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	REPLY 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 Reply Comments on Group 2 Issues. The QF Trade Associations continue to support the recommendations made in our September 16, 2022 Group 2 Comments and the revisions to the proposed rules attached thereto.[1] We will not repeat those recommendations here. These Reply Comments address certain issues raised by PacifiCorp, Portland General Electric Company ("PGE"), and Idaho Power Company ("Idaho Power") (collectively the "Joint Utilities"), and requests for additional comments made by Administrative Law Judge ("ALJ") Mapes at the September 23, 2022 Workshop.[2] A lack of response in these Reply Comments to any specific

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1 *See generally* Comments of CREA, NIPPC, and the Coalition on Staff's Proposed Group 2 Rules (Sept. 16, 2022).

2 ALJ Scheduling Memorandum at 1 (July 25, 2022).

arguments made by the Joint Utilities is not intended to reflect agreement with the Joint Utilities' proposals on any such points.

II. GROUP 2 REPLY COMMENTS

A. Reply Comments on Proposed New Rule #1: Obligation for Costs to Accept Deliveries from Off-System QFs

The QF Trade Associations maintain their position set forth in their opening comments with respect to Proposed New Rule #1. Specifically, the Commission should remove Proposed New Rule #1 from the rules or, alternatively, the Commission should adopt the proposed revisions attached to our opening comments to limit the adverse impact of this proposal on small qualifying facilities ("QFs").[3] These reply comments solely address Administrative Law Judge Mapes's request to further elaborate on the overlap between Proposed New Rule #1 at issue here (AR 631) and the related investigation in Docket No. UM 2032. As we explained previously and as further elaborated below, it would be premature to address Proposed New Rule #1 before the closely related issues in UM 2032 are resolved.[4]

Both Proposed Rule #1 and the disputed issue in UM 2032 address how to properly allocate the costs of network upgrades on the purchasing utility's transmission system. In Docket No. UM 2032, the Commission is addressing the question of how to allocate network upgrade costs in the case where an "on-system" QF directly interconnects to, and sells its entire

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[3] Comments of CREA, NIPPC, and the Coalition on Staff's Proposed Group 2 Rules at 12-20 (Sept. 16, 2022).

[4] Comments of CREA, NIPPC, and the Coalition on Staff's Proposed Group 2 Rules at 14 (Sept. 16, 2022).

net output to, the purchasing utility. In that circumstance, the network upgrade costs could be allocated to the QF or the purchasing utility through the interconnection process administered by the Commission. Similarly, Staff's Proposed Rule #1 includes a new procedure to allocate network upgrade costs in the case where an "off-system" QF interconnects to another utility and transmits its energy to the purchasing utility, but the purchasing utility must construct network upgrades to accept and deliver the QF's energy to the purchasing utility's loads. In that circumstance, the QF has no interconnection agreement with the purchasing utility, and thus Staff proposes to include a provision in the power purchase agreement ("PPA") for the purpose of allocating network upgrade costs to the QF after execution of the PPA, with provisions for resolution of disputes by the Commission. However, in both cases (UM 2032 and AR 631), the heart of the dispute is how to allocate the costs of network upgrades.

The issue has been fully litigated and briefed in Phase 1 of UM 2032. Thus, the Commission will soon issue an order answering the following question: "Who should be required to pay for Network Upgrades necessary to interconnect the QF to the host utility?"[5] Further, there may be a Phase 2 of UM 2032, where the following issues would be addressed:

> If the answer to Issue No. 1 is that users and beneficiaries of Network Upgrades (which typically are primarily utility customers) should pay for the Network Upgrades necessary to interconnect the QF to the host utility, how should that policy be implemented? For example, should utility customers, and other beneficiaries and/or users, fund the cost of the Network Upgrades upfront, or should the QF provide the funding for the Network Upgrade subject to reimbursement from utility customers? Should the QF, utility

[5] *In re Staff Investigation into Treatment of Network Upgrade Costs for QFs*, Docket No. UM 2032, ALJ Ruling at 2 (May 22, 2020).

> customers, and other beneficiaries and users, if any, share the costs of Network Upgrades?[6]

Under the current Oregon Public Utility Commission ("OPUC" or the "Commission") policy, the interconnecting QF essentially always pays for all network upgrade costs without receiving any refund for such costs.[7] Staff's Proposed Rule #1 appears to presume that the same approach should apply for off-system QFs, and it attempts to create a procedure to assign such network upgrade costs to the QF through the PPA.

But the QF parties and Staff have advocated for new policies to be adopted in UM 2032. The QF parties to UM 2032 have argued the Commission should adopt a policy similar to the federal interconnection policy under which, with limited exceptions, an interconnection customer should initially fund network upgrade costs but should receive a full refund of such costs over time (five to 20 years) because network upgrades benefit all users of the system, not just the interconnecting QF.[8] Staff also argues that the Commission should revise its current policy to expand the circumstances under which the interconnecting QF does not pay for network

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6 Docket No. UM 2032, ALJ Ruling at 2 (May 22, 2020).

7 *In re Staff Investigation into Interconnection of PURPA QF Larger than 10 MW*, Docket No. UM 1401, Order No. 10-132 at 3 (Apr. 7, 2010) (stating the QF must pay for network upgrades unless it can demonstrate "systemwide benefits"); *see also In re Rulemaking to Adopt Rules Related to Small Generator Interconnection*, Docket No. AR 521, Order No. 09-196 at 5 (June 8, 2009) (adopting similar policy for small generation facilities up to 10 MW). The utilities have never found that there are system wide benefits, always allocated all network upgrade costs to QFs, and never provided refunds. *See also* Docket No. UM 2032, Interconnection Customer Coalition/100, Lowe/12-16 (Oct. 30, 2020).

8 *See* Docket No. UM 2032, Posthearing Brief of CREA, the Coalition, and NIPPC at 2, 12-21 (Aug. 5, 2022); Docket No. UM 2032, Posthearing Brief of NewSun Energy LLC at 12-19 (Aug. 5, 2022).

upgrades or receives a refund for such costs if it initially pays.[9] In contrast, the Joint Utilities argue that the QFs should essentially continue to pay for all network upgrade costs, with some very limited exceptions.[10]

The outcome of the issue in Phase 1 of UM 2032 for on-system QFs would unquestionably inform the debate over what the Commission's administrative rules should state on the closely related issue for off-system QFs. For example, if the Commission agrees with the QF parties who argue that QFs should be afforded a full refund for network upgrades they finance, then it may be unnecessary to allow for a disputed proceeding before the Commission every time an off-system QF's delivery triggers the need for network upgrades, as Staff's Proposed Rule #1 now provides. Additionally, with more clarity on precisely how and under which circumstances the Commission deems it reasonable to allocate such network upgrade costs to QFs or utilities, the rules could more completely address the issue for off-system QFs. In short, it is premature and unwise to lock in rules for off-system QFs based on existing Commission policy because that policy may soon change in UM 2032.

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9 *See* Docket No. UM 2032, Prehearing Brief of Staff at 3 (June 3, 2022) (arguing that the current policy "has not necessarily been put into practice" and needs to be revised to ensure that costs are allocated commensurate with benefits); *see also id.* at 10 (arguing that "a Network Upgrade cost allocation method that is based on a presumption that interconnection-related Network Upgrades will benefit only a single user [, i.e., the interconnection QF,] is likely not warranted").

10 *See* Docket No. UM 2032, Prehearing Brief of Joint Utilities at 3 (June 3, 2022) (arguing "The Commission's current QF interconnection policies appropriately presume that interconnecting generators will bear the costs necessitated by their interconnection, including the costs of Network Upgrades").

Additionally, the Joint Utilities' own arguments further confirm the need to wait to address this subject until after UM 2032. The Joint Utilities argue that New Rule #1 should apply not just to off-system QFs, but also to on-system QFs.[11] They argue that it is necessary to ensure through the PPA that on-system QFs pay for all network upgrades that might be overlooked or not captured in the interconnection process. But that argument presupposes the cost allocation policy adopted for on-system QFs through the interconnection process will remain unchanged. If the Commission were to adopt the Joint Utilities' proposal here but the QF parties or Staff's proposals in UM 2032, then the policies would contradict each other. Thus, the Joint Utilities' proposal further demonstrates why the Commission should, at a minimum, defer consideration of Proposed Rule #1 until UM 2032 is complete.

B. Reply Comments on Proposed OAR 860-029-0120(11)-(14): Minimum Availability Guarantee and Minimum Delivery Guarantee

The Minimum Availability Guarantee ("MAG") and Minimum Delivery Guarantee ("MDG") rules need to be reasonable for small QFs. Regarding the MAG, Staff's Proposed Rules currently include a 90 percent MAG for wind facilities that starts at year three for new facilities and year one for renewed facilities with an allowance of 200 hours of planned maintenance per turbine per year that does not count towards the MAG.[12] The Joint Utilities are recommending an 85 percent MAG for new facilities that starts on the first year and a 90 percent MAG thereafter and a 90 percent MAG for renewing facilities but no allowance for planned

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11 Initial Group 2 Comments of Joint Utilities at 5-7 (Sept. 16, 2022).

12 Staff Proposed Rules at OAR 860-029-120(11)(a).

maintenance. The QF Trade Associations do not support the Joint Utilities' recommendations as this issue was already litigated and decided by the Commission.

In Docket No. UM 1610, the issue of MAG for standard contracts was raised in response to a completely unreasonable MAG that PGE included in its initial standard contract after UM 1129. In UM 1610, after the issue was fully litigated with discovery and testimony, the Commission adopted PacifiCorp's proposal—largely supported by the QF parties—for a 90-percent MAG that started in contract year three for new facilities and contract year one for renewing facilities.[13] Also, the Commission adopted Staff and PGE's recommendation to allow for 200 hours of planned maintenance per turbine per year that would not count towards the calculation of whether the facility complied with the 90-percent threshold of the MAG.[14] The Commission reasoned that "this planned maintenance allowance is reasonable in context of the total range that was proposed by the parties, and in context of the other requirements of the MAG."[15] These issues have already been fully litigated and the Commission correctly decided the issue.

The Joint Utilities' arguments for a higher threshold than 90 percent or reduction of the 200-hour maintenance carve-out overlook that a MAG needs to be more lenient for a small wind QF with only a few turbines than a large wind QF with hundreds of turbines. For example, PáTu

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[13] *In re Investigation into Qualifying Facility Contracting and Pricing*, Docket No. UM 1610, Order No. 14-058 at 30 (Feb. 24, 2014).

[14] Docket No. UM 1610, Order No. 14-058 at 30.

[15] Docket No. UM 1610, Order No. 14-058 at 30.

wind facility is only six turbines[16] while PGE's Biglow Canyon wind facility has 217 wind turbines.[17] If Biglow Canyon loses one or two turbines because a blade disconnects from the nacelle, as was recently reported as having happened at Biglow and is presumably also a possibility for a smaller facility,[18] those one or two turbines could be down for a year or more and the Biglow facility's availability would still be well over 90 percent. However, if PáTu were to lose just one turbine for a few months, it would easily fall below the 90 percent threshold for the year. The harm to the utility in the loss of expected wind generation is the same as the small QF (the loss of one or two turbines), but only the small QF is exposed to the significant harm associated with contract termination. Thus, the Proposed Rules of a 90 percent MAG and allowance of 200 hours of planned maintenance exemption, with the QF Trade Associations recommendations,[19] properly reflect this reality for smaller QFs that was properly litigated in Docket No. UM 1610 with utility proposals the Commission adopted. There is no evidence here

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16 PáTu Wind Farm, Alameda Municipal Power, available at: https://www.alamedamp.com/DocumentCenter/View/298/Patu-Wind-Farm-Profile-PDF.

17 Biglow Canyon Wind Farm, Oregon Department of Energy, available at: https://www.oregon.gov/energy/facilities-safety/facilities/Pages/BCW.aspx.

18 *See, e.g.*, Ted Sickinger, *Upcoming investigation: How an airborne blade exposed broader problems at PGE's flagship wind farm*, The Oregonian: Oregon Live (Aug. 27, 2022), available at: https://www.oregonlive.com/business/2022/08/upcoming-investigation-how-an-airborne-blade-exposed-broader-problems-at-pges-flagship-wind-farm.html.

19 *See* Comments of CREA, NIPPC, and the Coalition on Staff's Proposed Group 2 Rules at 33 (Sept. 16, 2022) ("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.).").

to justify a change in this policy and the Joint Utilities have identified no harm that has occurred under the current policy.

Regarding the MDG, the QF Trade Associations still support the Commission's pre-existing policy that intermittent resources, such as solar, are not subjected to a MDG.[20] However, if a MDG will apply, then the QF Trade Associations recommend the MDG be set at 70 percent, the QF should be allowed to provide a reasonable forecast of its annual expected energy that the MDG will be based on, and the various other recommendations in previous comments.[21] These rules will apply to small QFs of 10 MW or less. Similar to the wind QF example above, a 90 percent MDG will be too restrictive for small QFs. While a large, utility-scale facility could possibly still meet a 90 percent MDG if part of its facility went down, the same is not true for small QFs. Thus, the Commission should adopt the QF Trade Associations recommendations regarding the MDG and MAG.

C. Reply Comments on Proposed Rule OAR 860-029-0120(15): Modifications to Qualifying Facilities

At the September 28, 2022 Workshop, a question was presented to the QF Trade Associations regarding whether 10 percent was the upper range for QFs making incremental upgrades. The QF Trade Associations certainly agree that there should be no bar to modifications that increase expected net output by 10 percent, but we submit that focusing on a

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20 *See* Comments of CREA, NIPPC, and the Coalition on Staff's Proposed Group 2 Rules at 28-29 (Sept. 16, 2022).

21 *See* Comments of CREA, NIPPC, and the Coalition on Staff's Proposed Group 2 Rules at 28-33 (Sept. 16, 2022).

percentage above which upgrades will be disallowed is misplaced. Instead, as we have previously explained, QFs should be allowed, and even encouraged, to install modifications to their facilities that increase the capacity or output in any amount without jeopardizing the right to sell energy and capacity associated with the initial facility at the prices contained in the initial PPA.

The proper focus of the question to be resolved is how to price the incremental energy and capacity enabled by the modification. Failure to preserve the right to PPAs' prices for the initially installed energy and capacity will discourage QFs from upgrading existing facilities for the 15-year fixed-price term of the PPA. Oregon should not lock up valuable renewable energy sites with existing technology for 15-20 years when there are a limited number of locations to construct new generation and interconnection is constrained, and at a time when new technology is likely to enable the harnessing of additional renewable energy.

With Oregon House Bill 2021's aggressive emission reduction mandates, the Commission needs to encourage clean energy development, at both new and existing facility sites. In a time of rapidly advancing technologies and increasing need for carbon-free capacity, there is no legitimate public policy justification to prevent QFs from selling additional power or shifting the time of production through use of advanced 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. These upgrades should not be limited to an arbitrary 10 percent. The Commission should encourage any upgrades and any shifts in generation to times of higher need with the use of storage. 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.

Energy storage and hybrid co-located resource types are prime examples of why expansions should be allowed, including those that may not have been possible to consider at the time of contract execution. For example, the Federal Energy Regulatory Commission ("FERC") is adopting changes to the interconnection process to enable facilities under development or in operation to include co-located technology types and add energy storage.[22] FERC's findings in its Notice of Proposed Rulemaking on this point are informative and relevant to the related question of accommodating the same types of upgrades under the PPA. FERC states in its NOPR that at the time of Order No. 2003, it was not common to co-locate different resource types, but "[t]here are now a number of different types of generating facilities that may prove complementary, such as solar combined with electric storage, wind combined with solar, or natural gas combined with wind and electric storage, and that may seek to co-locate for various efficiency reasons."[23] Indeed, FERC found: "Currently, 42% (285 GW) of solar and eight percent (17 GW) of wind projects in the queue are proposed as hybrid resources that would include electric storage."[24] And "reduction of costs for technologies such as electric storage" are occurring so quickly that "[i]t has become increasingly common for generating facilities already

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22 *See Notice of Proposed Rulemaking:* Improvements to Generator Interconnection Procedures and Agreements, 87 Fed Reg 39,934, 39,974 (July 5, 2022) (addressing a number of "Reforms to Incorporate Technological Advancements Into the Interconnection Process").

23 87 Fed Reg at 39,973.

24 87 Fed Reg at 39,973 n 335.

in the interconnection queue to seek to change their interconnection requests to add electric storage or other types of generating facilities without changing the interconnection service level and/or MW total in the interconnection request."[25]

Thus, FERC proposes to amend its interconnection rules to require utilities to enable the following: (i) co-location of different resource types behind a single interconnection point; (ii) addition of co-located technologies even before execution of the interconnection agreement without loss of queue position; (iii) use of "surplus interconnection" capacity in an interconnection agreement for an existing facility to backfill with another technology to maximize use of interconnection and transmission capacity (e.g., adding solar to generate at low generation periods at an existing wind facility); and (iv) use of modeling assumptions that make sense for co-located resources.[26] In contrast, this Commission's proposed rules in this proceeding could prevent nearly all of these types of improvements for small renewable energy facilities in Oregon.

Even more notable, FERC is proposing these major changes to its interconnection policies even though there is no mandate in the Federal Policy Act to "encourage" the development of such new renewable and storage technologies. In contrast, Public Utility Regulatory Policies Act ("PURPA") and Oregon's state PURPA statute affirmatively require this Commission to adopt policies aimed to "encourage" development of such new technologies to

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[25] 87 Fed Reg at 39,974.
[26] 87 Fed Reg at 39,973-39,981.

the "highest degree possible."[27] Given the applicable directives under PURPA, this Commission should adopt policies that affirmatively encourage and facilitate existing facilities to continue to upgrade their facilities with rapidly evolving technologies. Arbitrary restrictions on doing so is simply not consistent with the law or in the public interest.

Therefore, the QF Trade Associations still recommend revising 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. However, if there is concern that an upgrade over ten percent becomes a new facility, then the QF should retain its executed PPA and contracted-for prices for the initial facility and the incremental portion of the QF's energy and capacity beyond ten percent should be paid the rates in effect at the time it executes an amended PPA governing the incremental output. Requiring a completely new PPA for all the output or requiring new rates for all output of the QF will discourage incremental upgrades or upgrades in advanced technologies such as storage. Thus, the Commission should adopt the QF Trade Associations recommendation and not place an arbitrary limit on incremental QF upgrades.

D. Reply Comments on Proposed New Rule #6: Default, Damages, and Termination

As recommended in our September 16th Comments, the Commission should maintain its longstanding policy from UM 1129 that the standard contracts should contain an upper limit of

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27 16 USC § 824a-3(a); ORS 758.515(2)(a).

the contract price for liquidated damages a QF might owe for undelivered energy. These reply comments respond solely to Administrative Law Judge Mapes's request for additional comments as to whether circumstances have changed since the Commission adopted the damages cap in UM 1129. As explained below, the QF Trade Associations disagree with assertions by the Joint Utilities that material circumstances have changed since UM 1129. If anything, the damages cap in standard contracts is even more justified now than it was then.

In UM 1129, the Commission generally directed that standard contracts should include a cap on damages at "100% of the QF contract price multiplied by the amount of energy the QF failed to deliver."[28] The precise issue addressed was "whether there should be a cap, for standard contracts, on the amount of default losses that can be recouped by a utility, by reducing future payments to a QF, in the event that a QF defaults due to under-deliveries of power, or a failure to start operations on-time due to construction delays."[29]

The specific concern that gave rise to the proposal to cap damages in UM 1129 was related to financing. The Oregon Department of Energy ("ODOE") and Staff submitted evidence demonstrating it is necessary that "the project obtains a power purchase contract with limited risk of disruptions to the project's revenue stream" to obtain financing and that a PPA allowing for the QF to potentially owe uncapped damages pegged to a market price index would preclude financing by creating too big of a risk for disruptions to project revenues.[30] Based on that

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28 *In re Staff Investigation Related to Electric Utility Purchases from QFs*, Docket No. UM 1129, Order No. 06-538 at 5-6 (Sept. 20, 2006); *see also id.* at 66-67.
29 *Id.* at 65.
30 *Id.*

evidence, "both ODOE and Staff recommend that a cap be placed on contract damages that may be imposed, under a standard contract, in the event a QF defaults."[31] After reviewing different methods of capping damages, Staff proposed use of the contract prices as a cap, reasoning that approach provided "enough certainty about damages to facilitate financing, while posing minimal risk to ratepayers."[32] The Commission found that "it is unlikely, except in extreme circumstances (such as the effective termination of a standard contract by a QF during a market crisis), that utilities and their ratepayers will need to cover a QF's default losses."[33] The Commission thus adopted the cap to "facilitate the development of QFs of all sizes, while keeping ratepayers indifferent to the development of QF power, versus other power sources."[34]

No material facts have changed, and uncapped damages would still be an impediment to QF development and financing if adopted in the final rules in this proceeding. If anything, the case for use of damages caps to facilitate QF financing is even stronger now than in UM 1129 because market prices now occasionally spike to levels that would certainly bankrupt certain QFs if damages were pegged to a market price index, as the current version of Staff's proposed rules appears to provide.

It is unclear what changed circumstances the Joint Utilities believe would justify removal of the damages caps previously adopted by the Commission. The QF Trade Associations are aware of none. While the Joint Utilities may argue that their pro forma RFP PPAs for large

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31 *Id.*
32 *Id.*
33 *Id.* at 66.
34 *Id.* at 66.

projects contain uncapped damages provisions, the utilities have not yet provided any evidence that *small* renewable energy facilities can be financed with a PPA that exposes the seller to extreme damages risks. The standard contract is for smaller projects, which face much more difficulty financing due their smaller economies of scale and potential revenues associated with smaller amounts of net output.

Notably, the Joint Utilities' position here contradicts the protections they regularly seek for themselves in their contracts with QFs, both small and large. None of the Joint Utilities have proposed to adopt an uncapped damages provision applicable to themselves in standard contracts. Quite to the contrary, the Joint Utilities each consistently secure broad exclusions of any indirect or consequential damages they might owe to a QF in their standard contracts.[35] If the QFs will be exposed to uncapped market index pricing damages, then the waiver of consequential damages owed by the utility in the event of utility default should also be removed from each utility's standard contract to ensure that utilities fully compensate QFs for all conceivable damages without any limitations or potential objections after a utility default.

In sum, as previously explained, the Commission should reaffirm its policy from UM 1129 and adopt the QF Trade Associations' proposed revisions to implement caps on damages at the contract prices.

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35 *See* Joint Utilities Comments at 11-12 (Aug. 12, 2021) (asserting the Joint Utilities "reserved their rights to include" consequential damages waivers in their standard contracts if not addressed in this rulemaking).

E. Reply Comments on Proposed New Rule #4(4): Ability to Come Online Prior to Scheduled COD

At the workshop, Administrative Law Judge Mapes requested further written comments on how PURPA's mandatory purchase obligation informs the Commission's decision on whether a small QF should be allowed to achieve commercial operation earlier than 90 days before the scheduled commercial operation date in its PPA. The QF Trade Associations maintain that PURPA's mandatory purchase obligation requires reasonable accommodation to allow a QF to achieve commercial operation earlier than the scheduled commercial operation date in its PPA. As explained further below, allowing a purchasing utility to refuse to accept QF output earlier than 90 days before the scheduled commercial operation date is not reasonable or lawful.

Rather, the Commission should adopt the QF Trade Association's proposal, contained in the revisions to the proposed rules submitted September 16, 2022. Those revisions would allow a QF to achieve commercial operation and its fixed-price and purchase terms in its PPA up to 180 days early if it provides 60 days of advance notice to the purchasing utility, and would allow commercial operation even earlier, if the purchasing utility has no valid reason to refuse to accept the QF energy.

PURPA's mandatory purchase obligation is enshrined in the statute and FERC's regulations.[36] FERC's regulations state, in pertinent part: "Each electric utility shall purchase . . . any energy and capacity which is made available from a qualifying facility[.]"[37] Thus, FERC

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[36] 16 USC § 824a-3(a) (directing FERC to promulgate rules that "require electric utilities to offer to . . . purchase electric energy from such facilities").

[37] 18 CFR § 292.303(a).

has explained "[u]tilities have an *absolute obligation* to purchase a QF's output[,]" and it has rejected contractual and tariff provisions that purport to negate that purchase obligation.[38] In *Southwest Power Pool*, for instance, FERC rejected a proposed tariff provision that would have granted utilities the unilateral right to refuse to purchase the unscheduled energy of QFs that was not registered in an energy imbalance market.[39] FERC explained that "the statutory obligation to purchase unscheduled QF energy is not subordinate to tariff considerations such as those proposed here."[40] Similarly, in *Entergy Services*, FERC rejected a proposal to curtail unscheduled QF deliveries prior to other resources, explaining that it found "Entergy's statutory obligation to purchase unscheduled QF energy is not subordinate to tariff considerations."[41] It follows that this Commission cannot lawfully adopt an administrative rule or a standard contract that affirmatively proscribes a QF from selling its energy sooner than the contractual deadline by which it commits to do so in its power purchase agreement.

Indeed, under FERC's rules, a QF has an absolute right to sell its energy even without signing any contract. FERC's rules expressly provide two mechanisms to sell energy—

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38 *Southwest Power Pool, Inc.*, 143 FERC ¶ 61,018 at P 17 (Apr. 5, 2013) (emphasis added).

39 *Southwest Power Pool, Inc.*, 143 FERC ¶ 61,018 at P 17.

40 *Southwest Power Pool, Inc.*, 143 FERC ¶ 61,018 at P 17.

41 *Entergy Services*, 137 FERC ¶ 61,199 at P 52 (Dec. 15, 2011); *see also Occidental Chem. Corp. v. Midwest Indep. Sys. Operator*, 155 FERC ¶ 61,068 at P 66 & n 127 (Apr. 21, 2016) (collecting decisions and noting that "an RTO may not condition a QF's registration as a market participant on the QF's relinquishing the QF's PURPA rights"); *Western Sys. Power Pool*, 66 FERC ¶ 61,201 at 61,459 (Feb. 16, 1994) (conditioning membership to power pool on QFs' waiver of right to sell at avoided cost rates was "illegal on its face").

"Purchases 'as available' or pursuant to a legally enforceable obligation."[42] The first option for as-available sales is "[t]o provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the electric utility's avoided cost for energy calculated at the time of delivery."[43] The second option is the contractual option to "provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term," for which the utility pays either time-of-delivery or forecasted avoided cost pricing.[44] FERC has explained "that a qualifying facility may provide energy or capacity on an 'as available' basis, i.e., without legal obligation."[45] In other words, "a QF has the option to provide energy or capacity to an electric utility pursuant to a legally enforceable obligation, such as a PPA or other contract, or to provide energy on an 'as available' basis."[46] The as-available option should "not require a QF to make a financially binding decision ahead of time as to the amount of energy that it will put to the host utility."[47] And a contract is not even necessary, or required, to make as-available sales, which frequently occur solely under a state-approved tariff without the QF ever signing a contract.[48]

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[42] 18 CFR § 292.304(d)(1).

[43] 18 CFR § 292.304(d)(1)(i).

[44] 18 CFR § 292.304(d)(1)(ii).

[45] *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, 45 Fed Reg 12,214, 12, 224 (Feb. 25, 1980).

[46] *Fla. Power & Light Co.*, 133 FERC ¶ 61,121 at P 22 n 38 (Nov. 3, 2010).

[47] *Occidental Chem. Corp.*, 155 FERC ¶ 61,068 at P 69.

[48] *See Fla. Power & Light Co.*, 133 FERC ¶ 61,121 at P 6 (discussing sales from three QFs that had occurred without a contact, but instead pursuant to utility's "COG-1 tariff governing as-available energy sales").

The standard contract under discussion here would be characterized as a legally enforceable obligation under FERC's rules. But nothing in the standard contract can lawfully override the QF's separate, statutory right to sell its energy before the contractually agreed to purchase term in the contract. The QF retains the *absolute right* to sell any energy it makes available outside of the contractual purchase period in the PPA. In other words, FERC's rules require this Commission to facilitate the QF's right to sell its output on an as-available basis prior to the scheduled commercial operation date even in the absence of its PPA. Thus, the QF Trade Associations' proposal to include reasonable provisions allowing the QF to begin selling energy to the utility earlier than scheduled in its PPA is merely a recognition of the fact that the QF has such a right in any event.

The QF Trade Associations' proposal provides the purchasing utilities with advance notice 60 days before the QF intends to begin operations early, which appears to be far more advance notice of commencement of such unscheduled sales than has been found reasonable elsewhere. Under existing FERC precedent, the QF Trade Associations could easily argue for the right to provide far less advance notice to early deliveries.[49] In any event, the Joint Utilities have presented no basis to conclude more advanced notice is necessary.

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[49] *See Occidental Chem. Corp.*, 155 FERC ¶ 61,068 at P 69 (approving of requirement that QFs making as-available sales either: (a) declare the amount of energy that is "put" to a company within one hour after the operating hour in which the energy is "put" or (b) on a Day-Ahead basis, notify the applicable company that the QF plans to "put" its entire eligible output).

Finally, the QF Trade Associations acknowledge that FERC's rules may entitle the purchasing utility to refuse to pay the full contractual fixed prices until the scheduled commercial operation date and to instead pay a time-of-delivery price (e.g., the market index price) until that time, but it is not clear why the Joint Utilities would insist on such an outcome. If the QF will become operational and begin selling to the utility before the scheduled commercial operation—as it unquestionably has the right to do under PURPA—it would make sense to allow for full commercial operation to commence. This would mean that the PPA's fixed-price term and purchase term would start at actual commercial operation date, instead of the later scheduled commercial operation date in the PPA.

The Joint Utilities have argued ad nauseum in this proceeding that they are harmed by any delay or extension in commencement of the 15-year fixed-price term in PPAs.[50] If correct, then the utilities should encourage early deliveries to reduce the total payments to the QF. Further, the contract prices are generally lower in early years and, thus, coming on line and starting the 15-year fixed-price term early reduces the alleged "harm" to the utility. It is entirely contradictory for the Joint Utilities to now argue against beginning the fixed-price term earlier for QFs able to do so.

For the reasons previously stated and those set forth above, the Commission should adopt the QF Trade Associations' proposed revisions to the proposed rules' provisions for achieving commercial operation early.

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50 *See, e.g.*, Joint Utilities' Initial Comments at 5-6, 18-21 (Mar. 11, 2022).

F. Reply Comments on Proposed New Rule #5: Force Majeure

The QF Trade Associations continue to oppose Staff's Proposed Rule #5 because it is overly detailed with contract-like language in rules. Contractual provisions, like force majeure, should not be adjudicated at the Commission. The QF Trade Associations maintain their previous comments and will not repeat those here.[51] In the event that the Commission decides to go forward with the Proposed Rule #5, the QF Trade Associations dispute the Joint Utilities' argument that there should be a 180-day limit on force majeure, and that their proposed rules' limitations on force majeure are a "standard commercial provision."[52] While the QF Trade Associations do not dispute that force majeure limitations can be included among other commercial provisions in a contract, the 180-day limit is not reasonable nor "standard" across the industry—even where the renewable facility is receiving major concessions not available here in exchange, like a 25-year fixed-price term.

For instance, Avista Corporation's PPA template for their 2022 All-Source Request for Proposals ("RFP") in Washington contains a force majeure provision that states

> In the event of a Force Majeure event, the time for performance shall be extended *by a period of time reasonably necessary to overcome such delay*. For the avoidance of doubt, Avista shall not be required

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51 *See* Comments of CREA, NIPPC, and the Coalition on Staff's Proposed Group 2 Rules at 1-7 (Sept. 16, 2022).

52 Joint Utilities' Initial Comments Regarding Group 2 Rules at 24-25 (Sept. 16, 2022).

> to pay for any of the Total Output which, as a result of any Force Majeure event, is not delivered [53]

Here no time limit is specified because the nature of the delay is unknown at the time of contract execution and thus nearly impossible to put a time limit on. Further, three of California's largest electricity providers offer a commission-approved standard contract for QFs less than 20 MW which all state contract termination is only available after a minimum of 365 days of a force majeure event:

> Either Party may terminate this Agreement on Notice, which Notice will be effective five Business Days after such Notice is provided, in the event of Force Majeure which materially interferes with such Party's ability to perform its obligations under this Agreement and which extends for more than 365 consecutive days, or for more than a total of 365 days in any consecutive 540-day period.[54]

The QF Trade Associations maintain no time limit on force majeure events is warranted in the Commission's rules or in the standard contracts for small QFs, but certainly the 180-day

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53 *Exhibit G – RFP PPA (Standard Contract) Template*, Avista Corporation at 40 (Aug. 17, 2022), available at: https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/asrfp/exhibit-g-rfp-ppa-template--2112022.pdf (emphasis added).

54 *New Standard Offer Contracts for Qualifying Facilities <= 20MW*, California Public Utilities Commission, available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/qualifying-facility--and-combined-heat-and-power-procurement-options (accessed Oct. 6, 2022) (Force majeure termination provision is on page 35 of the standard contracts for Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric Company); *see also In re Order Instituting Rulemaking Regarding Continued Implementation of PURPA and Related Matters*, California Public Utilities Commission Rulemaking No. 18-07-017, Decision No. 20-05-006 (May 7, 2020), available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M337/K709/337709639.PDF (adopting standard QF contracts).

"standard" promoted by the Joint Utilities is far too short. As the examples above demonstrate, the 180-day limit is not as standard as the Joint Utilities assert. Thus, the QF Trade Associations maintain the position that this sort of contract-like language should not be included in rules but offers these comments to show how the 180-day force majeure limitation is far too restrictive, which could harm utilities and QFs alike and hinder progress towards Oregon's aggressive emission reduction mandates.

III. CONCLUSION

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

Dated this 7th day of October 2022.

Respectfully submitted,

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