**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

AR 631

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

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I. INTRODUCTION

Portland General Electric Company (PGE), PacifiCorp dba Pacific Power (PacifiCorp), and Idaho Power Company (together, the Joint Utilities) respectfully submit these comments in response to Staff's revised draft rules circulated on September 3, 2021[1] (hereinafter, Draft Rules) for changes to the Public Utility Commission of Oregon's (the Commission) implementation of the Public Utility Regulatory Policies Act of 1978 (PURPA) contracting process and the terms for standard Power Purchase Agreements (PPAs) with Qualifying Facilities (QFs). The Joint Utilities applaud Staff's efforts to better ensure that the latest Draft Rules are consistent with PURPA's customer-indifference standard, which *requires* state regulatory commissions to implement PURPA consistent with PURPA's requirements, including its mandate that utility customers remain financially indifferent to QF development.[2] To this end, the Joint Utilities respectfully submit these comments to reiterate the importance of the customer-indifference standard and alert Staff to provisions in the Draft Rules that are still inconsistent with this principle, to clarify Staff's intent with regards to certain changes and proposed language in the Draft Rules, and to offer revisions such that the Draft Rules are internally consistent.[3]

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

[2] *See, e.g.*, *In the Matter of Portland Gen. Elec. Co.*, Docket UM 1894, Order No. 18-025 at 7 (Jan 25, 2018) ("[O]ne critical feature of our implementation of PURPA, including (but not limited to) the terms and conditions of our regulated PURPA contracts, is the need to ensure that ratepayers remain financially indifferent to QF development."); *In the Matter of Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Docket UM 1129, Order No. 05-584 at (May 13, 2005) ("We seek to provide maximum incentives for the development of QFs of all sizes, *while ensuring* that ratepayers remain indifferent to QF power by having utilities pay no more than their avoided costs.") (emphasis added).

[3] The Joint Utilities would note that this docket is still in the informal rulemaking stage, and that comments on evolving draft rules have been due on a fairly expedited schedule. The Joint Utilities have attempted to address key issues here but reserve the right to comment on additional issues and in more detail once the formal rulemaking has been opened and stakeholders have more time to comment on a static set of draft rules.

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II. DISCUSSION

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

As discussed in the Joint Utilities' previous comments, the Joint Utilities continue to advocate for updating the standard PPA terms and conditions to conform to current market practices in order to better ensure that customers remain indifferent and receive the same contractual protections when the utility executes a QF PPA. Because the rules controlling PPA terms, conditions, and processes necessarily allocate risks and financial burdens between customers and developers, the rules must be consistent with prevailing market commercial practices for allocating risk and financial obligations to reasonably ensure customer indifference.

PPA contractual terms that are not representative of prevailing market contractual terms not only impose risks on customers that leave them worse off and, by doing so, call into question the integrity of avoided cost pricing; but such preferential terms and conditions for QFs are also an improper subsidization of QFs that relieves them of the risks associated with project development, finance, design, and construction—risks that any other market developer recognizes and accepts—and improperly transfers them to utility customers.[4] Accordingly, contracting rules that favor QF development above and beyond what is market result in an impermissible subsidy for such development at the expense of the utility customer.[5] For example, Staff's proposed rules

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[4] *See, e.g.*, Docket No. UM 1429, Order No. 09-272, Appendix A at 46 of 71 (July 15, 2009) (in which IE notes that, for PPAs that are bid into a utility's RFP, "[m]ost risks are shifted to the seller, including capital cost risk (i.e. the risk of cost overruns) and operating cost risk"); *see also* FERC Order No. 872, 172 FERC ¶ 61,041, at 197 ¶ 344 (July 19, 2020) ("The Commission also disagrees with those commenters who assert that, as a consequence of the above factors, the Commission should 'require[] the variable energy component to be structured in a way that removes market risk from the QF.' This argument runs directly counter to one of the fundamental premises of PURPA, which is that QFs must accept the market risk associated with their projects by being paid no more than the purchasing utility's avoided cost, thereby preventing utility retail customers from subsidizing QFs."). The Commission has also declined to unnecessarily shift risk to customers in any number of contexts, including utility cost recovery mechanisms, direct access programs, wildfire mechanisms, and so forth.

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

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lengthening the scheduled Commercial Operation Date (COD) from three to four years could not only cause utility customers to pay above market prices for net output of projects that could have been financially viable under a three-year COD, but also subsidize development of QF projects that could have otherwise been uneconomic.[6] Such increased costs to utility customers are clearly a violation of the customer indifference standard under PURPA.

The Joint Utilities appreciate Staff's most recent efforts to take the customer indifference standard into consideration when drafting the revised Draft Rules and offer recommendations to further ensure that customers are not left bearing the risk of imprudent or non-competitive PPA terms and conditions that effectively subsidize QF development on the backs of utility customers.

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

While Staff greatly improved New Rule #1 in the Draft Rules by preserving the utilities' rights under *Blue Marmot* to decline a chosen Point of Delivery (POD),[7] the rule should: (1) apply to both on-system and off-system QFs; (2) include a repricing requirement for avoided costs in the standard PPA after receipt of an order from the Commission allocating transmission costs; (3) provide more time and flexibility for utilities to submit an application to the transmission provider, assess a response from the transmission provider, and inform QFs of that response; and (4) prevent QFs from hoarding capacity by only allowing a QF to come online 90 days prior to the scheduled COD.

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[6] Staff's Revised Draft Rules at 18. Proposed subsection 6(b) of OAR 860-029-0120 is also discussed below,

[7] Docket No. UM 1829, Order No. 19-322, at 7, 12-15 ("[N]either FERC precedent nor Oregon law require a utility to accept an off-system QF's unilateral choice of delivery point, regardless of transmission constraints and legitimate competing uses of reserved transmission. In doing so, [the Commission found] that holding a reasonable amount of transmission capacity to accomplish transfers into the EIM and secure the customer benefits of participation is a legitimate justification to decline to accept delivery from QFs at a constrained delivery point.").

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

The Joint Utilities continue to propose that New Rule #1 apply to both on-system and off-system QFs. During past discussions regarding the Conditional Designation of Network Resource (DNR) provision, Staff stated that while the provision may be appropriate for off-system QFs, Staff did not support this provision for on-system QFs, in part because the Commission currently requires Network Resource Interconnection Service (NRIS) for QFs, although Staff acknowledged interconnection policies are subject to litigation in docket UM 2032. Staff's position, as the Joint Utilities understand it, is that because the Commission's current policies allocate the cost of NRIS to QFs, there is little or no need for the protection of a Conditional Designation of Network Resource (DNR) provision because the upgrades needed for delivery of QF power to load in a constrained area will, by virtue of that policy, have been paid for by QFs. However, those policies are exactly what QF parties are disputing in docket UM 2032.

Assuming this is the basis for Staff's position, it ignores a major modification to these policies proposed by QFs in docket UM 2032 and provides limited contingencies, leaving customers exposed to a meaningful risk— the outcome of which should not depend on the rules developed in this proceeding. In short, Staff should not rely on policy that is pending in another docket in making policy decisions in this rulemaking. Thus, while a Conditional DNR provision remains important in PPAs with on-system QFs under the Commission's current NRIS policy to ensure customer indifference, it will become a critically important safety valve for customer indifference compliance to include this provision in PPAs with on-system QFs should the Commission's NRIS policy change in docket UM 2032 or otherwise in the event the Commission

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modifies its QF interconnection cost-allocation policies and the utility is faced with unexpected costs.[8]

Finally, it is important to note Commission precedent on this issue. Specifically, the Commission has approved including this provision for both on-system and off-system QFs in all three utilities' Community Solar Program PPAs. Moreover, PacifiCorp has executed PPAs with on-system QFs that include this provision, both in Oregon and other jurisdictions,[9] and provisions similar to this have been included in PacifiCorp's non-standard QF and non-QF PPAs, including the form of PPA included in its recent 2020 All-Source Request for Proposals (RFPs).[10] Accordingly, such a provision is market for both on-system QFs as well as off-system QFs, and consistent with Commission precedent.

If Staff chooses to retain the Conditional DNR provision for off-system QFs, but not for on-system QFs, the rule should be amended to indicate that, in the event applicable regulations or any determination of the Commission were to permit on-system QFs to interconnect using energy resource interconnection service (ERIS), such ERIS on-system QFs contracts also should contain the Conditional DNR provision.

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[8] The Joint Utilities note, however, that interconnection "deliverability" costs *should* be the responsibility of the QF. *See, e.g.*, FERC Order re Pioneer Wind Park I, LLC, 145 FERC ¶ 61,215, at 20 n. 73 (Dec. 19, 2013) (noting that the QF is not "exempt from paying interconnection costs, which may include transmission or distribution costs directly related to installation and maintenance of the physical facilities necessary to permit interconnected operations") (internal citations omitted).

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

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

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2. New Rule #1 Should Require Repricing of Avoided Costs in the Standard PPA After Receipt of a Commission Order Allocating Transmission Costs.

The Joint Utilities urge Staff to add a new subsection to New Rule #1, which would require repricing of avoided costs at then-available market rates after receipt of the Commission Order allocating transmission costs if the QF seeks to postpone the start of the Development Period from execution of the PPA to the date the Commission issues its allocation of transmission cost order as Staff's Draft Rule contemplates and enables. Without such a provision, the Development Period could be deferred for multiple years with the time between execution of the PPA and COD being as long as five (5) years or longer, with avoided cost prices in the agreement becoming extremely stale. Such an outcome would harm customers and violate the customer indifference standard. Moreover, while the Joint Utilities understand that the transmission-service cost-allocation processes described in section (4) could take time, a repricing requirement coupled with Staff's proposed deferral of the Development Period, balances the interests of QFs in maintaining enough time to finance, design and construct a facility with the utilities' interest in ensuring that customers remain indifferent when a QF's siting decision requires network upgrades.

3. New Rule #1 Should Provide More Time and Flexibility for Utilities to Submit an Application to a Transmission Provider and Inform QFs of a Response.

The Joint Utilities recommend that Staff extend the five (5) day turnaround periods in subsections 4(b) and 4(d) of New Rule #1 to fifteen (15) days and allow the Joint Utilities to extend deadlines in section 4 by ten (10) days, provided that the utilities provide notice and an explanation for the delay. In the Joint Utilities' collective experience, the five (5) day turnaround periods in subsections 4(b) and 4(d) are extremely short to permit a public utility to prepare an application to a transmission provider, review and assess the transmission provider's response, and inform the QF of that response. Indeed, no other deadline in these Draft Rules is so short whereby the public

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utility could potentially risk default of the standard PPA. Accordingly, in order to provide adequate time and flexibility for such transmission-service cost-allocation processes, the Joint Utilities offer the following suggested revisions to New Rule #1 below.

4. New Rule #1 Should Only Allow QFs to Come Online 90 Days Prior to the Scheduled COD.

The Joint Utilities recommend that Staff revise New Rule #1 such that a public utility only need request an effective date for commencement of network transmission service for a QF that is 90 days prior to the scheduled COD. The current time for a QF to come online prior to the scheduled COD—180 days or approximately half of a year—is far too long for utilities to be expected to reserve capacity, generating uncertainty in utilities' system planning. The Community Solar PPAs for all three Oregon utilities are consistent with the Joint Utilities' position. The Community Solar PPAs require requests to the transmission provider for in-service dates 90 (not 180) days before COD and require acceptance of energy 90 (not 180) days before COD. Accordingly, the Joint Utility recommend the following revisions to New Rule #1 below and discuss related revisions to proposed section 4 of New Rule #4 in Part E.

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 public utility from proposing an alternate Point of Delivery 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 during the contracting process.

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(2) If the qualifying facility proposes an alternate Point of Delivery in response to a public utility's written notice under subsection (1), the public utility will have fifteen (15) business days to complete its review of proposed alternate Point of Delivery 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 ~~Notwithstanding subsections (1) and (2)~~, 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 a 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 developer may elect to defer commencement of 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.

(b) Specify in the power purchase agreement that, if the developer so elects deferral of commencement of the development period, the development period in the standard power purchase agreement shall resume on the date of receipt of an order from the Commission allocating transmission costs. On such date, avoided costs in the standard power purchase agreement shall be repriced at the then-available rates approved under the utility's schedule.

(c) ~~(b)~~ No later than fifteen (15) ~~five (5)~~ 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.

(d) ~~(c)~~ Request an effective date for commencement of network transmission service for the qualifying facility that is (i) 90 ~~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 90 ~~180~~ days following the Effective Date.

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(e) ~~(d)~~ No later than fifteen (15) ~~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.

(f) ~~(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 ~~Notice and Comment~~proceeding[11] 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. 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) ~~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) If a public utility is unable to meet a deadline in subsection (4), the public utility shall have a thirty-day period to cure such failure.

(8) ~~(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.

(9) Notwithstanding the other subsections in this rule, nothing prevents a purchasing public utility or qualifying facility from proceeding with a contested case to address transmission-related Network Upgrade costs.

[11] A provision limiting or attempting to circumscribe the type of process that will be necessary for the Commission to decide Network Upgrade cost allocation disputes is inappropriate for the Draft Rules. The Joint Utilities therefore recommend that the type of proceeding to address these issues be left to parties to decide on a case-by-case basis. For example, the Community Solar PPAs simply refer to a Commission determination and do not attempt to define or limit in advance this type of proceeding.

(10) Should amendments to these rules or a determination of the Commission permit on-system qualifying facilities to interconnect using the Energy Resource Interconnection Service, a standard power purchase agreement for an on-system qualifying facility using the Energy Resource Interconnection Service may, at the public utility's discretion, include a provision specifying that costs to construct transmission-service related Network Upgrades of a 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 that are consistent with the requirements set forth in this section for standard power purchase agreements with off-system qualifying facilities.

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

The Joint Utilities recommend for New Rule #2 that Staff remove its most recent changes to subsection 4(d). Staff explained that they modified "subsection (4)(d) of proposed rule to clarify that projects will not be considered the same facility because they are developed by a single entity as recommended by Developer Coalition."[12] However, the new language added to subsection 4(d) is not only confusing but also inherently contradicts the same site rule. If two qualifying facilities within five miles are owned and developed by the same entity, then for the purposes of the same site rule those facilities should be counted as one single entity regardless of whether the owner-developer subsequently finds a buyer for one of the facilities. Staff's revision would suggest that a QF owner-developer could completely skirt the same site rule simply based on a claim, and nothing more, of an intention to subsequently sell one or both facilities. Such an outcome would increase system planning uncertainty and likely lead to additional litigation. The Joint Utilities therefore offer the following revisions.

(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) or are not otherwise associated will not be determined to be a single qualifying facility ~~because they are developed by a single entity~~ or have a shared interest or agreement regarding interconnection facilities, interconnection-related system upgrades, or any other infrastructure not providing motive force or fuel.

[12] Table for September Proposal at 5 (Sept. 3, 2021).

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

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

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

Second, if Staff decides to retain the maximum four-year COD period, then the Joint Utilities further suggest that Staff clarify that when a QF chooses to modify the scheduled COD under subsection (7)(a), it may not select a new scheduled COD more than three years from contract execution without an interconnection study affirming the feasibility of that project coming online within that time.

Third, circumstances under which delay of the scheduled COD is excused should be clarified with regards to the modification provision. Although these rules no longer define "Excused Delay", any provision reflecting such a concept should ensure that excused delay is limited to instances where the public utility is at default of its obligations to the QF under the PPA, the interconnection agreement or an interconnection study agreement. In addition, the relief, provided should not result in a change to the scheduled COD but rather a day for day extension to the cure period within which the QF much achieve commercial operation.

Fourth, while the Joint Utilities applaud the Commission's policy to support energy efficiency improvements for QFs, any rules implementing such a policy should be balanced by protecting utility customers from being required to pay for increased generation at prices locked in many years in the past. Accordingly, the Draft Rules should include a limit for increases in net annual output above a certain threshold for which the QF is entitled to original pricing. The Joint Utilities do not object to material increases in incremental additional output as a result of efficient upgrades or expansions *so long as* such increases do not alter the QF's eligibility for standard pricing, are permitted under the QF's interconnection agreement and, in order to ensure customer indifference, are subject to standard pricing in effect when the upgrades are made.

Fifth, because the current required credit worthiness language in the standard PPAs is completely inadequate to protect utility customers, the Joint Utilities propose clarifying language to the security provisions in the proposed rules that indicates that the security and creditworthiness requirements will be consistent with those generally applicable to long-term power purchases and sales.

Finally, the Joint Utilities propose that the insurance provision be clarified such that umbrella insurance is required upon request of the public utility.

1. <u>Scheduled COD Should be No More than Three Years from Contract Execution.</u>

The Joint Utilities continue to strongly disagree that it is appropriate to allow QFs to lock in avoided cost prices a full four years before deliveries commence. Any rule that allows them to do so ensures that some QFs will be paid stale prices, which risks significant overpayment by utility customers in violation of the "just and reasonable" requirement and PURPA's customer

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indifference principle.[13] Instead, a QF should be allowed to select a COD no more than three years from contract execution. This approach is consistent with existing QF and non-QF PPA contracting practices [14] and consistent with QF requirements in Idaho, Wyoming, and Utah where the COD must be within thirty (30) months of the PPA execution date, as well as under the approved WUTC PAC PPA where the scheduled COD must be within three (3) years of PPA execution.[15]

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

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[13] PURPA Section 210(b) (16 U.S.C. § 824a-3(b)); OAR 860-029-0040(1)(a); *see also, e.g.*, *In the Matter of Portland Gen. Elec. Co.*, Docket UM 1894, Order No. 18-025 at 7 (Jan 25, 2018) ("[O]ne critical feature of our implementation of PURPA, including (but not limited to) the terms and conditions of our regulated PURPA contracts, is the need to ensure that ratepayers remain financially indifferent to QF development."); *In the Matter of Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Docket UM 1129, Order No. 05-584 at (May 13, 2005) ("We seek to provide maximum incentives for the development of QFs of all sizes, *while ensuring* that ratepayers remain indifferent to QF power by having utilities pay no more than their avoided costs.") (emphasis added).

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

[15] *See* Section 2.1 of the WUTC PAC PPA.

to provide QFs with a longer time to construct period. Indeed, many non-QF developers face this same issue, and many receive interconnection studies that show they will not be online well beyond a three-year window due to the need for significant upgrades in their location. In such an instance, project viability is limited until such constraints are resolved and, often, developers will focus on advancing other projects that are more favorably positioned with regard to transmission constraints. Such an outcome should be no different for QFs that are similarly facing the challenges of siting projects in a constrained area.

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

In both cases, retail utility customers will be paying above market prices for net output and effectively subsidizing QF development. The amount of this premium can be substantial and reflects the difference in avoided cost prices at four years before COD versus three years before COD applied to all net output received during the fixed price period. This is a clear violation of the customer indifference standard that will cause utility customers to pay QFs substantial subsidies that are neither justified nor necessary to support QF or renewable resource development.

Moreover, as the Joint Utilities discussed in previous comments, Staff's proposal is also flawed because it appears to be based on the assumption that the harm to customers due to stale

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prices is equal to the customer savings resulting from reduction of the fixed-price term, but there is no basis for this assumption. Fourteen years and six months of stale pricing could be far worse for customers than 15 years of accurate, current pricing that reflects the up-to-date cost of the avoided resource.[16] For example, as shown in Attachment B to these Comments, the net present value of the amount PacifiCorp would have paid for 1 MW of 14.5 years of power from a tracking solar resource at PacifiCorp's 2020 standard avoided cost prices in effect before its August 26, 2020 post-IRP update is $1.1 million. The net present value of the amount PacifiCorp would have paid for 1 MW of 15 years of power from the same tracking solar resource at PacifiCorp's 2020 refreshed standard avoided cost prices in effect after PacifiCorp's August 26, 2020 post-IRP update is $0.6 million. In other words, 15 years of refreshed pricing represents a *45 percent reduction* in the cost per MW to PacifiCorp's customers, as compared to 14.5 years of stale pricing that reflects out-of-date avoided cost pricing. Staff's assumption that harm to customers due to stale prices is equal to customer savings resulting from a reduction of the fixed-price term is therefore inaccurate. Moreover, this example clearly demonstrates how stale pricing, resulting from off-market contract terms, can result in payments to QFs that do not accurately reflect the utility's avoided costs and violate PURPA's customer indifference standard. The Joint Utilities provide their recommended changes below.

> (6) A qualifying facility may specify a scheduled commercial on-line date for a standard power purchase agreement anytime within three years from the Effective Date of the standard power purchase agreement.

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

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If Staff nevertheless wishes to recommend that QFs may select a COD up to four years from PPA execution, the Joint Utilities greatly appreciate the interconnection study requirement as it helps avoid speculative contracting and protects customers. However, in order to prevent frivolous litigation, the Joint Utilities suggest that subsection (6)(b)(A) be clarified to require that the interconnection study demonstrate that interconnection is feasible within three (3) to four (4) years of the Effective Date of the standard PPA. Furthermore, the Joint Utilities recommend that subsection (6)(b)(B) be removed as it is redundant of subsection (6)(b)(A). That is, absent provision of an interconnection study demonstrating feasibility, in no other circumstances would a utility consent to a COD between three (3) and (4) years from execution of the agreement as doing so would effectively open the flood gates to speculative contracting and subsidize QFs at the expense of customers. Accordingly, the Joint Utilities offer the following revisions below.

> (6) A qualifying facility may specify a scheduled commercial operation date for a standard power purchase agreement subject to the following requirements:
>
> (a) The scheduled commercial operation date may occur ~~A~~anytime within three years from the Effective ~~d~~Date of the standard power purchase agreement ~~execution~~; or
>
> (b) The scheduled commercial operation date may occur ~~A~~anytime between three years and four years after the Effective Date of the standard power purchase agreement if the qualifying facility has received an interconnection-related system impact study report, cluster study report, or facilities study report indicating interconnection is feasible between three (3) and four (4) years from the Effective Date of the standard power purchase agreement.~~:~~
>
> ~~(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 between three and four years more than three~~

~~years from the Effective Date, which consent shall not be unreasonably withheld.~~

Should Staff decide not to remove subsection (6)(b)(B), utilities should retain *full* discretion on whether to consent to a COD between three (3) and (4) years where the QF does not provide an interconnection study demonstrating that interconnection is feasible within that timeframe. This is the current standard, reflected in the current rules, and Staff offers no reason to change it. Under the "unreasonably withheld" standard, which Staff added to subsection (6)(b)(B) in the September 2021 Draft Rules, a QF could always argue that a utility is acting unreasonably when it refuses to consent to a COD between three (3) and four (4) years from the execution of the agreement. This is because, without an interconnection study, there would be no objective metric upon which to determine whether the utility was acting reasonably or unreasonably. Accordingly, subsection (6)(b)(B), as written, would effectively act as a loophole to the interconnection study requirement and lead to increased litigation. Therefore, should Staff decided to keep this provision, the Joint Utilities urge Staff to remove the "unreasonably withheld" standard and maintain the public utility's *full* discretion to consent or reject a proposed COD as currently provided in OAR 860-029-0120(4)(b).[17]

> (6) A qualifying facility may specify a scheduled commercial operation date for a standard power purchase agreement subject to the following requirements:
>
> (a) The scheduled commercial operation date may occur ~~A~~anytime within three years from the Effective ~~d~~Date of the standard power purchase agreement ~~execution~~; or
>
> (b) The scheduled commercial operation date may occur ~~A~~anytime between three years and four years after the Effective Date of the standard power purchase agreement if:

[17] OAR 860-029-0120(4)(b) currently provides that a QF may specify a scheduled COD "[a]nytime later than three years after the date of agreement execution if the qualifying facility establishes to the utility that a later scheduled commercial on-line date is reasonable and necessary and the utility agrees."

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(A) The qualifying facility has received an interconnection-related system impact study report, cluster study report, or facilities study report indicating interconnection indicating interconnection is feasible between three (3) and four (4) years ~~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 between three (3) and four (4) years ~~more than three years~~ from the Effective Date of the standard power purchase agreement~~, 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 development ~~construction~~ period occurring after the three-year anniversary of the Effective date, with the reduction taken from the end of the fixed-price term.

Example: A standard power purchase agreement with a development ~~construction~~ 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.~~

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.

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

The Joint Utilities continue to urge Staff to clarify that *any* extension of the scheduled COD more than three years from contract execution under subsection (7)(a) similarly requires proof of feasibility. The Joint Utilities therefore propose the following revisions below to ensure that subsection (6)(b) and subsection (7)(b) are consistent.

(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

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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:

(i) includes an estimate of time to interconnect that is longer than development period in the executed standard power purchase agreement; provided that the qualifying facility will only have the right to modify the scheduled commercial operation date if the time to interconnect is no more than four years from the Effective Date of the executed standard power purchase agreement; or

(ii) 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. If the qualifying facility chooses to modify the scheduled commercial operation date under subsection 7(a) to anytime between three (3) and four (4) years after the Effective Date of the standard power purchase agreement, the qualifying facility must comply with the requirements under subsection (6)(b). If the modified scheduled commercial operation date is more than three (3) years after the Effective Date, the fixed-price term will be reduced one day for every day of development period occurring after the three-year anniversary of the Effective Date, with the reduction taken from the end of the fixed-price term.

3. <u>Circumstances Under Which Delay of the COD is Excused Should be Clarified.</u>

The Joint Utilities recommend that Staff revise subsection (7)(d) in order to clarify that excused delay is limited to a public utility's default under the standard PPA, or under interconnection study agreements and interconnection agreements. These are the only types of agreements under which a default by the public utility may excuse the QF's delay in reaching the scheduled COD. In addition, relief for delay should extend the applicable cure period of the standard PPA so that any delay caused by the public utility's default does not impact the QF's ability to achieve commercial operation within the applicable cure period.

(7)(d) To the extent ~~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 of an obligation to the qualifying facility under the standard power purchase

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agreement or under ~~any agreement related to the interconnection of the qualifying facility to the purchasing utility's system, including~~ interconnection study agreement~~s~~ or ~~and~~ interconnection agreement~~s~~, the ~~scheduled commercial operation date in the standard power purchase agreement~~ qualifying facility will be entitled to an extended cure period for achieving commercial operation that is commensurate~~ly~~ with the delay caused by the event of Force Majeure or the public utility's default, except for periods of delay that could have been prevented had 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).~~

4. Facility Upgrades Should be Limited to a Certain Net Annual Output Threshold.

The Commission's current policy allows operational QFs to implement upgrades to increase efficiency, but provides that to the extent that an upgrade increases nameplate capacity above the eligibility threshold for standard prices, such increased output will be compensated at negotiated prices.[18] This policy seeks to balance a QF's desire to maintain and upgrade facilities over time to optimize efficiency, while at the same time protecting utility customers from being required to pay for increased generation at prices locked in many years in the past.

For some types of facilities, however, it is possible to substantially increase expected generation without changing the nameplate capacity if the definition of nameplate capacity is AC-based. A solar facility's AC-based rating can differ from its DC-based rating if a project is designed to include more DC capacity than can be transformed into AC power at the inverter. A facility's AC-based rating may also differ from its DC-based rating if the project includes DC-based storage resources. Thus, a facility's total output could be substantially increased by adding generating or storage capability without altering the AC-based nameplate capacity.

[18] Docket UM 1129, Order No. 06-538 at 4 ("We direct each utility to revise its filed standard contract to provide that if a QF increases the nameplate capacity of its facility by a certain percentage above 10 MW, such as ten percent, then on a going-forward basis, that percentage of power delivered will receive new, negotiated pricing, while the remaining percentage of output will receive pricing under the pre-existing standard contract.").

To ensure that substantial increases in output receive the most current avoided cost prices, the Joint Utilities recommend including in the Draft Rules a ten (10) percent cap on increases to annual net output that would qualify for the original pricing in the PPA. For increases in annual net output that exceed the ten (10) percent cap, the Joint Utilities recommend a process that would allow for such upgrades to be made, subject to updated pricing for the incremental additional output, in the Draft Rules as shown below.

(14) Incremental Facility ~~Utility~~ Upgrades.

(a) 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(b), 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. During the term of the power purchase agreement, except as permitted under subsection 14(b), the facility may not be modified in a manner that materially deviates from the as-built supplement without the purchasing utility's prior written approval (which 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 (i) 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 (ii) 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. ~~At any time after the commercial operation date and with no less than six months' written notice, the qualifying facility may increase the Facility Nameplate Capacity Rating or expected net output of the Facility from what is specified in the standard power purchase agreement, but only to the extent any such increase is due to operational efficiency improvements or the replacement of damaged or defective equipment. The qualifying facility may not increase the Facility Nameplate Capacity Rating or the expected Net Output of the Facility from what is specified in the standard power purchase agreement by any other means, including installing additional generating units, replacing equipment that results in an increase in Net Output due to reasons other than operational efficiency improvements, or modifying inverter settings.~~

(b) In the event that the qualifying facility seeks to upgrade the facility during the term of the power purchase agreement in any manner that is not permitted under subsection 14(a), such upgrades may be made under this subsection 14(b) subject to the following requirements:

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(i) 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 to require network upgrades in order to maintain designated network status.

(ii) 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, their impact on expected net output and revised 12 x 24 delivery schedule, requesting indicative pricing for the incremental additional net output expected to be generated as a result of the upgrades.

(iii) 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.

(iv) 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.

~~If any upgrades or other modifications made to the Facility in accordance with subsection (14)(a), result in an increase to the Facility's Nameplate Capacity, the qualifying facility and public utility will amend the standard power purchase agreement to reflect the change, provided that the increase does not cause the qualifying facility to fail to meet the eligibility requirements for either the standard power purchase agreement or standard prices.~~

(c) Within 90 days after the date on which upgrades are installed under subsections 14(a) or (b), the qualifying facility is obligated to provide the purchasing utility an as-built supplement describing in detail the upgraded facility.

(d) ~~(c)~~ If the qualifying facility wishes to increase~~s~~ the Nameplate Capacity Rating above the size limit for a standard power purchase agreement or standard prices, the qualifying facility will no longer be eligible for the standard power purchase agreement or standard prices, or both, whichever is applicable.

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(e) ~~(d)~~ A qualifying facility that wishes to install upgrades that would cause the facility to no longer meet~~s~~ the eligibility criteria for either a standard power purchase agreement or standard prices due to an increase under subsection (14)(d)~~(a)~~ must terminate its existing power purchase agreement and ~~may choose to~~ negotiate a new non-standard power purchase agreement ~~or~~ with then current non-standard prices for the total expected net output of the facility following the installation of the upgrades. 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 failing any default caused by its failure to maintain eligibility for a standard power purchase agreement.~~

5. <u>The Project Development Security and Default Security Provisions Should be Clarified.</u>

The Joint Utilities appreciate Staff's proposal to allow for greater security requirements in order to protect utility customers in the event a project defaults, which is a not an uncommon occurrence for QFs. Because the current required credit worthiness language in the standard PPAs is completely inadequate to protect utility customers, the Joint Utilities propose clarifying language to the security provisions in the proposed rules that indicates that the security and creditworthiness requirements will be consistent with those generally applicable to long-term power purchases and sales. In addition, the Joint Utilities propose that all such required security is due within 30 days of the effective date of the applicable PPA to ensure that utility customers are protected and held harmless in the event of a QF default. Accordingly, the Joint Utilities propose the following changes below.

(15) Project Development Security. A qualifying facility entering into a standard power purchase agreement must post Project Development Security for the purchasing public utility's benefit within 30 days of the Effective Date of the standard power purchase agreement. The amount of required Project Development Security will be consistent with the utility's security requirements generally applicable to long-term power purchases and sales and shall be set forth in the purchasing public utility's form of standard power purchase agreement approved

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by the Commission. The obligation to maintain the Project Development Security will expire once the qualifying facility commences commercial operation.

(16) Default Security. A qualifying facility that has executed a standard power purchase agreement that does not meet the public utility's credit worthiness requirements must post Default Security within 30 days of the Effective Date of the standard power purchase agreement ~~prior to commencing commercial operation~~. The utility's credit worthiness requirements and the amount of required Default Security will be consistent with the utility's credit worthiness and security requirements generally applicable to long-term power purchases and sales and shall 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:

6. The Insurance Provision Should Be Clarified

The Joint Utilities offer the following revisions to the Insurance provision for clarification purposes.

(17) 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:

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

(b) Insurance coverage will include:

(A) G~~g~~eneral 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 public utility ~~qualifying facility~~.

E. New Rule #4—Delivery and Purchase

The Joint Utilities recommend that Staff revise New Rule #4 to (1) distinguish between excess energy for on-system QFs and imbalance energy for off-system QFs and (2) limit QFs from coming online more than 90 days prior to the scheduled COD.

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1. New Rule #4 Should Distinguish Between Excess Energy for On-System QFs and Imbalance Energy for Off-System QFs.

The Joint Utilities recommend that Staff revise New Rule #4 to distinguish between excess energy for on-system projects, which is a rare occurrence where the QF produces more than the facility's nameplate capacity, and the more common situation where off-system projects produce imbalance energy. As currently written, New Rule #4 would require public utilities to accept excess energy from on-system QFs regardless of the potential for a system reliability crisis where the public utility did not plan to buy such energy, did not arrange for transmission of such energy, or would otherwise have to curtail its own generation facilities in order to accept such generation. Requiring the public utility to take on excess energy from on-system QFs could therefore not only potentially affect the public utilities financially, but could also force public utilities into an unmanageable system planning situation where reliability problems become inevitable. Accordingly, the Joint Utilities propose removing the public utility's obligation to take excess energy from on-system QFs from New Rule #4.

The Joint Utilities believe New Rule #4 should rather address off-system arrangements where the public utility is receiving scheduled energy regardless of the net output of the QF. In those situations, if the QF generates more net output than what the QF schedules, the public utility should be obligated to purchase only the portion of the net output that is equal to scheduled energy. In the event the QF generates less net output than what the QF schedules, the public utility will accept the full amount of scheduled energy but should only be obligated to pay for the portion of the scheduled energy that is equal to the net output. The following revisions to the Draft Rules are intended to capture this concept and current practices:

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860-029-XXXX [New Rule #4]
Delivery and Purchase under Standard Power Purchase Agreement

(1) Commencing on 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.

(2) An off-system qualifying facility may supplement its output with energy imbalance ancillary services if:

(i) the transmitting entit(ies) require the qualifying facility to procure the services;

(ii) the transmitting entity requires the qualifying facility to schedule deliveries in increments of no less than one (1) megawatt;

(iii) the qualifying facility is not attempting to sell the purchasing public utility energy or capacity in excess of its Net Output; and

(iv) the energy imbalance service is designed to correct a mismatch between energy scheduled by the qualifying facility and the actual real time production by the qualifying facility.

(3) ~~(2)~~ The public utility must accept but is not obligated to pay for surplus delivery of ~~excess~~ energy from off-system qualifying facilities. For purposes of this rule "surplus delivery" of ~~excess~~ energy means any energy delivered by the qualifying facility in excess of hourly Net Output (i.e., to meet a scheduled delivery) that is not offset by the delivery of energy in deficit of hourly net output, netted over a monthly period.~~:~~

~~(a) for on-system qualifying facilities, net output at the Point of Delivery 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, netted over a monthly period.~~

2. New Rule #4 Should Prevent QFs from coming online more than 90 days prior to the scheduled COD.

The Joint Utilities recommend that section (4) be revised such that a QF may *only* come online 90 days prior to the scheduled COD. The current proposed default time allowing for a QF to come online prior to the scheduled COD—180 days or approximately half of a year—is far too long for utilities to be expected to reserve capacity. This long time period would, generate uncertainty in utilities' system planning; moreover, it raises concerns that would need to be vetted about whether utilities reserving transmission capacity so far in advance would face legal risks related to impermissible hoarding of transmission capacity in contravention of Federal Energy Regulatory Commission (FERC) policy. Accordingly, the Joint Utilities offer the following revisions to section (4).

> (4) A qualifying facility may not commence commercial operation any sooner than 90 ~~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 days prior to the scheduled commercial operation if the public utility is unable to accept delivery from the qualifying facility.~~

F. New Rule #5—Force Majeure

The Joint Utilities recommend that if an event of Force Majeure extends beyond 180 days, the public utility should have the right to terminate the PPA. Extraordinary events that are not reasonably foreseeable at the time of contracting and which cannot be overcome by reasonable diligence provide a basis for temporarily suspending the parties' obligations and performance. However, with changing avoided cost prices and the long-term nature of these contracts, it is unreasonable to permit indefinite extensions of the scheduled COD which expose utility customers to undue risk of paying stale prices. It is all the more appropriate to place a time limit on force majeure extensions when the only impact is to require the parties to revise pricing to reflect the then-current avoided cost prices.

> (7) If an event of Force Majeure exceeds 180 days, the public utility may terminate the power purchase agreement.

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

The Joint Utilities offer the following revisions to New Rule #6 for clarification purposes and so that the rules better align with standard contract provisions.

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

(1) The following events, if uncured within the applicable cure period, may constitute a default by the qualifying facility under a standard power purchase agreement for which the purchasing utility may terminate the power purchase agreement subject to the provisions of this OAR 860-029-XXX:

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

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

(c) failure to maintain qualifying facility 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,

(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,

(g) failure to satisfy applicable Minimum Availability Guarantee for two (2) consecutive years,

(h) failure to satisfy applicable Minimum Delivery Guarantee for three (3) consecutive years, or

~~(i) failure to receive or purchase all or part of Net Output, or~~

(i) ~~(j)~~ failure to comply with any other material obligation under the power purchase agreement ~~provide a timely notice of early termination under OAR 860-029-XXX [New Rule #1]~~.

(2) The following events, if uncured within the applicable cure period, may constitute a default by the purchasing utility under a standard power purchase agreement for which the qualifying facility may terminate the power purchase agreement subject to the provisions of this OAR 860-029-XXX:

(a) failure to receive or purchase Net Output,

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

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(c) failure to comply with any material obligation under the power purchase agreement.

~~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 (1)(a), t~~The qualifying facility has 180 days[19] ~~one year~~ from the date of the scheduled commercial operation date in which to cure ~~the default for~~ a failure to meet the scheduled commercial operation date.

(b) Except with respect to a failure to meet the Minimum Availability Guarantee or the Minimum Delivery Guarantee, which failures are not capable of cure, and as otherwise specified in subsection (3)(a) ~~If a Notice of Default is issued under subsection (1)(b), (1)(c), (1)(d), 1(e), 1(f), or 1(i)~~, ~~the~~ a non-defaulting party has thirty (30) days following written notice from the other party in which to cure any failure to comply with its obligations under the power purchase agreement ~~the event of default~~.

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

(4) ~~Imposition of damages.~~

~~(a) The public utility may claim impose damages after issuing a Notice of Default under subsection (1)(a) or (1)(d) as specified in OAR 860-029-0120(7).~~

~~(b)~~ If damages are incurred as a result of any breach under the standard purchase agreement ~~imposed~~, the breaching party must remit ~~they must be remitted~~ payment in the full amount of the damages to the non-breaching party no later than 30 days after the breaching party receives~~d~~ an invoice from the non-breaching party ~~for damages~~. The invoice for damages must include a written statement explaining in reasonable detail the calculation of the damages amount.

[19] As stated in the Joint Utilities' initial comments, the Joint Utilities believe that the cure period for failure to timely achieve scheduled COD should be reduced to three months. The current one-year cure period is 9-12 months longer than most negotiated cure periods in market-based PPAs and significantly longer than the cure periods applicable to QF standard PPAs in other states. For example, the standard PPA for PacifiCorp's Washington QFs provides for a cure period of up to 180 days but not to exceed the third anniversary of the execution date for the PPA and only so long as the QF complies with a detailed schedule recovery plan approved by PacifiCorp; provided, however, if the QF does not comply with the schedule recovery plan, the QF has 30 days to cure its default. Also, in Utah, PacifiCorp has entered into standard PPAs that provide for a 15-day cure period, and in Wyoming, PacifiCorp has entered into standard PPAs that provide for a 90-day cure period. As a compromise, the Joint Utilities propose that the one-year cure period for failure to meet scheduled COD be reduced to 180 days.

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(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 (1) or (2), as applicable.

(6) The non-defaulting party must provide the defaulting party a Notice of Termination at least 30 days prior to date of Termination. The notice period for termination may run concurrently with the applicable cure ~~default~~ period.

(7) Termination of Duty to Buy. If a standard power purchase agreement is terminated because of ~~an Event of D~~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 termination date, and may require the qualifying facility to post default security. 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 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 ("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.

(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.

H. Definition of Net Output

The Joint Utilities recommend that the definition of "Net Output" be reverted to the version in the August 2021 Draft Rules. The current definition of "Net Output", which is not consistent with the Joint Utilities' current standard PPAs, is problematic for two reasons. First, while the Joint Utilities do not object to measuring Net Output at the Point of Interconnection, Staff should clarify that utilities are only obligated to pay for and receive Net Output delivered to the Point of Delivery. Second, Net Output must be defined net of transformation and transmission line losses as the public utility does not have any obligation to pay for Net Output that is not delivered to its system. To the extent that a QF pays the transmitting utility to replace line losses,[20] that replacement energy was not generated by the QF and therefore the utility has no obligation to purchase the non-QF generation.[21]

The Community Renewable Energy Association (CREA), the Northwest & Intermountain Power Producers Coalition (NIPPC), and the Renewable Energy Coalition (the "Coalition") (collectively the "QF Developers") argue in their comments that the definition of Net Output should measure Net Output "at the point of interconnection to provide the off-system QF with opportunity to be paid the full avoided cost rates for all of its Net Output if it successfully delivers that amount of electric energy to the purchasing utility."[22] However, the purchasing public utility is only required to pay for Net Output that is *actually* delivered to its system, and therefore, the only reasonable way to measure Net Output that is delivered to the purchasing utility is to define

[20] *See* Joint Comments of Community Renewable Energy Association, Northwest & Intermountain Power Producers Coalition (NIPPC), and the Renewable Energy Coalition on Staff's Proposed Rules at 49-50 (Aug. 12, 2021).
[21] *In the Matter of Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Docket No. UM 1129, Order No. 07-360 at 38 (Aug. 20, 2007).
[22] Joint Comments of Community Renewable Energy Association, Northwest & Intermountain Power Producers Coalition (NIPPC), and the Renewable Energy Coalition on Staff's Proposed Rules at 49-50 (Aug. 12, 2021).

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the amount of Net Output as actual generation at the Point of Interconnection for off-system QFs minus transformation and transmission line losses. In this way transformation and transmission line losses are treated as offsets to actual generation just as is the case with station service. To do as the QF Developers suggest, would force purchasing public utilities to subsidize energy transmission losses for off-system QFs at the expense of utility customers, in violation of the customer indifference standard.

Moreover, the QF Developers misleadingly reference the definition of Net Output in PacifiCorp's Oregon Standard PPA to argue that their proposed definition removing netting of transformation and transmission losses is reasonable and considered market for off-system QFs.[23] Importantly, the QF Developers misquote the Net Output definition, which actually begins by stating that Net Output means "all energy and capacity produced by the Facility, *less station use and less transformation and transmission losses and other adjustments (e.g., Seller's load other than station use)*, if any, up to and including the Point of Interconnection."[24] Accordingly, the Joint Utilities note that it is common practice to subtract transformation and transmission losses from Net Output and recommend that the definition of Net Output from the August 2021 Draft Rules be retained with the following clarifications.

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

[23] *Id.* at 50.

[24] PacifiCorp's Off-System Standard Contract at § 1.30, *available* at https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/purpa/Power_Purchase_Agreement_for_Firm_Off_System_QF.pdf. (emphasis added).

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I. Other Definitions

The Joint Utilities recommend that Staff either add, remove, or make the following revisions to the definitions to the Draft Rules listed below:

- "Commercial operation date" means the date after start-up testing is complete and the qualifying facility has satisfied the criteria necessary to commence operation as provided under the power purchase agreement. ~~and begins to deliver its Net Output.~~

- "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 adjusted avoid cost price under the public utility's schedule ~~Index Price~~ in effect when the energy is generated.

- "Development period" means the time period commencing on the ~~power purchase agreement~~ Effective Date and ending 24:00 PPT the day before the scheduled commercial operation date.

- "Effective Date" means the date on which a power purchase agreement is executed by both the qualifying facility and the public utility or, in the case of an amendment to the power purchase agreement under OAR 860-029-XXXX [New Rule #1], the date on which the amendment is executed by both the qualifying facility and the public utility.

- "Governmental Authority" means federal, national, state, municipal, local, tribal, territorial, or other governmental department, commission, board, bureau, agency, regulatory authority, instrumentality, judicial, legislative or administrative body, domestic or foreign, including, without limitation, FERC and the Commission. For the purposes of these rules, "Governmental Authority" excludes the Bonneville Power Administration.

- "Interconnection Provider" or Transmission Provider" means an entity that owns, operates or controls facilities for the purpose of transmitting or transporting electric energy on behalf of the qualifying facility to or from the Point of Interconnection or Point of Delivery, as specified by the Generation Interconnection Agreement.

- "Maintenance Outage" means NERC Event Type MO and ~~, as provided in attached Exhibit J,~~ includes any outage involving ten percent (10%) of the Facility's Net Output that is not a Forced Outage or a Planned Outage.

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- ~~"New qualifying facility" means a qualifying facility that is not an existing qualifying facility.~~[25]

- "Point of Interconnection" means the point where the qualifying facility is electrically connected to an Interconnection Provider's ~~a public utility's~~ transmission or distribution system.

- "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).~~[26]

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

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

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

In addition, the Joint Utilities recommend that Staff and the Commission make clear that the Draft Rules do not impact, supersede, or otherwise interfere with Commission orders or

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[25] The Joint Utilities recommend removing this definition because it is not used anywhere within the Draft Rules.

[26] Staff explained that it modified this "definition to clarify the entity that executes a power purchase agreement does not have to be a certified QF." Table for September Proposal at 2. The Joint Utilities note that Staff's revised definition is internally inconsistent as a qualified facility under 18 C.F.R. Part 292 is necessarily certified. 18 C.F.R. § 292.101(b)(1); 18 C.F.R. § 292.203 (noting that qualifying facilities must have filed self-certification).

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

K. Staff Should Clarify that Certain Rules Not Addressed in the Redline for the Draft Rules Remain Intact.

Staff should clarify that certain provisions—although not present in the redline for the Draft Rules—remain unchanged and were not removed. For example, Staff explains that the September 2021 Draft Rules remove proposed revisions to OAR 860-029-0020 (Obligations of Qualifying Facilities to the Electric Utility) and OAR 860-029-0030 (Obligations of the Public Utility to Qualifying Facilities) because these rules apply "generally to all qualifying facilities, not just those entering into standard power purchase agreements."[27] Thus, neither OAR 860-029-0020 nor OAR 860-029-0030 include substantive revisions. Nonetheless, both provisions are present in the redline for the Draft Rules. Similarly, OAR 869-029-0085 (Requirements for Standard Avoided Cost Rates) is included in the Draft Rules although no revisions were made to that section. On the contrary, certain provisions are excluded from the redline of the September 2021 Draft Rules without explanation.

Accordingly, the Joint Utilities wish to confirm Staff's intent not to change the following provisions, which were *not* included in the redline for the Draft Rules: OAR 860-029-0001 (Purpose); OAR 860-029-0040 (Rates for Purchases); OAR 860-029-0046 (Integration Charges); OAR 860-029-0050 (Rates for Sales); OAR 860-029-0060 (Obligation to Pay and Reimbursement

[27] Table for September Proposal at 3. The Joint Utilities recommend that Staff retain the August 2021 Draft Rules' proposed subsections (4) and (11) to OAR 860-029-0020 below.

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of Interconnection Costs); OAR 860-029-0070 (System Emergencies); OAR 860-029-0080 (Electric Utility System Cost Data); OAR 860-029-0100 (Resolution of Disputes for Proposed Negotiated Power Purchase Agreements); and OAR 860-029-0130 (Nonstandard Power Purchase Agreements).

L. Staff Should Not Remove Subsections (4) and (11) of OAR 860-029-0020—as Proposed in the August 2021 Draft Rules—and Provide Language Clarifying that These Subsections are Limited to Standard PPAs.

Rather than completely remove the August 2021 Draft Rules' proposed subsections (4) and (11) in OAR 860-029-0020, Staff should move these sections to OAR 860-029-0120 (Standard Power Purchase Agreements) and include clarifying language in the new Draft Rules that such subsections are limited to standard PPAs. Staff explains that the September 2021 Draft Rules remove proposed revisions to OAR 860-029-0020 because the rule applies "generally to all qualifying facilities, not just those entering into standard power purchase agreements."[28] While that may be the case, Staff has neither explained why the subsections cannot be moved and further clarified to narrow application to standard PPAs, nor provided any explanation why such provisions are otherwise inappropriate. Indeed, Staff *did* move and provide further clarification for the August 2021 Draft Rules' proposed subsection (5) in OAR 860-029-0020, which was moved in the September 2021 Draft Rules to subsection (18) of OAR 860-029-0120. Accordingly, as no stakeholder has objected to subsections (4) and (11), and Staff determined that it was appropriate to retain subsection (5) and move it to OAR 860-029-0120, the Joint Utilities recommend that Staff also retain subsections (4) and (11) of OAR 860-029-0020—as proposed in the August 2021 Draft Rules—and move these sections to OAR 860-029-0120 as shown below.

[28] Table for September Proposal at 3.

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860-029-0120
Standard Power Purchase Agreements

[…]

(18) Any qualifying facility entering into a standard power purchase agreement with a public utility under PURPA will construct and operate the Facility in a manner that ensures its continuing status as a qualifying facility and in a manner consistent with its FERC Qualifying Facility certification.

(19) ~~(18)~~ 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 6 ~~24~~ months,[29] 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.

(20) For all standard power purchase agreements, the qualifying facility must deliver net output to purchasing utility to the Point of Delivery free and clear of all liens, claims and encumbrances.

(21) ~~(19)~~ All standard power purchase agreements between a qualifying facility and a public utility for energy, or energy and capacity must include language that substantially conforms to the following: This agreement is subject to the jurisdiction of those governmental agencies and courts having control over either party or this agreement. The public utility's compliance with the terms of this contract is conditioned on the qualifying facility submitting to the public utility and to the Public Utility Commission of Oregon, before the date of initial operation, certified copies of all local, state, and federal licenses, permits, and other approvals required by law.

III. CONCLUSION

The Joint Utilities applaud Staff's latest efforts in the revised Draft Rules to balance the

[29] The Joint Utilities believe that a minimum six-month threshold for a public utility to request that a QF provide documentation and information to establish its continued compliance with the eligibility requirements for a standard PPA is a reasonable and does not present a significant burden to QFs. The proposed 24-month period, on the other hand, is far too long and would prevent utilities from assessing whether a facility was improperly receiving avoided cost prices under a standard PPA when in fact the facility should be operating under a non-standard contract.

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interests of the QFs in promoting development with the requirement for utility customers to remain indifferent to such development, and feel comfortable proceeding to the formal rulemaking proceeding provided that the Joint Utilities' suggested revisions are considered. The Joint Utilities note that this set of comments is intended to highlight key issues of concern prompted by Staff's current round of revisions and does not represent the Joint Utilities' final redline of the Draft Rules. Finally, the Joint Utilities respectfully request that Staff adopt a schedule for the remainder of the informal phase that allows stakeholders at least one (1) week to review Staff's final proposal before the Commission public meeting.

DATED: September 20, 2021.

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ATTACHMENT A

to

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

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

ATTACHMENT B

to

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

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