ORDER NO. 26-241

ENTERED Jul 13 2026

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

AR 684

In the Matter of Rulemaking on PURPA Standard Avoided Cost Rates, Price Adjustment Mechanism, and HB 3863 Implementation.	ORDER

DISPOSITION: STAFF'S RECOMMENDATION ADOPTED

This order memorializes our decision, made and effective at our July 7, 2026 Regular Public Meeting, to adopt Staff's recommendation in this matter. The Staff Report with the recommendation is attached as Appendix A.

As discussed at the Regular Public Meeting, we expect to consider further changes to the rule language regarding penalties for non-performance after a Qualifying Facility (QF) submits a binding notice of renewal to the utility in the formal rulemaking process.[1] While we continue to believe that some level of certainty is important for utilities evaluating the amount of QF generation on their system if those QFs are exempted from the capacity price ramp period, we are also cautious of penalties that are too onerous and constitute a significant barrier to renewal. We also recognized there is a tension between the fact that QF projects are each unique and the need for administrative efficiency and clarity in application of any damages provisions.

Made, entered, and effective Jul 13 2026.

Letha Tawney
Chair

Les Perkins
Commissioner

Karin Power
Commissioner

[1] *See* proposed rule section OAR 860-029-0123(13).

ITEM NO. RM1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: July 7, 2026

RULEMAKING X **CONSENT** ____ **EFFECTIVE DATE** N/A

DATE: June 15, 2026

TO: Public Utility Commission

FROM: Ryan Bain

THROUGH: Scott Gibbens and Curtis Dlouhy **SIGNED**

SUBJECT: OREGON PUBLIC UTILITY COMMISSION:
(Docket No. AR 684)
Rulemaking on PURPA Standard Avoided Cost Rates, Price Adjustment Mechanism, and HB 3836 Implementation.

STAFF RECOMMENDATION:

Staff recommends the Oregon Public Utility Commission (the Commission) issue a Notice of Proposed Rulemaking to consider adopting Staff's Draft Rules Implementing Order No. 26-021, HB 3863, and the Commission adopted UM 2000 Phase III Avoided Cost Price Adjustment Mechanism.

DISCUSSION:

Issue

Whether the Commission should open a formal rulemaking to adopt rules to implement Order No. 26-021, HB 3863, and UM 2000 Phase III Avoided Cost Price Adjustment Mechanism.

Applicable Orders and Rules

ORS 756.060 authorizes the Commission to adopt and amend reasonable and proper rules and regulations relative to all statutes administered by the Commission.

ORS 758.535(2)(a) specifies that the terms and conditions for the purchase of energy or energy and capacity by a public utility from a qualifying facility shall be established by rule by the Commission.

Analysis

Background and Filing Overview
On January 23, 2026, the Commission adopted a new methodology for calculating Public Utility Regulatory Policies Act (PURPA) avoided cost standard rates, through Order No. 26-021. Major methodological changes included eliminating the non-renewable and renewable schedules in favor of one adjustable schedule, replacing the sufficiency/deficiency period pricing schema, and implementation of deliverability and policy compliance adjustments. On March 5, Docket No. AR 684 was opened for the purpose of codifying some of the components of Order No. 26-021, including the new size eligibility requirement for standard avoided cost rates specified by House Bill 3863; finalizing the particulars of how existing QFs should provide notice of an intent to renew a power purchase agreement; and specifying how avoided cost prices should be updated under the new methodology.

Since AR 684 was opened, Staff has gone through an iterative process with stakeholders in which Staff posted draft rules and received stakeholder comments, shared either in writing or during workshops. The rules proposed by Staff in this memorandum are the third iteration and include modifications based on comments Staff has received from stakeholders after each of the two previous iterations circulated by Staff.

Rules implementing HB 3863
The 2025 Oregon legislature passed, and the Governor signed, HB 3863, requiring the Commission to establish a cap at no less than 10 MWs for standard terms and conditions for buying power from a qualifying facility. HB 3863 became effective on the ninety-first day following the June 27 adjournment of the legislative session.

In response to HB 3863, Idaho Power Company (Idaho Power), Portland General Electric (PGE), and Pacific Power made filings to update their standard avoided cost tariff pages to reflect HB 3863 for consideration at the September 9, 2025, Public Meeting. Those filings increased the cap for solar and solar plus storage facilities from the then effective 3 MW to 10 MW.

Staff's draft rules amend OAR 860-029-0043(3) to state that "…all qualifying facilities with a nameplate capacity of 10 MW and less are eligible for standard avoided cost rates." Staff also proposes to amend OAR 860-029-0045(1) to state that "[a]ll qualifying facilities with a Nameplate Capacity Rating of 10 MW and less, are eligible for standard avoided cost prices." No parties wrote in opposition to these proposed changes required by statute.

Rules implementing Order 26-021
Staff's proposed rules implementing Order No. 26-021 include amendments:

1. Removing references to On- and Off-Peak Hours from OARs 860-029-0010, 860-029-0080, and 860-029-0120, which have been replaced by use of a 6x6 pricing schedule.
2. Removing language requiring utilities to furnish non-renewable, or renewable and non-renewable, avoided cost rates from OARs 860-029-0040(6), 860-029-0043(1), 860-029-0045(3), and 860-029-0085(2). These edits capture the Commission's intent in Order 26-021 to eliminate two distinct avoided cost prices streams for "renewable" and "non-renewable" QFs.
3. Specifying that utilities acting in compliance with Oregon's Renewable Portfolio Standard (RPS) must adjust avoided cost rates to account for value of compliance with the RPS when the QF is RPS-compliant and purchasing utility's avoided resource is not. (OAR 860-029-0043(2) and OAR 860-029-0045(3)).
4. Specifying that utilities acting in compliance with ORS 469A.210 must adjust standard avoided cost rates that account for value of avoided costs of compliance with ORS 469A.210 when the QF complies with the Small-Scale Renewable Energy Project Standard but the utility's avoided energy resource does not. (OAR 860-029-0043(3) and (OAR 860-029-0045(4)).
5. Specifying circumstances in which avoided cost rates must be adjusted to account for value of avoided deliverability (OAR 860-029-0043(6)).
6. Describing the Capacity Ramp-in, with a tractable, extensible, example ramp-in schedule. (OAR 860-029-0043(7)).
7. Imposing a $0.00 net cost of capacity price floor.[1] (OAR 860-029-0043(10)).

No stakeholder opposes the first three enumerated changes described above. However, PGE opposes rules implementing the Commission's decisions related to the rate adjustments for compliance with the RPS and Small-Scale Renewable Standard and avoided deliverability value. In informal comments submitted in response to Staff's draft rules, PGE argues that the Commission is authorized to announce policy decisions through a contested case rulemaking and that a "repetitive" rulemaking is inefficient and unnecessary.[2] PGE acknowledges that ORS 758.535(2) specifies that the "terms and conditions for the purchase of energy or energy and capacity from a qualifying facility shall be * * * established by rule by the commission if the purchase is by a public utility."[3] However, PGE notes that Staff is not attempting to codify every determination

1 UM 2000 – Order No. 26-021, pg. 16.
2 PGE's Comments to Staff's Redline Draft Rules at 2 (April 27, 2026).
3 *Id*.

of Order No. 26-021, and deduces that this means not every decision by the Commission related to the terms of PURPA sales must be codified in rules.[4]

Staff agrees it is not feasible to include every detail of PURPA ratemaking in rules. However, Staff disagrees with PGE that it is inappropriate to include rules codifying the Commission's decisions related to the RPS, Small Scale Renewable Standard, and avoided deliverability value adjustments, to standard avoided cost rates. In response to concerns about over-specificity, Staff has removed some detail from its draft rule related to the adjustment for avoided deliverability value and corrected an incorrect reference to the purchasing utility's avoided "capacity" resource. The remaining proposed revisions establish the circumstances in which the adjustments are appropriate, which is not overly prescriptive.

Rules related to the Notice of Intent to Renew
Commission Order 26-021 identified certain issues related to the Notice of Intent to Renew (NIR) to be resolved through AR 684. Staff's Second Finalized Redline draft rules contain the following proposals to address these issues:

- Addition of OAR 860-029-0010(40) defining the NIR.
- Addition of OAR 860-029-0043(9), stating that a QF renewing with the same utility will not face the capacity ramp-in should they submit a NIR or execute a new PPA at least one year prior to the termination of the existing PPA. Further stating that QFs failing to submit a timely NIR or execute a new PPA at least one year in advance will be subject to a two-year capacity ramp-in.
- Edits to OAR 860-029-0046 and OAR 860-029-0120 to state that utilities must furnish a draft standard PPA upon receipt of a NIR and that utilities must submit all forms of standard PPAs and NIRs to the Commission for approval.
- Addition of OAR 860-029-0123(13) to specify damages owed to the utility should the QF not commence operation under a new PPA by the scheduled commercial operation date indicated in the NIR, with a proposed cap on damages, and a clause exempting the QF from said damages should the Commission determine that the utility was a substantial factor in the failure to execute a new PPA.

Staff had removed consideration for damages from its prior Finalized Redline Draft Rules with the understanding that the executed PPA would encapsulate all potential damages, but after further consideration of both PGE's comments and the Commission's Resolution on Capacity Sufficiency and Deficiency Periods describing a "binding notice of renewal", Staff reinstated its earlier damages proposal in its Second Finalized Redline Draft Rules with the addition of a cap on damages. This rule

[4] *Id.*

encompasses the situation of a QF signing a NIR, but failing to execute a new PPA. Staff recommended a "financial penalty if the QF gives notice but does not renew" in its UM 2000 testimony, but acknowledges that this consideration is not clear in the Commission's resolution.[5] Staff believes that the addition of the damages consideration through OAR 860-029-0123(13) provides an appropriate mechanism to make the NIR meaningfully binding.

Phase III Issues
In Staff's February 24, 2023, scoping and process proposal document, the frequency and mechanism for pricing updates was envisioned for the Phase III rulemaking process. Staff's Second Finalized Redline Draft Rules include the following amendments focused on the pricing update mechanism, including:

- Adjusting OAR 860-029-0040(4)(a), OAR 860-029-0080(3), and OAR 860-029-0085(3) to state that post-IRP avoided costs will become effective 60 days after filing, as opposed to the current 30 days.
- Adjusting OAR 860-029-0080(7)(b) and OAR 860-029-0085(4)(b) to state that if a utility's IRP is acknowledged within 90 days of May 1, instead of the current 60 days, the utility may request a waiver of either the May 1 or post-IRP avoided cost update. This reflects the proposed adjustment to a uniform 60-day review period for both May 1 and post-IRP avoided cost updates.
- Editing and adding subparts E and F to OAR 860-029-0085(4)(a) and OAR 860-029-0080(7)(a) to provide May 1 avoided cost updates inclusive of updated RFP prices, REC prices, and transmission expansion investment.

Staff's earlier redline drafts did not include explicit language addressing updated RFP prices, REC prices, and updated transmission expansion investment values, but rather called for updates to "Forward-looking electrical capacity and energy prices", with the intent that under Order 26-021 methodology this would include updates to RFP, REC, and transmission expansion investment inputs. Stakeholders' requests for clarity on this issue at Staff's workshop in part prompted the second requested comment deadline. Staff is appreciative of parties' comments submitted on the pricing update mechanism, and made edits to OAR 860-029-0085(4)(a) and 860-029-0080(7)(a) to provide the requested clarity. Regarding the frequency of avoided cost price updates, Staff's proposal maintains the current update frequency of annual May 1 updates and post-IRP updates, with a common 60-day review period for either update. Staff anticipates that these avoided cost update filings will be filed in new dockets annually, eschewing the prior paradigm of updates being filed in each utility's respective UM 1728, 1729, & 1730 docket.

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[5] UM 2000, Order No. 26-021 at 19.

Conclusion

Staff's proposed rules are intended to implement revisions to the Commission's PURPA implementation policy as well as HB 3863 in compliance with ORS 758.535(2)(a), which specifies that the terms and conditions for the purchase of energy or energy and capacity by a public utility from a qualifying facility shall be established by rule by the Commission.

PROPOSED COMMISSION MOTION:

Staff recommends the Commission issue a Notice of Proposed Rulemaking to consider adopting Staff's Draft Rules Implementing Order No. 26-021, HB 3863, and the Commission adopted UM 2000 Phase III Avoided Cost Price Adjustment Mechanism.

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Appendix A

Staff's Second Finalized Redline Draft Rules

SECTION 1. 860-029-0010 - DEFINITIONS FOR DIVISION 029 RULES

(1) "AC" means alternating current.

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

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

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

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

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

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

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

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

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

(11) "Contract Price" means during the fixed price term, the applicable fixed price ~~for On-peak Hours and Off-peak Hours~~ specified in the purchasing utility's avoided cost

price schedule, and during the subsequent non-fixed price term, the purchasing utility's applicable Index Price in effect when the energy is generated.

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

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

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

(15) "Effective date" means the date specified in the power purchase agreement on which the power purchase agreement between the qualifying facility and the public utility becomes effective.

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

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

(18) "Energy costs" means:

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

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

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

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

(21) "FERC" means the Federal Energy Regulatory Commission.

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

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

(24) "Forced Outage" means

(a) An outage that requires immediate removal of a unit from service, another outage state, or a reserve shutdown state;

(b) An outage that does not require immediate removal of a unit from the in-service state but requires removal within six hours; or

(c) An outage that can be postponed beyond six hours but requires that a unit be removed from the in-service state before the end of the next weekend.

(25) "Generator Interconnection Agreement" means the generator interconnection agreement between the qualifying facility and qualifying facility's interconnection provider.

(26) "Index rate" means the market index rate approved by the Commission for inclusion in the purchasing public utility's standard power purchase agreement.

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

(28) "Maintenance Outage" means an outage that can be deferred beyond the next weekend but requires that the unit be removed from service before the next Planned Outage. A Maintenance Outage can occur any time during the year, has a flexible start

date, may or may not have a predetermined duration and is usually shorter than a Planned Outage.

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

(30) "MW" means megawatt.

(31) "MWh" means megawatt-hour.

(32) "Nameplate Capacity Rating" means maximum installed instantaneous power production capacity of the completed Facility, expressed in MW (AC), and measured at the Point of Interconnection, when operated in compliance with the Generation Interconnection Agreement and consistent with the recommended power factor and operating parameters provided by the manufacturer of the generator, inverters, and energy storage devices where relevant.

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

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

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

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

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

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

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

~~(40) "Off-peak hours" means all hours other than On-peak hours.~~

~~(41) "On-peak hours" means the hours designated as such in the purchasing public utility's avoided cost price schedule.~~

(40) “Notice of Intent to Renew” means the notice provided by an existing qualifying facility to a purchasing utility indicating the qualifying facility is seeking a new power purchase agreement to begin after the expiration of the qualifying facility’s current power purchase agreement. Utilities shall provide a draft power purchase agreement to an existing qualifying facility seeking a new power purchase agreement in accordance with the utility’s Commission-approved PURPA procedures and Commission rules.

(4~~2~~1) "Permits" mean the permits, licenses, approvals, certificates, entitlements and other authorizations issued by governmental authorities required for the construction, ownership or operation of the Facility or occupancy of the site on which it is located.

(4~~3~~2) "Planned Outage" means an outage that is scheduled well in advance and is of a predetermined duration. A "Planned Outage" is also known as a "Scheduled Outage~~-~~."

(4~~4~~3) "Point of Delivery" means for off-system qualifying facilities, the point on the purchasing public utility's distribution or transmission system where the qualifying facility and purchasing public utility have agreed the qualifying facility will deliver energy to the purchasing public utility. For on-system qualifying facilities, the Point of Delivery is the Point of Interconnection.

(4~~5~~4) "Point of Interconnection" means the point where the qualifying facility is electrically connected to an electric utility's transmission or distribution system.

(4~~6~~5) "Primary energy source" means the fuel or fuels used for the generation of electric energy. The term does not include minimum amounts of fuel required for ignition, start-up, testing, flame stabilization, and control uses; the term does not include minimum amounts of fuel required to alleviate or prevent unanticipated equipment outages and emergencies which directly affect the public health, safety, or welfare.

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(4~~7~~6) "Public utility" means a utility regulated by the Commission under ORS Chapter 757, that provides electric power to customers.

(4~~8~~7) "Purchase" means the purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

(4~~9~~8) "Purchase period" means the period of a power purchase agreement during which the qualifying facility is required to sell power to the public utility and the public utility is required to purchase power offered for sale.

(~~50~~49) "Qualifying facility" means a cogeneration facility or a small power production facility as defined in 18 CFR 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).

(5~~1~~0) "Rate" means any price, charge, or classification made, demanded, observed, or received with respect to the sale or purchase of electric energy or capacity or any rule, regulation, or practice respecting any such price, charge, or classification.

(5~~2~~1) "Renewable energy certificate" has the meaning given that term in OAR 330-160-0015(17).

(5~~3~~2) "Renewable Portfolio Standard" or "RPS' is the standard for large electric utilities in ORS 469A.052(1) or the standard for small electric utilities in ORS 469A.055 in effect as of October 23, 2018.

(5~~4~~3) "Renewable qualifying facility" means a qualifying facility that generates electricity that may be used for compliance with the RPS.

(5~~5~~4) "RPS attributes" means all attributes related to the Net Output generated by the qualifying facility that are required to provide the public utility with "qualifying electricity" as that term is defined in Oregon's Renewable Portfolio Standard Act, ORS 469A.010, in effect as of October 23, 2018. RPS attributes do not include environmental attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity.

(5~~6~~5) "Sale" means the sale of electric energy or capacity or both by a public utility to a qualifying facility.

(5~~7~~6) "Schedule" means the purchasing public utility's schedule filed with the Commission setting forth terms and rates for standard power purchase agreements.

(5~~8~~7) "Scheduled commercial operation date" means the commercial operation date specified by the qualifying facility and included in the standard power purchase agreement.

(5~~9~~8) "Small power production facility" means a facility which produces electric energy using as a primary energy source biomass, waste, solar energy, wind power, water power, geothermal energy, or any combination thereof. Only small power production facilities which, with any other facilities located at the same site, have power production capacities of 80 megawatts or less, are covered by these rules.

(~~60~~59) "Start-up Testing" means the start-up testing required by the manufacturer or interconnection provider that establishes that the Facility is reliably producing electric energy.

(6~~1~~0) "System" means the electric transmission and distribution system owned or operated by the purchasing public utility, or where applicable, another electric utility.

(6~~2~~1) "Test energy" means electric energy generated by the Facility during the Test Period, and renewable energy certificates and capacity rights associated with such electric energy.

(6~~3~~2) "Test period" means a period during which Start-up Testing is conducted.

(6~~4~~3) "Time of delivery" means:

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

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

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

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

(6~~5~~4) "Time the obligation to purchase the energy capacity or energy and capacity is incurred" means the earlier of:

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

(b) The date determined by the Commission.

(6~~6~~5) "Total output" means all energy produced by the Facility.

SECTION 2. 860-029-0040 – RATES FOR PURCHASES

(1) Rates for purchases by public utilities must:

(a) Be just and reasonable to the public utility's customers and in the public interest; and

(b) Be in accordance with this rule, regardless of whether the public utility making such purchases is simultaneously making sales to the qualifying facility.

(2) Establishing rates:

(a) Except for qualifying facilities in existence before November 8, 1978, and except when a public utility fails to make a good faith effort to comply with the request from a qualifying facility to wheel, a purchase rate satisfies the requirements of section (1) of this rule if the rate equals the avoided costs after consideration of the factors set forth in section (5) of this rule.

(b) If a public utility fails to make a good faith effort to comply with the request from a qualifying facility to wheel, the public utility must purchase at a rate which is the public utility's avoided cost or the index rate, whichever is higher. A good faith effort will be demonstrated by the public utility's publication of a generally applicable reasonable policy of the public utility to use the public utility's transmission facilities on a cost-related basis.

(c) When the purchase rates are based upon estimates of avoided costs over a specific term of the contract or other legally enforceable obligation, the rates do not violate these rules if any payment under the obligation differs from avoided costs.

(d) Nothing in these rules will be construed as requiring payment of avoided-cost prices to qualifying facilities in existence before November 1978, provided, however, that prices for such purchases shall be sufficient to encourage continued power production.

(3) Rates for purchases — time of calculation: Each qualifying facility has the option to:

(a) Provide nonfirm energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases must be based on the purchasing public utility's nonfirm energy avoided cost or if subsection (2)(b) of this rule is applicable, in effect when the energy is delivered; or

(b) Provide firm energy and/or capacity pursuant to a legally enforceable obligation for the delivery of energy and/or capacity over a specified term, in which case the rates for purchases must be based on:

(A) The avoided costs calculated at the time of delivery, or, if subsection (2)(b) of this rule is applicable, the index rate in effect at the time of delivery; or

(B) At the election of the qualifying facility, exercised at the time the obligation is incurred, the avoided costs, or the index rate then in effect if subsection (2)(b) of this rule is applicable, projected over the life of the obligation and calculated at the time the obligation is incurred.

(4) Standard rates for purchases shall be implemented as follows:

(a) In the same manner as rates are published for electricity sales, each public utility shall file with the Commission, within 30 days of Commission acknowledgement of its integrated resource plan, standard rates for purchases from eligible qualifying facilities to become effective ~~30~~ 60 days after filing. The publication shall contain all the terms and conditions of the purchase.

(b) If a public utility fails to make a good faith effort to comply with the request from a qualifying facility to wheel, the public utility shall purchase at a rate which is the public utility's standard rate or the index standard rate, whichever is higher. A good faith effort shall be demonstrated by the public utility's publication of its generally accepted reasonable policy to use the public utility's transmission facilities on a cost-related basis.

(c) The public utility's standard rate may differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(5) Factors affecting rates for purchases: In determining avoided costs and for determining the index rate the following factors will, to the extent practicable, be taken into account:

(a) The data provided pursuant to OAR 860-029-0080(3) and the Commission's evaluation of the data; and

(b) The availability of energy or capacity from a qualifying facility during the system daily and seasonal peak periods, including:

(A) The ability of the public utility to dispatch output of the qualifying facility;

(B) The expected or demonstrated reliability of the qualifying facility;

(C) The terms of any contract or other legally enforceable obligation;

(D) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the public utility's facilities;

(E) The usefulness of energy and/or capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(F) The individual and aggregate value of energy and capacity from qualifying facilities on the public utility's system; and

(G) The smaller capacity increments and the shorter lead times available, if any, with additions of capacity from qualifying facilities.

(c) The relationship of the availability of energy and/or capacity from the qualifying facility as derived in subsection (5)(b) of this rule, to the ability of the public utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(d) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility if the purchasing public utility generated an equivalent amount of energy itself or purchased an equivalent amount of energy and/or capacity.

~~(6) Each public utility that is currently complying with Oregon's renewable portfolio standard must offer renewable and non-renewable avoided cost rates to eligible qualifying facilities.~~

SECTION 3. 860-029-0043 – STANDARD RATES FOR PURCHASE

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

(2) Each public utility that acts to comply with Oregon's R~~r~~enewable P~~p~~ortfolio S~~s~~tandard must offer to eligible qualifying facilities standard ~~renewable~~ avoided cost rates ~~to eligible qualifying facilities~~ that account for value of avoided costs of compliance with that standard.

(3) Each public utility that is subject to the Small-Scale Renewable Energy Project Standard in ORS 469A.210 must offer to eligible qualifying facilities standard avoided cost rates that account for value of avoided costs of compliance with ORS 469A.210 when the qualifying facility complies with the Small-Scale Renewable Energy Project Standard but the public utility's avoided energy resource does not.

(~~3~~4) Unless the Commission adopts a higher threshold, all qualifying facilities with a nameplate capacity of ~~100 kW~~ 10 MW and less are eligible for standard avoided cost rates.

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

(6) Each public utility must offer standard avoided cost rates that account for avoided transmission costs and expansion investment as follows:

(a) When both the public utility's avoided resource and qualifying facility are off-system, avoided cost prices will include the avoided third-party transmission costs associated with the public utility's avoided resource.

(b) When the public utility's avoided resource is on-system and the qualifying facility is off-system, avoided cost prices will include no value for avoided transmission investment or costs except for as provided under subsection (e) of this rule.

(c) When the public utility's avoided resource is off-system and the qualifying facility is on-system, avoided cost prices will include value for avoided transmission expansion investment calculated consistently with the methodology specified by Commission order.

(d) When both the public utility's avoided resource and the qualifying facility are on-system, avoided cost prices will include the greater of the utility's avoided transmission expansion investment as calculated under subsection (c) of this rule, minus the cost of third-party transmission as calculated under subsection (a), or $0.00.

(e) In addition to value for avoided transmission expansion investment and costs calculated under subsections (a)-(d) of this rule, avoided cost prices for both off-system and on-system qualifying facilities will be adjusted to account for avoided costs of transmission for a public utility's on-system resource when the public utility would incur costs to transmit output from the on-system avoided resource to load. There is a rebuttable presumption that a public utility would not incur avoidable costs to transmit load from an on-system resource to its own load.

(7) Standard avoided cost rates will include a Capacity Ramp-in during which payments for the avoided cost of capacity are increased from zero in year one to full avoided capacity value in the first year following the Capacity Ramp-in period.

(a) The Capacity Ramp-in will begin on the Scheduled Commercial Operation Date.

(b) The duration of the Capacity Ramp-in for each public utility will be determined and periodically reviewed by the Commission.

(c) The capacity payments will increase from zero by an equal portion after each 12-month period of a power purchase agreement during the Capacity Ramp-in. For example, for a standard power purchase agreement with a Capacity Ramp-in of four years, the avoided capacity payments will be as follows:

Year 1 capacity value = 0
Year 2 capacity value = 25 percent
Year 3 capacity value = 50 percent
Year 4 capacity value = 75 percent
Post-Ramp in capacity value = 100

(~~5~~8) Each public utility must update its standard avoided costs in accordance with OAR 860-029-0085.

(9) (a) Notwithstanding subsection (7) of this section, qualifying facilities with an existing power purchase agreement that execute a new contract with the same purchasing utility are not subject to a Capacity Ramp-in if the qualifying facility submits to the purchasing utility a Notice of Intent to Renew or executes a new power purchase agreement at least one year prior to the termination of the existing power purchase agreement.

(b) Qualifying facilities with an existing power purchase agreement that do not submit a timely Notice of Intent to Renew or execute a new power purchase agreement at least one year prior to the termination of the existing power purchase agreement will be subject to a two-year Capacity Ramp-in.

(10) The net cost of capacity of the avoided capacity resource may not fall below $0.00 in any year modelled in the avoided cost study.

SECTION 4. 860-029-0045 – ELIGIBILITY FOR STANDARD AVOIDED COST PRICES AND PURCHASE AGREEMENTS

(1) ~~Solar qualifying facilities with a Nameplate Capacity Rating of 3 MW and less, and all other~~ All qualifying facilities with a Nameplate Capacity Rating of 10 MW and less, are eligible for standard avoided cost prices.

(2) All qualifying facilities with a Nameplate Capacity Rating of 10 MW and less are eligible to enter into a standard power purchase agreement.

(3) Renewable Portfolio Standard compliant qualifying facilities that satisfy the criteria of section (1) are eligible for ~~to select~~ an adjustment to standard avoided cost rates for the value of avoided costs of compliance with the Renewable Portfolio Standard when the purchasing public utility's ~~standard renewable~~ avoided ~~cost prices~~ energy resource is not Renewable Portfolio Standard compliant. A renewable qualifying facility ~~choosing the standard renewable avoided cost~~ that receives an adjustment for avoided Renewable Portfolio Standard compliance value under this subsection or that otherwise receives rates based on the avoided costs of a Renewable Portfolio Standard compliant resource ~~prices~~ must cede all renewable energy certificates generated by the qualifying f~~F~~acility to the purchasing public utility while the qualifying facility is receiving ~~deficiency period~~ administratively set pricing from the purchasing public utility and during any other period of the power purchase agreement ordered by the Commission.

(4) Qualifying facilities that satisfy the criteria of a small-scale renewable energy project under ORS 469A.210 are eligible for an adjustment to standard avoided cost rates for the purchasing utility's avoided cost of compliance with ORS 469A.210 when the purchasing utility's avoided energy resource does not meet the criteria of ORS 469A.210.

(5~~6~~) The determination of Nameplate Capacity Rating for purposes of determining whether a qualifying facility meets the size criteria in sections (1) and (2) is based on the cumulative Nameplate Capacity Rating of the qualifying facility seeking the standard avoided cost prices or power purchase agreement and that of any other Facilities owned by the same person(s) or affiliate(s) located on the same site.

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

(b) For purposes of this section:

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

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

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

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

(A) Family-owned. A project will be considered "family owned" if, after excluding the ownership interest of those who qualify as passive investor(s) under (4)(c), five or fewer individuals hold at least 50 percent of the project entity, or 15 or fewer individual entities hold at least 90 percent of the project entity. For purposes of counting the number of individuals holding the remaining share (i.e., determining whether there are 5 or fewer individuals or 15 or fewer individuals), an individual is a natural person. Notwithstanding the foregoing, an individual, his or her spouse, and his or her dependent children, will be aggregated and counted as a single individual even if the spouse and/or dependent children also hold equity in the project;

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

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

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

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

SECTION 5. 860-029-0046 – PROCESS FOR PROCURING STANDARD POWER PURCHASE AGREEMENT

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

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

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

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

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

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

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

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

(A) Demonstration of ability to obtain certified qualifying facility status prior to commercial operation; for qualifying facilities larger than 1 MW, a Form 556 self-certification of the proposed qualifying facility or a FERC order granting an application for certification of the proposed qualifying facility is required;

(B) Demonstration of eligibility for standard power purchase agreement and pricing under OAR 860-029-0045;

(C) Design capacity (MW);

(D) Estimate of station service requirements and net amount of power to be delivered to the purchasing public utility's electric System;

(E) Generation technology and other related technology applicable to the site;

(F) Non-binding estimate of 12 x 24 delivery schedule and 8760 generation profile when practicable; estimates of the net amount of power to be delivered to the public utility's electric system and the 12 x 24 delivery schedule are subject to revision until the date the qualifying facility commences commercial operation;

(G) Motive force or fuel plan;

(H) Proposed scheduled commercial operation date;

(I) Proposed contract term;

(J) Proposed pricing provisions;

(K) Point of Delivery as well as Point of Interconnection or multiple Points of Interconnection under consideration;

(L) Latitude and longitude of proposed facility and site layout;

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

(N) For a qualifying facility selecting a scheduled commercial operation date between three and five years after the Effective Date of the standard power purchase agreement pursuant to OAR 860-029-0120(5)(b), a copy of the interconnection study supporting the scheduled commercial operation date if one exists; and

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

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

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

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

(5) If the qualifying facility submits comments to the public utility or asks for revisions to the draft standard power purchase agreement, in writing, the public utility has 10 business days to:

(a) Notify the qualifying facility it cannot make the requested changes;

(b) Notify the qualifying facility it does not understand the requested changes or requires additional information; or

(c) Provide a revised draft power purchase agreement. However, the public utility will have 15 business days to respond or provide a revised draft standard power purchase agreement when the qualifying facility requests a change to the Point of Delivery.

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

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

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

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

(10) Both QF parties and purchasing utilities acting pursuant to this rule are obligated to act in good faith when dealing with counterparties.

SECTION 6. 860-029-0080 - ELECTRIC UTILITY SYSTEM COST DATA.

(1) Each public utility must provide sufficient data concerning its avoided costs and costs of interconnection to allow the owner or operator of a qualifying facility to estimate, with reasonable accuracy, the payment it could receive from the utility if the qualifying facility went into operation under any of the purchase agreements provided for in these rules.

(2) By January 1 of each odd-numbered year, each nonregulated utility must prepare and file with the Commission a schedule of avoided costs equaling the nonregulated utility's forecasted incremental cost of resources over at least the next 20 years.

(3) Each public utility must file with the Commission draft avoided-cost information at the time it files its integrated resource plan and file final avoided-cost information within 30 days of a Commission decision of acknowledgement of the integrated resource plan to be effective ~~30~~ 60 days after filing. The information submitted will be maintained for public inspection and include the following data for calculating avoided costs:

(a) The estimated avoided costs on its system, solely with respect to the energy component, for expected levels of purchases from qualifying facilities. The levels of purchases will be stated in blocks of not more than 100 megawatts for systems with peak demand of 1,000 megawatts or more and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1,000 megawatts. The avoided costs will be stated on a cents-per-kWh basis, ~~during peak and off-peak periods,~~ by year, for the current calendar year and each of the next five years; and

(b) The public utility's estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kW, and the associated energy costs of each addition or purchase, expressed in cents per kWh. These costs will be expressed in terms of individual generating resources and of individual, planned firm purchases.

(4) Each public utility contracting to purchase nonfirm energy from a qualifying facility under OAR 860-029-0040(3)(a) must file with the Commission each quarter its nonfirm energy avoided cost.

(5) Nothing in these rules shall preclude the determination of avoided costs:

(a) As the average avoided costs over an appropriate period of time; or

(b) To reflect variations in avoided costs due to changes in stream flows, generating unit availability, loads, seasons, or other conditions.

(6) State review: Any data submitted by a public utility under this rule shall be subject to review and approval by the Commission. In any such review, the public utility has the burden of supporting and justifying its data.

(7)(a) On May 1 of each year, a public utility must file with the Commission updates to the avoided cost information filed under section (2) of this rule to be effective within 60 days of filing to reflect:

(A) Updated natural gas prices for utilities not subject to ORS 469A.052;

(B) ~~On- and off-peak f~~Forward-looking ~~electricity market~~ electrical capacity and energy prices, inclusive of updates to RFP prices or third-party data;

(C) Changes to the status of Production Tax Credit; and

(D) Any other action or change including changes to the capital costs of a proxy resource in an acknowledged IRP update that is relevant to the calculation of avoided costs.

(E) Changes to the market price of Renewable Energy Certificates.

(F) Changes to transmission expansion investment calculated consistently with the methodology specified in Commission order.

(b) In the event a utility's integrated resource plan is acknowledged within ~~60~~ 90 days of May 1 in a particular year, the utility may seek a waiver of either the May 1 update or the post IRP-acknowledgement filing.

(8) A public utility may propose or the Commission may require a public utility to file the data described in OAR 860-029-0080(3) anytime during the two-year period between filing integrated resource plans to reflect significant changes in circumstances, including, but not limited to, the acquisition of a major block of resources or the completion of a competitive bid. Such a revision will become effective 90 days after filing.

(9) At least every two years, the public utility must file with the Commission the data described in OAR 860-029-0040(4) and 860-029-0080(3).

SECTION 7. 860-029-0085 – REQUIREMENTS FOR STANDARD AVOIDED COST RATES

(1) Each public utility must file with the Commission standard avoided cost rates within 30 days of a Commission decision regarding acknowledgement of the public utility's integrated resource plan.

~~(2) Each public utility currently complying with Oregon's renewable portfolio standard must file both "renewable" and "non-renewable" standard avoided cost rates.~~

(3) The standard avoided cost rates filed by a public utility under section~~s~~ (1) ~~and (2)~~ of this rule are subject to review and approval as well as modification by the Commission. The Commission may suspend the standard avoided cost rates during review. In any such review, the public utility has the burden of supporting and justifying its standard avoided cost rates. The standard avoided cost rates will be effective ~~30~~ 60 days after filing unless otherwise determined by the Commission.

(4)(a) On May 1 of each year, a public utility must file with the Commission updates to its standard avoided cost rates under section~~s~~ (1) ~~and (2)~~ of this rule to reflect:

(A) Updated natural gas prices for utilities not subject to ORS 469A.052;

(B) ~~On- and off-peak f~~Forward-looking ~~electricity market~~ electrical capacity and energy prices, inclusive of updates to RFP prices or third-party data;

(C) Changes to the status of Production Tax Credit; and

(D) Any other actions or changes that are acknowledged by the Commission upon review of an IRP Update and that are relevant to the calculation of avoided costs.

(E) Changes to the market price of Renewable Energy Certificates.

(F) Changes to transmission expansion investment calculated consistently with the methodology specified in Commission order.

(b) In the event a utility's integrated resource plan is acknowledged within ~~60~~ 90 days of May 1 in a particular year, the utility may seek a waiver of either the May 1 update or the post IRP-acknowledgement filing.

(c) Updates filed under this section are subject to review and approval as well as modification by the Commission. The Commission may set the effective date of the standard avoided cost rates during review. In any such review, the public utility has the burden of supporting and justifying its standard avoided cost rates. Standard avoided cost rates filed under this section will be effective within 60 days of filing.

(5)(a) Upon request or its own motion, the Commission may consider updates to avoided cost rates to reflect significant changes in circumstances including, but not limited to, the acquisition of a major block of resources or the completion of a competitive bid process.

(b) An update under this section may be considered at any time.

(c) Updates to avoided cost rates under this section are subject to review and approval by the Commission and will become effective within 90 days after filing.

SECTION 8. 860-029-0120 – STANDARD POWER PURCHASE AGREEMENTS

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

(2) Qualifying facilities have the unilateral right to select a purchase period of up to 20 years for a standard power purchase agreement. Qualifying facilities electing to sell firm output at fixed prices have the unilateral right to a fixed-price term of up to 15 years, subject to the reduction specified in section (6) for a development period that exceeds three years. In addition, the fixed-price term continues to run during the cure period should the qualifying facility fail to meet the scheduled commercial operation date. Qualifying facilities may also select a nonfixed-price term of up to five years to run at the conclusion of the fixed-price term.

(3) The development period of a standard power purchase agreement begins on the Effective Date, unless the start of the development period is delayed by the initiation of the Network Upgrade cost allocation process in OAR 860-029-0044. The development period ends at 24:00 in the time zone in which the qualifying facility is located on the day before the scheduled commercial operation date specified in the standard power purchase agreement or such earlier date on which the qualifying facility achieves the commercial operation date in compliance with these rules.

(4) The purchase period of a standard power purchase agreement begins on the earlier of the commercial operation date or the scheduled commercial operation date. The scheduled commercial operation date may be delayed by Force Majeure, extended by agreement of the purchasing public utility and the qualifying facility or modified under subsection (5)(b) or section (6) of this rule. In these cases, the purchase period and fixed price term commence on the earlier of the commercial operation date or the delayed or extended scheduled operation date.

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

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

(b) Anytime within five years from the date of agreement execution. If the qualifying facility can, utilizing the process specified in section (6), provide an interconnection study by the purchasing utility showing that the time it will take the purchasing utility to complete the interconnection to the qualifying facility necessitates a commercial operation date longer than three years from the Effective Date, then the additional time necessitated by the interconnection up to an additional two years will not be taken off the period of the fixed-price term. Under other circumstances, the additional time will be taken off the period of the fixed-price term; or

(c) In any standard power purchase agreement with a scheduled commercial operation date more than three years after the Effective Date, except as specified otherwise in these rules, the fixed-price term will be reduced one day for every day of the development period after 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 period of three years and six months will have a fixed-price term of 14 years and 6 months. The fixed-price term will begin on the scheduled commercial operation date and will end after 14 years and 6 months.

(6) Modification of Scheduled Commercial Operation Date or Termination

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

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

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

(b) A qualifying facility that chooses to modify the scheduled commercial operation date under subsection (a) of this section (6) may not select a new scheduled commercial operation date more than five years from the date the standard power purchase agreement was executed except as specified otherwise in these rules;

(c) If a qualifying facility terminates the standard power purchase agreement under subsection (a) of this section (6), it is liable for damages incurred by the public utility up until the date of termination, which may be taken from the Project Development Security posted by the qualifying facility;

(d) In the event the qualifying facility is delayed in reaching commercial operation because of an event of Force Majeure or the public utility's default under the standard power purchase agreement or any other agreement related to the interconnection of the qualifying facility to the purchasing utility's system, including interconnection study agreements and interconnection agreements, the scheduled commercial operation date in the standard power purchase agreement will be extended commensurately with the delay caused by the event of Force Majeure or the public utility's default, except for periods of delay that could have been prevented had the qualifying facility taken mitigating actions using commercially reasonable efforts. An extension of the scheduled commercial operation date under this subsection is not subject to the fixed-price term reduction in subsection (5)(c) or the five-year limitation in subsection (5)(b).

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

(a) Unless otherwise excused under the standard power purchase agreement, damages for failure to meet the scheduled commercial operation date in a standard power purchase agreement are equal to the positive difference between the utility's replacement power costs less the prices in the standard power purchase agreement during the period of default, determined on a daily basis with positive differences aggregated and invoiced as a monthly sum, plus costs reasonably incurred by the utility to purchase replacement power and additional transmission charges, if any, incurred by the utility to deliver replacement energy to the point of delivery.

(b) If the qualifying facility would have been required by the standard power purchase agreement to transfer Renewable Energy Credits to the public utility during the period when the qualifying facility is in default under this subsection, damages owed to the public utility will include the public utility's cost to acquire replacement Renewable Energy Credits.

(c) Notwithstanding subsections (a) and (b), damages incurred under this section may not exceed an amount equal to what the qualifying facility would have received under the standard power purchase contract for energy delivered during the default period.

(8) Subject to the one-year cure period in section (7) above, a utility may terminate a standard power purchase agreement for failure to meet the scheduled commercial operation date in the power purchase agreement, if such failure is not otherwise excused under the agreement.

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

(10) The standard power purchase agreement must include a mechanical availability guarantee (MAG) for wind, hydroelectric, and solar qualifying facilities as follows:

(a) A 90 percent overall guarantee, measured per turbine for wind resources and system-wide for other resources, starting three years after the commercial operation date for qualifying facilities with new contracts or one year after the commercial operation date for qualifying facilities that renew a contract or enter into a superseding contract, subject to an allowance for 200 hours of planned maintenance per turbine per year that does not count toward calculation of the overall guarantee.

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

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

(B) Multiplying the "shortfall" by the positive difference, if any, obtained by subtracting the Contract Price from the price at which the utility purchased replacement power; and

(C) Additional ancillary service and transmission costs to deliver replacement power to the point of delivery and the cost of replacement renewable energy certificates, if any.

(c) The 90 percent availability guarantee will be reduced on a pro rata basis for any portion of the annual period the qualifying facility was prevented from being available for reasons of Force Majeure or a default by the purchasing public utility under the power purchase agreement or interconnection agreement.

(d) Notwithstanding subsection (b), the total amount of damages owed to the purchasing public utility by a qualifying facility for failure to meet the MAG will not exceed what the qualifying facility would have been paid under the standard power purchase agreement had it delivered sufficient output to meet the MAG.

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

(12)(a) The standard purchase agreement will include an annual minimum delivery guarantee (MDG) for geothermal and biomass qualifying facilities equal to 90 percent of the qualifying facility's expected energy for the year.

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

(A) Determining the amount of the "shortfall" for the year, which is the difference between 90 percent of the qualifying facility's expected energy for the year and the actual Net Output delivered by the qualifying facility to the purchasing public utility in the year;

(B) Multiplying the "shortfall" by the positive difference, if any, obtained by subtracting the Contract Price from the price at which the utility procured replacement power; and

(C) Additional ancillary service and transmission costs to deliver replacement power to the point of delivery and the cost of replacement renewable energy certificates, if any.

(c) Notwithstanding subsection (b), the total amount of damages owed to the purchasing public utility by a qualifying facility for failure to meet the MDG will not exceed what the qualifying facility would have been paid under the standard power purchase agreement for energy it would have delivered had it met the MDG.

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

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

(14) Incremental Facility Upgrades.

(a) During the development period, the qualifying facility may make reasonable modification to the design and components of its facility from the design and components contained in the power purchase agreement. The qualifying facility is obligated to provide the purchasing public utility an as-built supplement describing the Facility within 90 days after the commercial operation date. Except with the purchasing utility's written consent or as described in subsection (b) of this rule, the Facility as reflected in the as-built supplement 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 an expected annual net output that is greater than 10 percent above that specified in the power purchase agreement at the time it was executed.

(b) In the event that the qualifying facility seeks to upgrade the facility during the development period or the term of the power purchase agreement in a manner that does not increase the Nameplate Capacity Rating of the facility in the power purchase agreement, but which is reasonably likely to cause the expected annual net output to exceed that listed in the power purchase agreement by more than 10 percent, such upgrades may be made without the utility's prior approval subject to the following requirements:

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

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

(C) Within 30 days after receiving such a request, the purchasing utility must respond with indicative pricing for the expected incremental additional Net Output to be generated as a result of the upgrades and which exceeds 10 percent of the expected annual Net Output specified in the power purchase agreement.

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

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

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

(15) Project Development Security. A new qualifying facility that has executed a standard power purchase agreement that does not meet the creditworthiness requirements in this rule must post Project Development Security for the purchasing public utility's benefit within 120 days of the Effective Date of the standard power purchase agreement. The amount of required Default Security will be $150/kWh. The obligation to maintain the Project Development Security will expire once the qualifying facility commences commercial operation. The qualifying facility may use either of the following options to post Project Development Security:

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

(b) Letter of Credit Security. The qualifying facility shall post and maintain in an amount equal to the Project Development Security either a guaranty from a party that satisfies the creditworthiness requirements under Section (18) of this rule, or a Letter of Credit in favor of the purchasing public utility. To the extent the public utility receives payment from the Project Development Security for damages in the event of default, the qualifying facility will, within 15 days, restore the Project Development Security as if no such deduction had occurred.

(16) Default Security. A qualifying facility that has executed a standard power purchase agreement that does not meet the public utility's creditworthiness requirements must post Default Security upon commencing commercial operation. The amount of required Default Security will be $50/kWh. The qualifying facility may use one of the following options to post Default Security:

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

(b) Letter of Credit Security. The qualifying facility shall post and maintain in an amount equal to the Default Security either a guaranty from a party that satisfies the creditworthiness requirements under section (18) of this rule, or a Letter of Credit in favor of the purchasing public utility. To the extent the public utility receives payment from the Default Security for damages in the event of default, the qualifying facility will, within 15 days, restore the Default Security as if no such deduction had occurred.

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

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

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

(18) Creditworthiness requirements under subsections (15) and (16) of this rule may be satisfied by:

(a) A senior, unsecured long term debt rating (or corporate rating if such debt rating is unavailable) of:

(A) 'BBB+' or greater from S&P Global Ratings; or

(B) 'Baal' or greater form Moody's Investor Services; provided that if such ratings are split, the lower of the two ratings must be at least 'BBB+' or 'Baal' from S&P Global Ratings or Moody's Investor Services.

(b) If a rating from S&P Global Ratings or Moody's Investor Services is not available, the qualifying must provide financial documentation that supports an equivalent rating as determined by the purchasing utility through a reasonable internal process review and utilizing a credit scoring model. In such case, the purchasing utility will request audited financial statements for the most recent two full years (including balance sheet, income statement, statement of cash flows, and accompanying footnotes), which information is evaluated considering:

(A) the type of generation resource;

(B) the size of the resource;

(C) the expected energy delivery start date; and

(D) the term of the power purchase agreement.

(c) The internal review process will evaluate, at minimum, certain profitability, cash flow, liquidity, and financial leverage metrics.

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

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

SECTION 9. 860-029-0123 – DEFAULT, DAMAGES, AND TERMINATION

(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 rule:

(a) Failure to begin power deliveries by scheduled commercial operation date;

(b) Failure to provide Project Development or Default Security in the applicable time frame;

(c) Failure to maintain qualifying facility status;

(d) Failure to meet the PPA obligation 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 MAG for two (2) consecutive years;

(h) Failure to satisfy applicable MDG for three (3) consecutive years;

(i) Breach of any warranty or representation in the power purchase agreement; and

(j) Failure to comply with any other material obligation under the power purchase agreement.

(2) The following events, if uncured within the applicable cure period, may constitute a default by the purchasing public utility under the standard power purchase agreement for which the Qualifying Facility may terminate the power purchase agreement subject to the provisions of this rule:

(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;

(c) Breach of any warranty or representation in the power purchase agreement; and

(d) Failure to comply with any material obligation under the power purchase agreement.

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

(4) Cure periods:

(a) The qualifying facility has one year in which to cure the default for failure to meet the scheduled commercial operation date, as specified in OAR 860-029-0120(7).

(b) Except with a respect to a failure to meet the MAG or MDG, which failures are not curable, the non-defaulting party has 30 days following written notice from the non-defaulting party in which to cure the event of default. This 30-day period shall be extended by an additional 90 days if:

(A) The failure cannot reasonably be cured within the 30-day period;

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

(C) The defaulting party commences the cure within the original 30-day period.

(5) Damages. If damages are incurred as a result of a breach under the standard purchase agreement, the breaching party must remit payment in the full amount of the damages to the non-breaching party no later than 30 days after the breaching party receives an invoice for damages from the non-breaching party if the amount of payment is not the subject of good-faith dispute. The invoice for damages must include a written statement explaining in reasonable detail the calculation of the damages amount.

(6) Subject to the cure periods in section (4), the non-defaulting party may issue a notice of termination to terminate a standard power purchase agreement for a default under sections (1) or (2), as applicable.

(7) 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 period.

(8) Termination of Duty to Buy. If a standard power purchase agreement is terminated because of default by the qualifying facility and the qualifying facility wishes to sell Net Output to the purchasing 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 scheduled end date in the terminated agreement. The purchasing utility may also 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 this section through use or establishment of a special purpose entity or other affiliate.

(9) 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 24 months following the date of termination, including any associated transmission necessary to deliver such replacement power; and

(b) The contract price for such 24-month period ("Termination Damages"), provided the damages may not exceed the cost the utility would have incurred to purchase the qualifying facility's power and Renewable Energy Credits under the terminated power purchase agreement. 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 30 days of receipt of the written Notice of Termination from the public utility.

(10) Duty/Right to Mitigate. Both the purchasing public utility and qualifying facility have a duty to mitigate damages and must 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.

(11) Security. If a standard power purchase agreement is terminated because of the qualifying facility's default, the purchasing 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 purchasing public utility in whatever form to reduce the amounts that the qualifying facility owes the purchasing public utility arising from such default.

(12) 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.

(13) Notice of intent to renew.

(a) A qualifying facility with an existing power purchase agreement that submits a Notice of Intent to Renew is subject to damages if the qualifying facility does not commence operation under a new power purchase agreement by the scheduled commercial operation date indicated in the Notice of Intent to Renew.

(b) Damages under this section will be calculated as described in subsection (9) of this rule and based on avoided costs in effect at the time of the purchasing utility's receipt of the Notice of Intent to Renew and assumptions regarding the qualifying facility's output from the qualifying facility's expired power purchase agreement, but will be owed for a period of no more than two years after the scheduled commercial operation date.

(c) Damages are not owed by a qualifying facility under this subsection if the qualifying facility executes a new power purchase agreement as indicated in the Notice of Intent to Renew, or if the Commission determines that the purchasing utility was a substantial factor, directly or indirectly, in the failure to execute a new power purchase agreement.