations propose that a QF may come online up to 180 days before the PPA's scheduled commercial operation date without consent of utility by providing advance notice to the utility, and the QF may come online earlier than 180 days early with the utility's consent, with such consent not to be unreasonably withheld. Further, the QF should begin receiving payments at the full contract price when it achieves commercial operation early so long as the QF follows the process in the rules to do so. At a minimum, if Staff's 90-day limit will be retained for early operation as a matter of right, the rule should state that the utility's consent to earlier commercial operation should not be unreasonably withheld.

E. The Commission Should Adopt the QF Trade Associations' Revisions to Proposed New Rule #7 Regarding Coordination between QFs and Utilities

The Proposed New Rule #7(2)-(5) would impose new maintenance and planned outage limitations and time constraints that have not previously been imposed on small Oregon QFs. The QF Trade Associations have serious concerns with some of these provisions. Notably, the proposal in the current draft of the proposed rules appears to be lifted almost verbatim from PacifiCorp's form contract it recently developed for use in other states, but which has never been vetted or approved by the Commission.[51] As one might expect, the terms drafted by PacifiCorp

[51] In previous comments, the QF Trade Associations have raised numerous concerns about the use of PacifiCorp's Washington standard PPA as a starting point and the various provisions within it. PacifiCorp's Washington standard PPA was not litigated, there was

are very favorable to the utility. The problem, however, is that placing unreasonable limits on the QF's ability to maintain and operate its facility may prove unworkable in practice, and if not carefully limited could even result in a QF breaching its power purchase agreement. Thus, the QF Trade Associations have offered a number of edits to Proposed New Rule #7 in the mark-up of the current draft rules attached hereto.

The rules propose to implement the concept of "High Demand Months" during which a QF may not conduct planned maintenance on its facility and should even refrain from unexpected maintenance outages.[52] But if such a concept will be adopted, the rules should explicitly require the utility to identify the "High Demand Months" in the power purchase agreement, so there is no ambiguity at the outset as to which months will be unavailable for planned outages. Additionally, the rules should clarify that the advance notice of twelve months required for the utility to change the High Demand Months is twelve months prior to the commencement of the contract years for which the High Demand Months will be changed, so that the QF may arrange its affairs prior to such change in allowable planned outages. The rules should also have a carve out that allows the QF to conduct Planned Outages during high use months at times when no motive force is available to the QF. For example, a solar QF will often conduct planned maintenance at night, even during high use months with no harm to the utility.

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no Staff Report, and was not approved by the Washington Utilities and Transportation Commission but was allowed to go into effect. *See* Joint Comments of CREA, NIPPC, and the Coalition on Staff's Updated Proposal at 34-51(June 9, 2021); *See also*, Joint Comments of CREA, NIPPC, and the Coalition on Staff's Draft Proposed Rules at 23-26 (Aug. 12, 2021).

[52] Proposed New Rule #7(2)-(3).

Further, for clarity, the definitions of the Planned Outage, Maintenance Outage, and Forced Outage should not simply cross reference the North American Electric Reliability Corporation ("NERC") outage types and definitions because NERC definitions could change over time and without notice to the Commission or stakeholders. PacifiCorp's power purchase agreement form included the NERC definitions as an exhibit to avoid confusion in its cross reference to those NERC definitions, but the Staff's Proposed Rule includes just the name of the referenced NERC definitions, leaving parties to resort to the internet locate the NERC definitions and understand the meaning of the Commission's administrative rules. Additionally, the NERC definitions appear to include gaps in the types of outages that could occur by, for example, limiting Planned Outages to an outage that "lasts for several weeks and occurs only once or twice a year." Planned outages will not always last several weeks and may occur more often than once per year. For example, solar QFs may conduct planned outages regularly at night over the course of a week to limit times when the facility is unavailable during daytime hours. Thus, the QF Trade Associations' edits provide more flexibility than simply relying on the NERC definitions.

F. The Commission Should Revise the Proposed Rule's Provisions for Minimum Delivery Guarantees, Mechanical Availability Guarantees, and Incremental Upgrades

1. Do Not Subject Solar QFs Eligible for Standard PPAs to a New Minimum Delivery Guarantee, and Make the Minimum Delivery Guarantee Representative of QF Operations (Proposed OAR 860-029-0120(13)-(14))

Staff's Proposed Rules include major policy changes adverse to qualifying facilities. The rules include a minimum delivery guarantee ("MDG") for solar, geothermal, biomass and baseload hydro facilities, a mechanical availability guarantee ("MAG") for wind facilities, but do not address whether run-of-river hydro facilities should be subject to an MDG or MAG. Current

Commission policy is that "[i]t is appropriate for standard contracts to require a QF to specify a minimum *annual* delivery requirement,"[53] but for intermittent resources there should be an MAG.[54] This policy recognizes that certain resource types will have substantial year-to-year variation in their net output due solely to availability of motive force and should not be penalized for such conditions. As explained below, the QF Trade Associations' generally support the Commission's pre-existing policies under which solar and run-of-river hydro facilities are not subjected to the MDG, and we submit that if a MDG will apply as the only option for solar and run-of-river hydro, there need to be significant revisions to the currently proposed MDG to make it work for such resources.

In reviewing this issue, it is important to keep in mind that, because Oregon QFs are only paid for the energy actually delivered to the utility, the QF has an economic incentive to make its facility as productive as possible. The Commission should be careful not to allow the performance guarantees to turn into punitive provisions when the QF already has an inherent incentive to maximize the facility's performance.

With respect to run-of-river hydro, the Commission's existing policy also allows run-of-river hydro to elect an MAG in lieu of the MDG. The QF Trade Associations are open to making the MDG the only option for run-of-river hydro facilities if the rule will include sufficient protections to ensure that the MDG is a reasonable requirement on such facilities, including providing the QF the discretion to identify its contractual minimum delivery level

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53 UM 1129, Order No. 06-538 at 2 (emphasis added).
54 UM 1129, Order No. 07-360 at 32-34; UM 1610, Order No. 14-058 at 28.

instead of using an arbitrarily imposed 90 percent of expected energy as is proposed in the Proposed Rule. Allowing the QF to provide a reasonable forecast of its annual expected energy and setting the minimum delivery amount at 70 percent would be more reasonable to ensure run-of-river QFs are not unreasonably penalized due to weather variations over which they have no control.

Additionally, the rules should include accommodations for the unique unforeseen impacts related to conditions caused by climate change and ensure that PPAs are not terminated due to such circumstances beyond the control of the QF. Climate-related events such as droughts and wildfires are beyond the QF's control but will have disproportionate effects on small-scale QFs such as solar and hydro facilities. Any year with a major drought or large wildfire could cause a small QF to be unable to meet the MDG requirement. Thus, small-scale QFs need flexibility for any MDG requirement during the course of the PPA due to unforeseen climate-related impacts the QF has no control over.

In addition, if solar must meet an MDG, then there should be additional changes to reflect a solar facility's operational characteristics. Staff proposes to eliminate the MAG for solar based "in part on Solar developers' representations in other dockets about predictability of solar generation for purposes of resource planning and as a capacity resource."[55] The QF Trade Associations agree that the predictability of solar generation has significantly increased; however, standard contracts are for projects 10 MW or less, and many will be 3 MWs or less

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[55] Staff Table for Proposal September at 10 (Sept. 3, 2021).

because pricing must be negotiated for projects above 3 MWs. In aggregate, solar generation on a utility's system should be predictable and reliable, and, in the case of avoided cost rates offered to QFs, the Commission should take such aggregate capacity value into account.[56] But there may still be sufficient intermittency for smaller projects such that an MAG is appropriate.

The requirement that the MDG be 90 percent of the QF's expected energy for the year is too restrictive for many facilities, especially solar and run-of-river hydro. Staff's Proposed Rule does not define "expected energy." However, assuming that Staff intends "expected energy" to be an annual average over a period of many years based on available motive force, the 90 percent number is not sufficient for solar because that is within the normal range of solar variability. A 90-percent requirement could be especially punitive if the utility insists that the PPA contain an unreasonably high value for the facility's expected energy delivery amount. The QF Trade Associations believe a more reasonable number would be 70 percent of the QF's expected energy over a 2-year period, and the QF should be given flexibility to set its expected energy and/or modify it based on changing conditions over time.

Similarly, the QF Trade Associations are open to considering whether to support an MDG for run-of-the-river hydro, which is generally predictable and should be treated as a capacity resource. However, the QF Trade Associations do not agree that 90 percent of an annual average generation amount is reasonable. Instead, if an MDG will be required, the QF

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[56] *See* 18 CFR § 292.304(e)(2)(II)(F) (stating that the factors to be taken into account in setting avoided cost rates include the "individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system").

should have to option to identify its MDG level to be included in the contract. A run of the river hydro facility should be allowed a significant amount of discretion to select its minimum delivery amount by reviewing historic stream flow conditions and forecast potential changes. It would not be appropriate for the utilities to challenge the minimum amount selected by the hydro facility.

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 "QF should be able to take into account the possibility of wind or water droughts in estimating annual minimum delivery commitments and specify an amount that can be met yearly, even if a wind or water drought occurs during the year."[57] Climate change will make it more difficult for hydro facilities to account for extreme weather events. The QF Trade Associations recommend that either: 1) drought be considered a Force Majeure event; or 2) hydro QFs be allowed to revise their minimum annual delivery amount a limited number of times in the contract.

To the extent a QF is subject to an MDG, it should only apply to facilities that are actually contracting to sell and be paid for capacity. Both standard and non-standard QFs have the flexibility to not offer capacity and to just be compensated for energy. A QF should not be

[57] UM 1129, Order No. 06-538 at 24-25.

required to pay damages for failure to deliver if it is not being fully compensated for guaranteeing that deliveries will occur.

The QF Trade Associations have included edits to the MDG provisions in the attached mark-up of the proposed rule to reflect our recommendations discussed above.

2. Mechanical Availability Guarantee – Proposed Rule OAR 860-029-0120(11)-(12)

The QF Trade Associations have included certain clarifying points on the proposed rule's mechanical availability guarantee provision in the attached mark-up of the current version of the proposed rules. The revisions are technical in nature and include that the MAG is to be measured on a per-turbine basis as opposed to requiring simultaneous availability of all turbines for 90 percent of the year, and to include the standard carve outs from the availability requirement (e.g., force majeure, purchasing utility default, curtailment, etc.). These points are important because in the past certain utilities have proposed unreasonable MAG provisions in their standard contracts that omitted these standard provisions.

3. Modifications to Qualifying Facility – Proposed Rule OAR 860-029-0120(15)

The QF Trade Associations support providing the QF with flexibility to incorporate technological advancements in the design of their facility after PPA execution. The QF Trade Associations recommend changing Staff's Proposed Rules so that QFs retain their executed PPA and are paid their contracted-for prices if, during the PPA term, the facility changes its nameplate capacity rating within the applicable threshold for that QF, or otherwise conducts any upgrade that increases the efficiency and net output of its facility without changing the nameplate capacity. Further, the QF Trade Associations recommend changing Staff's Proposed Rules so that the capacity threshold that applies to a given QF is the threshold applicable when the PPA was signed. With the aggressive HB 2021 emissions reduction mandates, the last thing the Commission should do is effectively preclude new QF generation from increasing its net output, efficiency, or contribution to the region's growing capacity needs for the next 15 to 20 years. The relevant consideration should be what price the new generation is paid and if new contractual provisions need to be included due to the larger nameplate capacity or additional functionality, such as added storage devices. In a time of rapidly advancing technologies and increasing need for carbon-free capacity, there is no legitimate public policy justification to prevent qualifying facilities from selling additional power or shifting the time of production through use of advancing storage technologies to supply the utility and the grid with a superior product to what was possible when they entered into their power purchase agreement.

It is important to understand the Commission's existing policy from UM 1129 to evaluate the proposal contained in current draft of the proposed rules. Under current Oregon policy, reasonable upgrades are allowed during the operational phase of the facility. Existing OPUC policy allows, in certain circumstances: 1) increases up to the size threshold for obtaining a standard contract with the incremental generation paid at the rate in the executed contract; and 2) increases beyond the size threshold with the incremental generation beyond the size threshold paid at a negotiated contract price.[58] Specifically, the Commission stated:

> a QF may upgrade operations and continue to receive its existing contract price for all power delivered up to 10 MW, but if the QF project is upgraded to a capacity that is above 10 MW, a new contract must be negotiated to price any power delivered over 10 MW at updated avoided costs…if a QF increases the nameplate

[58] Docket No. UM 1129, Order No. 06-538 at 38-39 (Sept. 20, 2006).

> capacity of its facility by a certain percentage above 10 MW, then on a going forward basis, that percentage of the power delivered by the QF will receive new, negotiated pricing, while the remaining percentage of output will receive pricing under the pre-existing standard contract.[59]

This is a good framework to build upon going forward. The QF Trade Associations understand that the Commission subsequently limited this policy to only certain types of project expansions.[60] However, Staff's Proposed Rules should adhere to the intent of current policy to allow expansions and, at a minimum, not take away existing expansion rights.

Staff's proposal on this subject has changed throughout the process, but the current proposal, included at proposed OAR 860-029-0120(15), is somewhat unclear. It appears Staff proposes to provide the utilities with unilateral discretion to reject any increase to the nameplate capacity, or even just an increase of the expected net output by 10 percent, by the QF after execution of the PPA and through its entire term.[61] Yet Staff's Proposed Rules also suggests the QF may potentially upgrade the facility to increase its net output without increasing the nameplate capacity, albeit with potentially lower pricing for the increment of estimated net output in excess of 10 percent from the amount projected at the time of power purchase agreement execution.[62] The Proposed Rules would pay the QF the then-current prices for the incremental additional net output that is not more than 10 percent than the forecasted net output in the original PPA or the Proposed Rules would pay the QF a blended rate for all the net output

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[59] Docket No. UM 1129, Order No. 06-538 at 39 (Sept. 20, 2006).
[60] Docket No. UM 1894, Order No. 18-284 at 5-8 (Aug. 2, 2018).
[61] *See* Proposed OAR 860-029-0120(15)(b)(A)-(B).
[62] *See* Proposed OAR 860-029-0120(15)(c).

from the facility. As currently drafted, these provisions are both confusing and more onerous than necessary. Revisions are needed to encourage renewable energy development.

Although somewhat ambiguous, it is clear that Staff's Proposed Rules are inconsistent with existing Commission policy. The QF Trade Associations recommend that Staff's Proposed Rules establish the following policy. First, a QF may increase its nameplate capacity up to the relevant capacity threshold for standard rates in effect at the time it executed its standard contract without a contract modification to its rates. For that incremental generation attributable to incremental power production capacity up to the standard contract threshold, the QF should also continue to receive the standard prices in the original contract. Second, if a QF increases its nameplate capacity beyond the relevant capacity threshold, then it needs to enter into a new contract for all net output; however, only the new generation above the relevant capacity threshold is paid the then-current prices.

However, Staff's Proposed Rules could be read as not allowing *any* increases in nameplate capacity unless an entirely new contract and prices are established for all net output because the rules state the utility may deny any meaningful upgrades that increase nameplate capacity or net output by 10 percent. This would be inconsistent with the current Commission policy that allows QFs to continue receiving their contracted-for pricing for all output up to the applicable threshold, with only the incremental output potentially subject to a negotiated PPA or new negotiated pricing.[63] At a minimum, to the extent Staff's Proposed Rules are inconsistent with Commission policy, the Proposed Rules should be revised.

However, the QF Trade Associations strongly oppose policies that limit expansions, especially if ratepayers are held harmless when new incremental generation is paid then-current prices. There is no justification to prevent reasonable expansions of current facilities, especially when Oregon and Washington face the significant task of meeting aggressive clean energy targets. Viable renewable energy sites should not be tied up and precluded from expansion during the entire term of the contract. Thus, even if our lead proposal is not adopted, QFs should be encouraged to expand by allowing for preservation of the initial contract prices for the increment of output attributable to the initial facility and new, current pricing paid only for the increment of output attributable to the expansion. But arbitrary limitations on the type or extent of an allowable expansion or upgrade should not exist.

Further, the rules should explicitly clarify that generators should have the option to improve their operations and on-site reliability through, for example, installing battery storage without facing the potential loss of their contracted-for pricing or PPA in the event that the storage is deemed to increase the project's overall output. Specifically, the QF Trade Associations recommend revising Staff's Proposed Rules so QFs can upgrade the capacity or output through installing battery storage of the facility and still be paid the contracted-for standard prices, as well as compensation for any additional capacity value conferred by the

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[63] *See* Docket No. UM 1894, Order No. 18-284 at 8.

additional storage component, and keep their executed contract if the facility's capacity is still within the applicable threshold. We have added a proposed OAR 860-029-0120(15)(e) to facilitate discussion of how this important policy could be implemented.

Existing Oregon policy does not directly address changes allowed during the development phase between PPA execution and commercial operation, but it would be reasonable to clarify those policies too. The need to make such changes occurs frequently in a normal development process. Consider, for instance, a QF that planned to use one type of solar panel and later found that it could obtain different solar panels that are more efficient. In fact, solar technology is developing so rapidly that solar panels that exist today will not exist in one, two, or three years, and project size and other characteristics may need to occur. These changes may or may not change the facility's nameplate capacity, but, even if they did, the QF should be allowed to make these changes. The currently proposed OAR 860-029-0120(15)(a) is phrased in a negative tense that does not clearly state that the developer may make reasonable changes to the proposed facility's design and components during the development period, and that point should therefore be clarified in the rules.

Collectively, these proposals will encourage renewable energy developers and facility owners to take advantage of rapidly changing technologies to deliver more and higher quality renewable energy to Oregon utilities and therefore are consistent with Oregon law and policy.

This docket should also discuss this issue in the context of non-standard contracts. The utility should not be permitted to terminate the contract if there are modifications. The QF Trade Associations believe that some flexibility can be built into these contracts in order to provide clarity and certainty to both parties regarding how much the size can change and what price will be paid. The QF Trade Associations are open to discussing these issues further.

G. Carryover Issues from Group 1 Rules

1. Project Development Security and Default Security

The Commission appears to be leaning towards adopting a liquid security requirement where the project developer/owner must post a security in the form of cash or letter of credit shortly after PPA execution. Thus far, Commissioner direction at the public meeting, as reflected in AHD's revised draft of the rules, appears to be that liquid security (i.e., cash or a letter of credit, including a parent guarantee) would be required of all non-creditworthy QFs prior to scheduled commercial operation date in the form of the "Project Development Security", but that after commercial operation the related "Default Security" could be met by non-creditworthy QFs through the liquid security, parent guarantee, *or* step-in rights. As previously stated, the QF Trade Associations oppose any new liquid security requirement before or after commercial operation for small QFs. However, to the extent liquid security will be required for any purpose, the QF Trade Associations agree that such liquid security is totally unnecessary after the project has achieved operation and has assets and incentive to continue operating. Thus, the QF Trade Associations support the amendment to the most recent version of the rule circulated by AHD that clarifies step-in rights must still be offered to all QFs after commercial operation as one of the options, to the extent that the QF does not meet the applicable creditworthiness requirements.

However, in response the Commissioners' discussion and the direction the Commission appears to be headed, the QF Trade Associations recommend at least three refinements to the current proposal if the Commission requires security: 1) The rules should provide objective criteria to ensure that creditworthy QFs, such as irrigation districts, can avoid the liquid security requirements; 2) the rules should provide 180 days after execution of the power purchase agreement for QF developers to provide the utility with the Project Development Security; and 3) existing QFs should be exempt from Project Development Security and should be able to meet creditworthiness requirements for Default Security the same as new QFs or by demonstrating the existing QF has paid electric utility bills on time for a year. We address each issue below and in our edits to the attached mark-up of the draft rules.

i. The Rules Should Provide Objective Criteria to Define Creditworthiness for Both Project Development Security and Default Security

As previously explained, the QF Trade Associations strongly recommend that the Commission define creditworthiness in the rules and not just leave the determination to the purchasing utility. The Joint Utilities have suggested that the average irrigation district should be able to satisfy their creditworthiness criteria and thus be exempt from the requirement to post a liquid security upon contract execution, but there is no real assurance that will be the case in practice. If a QF owner or developer has the balance sheet to pay any damages it might owe under the power purchase agreement, then it is punitive and unnecessary to require a liquid security to be posted. Such QF is not "judgment proof" and would have no incentive to withhold payment owing to the utility because doing so would subject it to the added cost of defending itself against a lawsuit to collect such amounts owing. Thus, the QF Trade Associations propose that the creditworthiness requirement may be met in a number of different ways, including the a reasonable purchasing utility credit evaluation, audited financial statements or internal financial statements prepared for the QF's tax return that demonstrate a net position equal to at least one year of projected revenue under the power purchase agreement, or a suitable Dun and Bradstreet rating.[64] Those criteria would apply consistently for evaluation of whether it is necessary to meet the Project Development Security or the Default Security requirements in the rules. The QF Trade Associations have made preliminary edits on this point to the draft rules to further discussion of this subject.

ii. The Rules Should Provide 180 Days After PPA Execution to Post Project Development Security

Staff's Proposed Rules required a QF to post Project Development Security 30 days after the Effective Date of the PPA.[65] The ALJ revised the deadline to post Project Development Security to 60 days after the Effective Date of the PPA per Commission guidance, but the Commission appeared willing to consider additional comments on whether a longer period is reasonable.[66] The QF Trade Associations still recommend a longer time to post Project Development Security, specifically 180 days. A short deadline to post Project Development Security will essentially put several QF developer business models out of business and prevent those types of entities from developing small renewable energy projects in Oregon. Further, the

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64 The QF Trade Associations believe that use of a Dun and Bradstreet Rating as one option for small QFs would also be appropriate but are still investigating the appropriate ratings level. Dun and Bradstreet is generally available as a private rating that can be obtained more easily for small businesses than Moody's or S&P, and thus could form the basis for a reasonable and objective rating metric. In our mark-up to the rules, we have therefore left a blank space for the rating level required for the Dun and Bradstreet option.

65 Staff's Proposed Rules at OAR 860-0029-0120(16).

66 Memorandum on Group 2 Schedule and Revised Group 1 Redlines, Proposed Rules at OAR 860-029-0120(16) (June 24, 2022) [hereinafter ALJ's Proposed Rules].

QF Trade Associations recommend that existing QFs should not be required to post Project Development Security and it should only apply to new QF projects.

In previous comments the QF Trade Associations provided an overview of the various small QF business models in Oregon including: 1) entities that sell electricity to the utility for a secondary purpose; 2) small-scale developers that are Oregon based; 3) private companies or individuals that only develop a few projects; 4) developers or financiers that only invest in small-scale projects; 5) entities that do only one part or various parts of the development process for small-scale projects; and 6) large, national or international companies.[67]

A 60 day deadline to post Project Development Security would have the effect of putting small-scale developers that are Oregon based and private companies or individuals that only develop a few projects out of business. These types of small QF business models typically know the area, find sites for development, initiate and complete the interconnection process, complete land use requirements, obtain permits, complete initial due diligence, and navigate the contracting process before being able to obtain financing. These steps are usually necessary for these developers before obtaining financing. Notably, the amount of the Project Development Security under discussion—from $25/kW proposed by the QFs all the way up to $150/kW proposed by the utilities—could be *very substantial* and the Commission appears poised to let that important issue be litigated in individual contract approval dockets. It is not reasonable to assume that such small-scale developers could finance those large sums on their own without the

67 *See* Joint Final Comments of CREA, NIPPC, and the Coalition on Staff's Proposed Rules Group 1 at 5-12 (May 10, 2022).

backing of an outside financial entity, which would only provide such backing if there is some reasonable expectation that the project is likely to successfully secure a viable power purchase agreement with suitable rates that will provide a return when compared to the project's costs. That necessarily requires a certain amount of due diligence to occur before the Project Development Security may be posted by the typical small-scale development company.

Sixty days is not enough time to obtaining financing for security after PPA execution for a large number of these smaller companies, who will no longer be able to conduct business in Oregon. If the QF owner has a strong relationship with a potential financing entity that has previously financed projects and that entity has been engaged on the new project before PPA execution, then it may be possible to negotiate and finalize financing or execution of development contract to potentially facilitate posting a substantial Project Development Security within 60 days after power purchase agreement execution for the new project. However, aside from that narrow circumstance, many financial entities are not willing to begin their due diligence process prior to execution of the power purchase agreement, especially with small QF developers with whom they do not have a pre-existing relationship. The due diligence process includes examining any preexisting contracts related to the project, verifying the project's compliance with local, state, and federal laws related to land use, environmental regulations, PURPA, as well as analyzing the economics of the project, ensuring adequate site control, and more.

Typically, the small QF developer will approach a number of financing entities *only after* execution of the power purchase agreement. Then, after initial discussions and exchange of basic project information, the developer and financing entity will enter into a non-disclosure agreement to allow the financing entity to begin its review for due diligence on a project regarding which the financial entity will likely have had little to no prior information. These financing entities will generally refuse to begin their due diligence, especially on smaller projects, until they know what the project revenues will be, which requires an executed power purchase agreement. Only after this due diligence process is complete can the developer and the financer expend the resources necessary to enter into a financing or asset and purchase agreement.

While there are certainly variations on how this process can play out, the overall process of obtaining financing, or least progress to the point where the financing entity will supply a substantial Project Development Security, takes time, and 60 days is simply not sufficient for the small QF business model. In addition, even if in some circumstances it is sufficient, it will result in harm and lower revenues to the small QF developer.   If faced with an expedited 60-day period to negotiate financing, the small QF developer will have little leverage in negotiation with the financing entity, which will know that the developer has limited time and opportunity to finalize any agreements. These circumstances will ultimately *discourage* development of small qualifying facilities in Oregon and deter small-scale developers from pursuing such projects in the first place.

The QF Trade Associations believe 180 days is a more reasonable timeline to post Project Development Security. This provides more time for a developer to approach potential financiers, negotiate relevant agreements, and obtain the financial backing needed to post a substantial liquid security deposit after it has obtained an executed PPA from the utility.

Additionally, a QF should not be required to post Project Development Security when the Proposed Rules provide an opportunity to terminate the PPA within six months of PPA execution if an interconnection study includes a longer development period or a cost estimate that makes the project uneconomic.[68] Thus, six months is a more reasonable timeline to post Project Development Security, and the QF Trade Associations recommend the Commission adopt a six-month timeline instead of 60 days.

iii. Existing QFs Should Not Be Subject to Project Development Security

The Commission should not subject existing QFs to Project Development Security. There is no basis to apply Project Development Security to an operating facility that was developed long ago because there is no risk that the facility—which is already operating—will encounter some "development" failure. The simple fact that the project has been operating for years and is able to enter into a new contract should be sufficient to show that it is creditworthy and should not need to increase its costs by posting liquid form of security held by the utility. Otherwise, irrigation districts that have successfully operated under a legacy power purchase agreement for decades would need to post a liquid form of security (i.e., cash or a potentially expensive letter of credit) when the money needed to do so could be used to make improvements on their facilities, such as improved fish screens or other environmental upgrades, or to lower dues charged for irrigation service to their members.

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[68] Staff's Proposed Rules at OAR 860-029-0120(7)(a).

2. Common Developer Exception

Based on statements at the public meeting, the Commissioners have suggested that they may adopt rules specifying that the time for determining if two projects are impermissibly affiliated such that their capacity should be aggregated as one project for standard contract/rate eligibility is at the time of the power purchase agreement execution. The ALJs' revised rule now includes that amendment to the draft rules.[69] If adopted, this new language in the common developer exception would, in effect, eliminate the current understanding of the Partial Stipulation from UM 1129, that has been in effect since 2007, that a developer can develop two or more adjacent projects within five miles without having the projects aggregated together so long as they will be separately owned and operated at *the time of energization*. As we have explained extensively in prior comments, this understanding aligns with how FERC measures its own separation requirements under PURPA's size limits, which measure qualification and affiliation as of the time of energization. This common developer exception has been relied upon by Oregon developers, and the proposal to bar common development of nearby facilities is a major step backward in the promotion of small-scale renewable energy development in the state.

If the Commission seeks to clarify that the common developer exception will now measure affiliation as of the time of power purchase agreement execution, any such clarification

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69 Proposed New Rule #2(4)(d) ("Two or more qualifying facilities will not be held to be owned or controlled by the same person(s) or affiliate(s) solely because they are developed by a single entity *so long as they are not owned or operated by the same person(s) or affiliate(s) of the same person(s) at the time each QF seeks to enter into a PPA*" (new language emphasized)).

should expressly state that this is a rule that will be applied prospectively and is not intended to opine on any developer's conduct under the Partial Stipulation from UM 1129 in effect prior to finalization of such administrative rule. Otherwise, the Commission may be upsetting settled expectations and investments in the abstract without any party having even ever raised a complaint at the Commission regarding use of the common developer exception.

3. Reasonableness Requirement for Utility Responses

The QF Trade Associations have recommended the Commission either adopt an overall reasonableness standard to the Proposed Rules or insert a reasonableness requirement in specific sections of the rules.[70] One place the QF Trade Associations recommended to insert a reasonableness requirement was the utility response requirements in the contracting process.[71] At the Public Meeting on May 25, 2022, Commissioners expressed concerns about this specific recommendation and were not inclined to add a reasonableness requirement to the contracting timelines. The QF Trade Associations wanted to clarify that this recommendation was not supposed to apply to normal contracting interactions and whether under normal circumstances the utility provided a draft in 14 or 15 days, but only require responses in shorter times when the utility imposes unreasonable requirements or acts unreasonably.

The case of *Falls Creek Hydro LLP v. PGE* highlights the importance of adding a reasonableness requirement to the contracting process rules so that in specific situations the

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70 *See, e.g.*, Joint Final Comments of CREA, NIPPC, and the Coalition on Staff's Proposed Rules Group 1 at 12-26.

71 *See* Joint Final Comments of CREA, NIPPC, and the Coalition on Staff's Proposed Rules Group 1 at 17-19.

utility cannot act unreasonably. In that proceeding, Falls Creek, a QF, brought a complaint against PGE arguing PGE had refused to purchase the energy from Falls Creek by refusing to execute a PPA, and PGE delayed the negotiation process causing harm to Falls Creek because of the surprise avoided cost price reductions.[72] Falls Creek accurately provided all the relevant information for PGE to prepare the draft contract. PGE put "Lane" county instead of "Linn" county in a draft PPA and listed the nameplate capacity of the facility as 4.96 MW instead of 4.1 MW.[73] Falls Creek then requested that PGE make these two corrections and to use the information that was initially provided by Falls Creek. Falls Creek also requested that, because of PGE's error, PGE expedite the remaining contracting process so that it would obtain an executable PPA at the same time it would have otherwise obtained the executable PPA, but for PGE's mistake.[74] The timing issue associated with PGE's mistake was material because PGE made a surprise avoided cost filing that reduced the prices.[75] Thus, PGE was simultaneously seeking to reduce the prices Falls Creek was eligible to receive on an expedited basis while it was delaying Falls Creek's ability to obtain a contract because of PGE's own mistakes. The parties ultimately reached a settlement and agreed to dismiss the case,[76] which likely would not have been possible if it was clear that the utility could act unreasonably and then refuse to provide a contract in a shorter period of time than the standard response time.

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72 *Falls Creek Hydro LLP v. PGE*, Docket No. UM 1859, Complaint at 1-4 (Aug. 7, 2017).
73 Docket No. UM 1859, Complaint at ¶ 23.
74 Docket No. UM 1859, Complaint at ¶¶ 24-57.
75 Docket No. UM 1859, Complaint at ¶¶ 24-57.
76 Docket No. UM 1859, Parties' Joint Stipulated Motion to Dismiss Complaint (Mar. 12, 2019).

If PGE's QF negotiation tariff (Schedule 201) had contained a reasonableness requirement, then perhaps PGE would not have taken the full time to fix its own mistake and provide Falls Creek with an updated PPA. In this situation a utility should act reasonably and promptly provide a correct PPA when the mistakes are the utility's fault and non-substantive. However, without the reasonableness requirement, a utility could take the full time to respond to what should be a simple change and potentially harm the QF if there is a pending avoided cost change or a surprise avoided cost filing as was the case with Falls Creek. A reasonableness standard would allow the Commission to review these types of scenarios, and it would also discourage this type of behavior from the utility from the start.

4. Reasonableness Requirement in Contract

Including a reasonableness requirement in a power purchase agreement is normal. The QF Trade Associations have argued that the Commission should adopt a reasonableness standard related to power purchase agreement terms.[77] The Joint Utilities have argued against adding a general reasonableness requirement to power purchase agreements.[78] Contrary to the Joint Utilities' assertions, it is reasonable and normal to add a general reasonableness requirement to a power purchase agreement. For example, Tri-State Generation and Transmission Association,

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[77] *See, e.g.*, Joint Comments of CREA, NIPPC, and the Coalition on Staff's Proposed Rules Group 1 at 29-31 (Mar. 11, 2022).

[78] *See, e.g.*, Joint Utilities' Responsive Comments at 39 (Mar. 25, 2022) ("the QFs' proposal to inject a *reasonableness requirement into* every rule, and possibly *every contract provision, is not appropriate*") (emphasis added).

Inc.'s ("Tri-State") Form Renewable Power Purchase Agreement for its 2022 request for proposals includes a general reasonableness requirement applicable to all parties.[79] It states:

> *The Parties shall act reasonably and in accordance with the principles of good faith and fair dealing* in the performance of this PPA. Unless expressly provided otherwise in this PPA, (i) where this PPA requires the consent, approval, or similar action by a Party, such consent or approval *shall not be unreasonably withheld, conditioned or delayed*, and (ii) wherever this PPA gives a Party a right to determine, require, specify or take similar action with respect to a matter, *such determination, requirement, specification or similar action shall be reasonable*.[80]

Thus, the Commission should add a reasonableness requirement similar to TriState's in the standard contract language.

III. CONCLUSION

The QF Trade Associations appreciate the opportunity for further comments and look forward to continued participation in this rulemaking.

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79 Tri-State Form Renewable PPA, available at: https://tristate.coop/2022rfp. Tri-State is a not-for-profit cooperative supplier of 45 members, including 42 electric distribution cooperatives and public power districts in Colorado, Nebraska, New Mexico, and Wyoming.

80 Tri-State Form Renewable PPA at Article 1.1(D) (emphasis added), available at: https://tristate.coop/2022rfp.

Dated this 16th day of September 2022.

Respectfully submitted,

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Revisions Key – Proposed Rules as Revised by ALJs at Commencement of Group 2

PUC Edits to Group 2 Rules in Notice of Proposed Rulemaking = **Indigo***

QF Trade Assocs.' Edits to Rules at Commencement of Group 2 = **Green**

* Group 1 Rule Revisions in the Proposed Rules and ALJ Group 1 edits are not marked

DIVISION 29
REGULATIONS RELATED TO AGREEMENTS BETWEEN ELECTRIC UTILITIES AND ELECTRIC COGENERATION AND SMALL POWER PRODUCTION FACILITIES

860-029-0010
Definitions for Division 029 Rules

(1) "AC" means alternating current.

(2) "Avoided costs" means the electric utility's incremental costs of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, the electric utility would generate itself or purchase from another source, including any costs of interconnection of such resource to the system.

(3) "Back-up power" and "stand-by power" mean electric energy or capacity supplied by a public utility to replace energy ordinarily generated by a qualifying facility's own generation equipment during an unscheduled outage of the facility.

(4) "Capacity" means the average output in kilowatts (kW) committed by a qualifying facility to an electric utility during a specific period.

(5) "Capacity costs" mean the costs associated with supplying capacity; they are an allocated component of the fixed costs associated with providing the capability to deliver energy.

(6) "Certified qualifying facility" means a qualifying facility that is certified as such under 18 C.F.R. Part 292.

(7) "Cogeneration" means the sequential generation of electric energy and useful heat from the same primary energy source or fuel for industrial, commercial, heating, or cooling purposes.

(8) "Cogeneration facility" means a facility which produces electric energy and steam or other forms of useful energy (such as heat) by cogeneration that are used for industrial, commercial, heating, or cooling purposes.

(9) "Commercial operation date" means the date after start-up testing is complete on which the total Nameplate Capacity Rating of the Facility is fully operational and reliable, and the Facility is fully interconnected, fully integrated, and synchronized with the system, and the qualifying facility has satisfied the criteria required by the power purchase agreement to commence operation and begin operating.

Commented [MK*P1]: We believe this is a reasonable caveat and have included it.

(10) "Commission" means the Public Utility Commission of Oregon.

(11) “Contract price” means for the fixed price term, the applicable fixed price for On-Peak Hours and Off-peak Hours specified in the purchasing utility’s avoided cost price schedule, and during the subsequent non-fixed price term, the purchasing utility’s applicable Index Price in effect when the energy is generated.

(12) "Costs of interconnection" means the reasonable costs of connection, switching, dispatching, metering, transmission, distribution, equipment necessary for system protection, safety provisions, and administrative costs incurred by an electric utility directly related to installing and maintaining the physical facilities necessary to permit purchases from a qualifying facility.

(13) "Demand" means the average rate in kilowatts at which electric energy is delivered during a set period, to be determined by mutual agreement between the electric utility and the customer.

(14) “Development period” means the time period commencing on the power purchase agreement Effective Date and ending at 24:00 in the prevailing time zone in which the qualifying facility is located on the day before the scheduled commercial operation date or such earlier date on which the qualifying facility achieves the commercial operation date in compliance with these rules.

(15) "Effective Date" means the date on which a power purchase agreement is executed by both the qualifying facility and the public utility.

(16) "Electric utility" means a nonregulated utility or a public utility as defined in ORS 758.505.

(17) "Energy" means electric energy, measured in kilowatt hours (kWh).

(18) "Energy costs" means:

(a) For nonfirm energy, the incremental costs associated with the production or purchase of electric energy by the electric utility, which include the cost of fuel and variable operation and maintenance expenses, or the cost of purchased energy;

(b) For firm energy, the combined allocated fixed costs and associated variable costs applicable to a displaced generating unit or to a purchase.

(19) “Existing QF” means a QF that is or has been operational before the effective date of a power purchase agreement.

(20) “Facility” means all equipment, devices, associated appurtenances, owned, controlled, operated and managed by a qualifying facility in connection with, or to facilitate, the production, storage, generation, transmission, delivery, or furnishing of electric energy by the qualifying facility to the purchasing public utility and required to interconnect with the System.

(21) “FERC” means the Federal Energy Regulatory Commission.

(22) "Firm energy" means a specified quantity of energy committed by a qualifying facility to an electric utility.

(23) "Fixed price term" means for qualifying facilities electing to sell firm energy or firm capacity or both, the period of a power purchase agreement during which the public utility is contracted to pay the qualifying facility avoided cost rates determined either at the time of contracting or at the time of delivery.

(24) “Force Majeure” is defined at OAR 860-029-XXXX [New Rule #].

(25) “Generator Interconnection Agreement” means the generator interconnection agreement between the qualifying facility and qualifying facility’s interconnection provider.

(26) “Forced Outage” means: (i) an outage that requires immediate removal of a unit from service, another outage state or a reserve shutdown state; (ii) an outage that does not require immediate removal of a unit from the in-service state but requires removal within six (6) hours; or (iii) an outage that can be postponed beyond six hours but requires that a unit be removed from the in-service state before the end of the next weekend. ~~NERC Event Types U1, U2 and U3, and specifically excludes any Maintenance Outage or Planned Outage~~.

Commented [QFs2]: Adapted from reference NERC outage types

(27) "Index rate" means the lowest avoided cost approved by the Commission for a generating utility for the purchase of energy or energy and capacity of similar characteristics including on-line date, duration of obligation, and quality and degree of reliability.

(28) "Interruptible power" means electric energy or capacity supplied by a public utility to a qualifying facility subject to interruption by the electric utility under certain specified conditions.

(29) "Maintenance power" means electric energy or capacity supplied by a public utility during scheduled outages of a qualifying facility.

(30) “Maintenance Outage” means an outage that can be deferred beyond the next weekend, but requires that the unit be removed from service before the next Planned Outage. A Maintenance Outage can occur any time during the year, has a flexible start date, may or may not have a predetermined duration and is usually shorter than a Planned Outage. ~~NERC Event~~

Commented [QFs3]: Adapted from reference NERC outage types

~~Type MO and includes any outage involving ten percent (10%) of the Facility's Net Output that is not a Forced Outage or a Planned Outage~~.

(31) "MW" means megawatt.

(32) "MWh" means megawatt-hour.

(33) "Nameplate Capacity Rating" means the maximum installed instantaneous power production capacity of the completed Facility, expressed in MW (AC), and measured at the point of interconnection, when operated in compliance with the Generation Interconnection Agreement and consistent with the recommended power factor and operating parameters provided by the manufacturer of the generator, inverters, energy storage devices, or other equipment within the Facility affecting the Facility's capability to deliver useful electric energy to the grid at the point of interconnection.

(34) "NERC" means the North American Electric Reliability Corporation.

Commented [QFs4]: Definition of "NERC" could be deleted if the Planned Outage, Maintenance Outage, and Forced Outage definitions are revised to remove reference to NERC.

(35) "Net Output" means all energy and capacity produced by the qualifying facility, less station use and losses, and other adjustments flowing through the Point of Interconnection.

(36) "Network Upgrades" means an addition, modification, or upgrade to the transmission system of a purchasing utility required at or beyond the Point of Delivery to accommodate the transmission provider's receipt of energy from a generation facility to the transmission provider's system.

(37) "New qualifying facility" means a qualifying facility that is not an existing qualifying facility.

(38) "Nonfirm energy" means energy to be delivered by a qualifying facility to an electric utility on an "as available" basis; or energy delivered by a qualifying facility in excess of its firm energy commitment. The rate for nonfirm energy may contain an element representing the value of aggregate capacity of nonfirm sources.

(39) "Non-fixed price term" means the portion of the purchase period of a power purchase agreement that begins after the fixed-price term has ended, during which the qualifying facility receives pricing equal to the purchasing public utility's index rate for comparable deliveries of energy. The length of the non-fixed price term is selected by the qualifying facility and specified in the power purchase agreement.

(40) "Nonregulated utility" means an entity providing retail electric utility service to Oregon customers that is a people's utility district organized under ORS Chapter 261, a municipal utility operating under ORS Chapter 225, or an electric cooperative organized under ORS Chapter 62.

(41) "Off-peak hours" means all hours other than On-peak hours.

(42) “On-peak hours” means the hours designated as such in the purchasing public utility’s avoided cost price schedule.

(43) “Permits” mean the permits, licenses, approvals, certificates, entitlements and other authorizations issued by governmental authorities required for the construction, ownership or operation of the Facility or occupancy of the site on which it is located.

(44) “Planned Outage” means ~~NERC Event Type PO and specifically excludes any Maintenance Outage or Forced Outage~~an outage that is scheduled well in advance and is of a predetermined duration. A “Planned Outage” is also known as a “Scheduled Outage”.

Commented [QFs5]: Adapted from reference NERC outage types

(45) “Point of Delivery” means for agreements with off-system qualifying facilities, the point on the purchasing public utility’s distribution or transmission system where the qualifying facility and purchasing public utility have agreed the qualifying facility will deliver energy to the purchasing public utility. For on-system qualifying facilities, the Point of Delivery is the Point of Interconnection.

(46) “Point of Interconnection” means the point where the qualifying facility is electrically connected to ~~a public~~an electric utility’s transmission or distribution system.

Commented [QFs6]: This definition of “Point of Interconnection” needs to be the point where the QF is interconnected to the grid, whether to the purchasing public utility or to nonregulated utility in order for other provisions of the rules to work, including “Net Output” definition and the settlement/imbalance provisions on scheduling requirements.

(47) "Primary energy source" means the fuel or fuels used for the generation of electric energy. The term does not include minimum amounts of fuel required for ignition, start-up, testing, flame stabilization, and control uses; the term does not include minimum amounts of fuel required to alleviate or prevent unanticipated equipment outages and emergencies which directly affect the public health, safety, or welfare.4(24) "Purchase" means the purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

(48) "Public utility" means a utility regulated by the Commission under ORS Chapter 757, that provides electric power to customers.

(49) "Purchase period" means the period of a power purchase agreement during which the qualifying facility is required to sell power to the public utility and the public utility is required to purchase power offered for sale.

Commented [MK*P7]: The redundant term “purchase term” should now have been replaced in all instances with “purchase period.”

(51) "Qualifying facility" means a cogeneration facility or a small power production facility as defined in 18 C.F.R. Part 292. Unless otherwise specified, “qualifying facility” includes proposed qualifying facilities, (e.g., entities that intend to obtain certification as a qualifying facility but that have not yet done so).

(52) “Qualifying facility’s cost to cover” means the positive difference, if any, between (a) the contract price per MWh, and (b) the net proceeds per MWh actually realized by qualifying facility for the output not purchased by the public utility as required by a power purchase agreement.

Commented [QFs8]: This term – “QF’s cost to cover” – is not used elsewhere in the draft rules at this point. We recommend it be deleted. The QF damages in the case of a utility default could be well in excess of this amount due to lost REC sales and PTCs, at a minimum, so it is also not an accurate statement of the cost to cover.

(53) "Rate" means any price, charge, or classification made, demanded, observed, or received with respect to the sale or purchase of electric energy or capacity or any rule, regulation, or practice respecting any such price, charge, or classification.

(54) “Renewable energy certificate” has the meaning given that term in OAR 330-160-0015(8) (effective September 3, 2008).

(55) "Renewable Portfolio Standard" or “RPS” is the standard for large electric utilities in ORS 469A.052(1) or the standard for small electric utilities in ORS 469A.055 in effect as of October 23, 2018.

(56) “Renewable qualifying facility” means a qualifying facility that generates electricity that may be used for compliance with the RPS.

(57) "RPS attributes" means all attributes related to the net output generated by the qualifying facility that are required to provide the public utility with "qualifying electricity" as that term is defined in Oregon's Renewable Portfolio Standard Act, ORS 469A.010, in effect as of October 23, 2018. RPS attributes do not include environmental attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity.

(58) "Sale" means the sale of electric energy or capacity or both by a public utility to a qualifying facility.

(59) “Schedule” means the purchasing public utility’s schedule filed with the Commission setting forth terms and prices for standard power purchase agreements and prices.

(60) "Scheduled commercial operation date" means the date selected by the qualifying facility on which the qualifying facility intends to be fully operational and reliable and able to commence the sale of energy or energy and capacity to the public utility.

(61) "Small power production facility" means a facility ~~which~~ that produces electric energy using as a primary energy source biomass, waste, solar energy, wind power, water power, geothermal energy, or any combination thereof. Only small power production facilities which, with any other facilities located at the same site, have power production capacities of 80 megawatts or less, are covered by these rules.

(62) “Start-Up Testing” means the start-up testing required by the manufacturer or interconnection provider that establish that the Facility is reliably producing electric energy.

(63) "Supplementary power" means electric energy or capacity supplied by a public utility, regularly used by a qualifying facility in addition to that which the facility generates itself.

Commented [QFs9]: This term – ‘supplementary power’ – is not used elsewhere in the draft rules. We recommend deleting it.

(64) “System” means the electric transmission and distribution system owned or operated by the purchasing public utility, or where applicable, another electric utility.

Commented [QFs10]: “System” is also used in the context of another utility’s system in the rules in the case of off-system QFs.

(65) "System emergency" means a condition on a public utility's system which is likely to result in imminent, significant disruption of service to customers, in imminent danger of life or property, or both.

(66) "Test energy" means electric energy generated by the Facility during the Test Period.~~, and RECs and capacity rights associated with such electric energy.~~

(67) "Test period" means a period during which Start-Up Testing is conducted.

(68) "Time of delivery" means:

(a) In the case of capacity, when the generation is first on-line and capable of meeting the capacity commitment of the qualifying facility to the electric utility under the terms of its contract or other legally enforceable obligation.

(b) In the case of firm energy and depending upon the contract between the parties, either:

(A) When the first kilowatt-hour of energy is able to be delivered under the commitment of the qualifying facility; or

(B) When each kilowatt-hour is delivered under the commitment of the qualifying facility.

(69) "Time the obligation to purchase the energy capacity or energy and capacity is incurred" means the earlier of:

(a) The date on which a binding, written obligation is entered into between a qualifying facility and a public utility to deliver energy, capacity, or energy and capacity; or

(b) The date determined by the Commission.

(70) "Total output" means all energy produced by the Facility.

OAR 860-029-0005 – Applicability of Rules

(1) These rules apply to all interconnection, purchase, and sale arrangements between a public utility and facilities that are qualifying facilities as defined herein. Provisions of these rules do not supersede contracts existing before the effective date of this rule. At the expiration of such an existing contract between a public utility and a cogenerator or small power producer, any contract extension or new contract must be offered on terms and conditions that comply with these rules.

(2) Nothing in these rules limits the authority of a public utility or a qualifying facility to agree to a rate, terms, or conditions relating to any purchase, which differ from the rate or terms or conditions that would otherwise be provided by these rules, provided such rate, terms, or conditions do not burden the public utility's customers.

Commented [MK*P11]: We deleted the last term "Total Term" as redundant.

Commented [MK*P12]: Joint Utilities flagged this as an item where changes are needed to ensure consistency with the new rules. We agree in principle but have not yet had a chance to undertake a comprehensive review.

(3) Upon request or its own motion, the Commission may waive any of the Division 29 rules for good cause shown. A request for waiver must be made in writing, unless otherwise allowed by the Commission.

860-029-0043
Standard Rates for Purchase

(1) Each public utility must offer standard non-renewable avoided cost rates to eligible qualifying facilities.

(2) Each public utility that acts to comply with Oregon's renewable portfolio standard must offer standard renewable avoided cost rates to eligible qualifying facilities.

(3) Each public utility must file standard avoided cost rates that differentiate between qualifying facilities of different resource types by taking into account the contributions to meeting the utility's peak capacity of the different resource types.

(4) Each public utility must update its standard avoided costs in accordance with OAR 860-029-0085.

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

Obligation for Costs to Accept Deliveries from Off-System Qualifying Facilities

(1) If the merchant function of the public utility has access to information that the proposed Point of Delivery in an off-system qualifying facility's request for a draft standard power purchase agreement may be unavailable due to transmission capacity constraints or competing uses of reserved transmission, the public utility will provide the qualifying facility with written notice of the possible constraint or reserved use and if applicable, the public utility's decision to decline the qualifying facility's proposed Point of Delivery. A public utility must act reasonably and without discrimination in declining the qualifying facility's proposed Point of Delivery. ~~Nothing in this subsection prevents~~ The qualifying facility may propose an alternate Point of Delivery at any time after the public utility denies its previously proposed Point of Delivery. To facilitate the qualifying facility's investigation of a suitable Point of Delivery, the public utility ~~from proposing~~shall: (a) provide all studies and information supporting its decision denying the qualifying facility's proposed Point of Delivery at the time public utility issues its denial, (b) provide a list of ~~an~~ all alternate Points of Delivery to which the public utility would agree to accept the qualifying facility's energy without constraint within fifteen (15) business days of a request of the qualifying facility for such list, and (c) provide ~~or requires the public utility to undertake~~ informational or other studies ~~or to change its standard study processes to seek information not~~ reasonably in its possession or which it has rights to obtain from the transmission provider regarding other alternate Point(s) of Delivery requested for study by the qualifying facility within five business days of receiving such information or studies from the applicable transmission provider. ~~during the contracting process.~~

(2) If the qualifying facility proposes an alternate Point of Delivery in response to a public

Commented [MN13]: Our current recommendation, also solidified by Commission guidance, is that this language remain in place unchanged for now, though we note that it may need to be addressed in future proceedings as the situation changes.

Commented [QFs14]: We maintain this rule should be deleted in its entirety, but offer the edits here in the case that it is not deleted.

utility's written notice under subsection (1), the public utility will have fifteen (15) business days to complete its review of ~~proposed~~ alternate Point(s) of Delivery upon the request of the qualifying facility in subsection (1)(b) and/or (c) and provide the notification described in subsection (1).

(3) Provided that the public utility and the qualifying facility have agreed upon a Point of delivery, the standard power purchase agreement for an off-system qualifying facility may, at the public utility's discretion, include a provision specifying that costs to construct transmission-service related Network Upgrades of the purchasing public utility's system necessary for transmission service for a qualifying facility's output may be allocated to the qualifying facility by Commission order after the process described in subsections (4), (5), and (6) of this rule.

(4) If the public utility chooses to include a transmission-service cost-allocation provision in the standard power purchase agreement for an off-system qualifying facility, the public utility must:

(a) Specify in the power purchase agreement that the development period in the standard power purchase agreement does not commence until after the processes in subsection (4), (5), and if applicable, subsection (6), are complete, and the scheduled commercial operation date, fixed price term, and purchase term in the power purchase agreement shall each be extended on a day-for-day basis until such processes are complete.

(b) No later than fifteen (15) business Days after the Effective Date of the standard power purchase agreement, 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.

(c) Request an effective date for commencement of network transmission service for the qualifying facility that is (i) 180 days prior to the scheduled commercial operation date, or (ii) as soon as practicable after the Effective Date of the executed standard power purchase agreement if the scheduled commercial operation date is less than 180 days following the Effective Date.

(d) No later than five (5) business days after the public utility's receipt of a response to the application submitted under subsection (b), inform the qualifying facility of the transmission provider's response.

(e) No later than fifteen (15) business days after the public utility's receipt of a response to the application submitted under subsection (b), notify the qualifying facility in writing whether it is submitting a request for a Network Upgrade cost allocation determination to the Commission and if applicable, file the request for cost allocation determination with the Commission.

(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 Network Upgrades. Unless waived by the qualifying facility, the Commission procedure will follow contested case procedures, including discovery and an opportunity for an evidentiary hearing. After providing notice and opportunity to comment regarding a request filed under subsection (5), the Commission will issue an order regarding the appropriate allocation of costs of transmission service Network Upgrades

(6) After receipt of notice under subsection (4)(e) of this section that the public utility is seeking a cost allocation determination, but no later than fourteen (14) days after any Commission order allocating costs of transmission service-related Network Upgrades to the qualifying facility, the qualifying facility may terminate the power purchase agreement upon written notice to the public utility. The qualifying facility's timely termination of the standard power purchase agreement under this subsection will not be an event of default, and no damages or other liabilities under the power purchase agreement will be owed by or to either party.

(7) Notwithstanding the other subsections in this rule, nothing prevents the purchasing public utility and qualifying facility from agreeing to amend the standard power purchase agreement to address transmission-related Network Upgrade costs or to substitute a new Point of Delivery. A qualifying facility may request that a public utility agree to an alternate Point of Delivery after execution of the power purchase agreement, and the public utility shall not unreasonably withhold such consent if it concludes that no transmission constraints preclude its ability to accept energy at the alternate Point of Delivery.

860-029-XXXX [New Rule #2]

Eligibility for Standard Avoided Cost Prices and Purchase Agreements

(1) Solar qualifying facilities with a nameplate capacity rating of three (3) MW and less, and all other qualifying facilities with a nameplate capacity rating of ten (10) MW and less, are eligible for standard avoided cost prices.

Commented [MK*P15]: Commission has given guidance that it does not want to reopen this item.

(2) All qualifying facilities with a nameplate capacity rating of ten (10) MW and less are eligible to enter into a standard power purchase agreement.

(3) Renewable qualifying facilities that satisfy the criteria of subsection (1) are eligible to select the purchasing public utility's standard renewable avoided cost prices. A renewable qualifying facility choosing the standard renewable avoided cost prices must cede all RECs generated by the Facility to the purchasing public utility while the qualifying facility is receiving deficiency-period pricing from the purchasing public utility and during any other period of the power purchase agreement ordered by the Commission.

(4) The determination of nameplate capacity rating for purposes of determining whether a qualifying facility meets the size criteria in subsections (1) and (2) is based on the cumulative nameplate capacity rating of the qualifying facility seeking the standard avoided cost prices or power purchase agreement and that of any other Facilities owned by the same person(s) or affiliates(s) located on the same site.

(a) Two qualifying facilities are located on the same site if the generating facilities or equipment providing fuel or motive force associated with the qualifying facilities are located within a five-mile radius and the qualifying facilities use the same source of energy or motive force to generate electricity.

(b) For purposes of this section:

(A) Person(s) are natural persons or any legal entities.

(B) Affiliate(s) are persons sharing common ownership or management, persons acting jointly or in concert with, or exercising influence over, the policies of another person or persons, or wholly owned subsidiaries.

(C) To the extent a person or affiliate is a closely held entity, a "look through" rule applies so that project equity held by LLCs, trusts, estates, corporations, partnerships, and other similar entities is considered to be held by the owners of the look through entity.

(c) Notwithstanding subsections (4)(a) and (b), the qualifying facility seeking standard prices or a standard power purchase agreement, and other Facilities within the same five-mile radius, will not be considered owned or controlled by the same person(s) or affiliate(s) if the person(s) or affiliate(s) in common are passive investors whose ownership interest is primarily for obtaining value related to production tax credits, green tag values, or MACRS depreciation, and the qualifying facility and other Facilities at issue are "family-owned" or "community-based" project(s).

(A) **Family-owned.** A project will be considered "family owned" if, after excluding the ownership interest of those who qualify as passive investor(s) under (4)(c), five or fewer individuals hold at least 50 percent of the project entity, or fifteen or fewer individual entities hold at least 90 percent of the project entity. For purposes of counting the number of individuals holding the remaining share (i.e., determining whether there are five or fewer individuals or 15 or fewer individuals) an individual is a natural person. Notwithstanding the foregoing, an individual, his or her spouse, and his or her dependent children, will be aggregated and counted as a single individual even if the spouse and/or dependent children also hold equity in the project.

(B) **Community Based.** A community-based (or community-sponsored) project must include participation by an established organization that is located either in the county in which the qualifying facility is located or within 50 miles of the qualifying facility and that either:

(i) has a genuine role in developing, or helping to develop, the qualifying facility and intends to have a significant continuing role with, or interest in, the qualifying facility after it is completed and placed in service, or

(ii) is a unit of local government that will not have an equity ownership interest in or exercise any control over the management of the qualifying facility and whose only interest is a share of the cash flow from the qualifying facility, that may not exceed 20 percent without prior approval of the Commission for good cause.

(d) Notwithstanding subsections (4)(a) and (b), two or more qualifying facilities that otherwise are not owned or operated by the same person(s) or affiliates(s) will not be determined to be a single qualifying facility based on the fact that they have in place a shared interest or agreement regarding interconnection facilities, interconnection-related system upgrades, or any other infrastructure not providing motive force or fuel. Two or more qualifying facilities will not be held to be owned or controlled by the same person(s) or affiliate(s) solely because they are developed by a single entity so long as they are not owned or operated by the same person(s) or affiliate(s) of the same person(s) at the time each QF seeks to enter into a PPA.

Commented [MK*P16]: Clarifying change.

Commented [MK*P17]: Clarifying change.

Commented [MK*P18]: Addition based on Commission guidance.

860-029-XXXX [New Rule #3]

Process for Procuring Standard Power Purchase Agreement

(1) Each public utility must file with the Commission a schedule outlining the process for acquiring a standard power purchase agreement that is consistent with the provisions of OAR 860 division 029 and Commission policy and that satisfies the requirements of this section.

(2) Upon request, each public utility must provide a draft standard power purchase agreement to an eligible qualifying facility after the qualifying facility has provided the public utility, in written form:

(a) An executed standard form of interconnection study agreement and evidence that all related interconnection study application fees have been paid, or evidence that no study is required;

(b) Documentary evidence that the qualifying facility has taken meaningful steps to seek site control of the proposed location of the qualifying facility including, but not limited to, documentation demonstrating:

(A) an ownership of, a leasehold interest in, or a right to develop, a site of sufficient size to construct and operate the qualifying facility;

(B) an option to purchase or acquire a leasehold interest in a site of sufficient size to construct and operate the qualifying facility; or

(C) another document that clearly demonstrates the commitment of the grantor to convey sufficient rights to the developer to occupy a site of sufficient size to construct and operate the qualifying facility, such as an executed agreement to negotiate an option to lease or purchase the site.

Note: The provision of a letter of intent or other non-binding documentation of site control, such as an indication of interest to lease, or a qualitative description of the state of site control development, in and of themselves or together, are not sufficient to satisfy this required site control evidence. A letter of intent or other documentation showing that the lease will be granted contingent upon receipt of a PPA by the developer will be sufficient.

Commented [MK*P19]: Our intention is for this to be a clarification in the order, not incorporated into the text of the rules.

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

(A) demonstration of ability to obtain certified qualifying facility status prior to commercial operation; for QFs larger than 1 MW, a Form 556 self-certification of the proposed qualifying facility or a FERC order granting an application for certification of the proposed qualifying facility is required.
(B) demonstration of eligibility for standard power purchase agreement and pricing under OAR 860-029- XXXX [New Rule # 2],
(C) design capacity (MW),
(D) estimate of station service requirements and net amount of power to be delivered to the purchasing public utility's electric system,
(E) generation technology and other related technology applicable to the site,
(F) non-binding estimate of 12 x 24 delivery schedule and 8760 generation profile when practicable,
(G) motive force or fuel plan,
(H) proposed scheduled commercial operation date,
(I) proposed contract term,
(J) proposed pricing provisions,
(K) Point of Delivery as well as Point of Interconnection or multiple Points of Interconnection under consideration,
(L) latitude and longitude of proposed facility and site layout,
(M) for a qualifying facility with battery storage system, description of the storage design capacity, description of technology used by battery storage system, storage system duration, and net power output, and
(N) other information specified in the utility's avoided cost rates schedule or standard power purchase agreement approved by the Commission.

Commented [MK*P20]: Edit to attempt to conform with Commission guidance.

Commented [MK*P21]: We seek comment on this clarification of this requirement.

Commented [MK*P22]: We are inclined to leave this in – but note that the other information to be asked for is still subject to Commission approval; it is not a blank check. For the same reason we have not added a "reasonableness" standard here – the Commission will consider that when reviewing the standard contract.

(3) Once a qualifying facility has asked for a draft standard power purchase agreement and provided the information required under subsection (2), the public utility has fifteen (15) business days to provide the qualifying facility a draft standard power purchase agreement

including current standard avoided cost prices and/or other optional pricing mechanisms as approved by the Commission.

(4) After receipt of a draft standard power purchase agreement, the qualifying facility may submit comments to the public utility regarding the draft agreement or request that the public utility prepare a final executable power purchase agreement.

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

Commented [MK*P23]: We are leaving this as is.

(6) The process outlined in subsections (4) and (5) will continue until both the qualifying facility and public utility agree to the terms of the draft standard power purchase agreement, i.e., neither the qualifying facility nor~~t~~ the purchasing public utility have outstanding issues, corrections, or comments regarding the draft power purchase agreement.

(7) After the parties concur on the terms of the draft standard power purchase agreement, the qualifying facility can submit a written request to the public utility for a final executable version of the purchase agreement. The public utility has ten (10) business days from the receipt of the written request to provide a final executable form of the purchase agreement to the qualifying facility.

(8) Upon receipt of the final executable form of the purchase agreement executed by the qualifying facility, the purchasing public utility has five (5) business days in which to sign the final executable agreement.

(9) A legally enforceable obligation will be considered established on the date on which the qualifying facility executes the final executable form of the power purchase agreement or such earlier date that the Commission may order.

Commented [QFs24]: Certainly, the execution of a final, negotiated PPA by the QF creates an LEO. However, the rule must also clarify, as do the commission's orders, that a LEO can be formed before that time if the utility delays in supplying the draft PPA. There may be other circumstances too. To avoid a problem of facial illegality in violation of the LEO rule, there should be the clarification here that the Commission may order an earlier LEO date. This is also consistent with the definitions in Section (69)(b).

860-029-0120
Standard Power Purchase Agreements

(1) Each public utility must offer standard power purchase agreements to eligible qualifying facilities. Each public utility must submit all forms of standard power purchase agreements to the Commission for approval.

(2) Qualifying facilities have the unilateral right to select a purchase period of up to 20 years for a standard power purchase agreement. Qualifying facilities electing to sell firm output at fixed prices have the unilateral right to a fixed-price term of up to 15 years in the standard power purchase agreement, subject to the reduction specified in subsection (6) for a

development period that exceeds three years, and may select a non-fixed price term of up to five years.

(4) The development period of a standard power purchase agreement begins on the Effective Date, unless the start of the development period is delayed by the initiation of the Network Upgrade cost allocation process in OAR 860-029-XXXX [Rule #1]. The development period ends at 24:00 in the time zone in which the qualifying facility is located on the day before the scheduled commercial operation date specified in the standard power purchase agreement or such earlier date on which the qualifying facility achieves the commercial operation date in compliance with these rules.

(5) The purchase period of a standard power purchase agreement begins on the earlier of the commercial operation date or the scheduled commercial operation date. The scheduled commercial ~~on-line~~operation date may be delayed by an excused delay, Force Majeure~~, or~~ extended by agreement of the purchasing public utility and the qualifying facility or under subsection (7) of this section, or pursuant to section (6)(d). In these cases, the purchase period and fixed price term commence and the development period ends~~s~~ on the earlier of the commercial operation date or the delayed or extended scheduled commercial ~~on-line~~operation date. ~~In any event, the purchase period of a standard power purchase agreement will start on the scheduled commercial operation date even if the qualifying facility does not begin deliveries on the scheduled commercial operation date.~~

(6) A qualifying facility may specify a scheduled commercial operation date for a standard power purchase agreement subject to the following requirements:

(a) Anytime within three years from the date of agreement execution; or

(b) Anytime between three years and four years after the Effective Date of the standard power purchase agreement if:

(A) The qualifying facility has received an interconnection-related system impact study report, cluster study report, or facilities study report indicating interconnection will take longer than three years from the Effective Date of the standard power purchase agreement; or

(B) The qualifying facility demonstrates to the public utility it cannot reasonably be expected to achieve commercial operation within three years from the Effective Date and the utility consents to a scheduled commercial operation date more than three years from the Effective Date, which consent shall not be unreasonably withheld.

(c) In any standard power purchase agreement with a scheduled commercial operation date more than three years after the Effective Date, the fixed-price term will be reduced one day for every day of the ~~construction~~ development period after three-year anniversary of the Effective date, with the reduction taken from the end of the fixed-price term except as specified ~~in subsection (d) below~~otherwise in these rules.

Commented [QFs25]: The proposed language is necessary to make sense of the QF's right to achieve online status before the scheduled commercial operation date, i.e., the 15-year period should start the earlier of the commercial operation date or the scheduled commercial operation date.

Commented [QFs26]: This last sentence in (5) contradicts the rest of the exceptions listed in (5) and is very confusing. We recommend it be deleted.

Commented [MK*P27]: This was previously a stand-alone note that we have incorporated into the rule text.

Commented [QFs28]: The term used in these rules "development period"

Commented [QFs29]: The "Excused Delay" in (7)(d) also tolls the 15-year period commencement.

Example: A standard power purchase agreement with a ~~construction~~ development period of three years and six months will have a fixed-price term of fourteen years and six months The fixed-price term will begin on the scheduled commercial operation date and will end after 14 years and 6 months.

(d) If the qualifying facility can provide an interconnection study showing that the time it will take the purchasing utility to process its interconnection queue necessitates a commercial operation date between three and four years from the Effective Date, the~~a~~n the additional time necessitated by the interconnection queue will not be taken off the period of the fixed-price term.

(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 except as specified otherwise in these rules.

(7) Modification of Scheduled Commercial Operation Date or Termination

(a) Anytime within six (6) months after the Effective Date of a standard power purchase agreement, the qualifying facility may terminate the standard power purchase agreement or modify the scheduled commercial operation date in the standard power purchase agreement if the qualifying facility receives an interconnection study report that is completed after the Effective Date that:

(A) includes an estimate of time to interconnect that is longer than the development period in the executed standard power purchase agreement; or

(B) includes an estimate of costs to interconnect that render the project uneconomic in the qualifying facility's opinion.

(b) A qualifying facility that chooses to modify the scheduled commercial operation date under subsection (7)(a) may not select a new scheduled commercial operation date more than four years from the date the standard power purchase agreement was executed except as specified otherwise in these rules.

(c) If a qualifying facility terminates the standard power purchase agreement under subsection (7)(a), it is liable for damages incurred by the public utility up until the date of termination, which may be taken from the Project Development Security posted by the qualifying facility.

(d) In the event the qualifying facility is delayed in reaching commercial operation because of an event of Force Majeure or the public utility's default under the standard power purchase agreement or any other agreement related to the interconnection of the qualifying facility to the purchasing utility's system, including interconnection study agreements and interconnection agreements, the scheduled commercial operation date in the standard power purchase agreement will be extended commensurately with the delay caused by the event of Force Majeure or the public utility's default, except for periods of

Commented [QFs30]: We continue to strongly submit that this Excused Delay concept should apply to any utility-caused delay and not be limited to "defaults" under various agreements, as previously explained.

delay that could have been prevented had the qualifying facility taken mitigating actions using commercially reasonable efforts. An extension of the scheduled commercial operation date under this subsection is not subject to the fixed-price term reduction in subsection (6)(c) or the four-year limitation in subsection (6)(~~d~~c) or (7)(b).

(8) Unless otherwise excused under the standard power purchase agreement, the utility is authorized to issue a Notice of Default if the qualifying facility does not meet the scheduled commercial operation date in the standard power purchase agreement. If a Notice of Default is issued for failure to meet the scheduled commercial operation date in the standard power purchase agreement, the qualifying facility has one year in which to cure the default for failure to meet the scheduled commercial operation date, during which the public utility may collect damages for failure to deliver.

(a) Unless excused under the standard power purchase agreement, damages for failure to meet the scheduled commercial operation date in a standard power purchase agreement are equal to the positive difference between the utility's replacement power costs less the prices in the standard power purchase agreement during the period of default, capped at the applicable prices in the power purchase agreement during such delay period, as determined on a daily basis with positive differences aggregated and invoiced as a monthly sum, plus costs reasonably incurred by the utility to purchase replacement power and additional transmission charges, if any, incurred by the utility to deliver replacement power to the point of delivery to the extent that such costs when aggregated with the costs for replacement energy do not exceed the applicable prices in the power purchase agreement during such delay period.

(b) If the qualifying facility would have been required by the standard power purchase agreement to transfer Renewable Energy Credits to the public utility during the period when the qualifying facility is in default under this subsection, damages owed to the public utility will include the public utility's cost to acquire replacement Renewable Energy Credits to the extent that such costs when aggregated with the costs for replacement energy in subsection (8)(a) do not exceed the applicable prices in the power purchase agreement during such delay period.~~.~~

(9) Subject to the one-year cure period in section (5) above, a utility may terminate a standard power purchase agreement for failure to meet the scheduled commercial operation date in the power purchase agreement, if such failure is not otherwise excused under the agreement.

Commented [MK*P31]: Conform when final.

(10) Point of Delivery. An off-system qualifying facility may propose the Point of Delivery for a standard power purchase agreement. The purchasing public utility must agree to the Point of Delivery before it is included in the standard power purchase agreement. The purchasing public utility may not unreasonably withhold agreement.

(11) The standard power purchase agreement must include a mechanical availability guarantee (MAG) for wind qualifying facilities as follows:

(a) A 90 percent overall guarantee, measured per turbine, starting three years after the commercial operation date for qualifying facilities with new contracts or one year after the commercial operation date for qualifying facilities that renew contract or enter into a superseding contract, subject to an allowance for 200 hours of planned maintenance per turbine per year that does not count toward the calculation of the overall guarantee. The 90 percent availability guarantee will be reduced on a pro rata basis for any portion of the annual period the qualifying facility was prevented from being available for reasons of Force Majeure, a default by the public utility under the power purchase agreement or interconnection agreement, or any interconnection and transmission curtailment initiated by the purchasing utility or the transmitting utility.

(b) A qualifying facility may be subject to damages for failure to meet the MAG calculated by:

(A) Determining the amount of the "shortfall" for the year, which is the difference between the projected average on- and off-peak net output from the project that would have been delivered had the project been available at the guaranteed availability for the contract year and the actual net output provided by the qualifying facility for the contract year;

(B) Multiplying the shortfall by the positive difference, if any, obtained by subtracting the Contract Price from the price at which the utility purchased replacement power and additional transmission costs to deliver replacement power to the point of delivery, capped at the applicable prices in the power purchase agreement during such period~~, if any~~; and

(C) Adding any reasonable costs incurred by the utility, if any, to purchase replacement power and additional transmission costs to deliver replacement power to the point of delivery to the extent that such costs when aggregated with the costs for replacement energy in subsection (11)(b)(B) do not exceed the applicable prices in the power purchase agreement during such delay period~~, if any~~.

(12) A public utility may issue a Notice of Default, and subsequently terminate a standard power purchase agreement pursuant to its terms and limitations, for failure to meet the MAG if the qualifying facility does not meet the MAG for two consecutive years and~~if~~ such failure is not otherwise excused by the power purchase agreement.

(13) The standard purchase agreement that includes the sale of the qualifying facility's capacity will include an annual minimum delivery guarantee (MDG) for solar, geothermal, biomass, and baseload hydro qualifying facilities equal to 7~~9~~0 percent of the qualifying facility's expected energy for the year.

(a) The qualifying facility's expected energy for the year will be based on the qualifying facility's reasonable estimate of its annual average energy production supplied prior to execution of the power purchase agreement. The power purchase agreement shall allow the qualifying facility to reasonably update its annual expected energy for future contract years with advance notice to the public utility prior to the first contract year during which the updated expected energy amount will apply.

Commented [QFs32]: This mirrors the exceptions listed in (13) for the MDG, and these standard exceptions should be included in the rule.

Commented [QFs33]: There is no reason this formula should be materially different from the MAG damages in (11). As written, and read literally in the proposed rule, (13) has a duplicative damages assessment to the QF instead of a replacement price that is the delta between replacement and contract prices.

Commented [QFs34]: Note that the QF Trade Assocs. Object to applying a MDG to solar, but if solar is to be included, the clarifications on the 70% minimum and the meaning of expected energy included here are necessary.

(b) A qualifying facility may be subject to damages for failure to meet the MDG calculated by:

(A) Determining the amount of the "shortfall" for the year, which is the difference between the projected average on- and off-peak net output from the project that would have been delivered had the project supplied the amount of net output required by its annual minimum delivery guarantee for the contract year and the actual net output provided by the qualifying facility for the contract year;
(B) Multiplying the shortfall by the positive difference, if any, obtained by subtracting the Contract Price from the price at which the utility purchased replacement power and additional transmission costs to deliver replacement power to the point of delivery, capped at the applicable prices in the power purchase agreement during such period; and
(C) Adding any reasonable costs incurred by the utility, if any, to purchase replacement power and additional transmission costs to deliver replacement power to the point of delivery to the extent that such costs when aggregated with the costs for replacement energy in subsection (13)(b)(B) do not exceed the applicable prices in the power purchase agreement during such delay period.

~~(a) The qualifying facility will owe damages for failure to meet the MDG equal to:~~

~~(A) the product of the deficiency for such period and the utility's cost to cover;~~

~~(B) the cost of any replacement energy procured by the utility as a result of the qualifying facility's failure to meet the MDG and any resulting incremental ancillary services and transmission costs; and~~

~~(C) the cost of replacement Renewable Energy Credits.~~

(b) The 70~~90~~ percent MDG will be reduced on a pro rata basis for any portion of the annual period the qualifying facility was prevented from generating or delivering electricity for reasons of Force Majeure, a default by the public utility under the power purchase agreement or interconnection agreement, or any interconnection and transmission curtailment initiated by the purchasing utility or the transmitting utility.

(14) A public utility may issue a Notice of Default, and subsequently terminate a standard power purchase agreement pursuant to its terms and limitations, for failure to meet the MDG if the qualifying facility does not meet the MDG for three consecutive years and~~if~~ such failure is not otherwise excused by the standard power purchase agreement.

(15) Incremental Utility Upgrades.

Commented [QFs35]: The QF Trade Associations have a number of concerns with this section (15), and may have further edits as these issues are discussed and policy decisions are made.

(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 utility an as-built supplement describing the facility within 90 days after the commercial operation date. Except as expressly permitted under subsection ~~14~~15(b), at the time of commercial operation, the facility may not:

(A) have a nameplate capacity rating that exceeds the nameplate capacity 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 14(c),~~ the facility may ~~not~~ be modified in a manner that materially deviates from the as-built supplement with~~out~~ 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 does not comply with the requirements of this subsection (15). ~~:~~

~~(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 above the threshold for standard rates in effect at the time it executed its ~~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 ~~14~~15(c) subject to the following requirements:

(A) The proposed upgrades shall be conditioned upon any necessary amendment to the generation interconnection agreement, agreements governing necessary network upgrades in order to maintain designated network status (if any), and the transmission agreement with the transmitting utility (if any).

~~(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~~confirming that the qualifying facility remains eligible for the contract pricing in its power purchase agreement for the expected incremental additional net output to be generated as a result of the upgrades, or explaining why the public utility disagrees that the qualifying facility is entitled to its existing rates if it performs the upgrade ~~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 purchasing utilities response required in subsection (C), the qualifying facility may request a draft amendment to the power purchase agreement to reflect ~~revised pricing for the remaining term of the power purchase agreement,~~the upgrades 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 14(a) (b) or (c), the qualifying facility is obligated to provide the purchasing utility an as-built supplement describing in detail the upgraded facility.~~

(~~e~~d) A qualifying facility that wishes to install upgrades that would cause the facility to increase its nameplate capacity rating above the threshold for standard rates in effect at the time it executed its power purchase agreement ~~must terminate its existing power purchase agreement and may choose to enter a new standard or new non-standard power purchase agreement based~~ may enter into an amendment to its power purchase agreement under which it is paid the Contract Prices in its initial power purchase agreement for all net output delivered up to the standard rate threshold, and a non-standard rate based on current avoided costs for the increment of net output in excess of that amount. ~~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. An upgrade pursuant to this subsection (d) is subject to the following requirements:

(A) The proposed upgrades shall be conditioned upon any necessary amendment to the generation interconnection agreement, agreements governing

Commented [MK*P36]: Clarifying edits.

necessary network upgrades in order to maintain designated network status (if any), and the transmission agreement with the transmitting utility (if any).

(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 additional net output to be generated as a result of the upgrades and which exceeds the threshold for standard rates.

(D) Within 30 days after receiving indicative pricing, the qualifying facility may 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.

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(e) Qualifying facilities may also upgrade their facilities by adding storage to the facility consistent with the provisions of subsection (a), (b), (c), and (d). If a qualifying facility offers to upgrade its facility by adding storage, the public utility shall offer to amend the power purchase agreement to compensate the qualifying facility for the increased energy and capacity value provided by the proposed storage upgrade. An upgrade pursuant to this subsection (e) is subject to the following requirements:

(A) The proposed upgrades shall be conditioned upon any necessary amendment to the generation interconnection agreement, agreements governing necessary network upgrades in order to maintain designated network status (if any), and the transmission agreement with the transmitting utility (if any).

(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 energy and capacity value 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 energy and capacity value as a result of the upgrades.

(D) Within 30 days after receiving indicative pricing, the qualifying facility may 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.

(f) Within 90 days after the date on which upgrades are installed under subsections 15(a), (b), (c), (d), or (e) the qualifying facility is obligated to provide the purchasing utility an as-built supplement describing in detail the upgraded facility.

(16) Project Development Security. A new qualifying facility that has executed a standard power purchase agreement that does not meet the ~~purchasing public utility's~~ creditworthiness requirements in this rule must post Project Development Security for the purchasing public utility's benefit within ~~60~~ 180 days of the Effective Date of the standard power purchase agreement. For purposes of this rule, a qualifying facility will be creditworthy if it meets any of the following conditions: (i) its audited financial statements or internal financial statements prepared for the QF's tax return reflect a net position equal to or greater than one year of projected revenue under the power purchase agreement, (ii) it supplies evidence of an overall Dun and Bradstreet credit score of at least __, or (iii) it otherwise meets the creditworthiness requirements used by the public utility, which requirements shall be commercially reasonable. The amount of required Default Security will be set forth in the public utility's form of standard power purchase agreement approved by the Commission. The obligation to maintain the Project Development Security will expire once the qualifying facility commences commercial operation. The qualifying facility may use either of the following options to post Project Development Security:

(a) Cash Escrow Security. The qualifying facility shall deposit in an escrow account established by the purchasing utility in a banking institution acceptable to both the qualifying facility and purchasing utility, Project Development Security. Such sum shall earn interest at the rate applicable to money market deposits at such banking institutions from time to time. To the extent the purchasing utility receives payment from the Project Development Security for damages in the event of default, the qualifying facility will, within 15 days, restore the Project Development Security as if no such deduction had occurred.

(b) Letter of Credit Security. The qualifying facility shall post and maintain in an amount equal to the Project Development Security: (a) a guaranty from a party that satisfies the purchasing public utility's creditworthiness requirements, in a form acceptable to the public utility in its reasonably-exercised discretion, or (b) a Letter of Credit in favor of the purchasing public utility. To the extent the public utility receives payment from the Project Development Security for damages in the event of default, the qualifying facility

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Commented [MK*P37]: We invite the participants to propose guidelines for determining the amount of Project Development Security that could be included in the PPAs.

Commented [QFs38]: There is no basis to apply development security to an operating facility that is already developed long ago.

Commented [MK*P39]: Based on Commission guidance.

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Commented [MK*P40]: Deleted reference to creditworthiness standard being in the PPA – once we are closer to a final standard we will need to figure out the best way for the Commission to adopt it.

We did not add a reasonableness standard here because the Commission will approve the amount in the PPA based on the standards it deems appropriate, which will include whether the amount is reasonable.

Commented [MK*P41]: Added "reasonableness" standard here.

will, within 15 days, restore the Project Development Security as if no such deduction had occurred.

(17) Default Security. A qualifying facility that has executed a standard power purchase agreement that does not meet the ~~public utility's~~ credit worthiness requirements in this rule must post Default Security upon commencing commercial operation. For purposes of this rule, a qualifying facility will be creditworthy if it meets any of the following conditions: (i) its audited financial statements or internal financial statements prepared for the QF's tax return reflect a net position equal to or greater than one year of projected revenue under the power purchase agreement, (ii) it supplies evidence of an overall Dun and Bradstreet credit score of at least __, or (iii) it otherwise meets the creditworthiness requirements used by the public utility, which requirements shall be commercially reasonable. The amount of required Default Security will be set forth in the public utility's form of standard power purchase agreement approved by the Commission. The qualifying facility may use one of the following options to post Default Security:

Commented [MK*P42]: Same comment as on "Project Development Security" above.

(a) Cash Escrow Security. The qualifying facility shall deposit the Default Security in an escrow account established by the purchasing utility in a banking institution acceptable to both the qualifying facility and purchasing utility. Such sum shall earn interest at the rate applicable to money market deposits at such banking institutions from time to time. To the extent the purchasing utility receives payment from the Default Security for damages in the event of default, the qualifying facility will, within 15 days, restore the Default Security as if no such deduction had occurred.

(b) Letter of Credit Security. The qualifying facility shall post and maintain in an amount equal to the Default Security: (a) a guaranty from a party that satisfies the Credit Requirements, in a form acceptable to the public utility in its reasonably-exercised discretion, or (b) a Letter of Credit in favor of the purchasing public utility. To the extent the public utility receives payment from the Default Security for damages in the event of default, the qualifying facility will, within 15 days, restore the Default Security as if no such deduction had occurred.

Commented [MK*P43]: Added reasonableness standard.

(c) Step-In Rights and Senior Liens. Default security can be satisfied through grant of step-in rights or a senior lien to the purchasing utility in a form acceptable to the purchasing public utility in its reasonable-exercised discretion.

(18) Insurance requirements. The standard power purchase agreement must specify that a qualifying facility with a Nameplate Capacity Rating greater than 200 kW must secure and maintain general liability insurance coverage that complies with the following:

Commented [MK*P44]: Based on Commission guidance, we are proposing to leave this as-is.

(a) The insurance provider must have a rating no lower than "A-" by A.M. Best Company.

(b) Insurance coverage will include:

(A) general commercial liability insurance covering bodily injury and property damage in the amount of $1,000,000 each occurrence combined single limit, or greater if desired by the qualifying facility; and

(B) Umbrella insurance in the amount of $5,000,000, or greater if desired by the qualifying facility.

(19) Except as explicitly provided in these rules, any qualifying facility that has entered into a standard power purchase agreement with a public utility under PURPA will not make any changes in its ownership, control or management that would cause the qualifying facility to fail to satisfy the eligibility requirements for entering into the standard power purchase agreement or receipt of standard pricing reflected in the agreement. No more than once every 24 months, at the request of the public utility, the qualifying facility will provide documentation and information reasonably requested by the public utility to establish the qualifying facility's continued compliance with eligibility requirements for the standard power purchase agreement executed by the qualifying facility and public utility. The public utility shall take reasonable steps to maintain the confidentiality of any such documentation and information the qualifying facility identifies as confidential, provided that the public utility may provide all such information to the Commission in a proceeding before the Commission.

Commented [MK*P45]: Deleting jurisdiction clause based on guidance from the Commission.

860-029-XXXX [New Rule #4]

Delivery and Purchase under Standard Power Purchase Agreement

(1) Commencing on the earlier of the commercial operation date or the scheduled commercial operation date of the standard power purchase agreement and continuing until the end of the total term (the "purchase period"), the qualifying facility will be obligated to deliver and sell, and the purchasing public utility will be obligated to receive and purchase, the Net Output delivered to the Point of Delivery or Point of Interconnection, subject to other relevant requirements in this division. 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.

(2) The public utility must accept ~~but is not obligated to pay for~~ excess energy, but may pay the qualifying facility the lesser of the index rate or the contract price for such excess energy. For purposes of this rule excess energy means:

(a) for on-system qualifying facilities, net output at the Point of Interconnection that exceeds the qualifying facility's Nameplate Capacity Rating;

(b) for off-system qualifying facilities, energy delivered to the Point of Delivery in excess of ~~scheduled amounts~~the qualifying facility's net output at the Point of Interconnection, netted over a monthly period.

(3) Title and risk of loss related to the energy shall transfer from the qualifying facility to the purchasing public utility at the Point of Delivery, except that title to RECs transferred under a

power purchase agreement shall transfer to the purchasing utility when generated.

(4) A qualifying facility may ~~not~~ commence commercial operation ~~any sooner than~~ ~~180 days~~ before the scheduled commercial operation date of the standard power purchase agreement ~~unless the public utility consents to early operation~~. A public utility may require a qualifying facility to wait to commence commercial operation until no sooner than ~~90~~ 180 days prior to the scheduled commercial operation if the public utility is unable to accept delivery from the qualifying facility prior to that time. If the qualifying facility intends to commence commercial operation prior to the scheduled commercial operation date, the qualifying facility shall provide the public utility notice of its intent to commence commercial operation sooner than the scheduled commercial operation date at least 60 days before it commences commercial operation.

(5) The public utility will pay the qualifying facility the index rate for Test Energy delivered prior to the scheduled commercial operation date, except in the case where the qualifying facility achieves commercial operation earlier than the scheduled commercial operation date in accordance with subsection (4), in which case the public utility shall pay the contract price applicable during the fixed price term commencing on the commercial operation date.~~.~~

860-029-XXXX [New Rule #5]

Force Majeure

(1) Every power purchase agreement shall include a Force Majeure provision that complies with the requirements of this section.

(2) "Force Majeure" means an event that prevents a party to the power purchase agreement (hereinafter referred to as "party") from performing an obligation under a power purchase agreement and that:

> (a) is not reasonably anticipated as of the effective date of the power purchase agreement,
>
> (b) is not within the reasonable control of the party affected by the event,
>
> (c) is not the result of such party's negligence or~~f~~ failure to act, and
>
> (d) could not be overcome by the affected party's use of due diligence in the circumstances.

(3) Force majeure includes events of the following types (but only to the extent that such an event, in consideration of the circumstances, satisfies the requirements in subsection (2)); environmental disasters, civil disturbance, sabotage, strikes, lock-outs, work stoppages, and action or restraint by court order or Governmental Authority.

(4) Notwithstanding subsections (2)-(3), none of the following constitute Force Majeure:

(a) the qualifying facility's ability to sell, or the public utility's ability to purchase energy or capacity at a more advantageous price than is provided under the power purchase agreement,

(b) the cost or availability of fuel or motive force to operate the Facility, unless due to a Force Majeure event,

(c) economic hardship, including lack of money or increased cost of electricity, steel, labor, or transportation,

(d) any breakdown or malfunction of the Facility's equipment (including any serial defect) that is not caused by an independent event of Force Majeure,

(e) The imposition upon either qualifying facility or purchasing public utility of costs or taxes,

(f) delay or failure of qualifying facility to obtain or perform any required facility document unless due to a Force Majeure event;

~~(g) any delay, alleged breach of contract, or failure by the transmission provider or interconnection provider unless due to a Force Majeure event as defined in any agreement with the transmission provider or interconnection provider,~~

~~(h) maintenance upgrade(s) or repair(s) of any facilities or right of way corridors constituting part of or involving the interconnection facilities, whether performed by or for the qualifying facility, or other third parties (except for repairs made necessary as a result of an event of Force Majeure;~~

~~(i) the qualifying facility's failure to obtain, or perform under the Generation Interconnection Agreements, or its other contracts and obligations to transmission owner, transmission provider or interconnection provider, unless due to a Force Majeure event; or~~

~~(j) any event attributable to the use of interconnection facilities for deliveries of Net Output to any party other than the purchasing public utility.~~

(5) If either qualifying facility or purchasing public utility is rendered wholly or in part unable to perform its obligation under the power purchase agreement because of a Force Majeure, the affected party shall be excused from whatever performance is affected by the Force Majeure to the extent and for the duration of the event of Force Majeure. after which such party will recommence performance of such obligation, provided that the non-performing party:

(a) provides the other party written notice describing the Force Majeure, no later than two weeks after its occurrence,

(b) ensures its failure to perform is of no greater scope and of no longer duration than what is required by the Force Majeure, and

(c) uses its best efforts to remedy its inability to perform.

(6) No obligation of either the qualifying facility or public utility that arose before the Force Majeure causing suspension of performance will be excused as a result of Force Majeure.

860-029-XXX/Default, Damages and Termination [New Rule #6]

(l) The following events may constitute a default under a standard power purchase agreement, unless otherwise excused under these rules, the applicable power purchase agreement, or applicable law:

(a) failure to begin power deliveries by scheduled commercial operation date,

(b) failure to provide Project Development or Default Security,

(c) failure to maintain status as a certified qualifying facility once power deliveries have commenced,

(d) failure of the qualifying facility to sell entire net output to the purchasing public utility, unless the qualifying facility has no obligation to sell its entire net output under its power purchase agreement,

(e) failure to make a payment when due under the power purchase agreement, if amount of payment is not the subject of good faith dispute,

(f) abandonment of the Facility,

(~~h~~g) the public utility's failure to receive or purchase all ~~or part of~~ Net Output made available by the qualifying facility,

(~~i~~h) failure to satisfy applicable Minimum Availability Guarantee for two (2) consecutive years, or

(~~j~~i) failure to satisfy applicable Minimum Delivery Guarantee for three (3) consecutive Years.~~, or~~

~~(k) failure to provide a timely notice of early termination under OAR 860-029-XXX [New Rule #1].~~

Commented [QFs46]: It is not clear why failure to exercise a right of termination would be an event of default. So we recommend deleting subsection (k).

(2) 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 subsection (1).

(3) Cure periods

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

(b) If a Notice of Default is issued under subsection (l)(b), (1)(c), (1)(d), (1)(e), (1)(f), ~~or~~ (l)(g), or any other failure to perform other than those under subsections (1)(a), (1)(h), or (1)(i), the non-defaulting party has thirty (30) days in which to cure the event of default. This thirty (30) day period shall be extended by an additional ninety (90) days if (i) the failure cannot reasonably be cured within the thirty (30) day period despite diligent efforts, (ii) the default is capable of being cured within the additional ninety (90) day period, and (iii) the defaulting Party commences the cure within the original thirty (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 (l)(h) or~~,~~ (l)(i)~~ or (j)~~.

(4) Imposition of damages.

(a) The ~~public utility~~non-defaulting party may ~~impose~~ issue an invoice presenting its calculation of damages after issuing a Notice of Default under subsection (l)(a) or (l)(d) as specified in OAR 860-029-0120(8~~7~~).

(b) If an invoice for damages ~~are imposed~~is sent, the defaulting party~~y~~ must be remit~~ted~~ payment to the non-breaching party no later than 30 days after the breaching party received an invoice for damages if the amount of payment due is not the subject of good faith dispute. The invoice for damages must include a written statement explaining in reasonable detail the calculation of the damages amount.

(5) Subject to the cure periods in subsection (3), the non-defaulting party may issue a Notice of Termination to terminate a standard power purchase agreement for a default under subsection (l). Non-material violations of the terms and conditions of the power purchase agreement, including but not limited to the following failures, shall not result in termination of the power purchase agreement:

(a) Failure to provide timely notice of Planned Outages;
(b) Failure to provide timely notice of Maintenance Outages;
(c) Failure to provide timely notice of Forced Outages;
(d) Failure to adhere to scheduling requirements;
(e) Failure to provide timely notice of material adverse event;
(f) Failure to grant purchasing utility access rights upon reasonable prior notice.

(6) The non-defaulting party must provide the defaulting party a Notice of Termination at least

Commented [QFs47]: This is a standard provision that is currently included in PacifiCorp's OR standard contract for small QFs. Idaho Power has a similar provision providing an additional 60 days in its OR standard contract.

Commented [QFs48]: This appears to be an incorrect cross reference.

30 days prior to date of Termination. The notice period for termination may run concurrently with the default period.

(7) Termination of Duty to Buy. If a standard power purchase agreement is terminated because of an Event of Default by the qualifying facility and the qualifying facility wishes to sell Net Output to the purchasing public utility following such termination, the public utility may require the qualifying facility do so subject to the terms of the terminated agreement, including but not limited to the contract price, until the until end of the purchase term in ~~termination date~~ the terminated agreement. The qualifying facility may not take any action or permit any action to occur the result of which avoids or seeks to avoid the restrictions in this subsection through use or establishment of a special purpose entity or other Affiliate.

(8) Termination Damages. If the standard power purchase agreement is terminated by the public utility as a result of an event of default by the qualifying facility, termination damages owed by the qualifying facility to the public utility will be the positive difference, if any, between (a) the public utility's estimated costs to secure replacement power and Renewable Energy Credits, if applicable, for a period of twenty four (24) months following the date of termination, including any associated transmission necessary to deliver such replacement power; and (b) the contract price for such twenty four (24) month period, but (c) only to the extent that such amount does not exceed the amount the public utility would have paid for energy and Renewable Energy Credits under the power purchase agreement during such 24 month period ("Termination Damages"). The public utility must calculate the Termination Damages on a monthly basis and in a commercially reasonable manner and provide to the qualifying facility a written statement explaining in reasonable detail the calculation of Termination Damages in the Notice of Termination. Termination damages are due by qualifying facility within thirty days of receipt of the written Notice of Termination from the public utility unless the amount owing is subject to a good faith dispute.

(9) Duty/Right to Mitigate. Both the public utility and qualifying facility have a duty to mitigate damages and will use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance under a standard power purchase agreement.

(10) Security. If a standard power purchase agreement is terminated because of the qualifying facility's default, the public utility may, in addition to pursuing any and all other remedies available at law or in equity, proceed against any security held by the public utility in whatever form to reduce the amounts that the qualifying facility owes the public utility arising from such default.

(11) Cumulative Remedies. Except in circumstances in which a remedy provided for in the power purchase agreement is described as a sole or exclusive remedy, the rights and remedies provided to the parties in the standard power purchase agreement are cumulative and not exclusive of any other rights or remedies of the parties.

860-029-XXXX [New Rule #7]

Coordination between qualifying facility and public utility under standard power purchase agreements.

(l) Coordination with System. The qualifying facility's delivery of electricity to purchasing public utility under a standard power purchase agreement must be at a voltage, phase, power factor, and frequency as reasonably specified by purchasing public utility. The qualifying facility will furnish, install, operate, and maintain in good order and repair, and without cost to the purchasing public utility, such switching equipment, relays, locks and seals, breakers, automatic synchronizers, and other control and protective apparatus determined by the public utility to be reasonably necessary for the safe and reliable operation of the Facility in parallel with the System, or the qualifying facility may contract with the purchasing public utility to do so at the qualifying facility's expense. The purchasing public utility must at all times have access to all switching equipment capable of isolating the Facility from the System.

(2) Planned Outages in standard power purchase agreements.

(a) The qualifying facility must provide the purchasing public utility with an annual forecast of Planned Outages for each year of the purchase period at least one month, but no more than three months, before the first day of that year, and may update such Planned Outage forecast as necessary to comply with Prudent Electrical Practices. Any such update to the Planned Outage forecast must be promptly submitted to the public utility. Although the Planned Outage schedule should include predetermined outage duration, the outage may be extended when the original scope of work requires more time than originally scheduled.

Commented [QFs49]: Qualifier consistent with NERC definitions referenced in Staff's proposed rule.

(b) The public utility may specify in the power purchase agreement two (2) calendar months in each year in which the qualifying facility may not schedule planned outages during times when motive force is available to generate and deliver net output from the facility ("High Demand Months") except to the extent reasonably required to enable a vendor to satisfy a guarantee requirement. Failure to identify the High Demand Months in the power purchase agreement shall constitute waiver of the public utility's right to require Planned Outages to occur in such months. The public utility may change either or both High Demand Months by providing notice to the qualifying facility ~~with~~ no less than twelve (12) months prior to the first contract year for which the utility intends to change the High Demand Month(s). ~~advance notice to the qualifying~~ Nothing in the power purchase agreement's provisions limiting Planned Maintenance during High Use Months may prohibit a qualifying facility from conducting Planned Maintenance during High Use Months at times when motive force is unavailable to generate and deliver energy, such as during nighttime for a solar qualifying facility.
~~facility.~~

(3) Maintenance Outages in standard power purchase agreements.

(a) If the qualifying facility reasonably determines that it is necessary to schedule a Maintenance Outage, the qualifying facility must notify the purchasing public utility of the proposed Maintenance Outage as soon as practicable but in any event at least five (5) days before the outage begins. The qualifying facility must take all reasonable measures consistent with Prudent Electrical Practices to not schedule any Maintenance Outage during the High Demand Months identified by the public utility in accordance with subsection (2)(b)..

(b) Notice of a proposed Maintenance Outage by the qualifying facility must include the expected start date and time of the outage, the amount of generation capacity of the Facility that will not be available, and the expected completion date and time of the outage. The purchasing utility will promptly respond to such notice and may request reasonable modifications in the schedule for the outage. The qualifying facility must use all reasonable efforts to comply with any request to modify the schedule for a Maintenance Outage provided that such change has no substantial impact on the qualifying facility.

(c) Once the Maintenance Outage has commenced, the qualifying facility must keep the public utility apprised of any changes in the generation capacity available from the Facility during the Maintenance Outage and any changes in the expected Maintenance Outage completion date and time. As soon as practicable, any notifications given orally must be confirmed in writing. Although the Notice of Proposed Maintenance Outage must include an expected completion date and time of the outage, the outage may be extended when the original scope of work requires more time than originally scheduled. The qualifying facility ~~may~~ must take all reasonable measures consistent with Prudent Electrical Practices to minimize the frequency and duration of Maintenance Outages.

(4) Forced Outages in standard power purchase agreements. The qualifying facility must promptly notify the purchasing public utility orally, via telephone to a number specified by the public utility (or other method approved by the public utility), of any Forced Outage resulting in more than ten percent (10%) of the Nameplate Capacity Rating of the Facility being unavailable. This report from qualifying facility must include the amount of the generation capacity of the Facility that will not be available because of the Forced Outage and the expected return date of such generation capacity. The qualifying facility must promptly update the report as necessary to advise the public utility of changed circumstances. As soon as practicable, any oral report of a Forced Outage must be confirmed in writing to the public utility.

(5) Notice of Emergency Deratings and Outages in standard power purchase agreements. Notwithstanding the requirements of subsections (4)-(6), the qualifying facility will inform the purchasing public utility, via telephone to a number specified by public utility (or other method approved by public utility), of any limitations, restrictions, deratings or outages reasonably predicted by qualifying facility to affect more than five percent (5%) of the Nameplate Capacity rating of the Facility for the following day and will promptly update such notice to the extent of any material changes in this information.

Commented [QFs50]: Qualifier consistent with NERC definitions referenced in Staff's proposed rule.

Commented [QFs51]: This appears to be the incorrect cross reference.