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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1610

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation Into Qualifying Facility Contracting and Pricing.	ORDER

DISPOSITION: UPDATES ADOPTED; OFFICIAL NOTICE TAKEN; PHASE II OPENED

I. INTRODUCTION

We opened this docket to continue our evaluation of policies and procedures to implement the Public Utility Regulatory Policies Act (PURPA), federal legislation enacted in 1978 with the primary purpose of providing a market for the electricity produced by small power producers and cogenerators. Although PURPA is a federal law, states are responsible for implementing significant aspects of the law.

In this docket, we consider specific proposals raised by Staff and the parties to revise the rates, terms, and conditions for Qualifying Facility (QF) standard contracts in Oregon. While considering these proposals, however, we remain grounded in the policies we articulated in previous orders addressing these issues, and decline to make changes without compelling evidence of a need for the proposed revision. Our consideration of any proposal to revise the rates, terms, and conditions for QF standard contracts is done on a prospective basis only. To the extent issues were raised regarding reformation of existing PURPA contracts, we decline to address them in this forum.

We accept some proposed changes, postpone others for consideration during a second phase of this docket, and decline to take up the remaining issues proposed by the parties at this time, as follows:

A. No Changes and No Further Consideration Needed in Phase II

We make no changes to the following standard contract elements:

- We retain the eligibility cap for standard contracts at 10 megawatts. We reject Idaho Power's proposal to use a 100 kilowatt eligibility cap for standard contracts in its service territory, consistent with its Idaho service territory.
- We retain our current methodology for calculating standard avoided cost prices and standard renewable avoided cost prices, with the modifications described below.

We make no changes to current QF pricing, contract, and procedural elements other than those identified below.

B. Changes to Be Made to Prospective Standard Contracts

We adopt the following prospective changes to our current QF policies:

- We modify the current methodology for calculating standard avoided cost prices and standard renewable avoided cost prices to account for the capacity contribution of different QF resources and wind integration costs.

- We adopt a new requirement for utilities to provide a limited update to avoided cost prices on May 1 each year. We retain our requirement for an update to avoided cost prices within 30 days after acknowledgement of an Integrated Resource Plan (IRP), but may use our discretion to waive the post-IRP update if it falls within 60 days of May 1 in a particular year. We retain our current provisions for requests for mid-cycle updates.

- We eliminate the requirement that utilities offer the following standard avoided cost pricing options: Gas-Market Indexed; Banded Gas Market Indexed; Deadband Index Gas; Index Gas; and Mid-C Index.

- We modify the criteria for a single project to limit the passive investor exemption to independent family or community-based projects.

- We adopt revised requirements for mechanical availability language in standard contracts, and we direct the parties to develop a methodology in Phase II of these proceedings to implement one requirement.

C. Issues to be Further Addressed in Phase II

We take no action on the following issues now, but will address them in a Phase II proceeding:

- Definition of legally enforceable obligation (*Issue 6B*)

- Methodology for non-standard rates (*Issue 1A*)

- How to calculate the third-party transmission costs to move QF output in a load pocket to load *(Issue 4B)*

II. HISTORICAL BACKGROUND

As we stated in Order No. 05-584, PURPA encourages resource competition and the development of QF cogeneration and renewable energy technologies by requiring electric utilities to offer to purchase QF electric energy. PURPA requires that the rates utilities pay for electric energy purchased from QFs may not exceed the incremental cost to the electric utility of alternative electric energy, and defines "incremental cost" as "the cost to the electric utility of the electric energy which, but for the purchases from such [QF], such utility would generate or purchase from another source."[1] PURPA further requires that electric utilities "purchase power from QFs at rates that are just and reasonable to the utility's customers, in the public interest, and that do not discriminate against QFs, but that are not more than avoided costs."[2] The Federal Energy Regulatory Commission (FERC) promulgated regulations implementing PURPA, with the aim to create a market for QF electricity by requiring utilities to purchase QF energy at the utility's full avoided costs, and to adopt non-discriminatory interconnection and back-up power policies and pricing.[3]

Because PURPA and FERC regulations delegate the calculation of appropriate QF contract rates to individual state agencies, Oregon passed PURPA legislation, and this Commission developed rules implementing the federal and state requirements in 1980. In Order No. 81-319, the Commission established policies for contracting with QFs, noting that its primary goal was "to provide maximum economic incentives for development of qualifying facilities while insuring that the costs of such development do not adversely impact utility ratepayers who ultimately pay these costs."[4] The Commission further expounded on the goals of PURPA implementation in a 1988 report to the Oregon Legislature, noting that it is the Commission's policy that "federal and state laws and regulations will be carried out in a manner that encourages the economically efficient development of qualifying facilities in Oregon. It is the goal of the Commission to ensure desired qualifying facility development through stable and predictable actions by the Commission, accurate price signals, and full information to developers and the public regarding power sales requirements."[5]

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[1] *See* Order 05-584 at 6, *citing* 16 U.S.C. § 824a-3(a)-(b), 18 C.F.R. § 292.101 *et seq.*
[2] *See* Order 05-584 at 6, *citing* 16 U.S.C. § 824a-3(d).
[3] *See* 18 C.F.R. § 292.101 *et seq.*
[4] *See In the Matter of the Investigation into Electric Utility Tariffs for Cogeneration and Small Power Production Facilities*, Docket No. R-58, Order No. 81-319 at 3 (May 6, 1981).
[5] *See* Order No. 05-584 at 9, *citing* 1988 OPUC Report to the Oregon Legislature.

In docket UM 1129, the Commission opened an investigation into its implementation of PURPA, and subsequently issued Orders No. 05-584, 06-538, and 07-360. In Order No. 05-584, we adopted a 10 MW size threshold for standard contracts, 20-year standard contracts with 15-year fixed prices, and the use of the proxy method for calculation of PGE's and Pacific Power's avoided cost rates. In Order No. 06-538, we addressed issues related to the utilities' proposed filed standard power purchase contracts. In Order No. 07-360, we addressed issues related to larger QFs, and adopted specific guidance for adjusting avoided cost rates. Subsequently, we addressed policies for small generator interconnections in Order No. 09-186, and designated the IRP as the appropriate venue for the resource sufficiency/deficiency demarcation, and required PGE and Pacific Power to purchase renewable QF power at a renewable avoided cost rate, in Orders No. 10-488 and 11-505.[6]

III. PROCEDURAL HISTORY

On January 27, 2012, Idaho Power Company filed an application to lower the eligibility cap for a QF standard contract from 10 MW to 100 kW.[7] The application was made to address requests received by the company for Oregon standard contracts from nine different QFs with a total nameplate capacity of 73 MW, when average total load for Idaho Power's Oregon customers in 2011 was only 87 MW.[8] The Commission considered the filings at its February 13, 2012 Public Meeting and rejected them, as documented in Order No. 12-042. The Commission concluded, however, that the requirement in Idaho Power's Schedule 85 that the company respond within 15 days to any request for an Energy Sales Agreement be suspended until Idaho Power's avoided costs were updated through the IRP process, thereby effectively prohibiting Idaho Power from entering into any standard contracts for that period of time.

At a public meeting on April 24, 2012, the Commission addressed an application (docket UM 1590) by Idaho Power to revise its methodology to calculate standard avoided-cost prices paid to QFs.[9] After a broader discussion acknowledging other recent issues related to QF contracting, avoided costs pricing, and the transmission of QF power, the Commissioned ordered, in Order No. 12-146, that a generic docket be opened to

[6] In 2007, Oregon enacted Senate Bill 838 (SB 838), establishing a renewable portfolio standard (RPS) that required large utilities to provide 25 percent of their retail electric sales from new renewable energy sources by 2025, and setting as a goal that small-scale renewable energy projects with a generating capacity of 20 MW or less comprise of at least 8 percent of Oregon's retail electric supply by 2025. In Order No. 11-505, we directed Pacific Power and PGE to file applications with proposed rates and tariffs for a renewable-based avoided cost price option, available for QFs whose output counted toward compliance with the RPS in SB 838.

[7] The application was docketed as UM 1575. Concurrent with the application, Idaho Power also made an Advice filing, docketed as UE 244, to revise Schedule 85, the company's PURPA implementation schedule in Oregon, to reflect the requested reduced eligibility cap from 10 MW.

[8] Idaho Power/400, Stokes/3.

[9] *See* UM 1590. The Commission also addressed, at the same time, a filing by Idaho Power to raise avoided-cost prices paid to QFs (Docket No. UM 1593). *See* Order No. 12-146 (Apr 25, 2012).

generally investigate issues related to electric utilities' purchases from QFs. The general investigation was docketed as UM 1610. In Order No. 12-146, the Commission also adopted Staff's recommendation that Idaho Power use the Standard, or Oregon, Method for avoided cost methodology used by PGE and Pacific Power.

After engaging in discussion about the scope of issues to be addressed in these proceedings, parties submitted lists of proposed issues on October 3, 2012. On October 25, 2012, the administrative law judge (ALJ) issued a ruling adopting an issues list.[10] On December 21, 2012, the ALJ issued a ruling adopting the Phase I schedule and addressing related dockets. Testimony was filed by the following parties: Commission Staff; Portland General Electric Company (PGE); PacifiCorp, dba Pacific Power; Idaho Power Company; Oregon Department of Energy (ODOE); the Community Renewable Energy Association (CREA); Renewable Northwest Project (RNP); the Renewable Energy Coalition (REC); Small Business Utility Advocates (SBUA); OneEnergy, Inc. (OneEnergy); Threemile Canyon Wind I, LLC (Threemile); and Obsidian Renewables, LLC (Obsidian). A hearing was held on May 23, 2013, with briefs filed both before and after the hearing. A motion was granted on January 3, 2014, taking official notice of a FERC Order Granting Petition for Declaratory Order in Part in Docket No. EL14-1-000 issued on December 16, 2013 (145 FERC ¶ 61,215).

IV. DISCUSSION

A. Eligibility Cap for Standard Contracts (Issue 5A)

Under our current QF framework, QFs of all resource types that have a nameplate capacity of 10 MW or less are eligible to receive a standard contract with standard avoided cost rates calculated using the Standard or Oregon Method. QFs with a nameplate capacity greater than 10 MW must negotiate a non-standard contract, which uses the utility's standard avoided cost rates as a starting point, and permits modifications to be negotiated according to specific guidelines and methodologies approved by the Commission.[11]

As discussed above, this docket was opened following dual applications by Idaho Power to lower the eligibility cap for a QF standard contract from 10 MW to 100kW, and to revise its methodology to calculate standard avoided-cost prices paid to QFs. A primary reason we opened this docket was to investigate concerns that avoided cost prices paid to QFs exceeded reasonable estimates of avoided costs. The parties ask whether we should

[10] The Issues List, as amended by a ruling issued on January 30, 2013, is attached to this order as Appendix A.

[11] *See* Order No. 05-584 at 16-17. A standard contract is a term "used to describe a standard set of rates, terms and conditions that govern a utility's purchase of electrical power from QFs at avoided cost. Standard contracts are made available to a defined class of QFs that are deemed eligible under federal or state law to receive standard rates." *Id.* at 12.

change the 10 MW eligibility cap for standard contracts that we set in Order No. 05-584, thereby requiring most QFs to negotiate a contract and allowing the calculation of avoided cost rates paid to be adjusted based on the specific characteristics of a particular project.

1. Parties' Positions

Staff, ODOE, CREA, SBUA, and REC recommend that we retain our current eligibility cap for standard contracts. The parties argue that any mismatches between the value of a QF's energy to a utility and its customers and the prices paid for that energy are best addressed by adjusting avoided cost rates in standard contracts, rather than changing the cap. These parties also note that not having a standard contract would disrupt project development for small QFs, and would interfere with Oregon's efforts to meet its obligations under SB 838. OneEnergy agrees the current cap should be retained, but argues for creation of a subclass of QFs with output of 3 MW or less that are directly interconnected to the purchasing utility's distribution system and provide additional standard contract options in recognition of the special benefits this QF class provides—for example, tilted prices, 25-year fixed term, and a 3.9 percent line loss adder.

Idaho Power, PGE, and Pacific Power argue for a change in our existing cap. Idaho Power argues that for wind and solar QFs, the cap should be lowered to 100 kW or less, to be consistent with the company's Idaho jurisdiction and to prevent "regulatory arbitrage." Idaho Power notes that since the Commission adopted the 10 MW eligibility cap for standard contracts, the company has been faced with a deluge of QF project developments, and the resulting influx of largely intermittent QF power is having significant unintended detrimental operational and financial impacts on Idaho Power's system and customers. Idaho Power argues lowering the eligibility cap for wind and solar QFs will allow the avoided cost rate to be tailored for the availability, dispatchability, reliability and the usefulness of the QF's energy and capacity. PGE likewise recommends a 100 kW cap, asserting that 100 kW is a fair demarcation between a small project for which barriers to development truly exist and a large project with more capability to negotiate contracts.

Finally, Pacific Power argues the cap should be lowered to 3 MW, because Pacific Power's experience has been that QFs over 3 MW generally have technical, business, and legal experts engaged in the analysis, development, and contracting phases of the project, regardless of the resource technology. Pacific Power states standard avoided costs rates may reflect an inherent overpayment to QFs to the extent the QF's characteristics are not as optimized as the characteristics of the proxy plant on which standard avoided costs are based. Pacific Power argues lowering the cap would mitigate issues before the Commission, including the disaggregation of large single projects into multiple projects, because it would be much more difficult for smaller projects to disaggregate.

2. *Resolution*

As we have noted in previous orders addressing this issue, because standard contracts have pre-established rates, terms, and conditions that an eligible QF can elect without any negotiation with the purchasing utility, "standard contract rates, terms and conditions are intended to be used as a means to remove transaction costs associated with QF contract negotiation, when such costs act as a market barrier to QF development."[12] If a QF is not eligible for a standard contract, a utility is still obligated to purchase a QF's net output at the utility's avoided cost, but the QF must negotiate the rates, terms and conditions of a power purchase contract with the purchasing utility. The eligibility cap of 10 MW is intended to address the challenges smaller QFs face in entering our market, including the transaction costs incurred in negotiating an agreement, and other market barriers such as asymmetric information and an unlevel playing field, all of which complicate the negotiation of non-standard QF contracts. These kinds of market barriers "can render certain QF projects uneconomic to get off the ground if an individual contract must be negotiated."[13]

Reviewing our rationale for our current policy, and the arguments of Staff, ODOE, CREA, SBUA, and REC, we retain the 10 MW eligibility cap for standard contracts for all utilities. RNP, REC, CREA, SBUA, and ODOE testified that lowering the eligibility cap would deter QF development in Oregon, largely because of the increased transaction costs incurred when negotiating an agreement. These parties note that a QF developer may only have access to financing after a PPA has been signed; prior to that time, the QF developer may rely only on the developer's own resources. Small QFs under 10 MW may lack the resources to negotiate complex modeling and inputs with a utility.

We acknowledge the concerns raised by Idaho Power, Pacific Power, and PGE that the application of our current methodology may result in the utility and its customers offering prices in excess of actual avoided costs. However, as explained below, we conclude that the utilities' concerns about potential overpayments are best addressed through our decisions to require annual updates to avoided costs. As discussed below, we also address ways to incorporate wind integration costs and resource capacity contributions into standard avoided cost price calculations and standard renewable avoided cost price calculations, and we direct the parties to further consider in the next phase of these proceedings how to calculate the third-party transmission costs attributable to a QF.

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[12] Order No. 05-584 at 16, *citing* Order No. 09-1605 at 2 (noting that the "transaction costs associated with negotiating a QF/utility power purchase agreement could be prohibitive for small QFs and effectively eliminate them from the marketplace. The standard rate is intended to address this concern by minimizing the transaction costs of negotiating a power purchase agreement.").
[13] *Id.*

Further, we find it reasonable for all three utilities to be subject to the same standard contract methodology. We see no off-setting gain in administrative efficiencies to adopt different standards for different Oregon utilities.

B. Calculation of Avoided Cost Prices for Standard and Non-Standard Contracts (Issues 1A, 2A, and 4A)

Issue 1A asks what methodology should be applied for calculating avoided cost prices, and whether the same methodology should apply to all three electric utilities operating in Oregon. Issue 2A asks whether there should be different avoided cost prices for different renewable generation sources. Finally, Issue 4A asks whether the costs associated with the integration of intermittent resources should be included in the calculation of avoided cost prices or otherwise be accounted for in the standard contract. Together, these three questions address whether and how to change the calculation of avoided cost prices in Oregon.

Under our current rules, Pacific Power and PGE must use the Standard Method to calculate standard avoided cost prices, and the Renewable Method to calculate renewable avoided cost prices.[14] The Commission requires electric utilities to set rates based on the cost of a proxy resource during periods of resource deficiency and on monthly market prices during periods of resource sufficiency. The proxy is a natural gas combined-cycle combustion turbine (CCCT) proxy resource for standard avoided cost prices, and the next avoidable renewable resource identified in the electric company's IRP for renewable avoided cost prices. Currently, the next avoidable renewable resource in PGE's and Pacific Power's IRPs are wind resources. The total fixed costs of the avoided proxy wind resource are allocated to on- and off-peak prices. The on-peak price includes an implicit, small capacity contribution. Non-standard avoided cost rates for large QFs are negotiated between the utility and the individual QF using the standard avoided cost rates as a starting point, with specific guidelines and methodologies approved by the Commission.

Until recently, Idaho Power used the Surrogate Avoided Resource (SAR) methodology to determine standard contract avoided cost prices. In March of 2012, Idaho Power submitted an application to revise the methodology used to determine its standard avoided cost prices, arguing that the SAR method resulted in avoided cost prices that exceed true avoided costs, and requesting an investigation into the use of its proposed IRP method. Staff suggested, alternatively, that Idaho Power use the Standard Method for avoided cost methodology used by PGE and Pacific Power, finding no reason to differentiate between the utilities. In Order No. 12-146, we adopted Staff's recommendation and approved Idaho Power's revised avoided cost prices, calculated using the Oregon Method. Idaho Power's alternate Schedule 85, filed on April 20, 2012, went into effect on April 25, 2012. The Idaho Public Utilities Commission (IPUC)

[14] The Standard Method has been used by PGE and Pacific Power since the issuance of Order No. 06-538 (Sept 20, 2006), and is calculated using a spreadsheet with easily identifiable inputs and assumptions.

recently issued an order requiring the continued use of a SAR-based avoided cost methodology for all QF projects below the published rate eligibility cap. The IPUC retained the 100 kW published rate eligibility cap for wind and solar QFs, as well as a 10 MW cap for all other resource types.[15]

1. Parties' Positions

Staff: Staff advocates that the Commission retain its current methodologies for calculating standard avoided cost prices and standard renewable avoided cost prices, with modifications to account for the capacity contribution of different QF resources types, integration costs, and third-party transmission costs. Staff recommends the Commission allow an offset to avoided cost prices when utilities incur costs to integrate power from a wind QF into their systems, and expressly include avoided costs to integrate intermittent resources in the calculation of standard avoided cost prices when those costs are avoided. With regard to the integration of intermittent resources, Staff argues that both avoided and incurred integration costs for wind QFs should be accounted for under the Renewable Method. Staff states solar QFs should not be responsible for integration costs due to the lack of quantification of such costs and the likelihood that they are minimal.

ODOE: ODOE argues the avoided costs determined by the current proxy plant method should be adjusted based on the capacity contribution and integration costs attributable to QF resource type. Avoided cost prices paid to the QF during the resource deficiency period should be adjusted for the relative capacity value of the QF resource compared to the utility's avoided resource. ODOE further argues avoided cost prices should be calculated during the resource sufficiency period using energy prices from a single market hub rather than blended market prices. One of two market hubs should be used, depending on the QF's location, to best represent the costs that would be avoided by purchasing energy from the QF. Finally, with regard to integration of intermittent resources, ODOE argues avoided cost prices paid to a wind QF should be adjusted for the relative integration cost of that QF versus the avoided resource. The utility's acknowledged IRP should be the source of the wind integration cost. Solar QFs should not be charged for integration until utilities demonstrate there are material integration costs for solar generations.

CREA: CREA argues no compelling evidence exists to depart from the general framework established in docket UM 1129, and argues that all three utilities should be subject to the same methodology. Regarding different renewable generation sources, CREA argues renewable avoided cost rates should be adjusted upwards during the deficiency period to compensate those renewable QFs who allow the utility to partially or fully avoid the costs of integrating renewable power from the avoided large utility wind plant. An upward adjustment should apply to baseload QFs, solar QFs, and even wind

[15] *See* IPUC Order No. 32697, Case No. GNR-E-11-03 (Dec 18, 2012).

QFs that are too small to impose significant integration costs or that contract with a third party or a transmission provider to integrate their output prior to delivery to the utility.

Addressing the costs of integrating intermittent resources, CREA advocates for maintaining our existing policy, and calculating standard rates in the aggregate without adjustment for project-specific costs and benefits. CREA argues the utilities have failed to demonstrate that small QFs impose the same integration costs as a large utility wind plant. CREA states the problem with adjusting avoided cost prices for wind integration is that it cuts against the framework established in docket UM 1129, where the Commission chose to calculate rates in the aggregate and overlook granular individual costs as well as benefits of small QFs.[16] Standard rates now fail to account for many characteristics that would *increase* avoided cost rates for small projects; as a result, if an integration charge is implemented for standard rates, upward adjustments for aggregate benefits to the system provided by small QFs must also be made to standard rates.

OneEnergy: OneEnergy states that while the current framework should be retained, the Commission should reaffirm that the current methodology is intended to calculate a utility's full avoided cost, including firm gas transportation, transmission capacity, water rights, taxes, and operating efficiency. OneEnergy states current methodologies either omit major CCCT expenses or make stakeholder vetting of cost inputs impossible. With regard to methodologies for the three electric utilities, OneEnergy argues Mid-Columbia should be used unless a QF is delivering to Pacific Power south of either the Alvey transmission substation near Eugene or the Grizzly substation near Redmond.

OneEnergy argues the renewable avoided cost should not be decremented for integration during the sufficiency period, and states the full avoided cost must account for all costs the utility avoids by purchasing QF output instead of building the avoided renewable resource, including expected lost generation due to Balancing Authority curtailments of the renewable resource and degradation in performance of the renewable resource over its lifetime, and state and local taxes paid by the renewable resource. Finally, OneEnergy argues integration charges should only apply to wind until utilities quantify non-wind integration costs and such costs are vetted through a public process. OneEnergy states solar integration costs are unstudied and likely insignificant, and that utilities have not met their burden here to justify adjusting avoided costs.

SBUA: SBUA endorses retaining the current methodology, arguing that it maintains transparency and accuracy.

RNP: RNP notes the cost of solar integration has not been through the IRP process. For wind QFs, RNP does not object to integration cost adjustments to avoided costs, so long as the Commission provides for timely updates and a "robust" process for reviewing utility wind integration wind studies.

[16] CREA's Prehearing Brief at 8, *citing* Order No. 05-584 at 38-39.

REC: REC states the Commission should retain the current methodologies for calculating avoided cost rates. REC argues Idaho Power should be permitted to use a different methodology than PGE or Pacific Power, namely the methodology approved by the IPUC, which will result in more accurate rates. REC states renewable avoided cost rates should be distinguished based on whether the resources require integration. Baseload renewable QFs allow the utilities to avoid integration costs, and should be compensated for this more valuable power. With regard to Issue 4A, REC argues the Commission should establish a reciprocal policy that treats QFs fairly and, if the cost of integration will be included in standard rates, then it is appropriate to charge variable resources and credit non-variable resources as PGE does. REC opposes integration charges for solar resources based on wind integration costs, because integration costs should be based on accurate information and actual costs and utilities should not be allowed to impose integration costs not based on a study.

Obsidian: Obsidian argues that the Commission should retain its current methodologies, and should make the renewable rate, calculated consistently with Order No. 11-505, available to QFs immediately. Addressing the costs associated with intermittent resource integration, Obsidian argues the output variability of a QF varies by generation technology and fuel source. Obsidian states, that PGE and Pacific Power urge the Commission to treat all variable energy resources the same, but do so without evidence to back up the request. Finally, Obsidian argues any integration charge for solar facilities must be based on actual integration costs.

PGE: PGE argues the Commission should retain the current method for calculating avoided cost prices based on the cost of the next avoidable resource in the company's current IRP, but only for projects smaller than 100kW. PGE further argues avoided costs should be based on the resource the utility is avoiding. However, the price should be adjusted for the capacity contribution to peak load based on the type of resource and for integration. Finally, PGE argues the costs associated with integration of intermittent resources should be included in the calculation of avoided cost prices, because intermittent QF resources impose real costs on PGE's system that should not be subsidized by customers. At a minimum, PGE advocates Staff's proposals to adjust for capacity and integration should be adopted.

Idaho Power: Idaho Power argues the Commission should adopt Idaho Power's Standard Method (or Oregon Method) for determining standard avoided cost prices, except for one modification: the separate calculation of the energy and capacity components of the avoided cost price, to take into account the specific capacity contributions made by different types of QFs. Idaho Power states this modification would account for a QF's capacity contributions by multiplying avoided cost of capacity based on a CCCT by a factor that reflects the QF's contribution to meeting the company's peak-hour load. For negotiated QF contracts, Idaho Power argues that it should use the incremental cost IRP methodology, as it does before the IPUC. This fixes the flaws with the current methodology, which results in customers assuming an inordinate market risk, and better embodies FERC's definition of avoided cost. Idaho Power argues there should be an integration charge for any wind QF, commensurate with the results of its most recent wind integration study.

Pacific Power: Pacific Power advocates for adoption of two distinct methods for calculating avoided costs: a standard method based on a proxy resource to calculate prices for QFs up to 3 MW (Proxy Method), and a model-based approach referred to as the partial displacement differential revenue requirement method (PDDRR Method) for QFs larger than 3 MW that captures resource-specific characteristics and impacts on the utility system to calculate a negotiated avoided cost price. With regard to different renewable generation sources, Pacific Power argues that both standard and non-standard avoided cost prices should be differentiated for intermittent and non-intermittent renewable resources, and that avoided cost prices should be adjusted for integration costs for QFs supplying intermittent generation. Pacific Power proposes to calculate the cost of integrating *all* intermittent resources on its system based on its wind integration analyses. For standard avoided costs, Pacific Power proposes to specify in the company's Schedule 37 that the price offered to intermittent QFs during the renewable resource sufficiency period will be reduced for the cost of integration as identified in the company's IRP. For non-standard prices determined by the PDDRR Method, Pacific Power proposes calculating integration costs in GRID annually based on the additional reserves required to regulate and follow wind per the wind integration study.

2. Resolution

We first return to the goal of this docket: to ensure that our PURPA policies continue to promote QF development while ensuring that utilities pay no more than avoided costs. To that end, we retain our current methodology for both Standard and Standard Renewable avoided cost prices, subject to modifications for integration costs and capacity contributions addressed below. We defer review of any proposed changes to the calculation of rates for non-standard contracts to the Phase II proceeding.

<u>Avoided Cost Prices</u>

PGE and Pacific Power have used our current methodologies to calculate standard avoided costs since we issued Order No. 06-538 in 2006, and Idaho Power has used them since 2012. Calculation of each utility's standard avoided costs begins with the utility filing an IRP for a 20-year planning horizon, as required every two years. Utilities' avoided cost methodologies were designed to capture the avoided costs actually realized by the utility when it purchases power from a QF, and are intended to be simple and clear, with inputs and assumptions taken from IRPs that are subject to stakeholder review. With the modifications discussed below, we believe these methodologies will produce accurate estimates of avoided cost prices.

Under our current rules, non-standard avoided cost prices for large QFs are negotiated between the utility and the individual QF using standard avoided cost rates as a starting point, subject to specific guidance on certain factors. The utilities have proposed the use of alternative modeling methods to generate non-standard avoided cost rates. Pacific Power requests that we adopt a model-based approach for QFs larger than 3 MW to capture resource-specific characteristics on its system, to calculate a negotiated avoided cost price. Idaho Power asks that we use its incremental cost IRP methodology for negotiated contracts, relying on Idaho Power's AURORA power cost model to calculate incremental cost for each hour of the proposed QF contract term.[17] The QF parties argue that the utilities' proposed methodologies are less transparent, and could result in gaming by the utilities. To ensure an adequate examination of parties' arguments and positions, we will take up the issue of non-standard avoided cost prices in Phase II of this docket.

Integration Costs

The parties note that at the time we decided Order No. 05-584, there was limited data available regarding integration costs, and PGE and Pacific Power did not include wind integration studies in their IRPs. Since then, there has been substantial wind development and both utilities and Idaho Power now produce estimates of wind integration costs in their IRPs. We agree with the parties that integration costs are legitimate costs that should be factored into avoided cost calculations.[18]

We adopt Staff's recommendations on the treatment of wind integration costs in Standard and Standard Renewable avoided cost pricing calculations, as described in Staff/201. In adopting Staff's recommendation, we distinguish between several categories of avoided costs.

We first review our Standard and Standard Renewable Methods. Under our Standard Method, avoided cost prices are based on a CCCT proxy resource, which does not incur integration costs. Under our Standard Renewable Method, renewable avoided cost prices reflect the avoided renewable resource, currently wind for both PGE and Pacific Power, which does incur integration costs. With these methods in mind, we identify the following avoided cost methodologies.

Standard Method

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[17] Idaho Power notes that its current Schedule 85 states that the starting point for negotiated QF contracts is the avoided cost calculated under the modeling methodology approved by the IPUC for QFs over 10 MW. Up until now, the IPUC-approved method was the original IRP-based methodology, which Idaho Power used in Idaho and Oregon. However, the IPUC recently authorized Idaho Power to use the "incremental cost" IRP methodology as the starting point for negotiated contracts instead of its previous plan IRP-based methodology. The incremental IRP methodology determines the avoided cost of energy by using Idaho Power's AURORA power cost model to calculate the incremental cost for each hour of the proposed QF contract term.

[18] *See* 18 C.F.R. § 292.304(c).

First, for a wind QF located inside a contracting utility's Balancing Authority Area (BAA), under our Standard Method the integration costs that the wind facility imposes on the contracting utility will be subtracted from the Standard Method avoided cost rate, using the wind integration cost estimates produced in the utility's most recently acknowledged utility IRP or IRP update.

Second, for a wind QF located outside a contracting utility's BAA, there will be no adjustment to the Standard Method avoided cost price for the integration costs imposed by the QF. The utility that operates the BAA in which the QF is located can request recovery of the QF's imposed integration costs under that utility's FERC-jurisdictional Open Access Transmission Tariff.

Third, if a QF is any resource other than wind, no adjustments to the Standard Method avoided cost rate are needed, because the QF is assumed to not impose integration costs on the utility.

Standard Renewable Method

First, if a QF is a renewable resource facility other than wind, the wind integration costs associated with the proxy resource under our Standard Renewable Method are avoided, and those avoided costs are added to the Standard Renewable Method avoided cost price. Second, if a QF is a wind facility, there are three possible cases:

- If both the QF and the proxy wind facility are in the contracting utility's BAA, then integration costs are not avoided, proxy resource wind integration costs and QF wind integration costs net to zero, and no price adjustment is made to the Standard Renewable Method avoided cost rates.[19]

- If the QF is in the contracting utility's BAA, and the proxy wind facility is outside the contracting utility's BAA, in a Bonneville Power Administration (BPA) service area or the area of a utility's BAA that imposes FERC-approved integration charges, then an adjustment to the Standard Renewable Method avoided cost rates will be made for the net difference between the QF's imposed integration costs and the avoided proxy resource integration costs.

- If the QF is outside the contracting utility's BAA, then no adjustments are made to the Standard Renewable Method avoided cost price for integration costs. The utility that operates the BAA in which the QF is located can

[19] Since QFs will be charged for the cost of their own integration, and receive a credit for the utility's avoided integration cost, those two costs will net out, with no net adjustment to avoided cost price.

> request recovery of the QF's imposed integration costs under that utility's FERC-jurisdictional Open Access Transmission Tariff.

For the reasons offered by ODOE and others, we will require no adjustment for integration costs associated with solar QFs, but we will revisit this issue in the future after more solar development occurs. The parties argue that solar QF development is too small to pose harm to ratepayers, and there is too little data to produce accurate solar integration cost estimates.[20]

Capacity Contribution of QF Resources

Currently, no adjustments are made to Standard and Standard Renewable avoided cost prices to account for the actual contribution to capacity made by each QF resource type. To produce more accurate avoided cost estimates, parties propose adjusting the capacity component in standard and renewable avoided cost prices to capture the expected capacity contribution of each QF resource type. For the Standard Method, Staff proposes multiplying the capacity component currently embedded in the method by a "capacity contribution factor," equal to the expected contribution to peak load of the specific QF resource type. The assumed capacity contribution to peak load would be the contribution estimate used in the utility's acknowledged IRP for the specific type of generation (wind, solar, etc.).

For the Standard Renewable Method, Staff proposes adjusting the capacity component implicit in the renewable on-peak price by the incremental capacity contribution of the specific QF resource type relative to the avoided renewable resource. For a wind QF, this would currently result in no change to its renewable avoided cost prices obtained under the current Renewable Method because the next avoidable resource for both PGE and Pacific Power is a wind resource. For solar and baseload QFs, the price adjustment would result in a higher capacity component (and therefore a higher on-peak price) than in the current method. The capacity contribution for each renewable QF resource type used in this adjustment would be the capacity contribution assumed for that resource type in the utility's acknowledged IRP.

We agree on the need to adjust for capacity contribution of each resource type and adopt Staff's proposed method for calculating capacity adjustments, as set forth in Staff/102-103, using input estimates derived from the utility's acknowledged IRP. We direct the parties to address issues regarding calculation methodology in future utility IRPs.

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[20] *See* CREA Post-Hearing Brief at 16 ("The record contains no credible evidence that supports using wind integration as a proxy for solar integration.* * * The utilities' levels of solar penetration are far too low to support the conclusion that solar QFs will impose integration costs."), *citing* RNP/100, Lindsay/9.

C. Third-Party Transmission Costs to Move Energy Out of a Load Pocket (Issue 4B)

Issue 4B asks whether the costs and benefits associated with third-party transmission should be included in the calculation of avoided cost prices, or otherwise accounted for in the standard contract. Parties discussed two distinct matters under Issue 4B. First, parties discussed whether avoided third-party transmission costs associated with the proxy resource should be included in avoided cost prices. Second, parties discussed how to account for third-party transmission costs imposed on a utility to move QF output in a load pocket to load. We resolve each of these issues separately.

<u>*Avoided Third-Party Transmission Costs*</u>

1. Parties' Positions

Pacific Power: Pacific Power explains that the current method—that is, the Proxy Method—for calculating the company's full avoided cost rates paid under a standard contract assumes that the proxy resource is optimally located to load. Because the proxy resource is on-system and directly interconnected to Pacific Power's system, transmission costs are not included in the calculation of full avoided cost. Pacific Power acknowledges that if the proxy resource was an off-system resource, then third-party transmission would be included in the cost of the proxy resource, which is the approach Pacific Power understands PGE takes.

Staff: Staff states that avoided transmission costs should be included in the calculation of avoided cost prices. Staff recommends including avoided third-party transmission costs in the calculation of avoided cost prices under both the Standard and Renewable Methods.

PGE: PGE indicates it already includes the costs and benefits of third-party transmission in the calculation of avoided cost prices if the avoided resource is off system, and recommends continuing this policy. PGE explains that it assumes the avoided resource is outside of the company's balancing authority, and that the transmission of electricity is necessary. PGE includes BPA wheeling costs in the company's avoided cost calculations.

CREA: CREA asserts that for PGE and Pacific Power, the calculation of avoided costs should include an adjustment for avoided transmission costs. CREA indicates that FERC has already determined that a state commission may include the costs of avoided transmission in the calculation of avoided cost rates.[21] CREA argues that since PURPA

[21] CREA's Post-Hearing Legal Brief at 20. *See Calif. Pub. Util. Commn.*, 133 FERC ¶ 61,059, P 31 (2010).

requires a QF to pay third-party transmission costs to deliver its output to the purchasing utility's system, the utility avoids transmission costs that would have been associated with delivery of the alternate resource. CREA contends that the avoided costs rate calculation for PGE and Pacific Power should include an avoided third-party transmission cost adder because both utilities commonly build resources off-system.

2. *Resolution*

We affirm the existing policy that if the proxy resource used to calculate a utility's avoided costs is an off-system resource, the costs of third-party transmission are avoided, and are therefore included in the calculation of avoided cost prices. This is the situation for PGE, and it was not contested in these proceedings.
If the proxy resource used to calculate a utility's avoided costs is an on-system resource, there are no avoided transmission costs, and thus the costs of third-party transmission are *not* included in the calculation of avoided costs prices. This is the situation for Pacific Power.

<u>*Imposed Third-Party Transmission Costs*</u>

1. *Parties' Positions*

Pacific Power: Pacific Power refers to areas within its non-contiguous service territory that are reliant, either partially or entirely, on third-party transmission as "load pockets." Pacific Power explains that when transmission lines are owned by a third party, the utility must purchase transmission service across the third party's lines in order to deliver (or export) generation to (or from) an isolated portion of the utility's service territory. Pacific Power notes that when new generation, such as a QF, is interconnected to a load pocket and the QF's output creates a surplus of local resources, the company can take one of three actions: 1) back down its own resources (which may be lower cost resources than the QF power); 2) curtail the new generation (but the ability to do so is limited under PURPA if the source is a QF; or 3) move the generation elsewhere. To move the generation elsewhere from the load pocket, however, the company indicates that it must either build new transmission facilities or make third-party transmission contractual arrangements. Pacific Power asserts that the costs associated with third-party transmission should be allocated to the QF on an individual project basis, by reflecting the actual costs of the third-party transmission arrangements in an addendum to the standard contract executed for the particular QF. Pacific Power argues that the need for an addendum would be limited and would not materially increase the transaction costs associated with a standard contract. Pacific Power states that it does not dispute the PURPA obligation to purchase a QF's output and deliver it to load. The company asserts, however, that it does dispute any requirement to incur costs above its avoided costs when purchasing the QF output. Pacific Power contends that "[p]ayments to QFs under PURPA must be just and reasonable, non-discriminatory, and not in excess of a utility's avoided cost."[22] Pacific Power argues this principle is violated if a utility is required to pay third-party transmission costs attributable to a QF and in excess of costs that would be incurred to buy power from another source. Pacific Power asserts that FERC has consistently demonstrated "its willingness to allow states the flexibility in avoided cost pricing to ensure that all costs associated with QF power are reflected in avoided cost rates."[23]

Pacific Power argues that customer indifference to the purchase of QF power, as required by PURPA and rules that implement it, "is ensured by relying on a 'but-for' causation principle when determining the avoided cost rate and accompanying charges."[24] Pacific Power asserts that under this principle, any costs that would not otherwise be incurred but for the purchase of a QF's output must be recovered from the QF. If Pacific Power is required to pay full avoided cost rates to a QF plus incur third-party transmission costs on behalf of that QF, then Pacific Power will pay more than full avoided costs in violation of federal and state law. When a QF chooses to locate a facility in a load pocket where output will exceed load, and third-party transmission costs will be incurred to move the output to load, Pacific Power contends that the QF should be responsible for such costs.[25] Pacific Power argues third-party transmission costs are analogous to system upgrades for interconnection of a QF to a utility's system which the Commission has already deemed to be assignable to the QF.[26] Pacific Power calls the argument by Threemile that, under 18 C.F.R. §292.303(d), the calculation of avoided costs may account for third-party transmission costs only when a QF makes an indirect sale to a utility, misguided. Pacific Power asserts that the regulatory section cited by Threemile pertains only to a utility's obligations under PURPA, and does not pertain to the calculation of avoided costs. Pacific Power observes that the regulations addresses the utility's obligation to purchase power wheeled across another utility's transmission system—an issue not in contention in these proceedings. Pacific Power indicates that the next section, §304, addresses the appropriate parameters for payments to QFs under PURPA—which is an issue in contention here, providing in pertinent part: "nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases."[27]
Pacific Power disputes the relevance of the argument by Threemile and CREA that it is discriminatory for the company to assign third-party transmission costs to QFs in load

[22] Pacific Power's Post-Hearing Brief at 20.
[23] Pacific Power's Response to Threemile's Motion to Take Official Notice of FERC Ruling at 2.
[24] Pacific Power's Post-Hearing Brief at 20. *Id.*
[25] Pacific Power acknowledges that PURPA does not directly refer to the term, "load pockets," but argues that it uses the term only to refer to a common situation on its system that creates costs above the standard calculation of avoided costs, and that PURPA explicitly prohibits such.
[26] *See In re Rulemaking to Adopt Rules Related to Small Generator Interconnection*, Docket No. AR 521, Order No. 09-196 at 5 (Jun 8, 2009); *See also In re Investigation into Interconnection of PURPA Qualifying Facilities with Nameplate Capacity Larger than 20 Megawatts to a Pub. Util.'s Transmission or Distribution System*, Docket No. UM 1401, Order No. 10-132 at 3 (Apr 7, 2010).
[27] 187 C.F.R. § 202.304(a)(2).

pockets when the company itself pays third-party transmission costs for other off-system resources. Pacific Power responds that both parties fail to recognize that Pacific Power's proxy resource is on-system with no assumed transmission costs.

Staff: Staff also states that third-party transmission costs imposed on a utility to wheel a QF's output to load should be passed on to the QF. Staff argues that requiring a QF to pay third-party transmission costs incurred to move the QF's output to load is consistent with precedent in Order No. 07-360. In that order, the Commission determined that costs to upgrade transmission facilities to move QF power are appropriately charged under non-standard contracts to the QF as part of the interconnection process. The Commission also concluded that avoided costs rates in non-standard contracts should "be adjusted if parties agree the utility will back down other resources in lieu of wheeling QF power outside of a load-constrained area."[28] Staff explains that the third-party transmission costs at issue in these proceedings should be understood as incurred costs instead of costs to upgrade transmission facilities or to back down more economic generation. Staff indicates that a utility and QF already have the option to negotiate an adjustment to non-standard avoided costs rates to account for incremental costs or benefits associated with the QF's location, and the question presented in this docket is whether the Commission should authorize a means to recognize such costs or benefits in a standard contract. Staff recommends a utility be allowed to "net" the avoided and incremental costs of third-party transmission against standard avoided costs prices for wind QFs when the utility is required to incur such costs to move the QF's energy out of a load pocket.

CREA: With regard to the question of how to account for the costs of third-party transmission to move a QF's power from the initial point of delivery to load, CREA argues that such costs cannot be assigned to the QF. CREA challenges Pacific Power's claim that its proxy-avoided resource does not use third-party transmission to move power from the initial point of delivery to loads. CREA argues that, "[i]f PacifiCorp assigns to small QFs the cost of third-party transmission associated with 'load pockets,' it is an avoided cost that PacifiCorp must include in the calculation of all standard avoided cost rates."[29]

CREA criticizes Pacific Power's addendum proposal because it would deny the opportunity to some QFs to obtain standard rates in violation of PURPA. CREA notes that the cost of third-party transmission costs would not be known upfront and would vary over time. CREA also argues that PURPA does not allow Pacific Power to assign third-party transmission costs beyond the point of delivery to the QF.

Threemile: On July 1, 2011, Threemile filed a formal complaint that alleged Pacific Power had violated PURPA and Order No. 05-584. The complaint was docketed as UM 1546 and was stayed pending this docket. Threemile indicates that it "is *not* asking

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[28] Order No. 07-360 at 27.
[29] *Id.*

the Commission to provide redress in this proceeding for the allegations it made against PacifiCorp in UM 1546," but is asking "that the Commission expressly reject PacifiCorp's attempt in this proceeding to retroactively reverse the Commission's current policy prohibiting 'price adjustments' for small QFs."[30] Threemile asserts that any policy changes made by the Commission in these proceedings must be on a prospective basis only.

Threemile also argues, however, that the Commission should not authorize the policy change even on a prospective basis. Threemile contends that Pacific Power's proposal to recover third-party transmission costs incurred after it receives a direct sale of energy from a QF is contrary to federal law and should be rejected. Threemile argues that when a utility receives QF power at a designated point of delivery, it is the utility's sole responsibility, under 18 C.F.R § 202.303(a), to manage that power and deliver it to load. Threemile asserts this was the point made by FERC, in *Entergy Servs., Inc.*, 137 FERC ¶ 61,199 (2011), when it rejected a utility's proposal to curtail unscheduled energy deliveries by a QF when firm transmission service was insufficient. Threemile indicates FERC ruled there that a utility is obligated under federal law to purchase unscheduled QF energy, and once the energy is purchased, it is the utility's responsibility to deliver the energy to load.[31] Threemile Canyon also asks the Commission to take official notice of a recent FERC order that further addressed the inability of a utility to curtail QF power.[32]

Threemile argues that FERC's holding in this order means "that PacifiCorp may not charge a wind QF for third-party transmission costs incurred to move power output from the point of interconnection to PacifiCorp's load," nor "curtail a wind QF when PacifiCorp does not have firm transmission on its own system to move power output from the point of interconnection to load."[33] Threemile argues that 18 C.F.R. § 292.303(d), provides the only exception under PURPA when a QF is expected to take responsibility for the transmission of energy after the point of delivery to the host utility when the QF makes a voluntary, indirect sale to a second utility, and the host utility agrees to wheel the output. Threemile asserts that Pacific Power agrees the exception does not apply to the situation at issue. Threemile opines, however, that Pacific Power's proposal, if implemented, would render 18 C.F.R. § 292.303(d) superfluous. Threemile reasons that "[i]f PacifiCorp had the blanket right to recover transmission costs from QFs, no special exceptions allocating transmission costs to QFs would be necessary."[34] Threemile observes that a legal provision should not be interpreted in a way that renders another legal provision meaningless.[35]

[30] Threemile's Post-Hearing Brief at 7.
[31] *Id.* at 14, *citing Entergy Servs., Inc.*, 137 FERC ¶ 61,199 (2011).
[32] The Commission takes official notice of *Pioneer Wind Park, LLC,* 145 FERC ¶ 61,215 (2013).
[33] Threemile's Motion to Take Official Notice of FERC Ruling at 2.
[34] Threemile's Pre-Hearing Memorandum at 11.
[35] *Id. See* ORS 174.010.

There is no other exception to the rule that when a utility receives QF power at a designated point of delivery, the utility has sole responsibility to manage that power and deliver that power to load, Threemile asserts. Pacific Power's attempt to create an exception for "load pockets," is misplaced. Threemile also notes that PURPA does not restrict a QF's right to deliver output to a point within an area that Pacific Power may define as a "load pocket."

Pacific Power's position that it is unfair for ratepayers to pay for third-party transmission is spurious, Threemile contends, because the company's ratepayers already incur significant third-party transmission costs for non-QF power. Threemile argues that given Pacific Power spends significant funds on third-party transmission to move non-QF generation to load, and passes these costs on to ratepayers, it's not "unfair" for ratepayers to pay for the same transmission costs to move QF generation to load.

Finally, Threemile condemns Pacific Power's proposal on the basis that it would require small QFs to negotiate individualized, non-standard contracts. Threemile asserts that small QFs are entitled, pursuant to Order No. 05-584 and FERC Order 69, to a standard rate without price adjustment to account for individual project characteristics.

2. *Resolution*

We state upfront that, as requested by the parties, we decline to address any issue about an existing contract that would more properly be addressed in another docket, such as docket UM 1546. We also reiterate that the sole purpose of these proceedings is to consider *prospective* revisions to policies and rules for QF standard contracts.

Pacific Power's entire service territory is non-contiguous, and interconnected in places by third-party transmission. Pacific Power calls these areas that are reliant on third-party transmission "load pockets," and we will adopt this phrase for purposes of this discussion. To import to, or export from, these load pockets, third-party transmission must be used. Issue 4B asks how the associated costs should be accounted for in a standard contract when QF output is received in a load pocket that is surplus to the load there, and must be transported by third-party transmission to load in another part of the utility's service area.

To begin, we clarify that this question focuses on *cost* responsibility—as opposed to physical or managerial responsibility—for any third-party transmission that is used to deliver QF output from the point of delivery to load. We agree with Pacific Power that the PURPA obligation of a utility to purchase a QF's output where it is received, and to have it physically delivered to load, whether via the utility's own transmission facilities or the transmission facilities of a third party, is not in dispute. Indeed, in taking official notice of FERC's recent order, *Pioneer Wind Park I, LLC*, we acknowledge FERC's direction that a QF cannot be required to obtain transmission service to deliver its output from the point of delivery to load.[36]

We observe, however, that this order, and similar orders, leave open the issue of how a state Commission may account for transmission costs in relation to avoided costs, whether by lowering avoided cost rates, separately in interconnection cost assessments, through an addendum as suggested by Pacific Power, or by some other means.[37]

To answer the question of how costs imposed on a utility to arrange third-party transmission to transport QF output from receipt in a load pocket to load should be accounted for in a standard contract, we refer back to our discussion regarding imposed costs. We determine that when a QF located within a utility's BAA imposes integration costs on the utility, the avoided cost rates paid to the QF should be adjusted. We find this general principle—that avoided cost rates should be adjusted for costs imposed on a utility by the particular circumstances of a QF—to apply here.

In applying this principle here, we first conclude that our adopted method of determining avoided cost prices based on avoided proxy resources reflects full avoided costs. Second, we conclude that any third-party transmission costs incurred by a utility to move QF output from the point of delivery to load would be costs that are not included in the calculation of avoided cost rates in standard contracts, and therefore are costs that are additional to avoided costs. Third, we conclude that any costs imposed on a utility that are above the utility's avoided costs must be assigned to the QF in order to comport with PURPA avoided cost principles.[38] We find, however, that Staff and the parties did not fully address how to calculate and assign the third-party transmission costs that are attributable to the QF. We defer this issue to the second phase of these proceedings. We anticipate asking parties to recommend how third-party transmission costs to transport QF output from receipt in a load pocket to load should be accounted for in

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[36] *Pioneer Wind Park I, LLC,* 145 FERC ¶ 61,215 at 38.
[37] *Id.* at 38, fn. 73 (stating: "This is not to suggest that the QF is exempt from paying interconnection costs, *see* 18 C.F.R. §§ 292.101(b)(6), 292.306 (103), which may include transmission or distribution costs directly related to installation and maintenance of the physical facilities necessary to permit interconnected operations. 18 C.F.R. § 292.101(b)(6) (2013). Such permissible interconnection costs do not, however, include any costs included in the calculation of avoided costs. *Id.* Correspondingly, implicit in the Commission's regulations, transmission or distribution costs directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations may be accounted for in the determination of avoided costs if they have not been separately assessed as interconnection costs."); *Idaho Wind Partners I, LLC.*, 140 FERC ¶ 61,219, at 41 (2012) ("as a matter of law, changes over time, such as light loading periods, are considered in the calculation of avoided cost rates in a long-term bilateral PPA that provides for an avoided-cost rate determined at the time the legally enforceable obligation is incurred), *reh'g denied,* 143 FERC ¶ 61,248 (2013); *Entergy Servs., Inc.*, 137 FERC ¶ 61,199, at 56 (2011).
[38] Under PURPA, a utility need not pay any price that is higher than the utility's avoided costs. FERC defines avoided costs as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6).

standard contracts; for example, by lowering avoided standard avoided cost rates, separately in interconnection cost assessments, through an addendum as suggested by Pacific Power, or by some other means.

D. Unused Standard Avoided Cost Pricing Options (Issue 1D)

Issue 1D asks whether the Gas Market Indexed and Banded Gas Market Indexed avoided cost pricing options should be eliminated from standard avoided cost options.

1. Parties' Positions

All parties who addressed this issue argued that unused pricing options should be eliminated. Pacific Power argued its pricing options have been available for over seven years, but no QF under the standard avoided cost eligibility cap has ever entered into a contract using these options. Pacific Power states being required to make the contracts available on request undermines the purpose of providing a publicly available document detailing all rates and terms for service. Staff and PGE agree that the unused pricing options should be eliminated. CREA also agrees, but adds the options should be available by request.

2. Resolution

We agree with the parties that unused pricing options should be eliminated from standard avoided cost options. All three Oregon electric utilities report that since 2005, no QF has used these variable market-based options. It appears that QFs are not utilizing the options, which means that they complicate, rather than encourage, QF participation. We adopt the parties' recommendation that the following pricing options be eliminated from utilities' standard avoided cost pricing options:

(1) Pacific Power's Gas-Market Indexed and Banded Gas Market Indexed pricing options; and
(2) PGE's Deadband Index Gas Price Option, Index Gas Price Option, and Mid-C Index Option.

E. Schedule of Avoided Cost Price Updates (Issue 3A)

Issue 3A considers whether the Commission should revise the current schedule for avoided cost price updates. Oregon law provides that avoided cost rates shall be reviewed and approved by the Commission at least every two years, but must occur in a manner that allows for a settled and uniform institutional climate for QFs.[39]
The Commission has historically allowed utilities to update their avoided cost rates every two years coincident with the IRP process, with avoided cost updates filed 30 days after

[39] ORS 758.515(3)(b); OAR 860-029-0040(4)(a).

IRP acknowledgement. When the IRP cycle has taken longer than two years, the Commission has allowed utilities an additional update after IRP acknowledgement.

1. Parties' Positions

The parties agree the current schedule should be revised, with the majority of the parties advocating for an annual update. However, the parties disagree as to what should be addressed in the annual update.

Staff: Staff argues the Commission should continue to require a complete update to all avoided cost price inputs within 30 days of IRP acknowledgement, but should also require utilities to annually update their standard avoided cost prices by updating the gas price forecast, the on- and off-peak forward market prices, the status of the production tax credit, and changes in the cost and on-line date of the proxy resource taken from the last acknowledged IRP update. Staff states these updates are readily ascertainable and can significantly affect avoided cost prices.

ODOE: To improve accuracy and price certainty, regularly scheduled avoided cost filings should be done annually on a date certain. The regular filing process should include an evidentiary process of fixed duration sufficient for robust stakeholder engagement. Avoided cost updates should also continue to be filed 30 days after IRP acknowledgement.

Idaho Power: Avoided cost prices should be updated annually, using the natural gas forecast published by the U.S. Energy Information Administration (EIA), in conjunction with the release of the EIA forecast. With respect to the incremental IRP methodology, Idaho Power proposes an annual update of the gas price forecast and load forecast.

CREA: Since utilities control the filing of price updates, the Commission should ensure a fair and predictable schedule for QFs. Updates after IRP acknowledgement should be supplemented with an annual update limited to gas prices, market prices, new loads, contracts in excess of four years, and the status of production tax credits.

OneEnergy: Annual ministerial updates (updates that can be accomplished transparently without the exercise of independent judgment, such as updates to gas price) at the same time each year would result in more accurate avoided costs. Changes to the sufficiency period are not ministerial and should not be part of the annual update.

PGE: PGE recommends annual updates to avoided cost prices. As part of this update, utilities should be able to capture the most recent gas and electricity prices, plus any changes that occur in a Commission-acknowledged IRP or IRP update.

Pacific Power: To increase accuracy, it is critical that inputs to the avoided cost calculation be updated as often as practical. For standard avoided cost prices, including renewable avoided cost prices, the Commission should require an annual update and an update within 30 days after IRP acknowledgement. A utility must be able to update the timing of the resource sufficiency period in any annual update. REC's proposal to defer annual updates when they are scheduled to occur within 90 days of IRP acknowledgement is unworkable, because a utility cannot predict the date of acknowledgement. For non-standard avoided cost prices, inputs to the PDDRR Method should be updated using the best information available at the time the QF requests prices. At the time a QF requests prices, forward market prices for electricity and natural gas should be based on Pacific Power's most recent official forward price curve, and contracts should be updated accordingly.

REC: The Commission should allow the utilities to update avoided costs on a more frequent basis, but should ensure that changes occur on a predictable basis. In practice, utilities request and sometimes obtain avoided cost rate updates more frequently than every two years, and the Commission's standard two-year cycle has not been consistently applied, which has resulted in ad hoc updates and significant pricing uncertainty to QFs negotiating contracts with utilities. Predictability of pricing changes is one of the most important aspects of project development. QFs need to know they can finalize a contract without prices changing, which can only occur if the update process is infrequent, well understood and consistently applied. Frequent updates also give utilities an opportunity to delay the negotiation process. QFs and utilities have an asymmetrical level of information, including whether an update will increase or decrease the avoided cost rates. Avoided cost rates should be updated 30 days after acknowledgement of an IRP, and then on an annual basis until the next IRP acknowledgement. The avoided cost rate update should always occur at least 12 months after the last update. If a new avoided cost rate update is scheduled to occur within 90 days of when a new IRP is scheduled to be acknowledged, the rate update should be deferred until acknowledgement occurs. No matter the approach, avoided cost rates should not change more than once in any 12 months.

2. Resolution

After reviewing the parties' proposals, we adopt a new requirement for an annual update on a specific day each year, in addition to the current complete avoided cost update following each IRP acknowledgement order. We direct electric utilities to update their avoided cost rates 30 days after IRP acknowledgement, and on May 1 every year. In the event that an IRP is acknowledged within 60 days of May 1 in a particular year, the Commission will use its discretion at that time to direct a utility to waive its 30-day post-IRP update.

Annual updates, filed every May 1, will include the following four factors:

(1) Updated natural gas prices;
(2) On- and off-peak forward-looking electricity market prices;

(3) Changes to the status of the Production Tax Credit; and
(4) Any other action or change in an *acknowledged* IRP update relevant to the calculation of avoided costs.

Electric utilities' annual updates will be presented at a public meeting, with a rate effective date within 60 days of the May 1 filing.[40] Finally, in light of our adoption of a yearly update, we will continue to allow requests for mid-cycle updates for significant changes to avoided cost prices. However, in light of our decision here to require annual updates in addition to updates following IRP acknowledgement, we caution stakeholders that the "significant change" required to warrant an out-of-cycle update will be very high. We expect the parties to use this option infrequently.

F. Definition of a "Single" QF Project (Issue 5B)

Issue 5B asks what the criteria should be to determine whether a QF is a "single QF project" for the purposes of qualifying for a standard contract.

1. Parties' Positions

Staff: Staff notes the current criteria were agreed to by parties in docket UM 1129 in a partial stipulation adopted by the Commission in Order No. 05-584. These criteria specify that a single facility must be owned by the "same person(s) or affiliated person(s)" and that multiple sites must be located within a 5-mile radius. The criteria also include an exemption specifying that multiple facilities owned by a "passive investor" are not owned by the same person. Staff is persuaded by Pacific Power's testimony that the applicability of the passive investor exemption should be limited to independent, family owned or community-based projects.

Pacific Power: Pacific Power argues the partial stipulation adopted in docket UM 1129 be modified to remove the passive investor exception to add exemption only for independent family owned or community-based projects. Pacific Power states the "purpose and intent of the partial stipulation was to develop a mechanism that would give independent family owned or community-based QF projects an exemption from the single-site restriction so that these projects could share common infrastructure and have common passive investors without violating PURPA or state regulations" but in practice, "the passive investor exception has allowed large projects to circumvent the intent of the partial stipulation and devise ownership structures that allow them to disaggregate and still technically meet the Commission's eligibility criteria."[41]

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[40] The yearly May 1 updates are not tariff filings, and do not need to comply with the requirements of ORS 757.210. The Commission will not conduct a hearing to address the yearly updates.
[41] Pacific Power Prehearing Memorandum at 12.

PGE: PGE agrees with Pacific Power's proposal to remove the passive investor exception from the partial stipulation approved in docket UM 1129.

CREA: CREA urges the Commission to reject proposals to eliminate the passive investor exception because passive investors are important to the development of community renewable energy projects. CREA notes that Idaho Power admits the 5-mile separation rule largely mitigates the risk of widespread disaggregation. CREA recommends the Commission address concerns about remaining loopholes by using the IRS definition of "passive investor," which provides that a passive investor may not "materially participate" by way of involvement in operations in a way that is regular, continuous and substantial.[42]

2. Resolution

We agree with Staff and Pacific Power that the applicability of the passive investor exemption should be limited to independent family-owned or community-based projects.[43] The current criteria used to determine whether a QF is a "single project" includes an exemption specifying that multiple facilities owned by a "passive investor" are not owned by the same person. We adopt Pacific Power's proposal to modify the criteria and limit the passive investor exemption to independent family owned or community-based projects.

G. Legally Enforceable Obligations (Issue 6B)

Under PURPA, a QF may sell to a utility pursuant to a contract *or* a legally enforceable obligation (LEO).[44] FERC has indicated that individual states should determine when a LEO is incurred under state law.[45] Issue 6B asks the Commission to evaluate when a LEO arises during the transactional process to execute a standard contract between a utility and a QF.

1. Parties' Positions

Pacific Power, PGE, Idaho Power, CREA, OneEnergy, and Threemile: These parties present varying definitions of a LEO with significant divergence among the proposed definitions.

REC and Staff: REC takes the position that the delineation of a LEO should not be considered separate from Issue 6C (regarding the maximum time that should be allowed between the execution of a standard contract and the delivery of power by the QF), and

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[42] *See* 26 U.S.C. §469(c), (h)(1).
[43] Staff/200, Bless/25, *citing* PAC/200, Griswold/24.
[44] *See Cedar Creek*, LLC, 137 FERC ¶ 61,006 at P 32 (Oct 4, 2011). *See also* OAR 860-029-0010(29).
[45] *West Penn Power Co.*, 71 FERC ¶ 61,153 at 61,495 (1995).

recommends that Issue 6B be deferred to Phase II. REC argues that one of the party's positions on Issue 6B, indicating that a LEO should not be recognized more than one year prior to power delivery, directly implicates Issue 6C. REC observes that QF project development and the standard contract transactional process take time, and there are number of factual issues implicated by Issue 6C and PGE's position on Issue 6B that were not fully addressed due to the deferral of Issue 6C. Although Staff initially took a different position, Staff concludes that it is inappropriate to resolve the contractual definition of an LEO separate from all of the other contractual issues that parties agreed to address in the second phase of the docket. Consequently Staff recommends that the Commission defer resolution of this issue until the second phase of the docket.

2. Resolution

Parties agree to address several contractual issues in the second phase of these proceedings. We are persuaded that consideration of this issue may overlap with factual and policy arguments underpinning one or more of the issues already deferred to Phase II. In particular, we recognize the overlay between determining when a LEO forms and limits on when power must be delivered under a QF contractual obligation. Consequently, we direct Staff and the parties to further consider Issue 6B in the second phase of this docket.

H. Mechanical Availability (Issue 6E)

1. Parties' Positions

Staff: Staff states that the Commission has previously authorized utilities to adopt a MAG (mechanical availability guarantee) for intermittent QFs in standard contracts, but did not prescribe specific language for the term.[46] Staff notes that there is no "industry standard" for a MAG in wind QF contracts, and recommends that the Commission continue to not impose specific language. Rather, Staff advises the Commission to direct the utilities to draft specific MAG language that includes a reasonable combination of three requirements: an overall mechanical availability percentage, a planned maintenance allowance, and a penalty for the failure to meet the overall guarantee. Staff suggests two parameters for this language. For planned maintenance, Staff states there should be: (1) an allowance for 200 hours of planned maintenance per turbine per year that does not count against the overall MAG; and (2) a requirement that the penalty for non-compliance with a MAG be a monetary penalty based on actual net replacement power costs for the incremental unavailable hours that exceed the aggregate annual mechanical unavailability limit for all turbines, with contract termination permitted only after failure to meet the MAG for three consecutive years.

[46] A different type of performance guarantee is applied to non-intermittent QFs and was not addressed by the question posed in Issue 6E.

PGE: PGE proposes what it calls a "significant concession" with regard to future MAG language, as compared with current language in its standard contract. PGE recommends that its MAG clause be revised to explicitly allow 200 hours of planned maintenance each year per wind turbine, with non-available time calculated on a turbine-by-turbine basis, meaning that if one turbine is down, the entire facility would not be considered down.

Idaho Power: Idaho Power requests that the Commission align Oregon's standard contract MAG with Idaho's standard contract MAG. To do so, Idaho Power proposes that the MAG for all intermittent QFs be 85 percent monthly availability, with the monthly price paid adjusted by an "availability shortfall price" if the MAG not achieved.

The company also proposes a modification for the performance guarantee for non-intermittent resources to introduce a 90 percent/110 percent monthly performance standard. Idaho Power recommends that a "shortfall energy price" be applied to deliveries outside of the 90/110 percent monthly performance standard. For non-intermittent resources, Idaho Power recommends the application of a 90/110 percent monthly performance standard to which as the shortfall energy price would also be applied.

ODOE: ODOE argues that QFs should incur financial penalties that are based on actual damages to the utility for non-performance, measured after notification and an opportunity to remedy. ODOE recommends that standard contracts explicitly provide for notification and an opportunity to remedy. ODOE argues that a MAG that provides for contractual termination makes a QF subject to it non-financeable. ODOE also requests that mechanical availability be based on an annual, rather than a monthly, basis.

Threemile: Threemile argues the MAG is outdated concept, and is no longer a necessary term in standard contracts. Threemile explains that QFs are already damaged under standard contracts for non-performance because they do not get paid. For example, Threemile observes, all pricing under Pacific Power's Schedule 37 is paid based on actual energy production, not capacity, which means that a QF doesn't get paid during an outage, thereby penalizing the QF.

Pacific Power: Pacific Power recommends increasing its output guarantee in its standard contracts, as follows: 1) for new wind QF contracts, Pacific Power recommends that the guaranteed availability be increased from 0.875 to 0.90 percent for contract year three and thereafter; 2) for existing QF projects that renew a contract or previously had a contract with another utility, the guaranteed availability should be set at 0.90 percent starting in contract year one. Pacific Power represents that in the company's experience, wind QFs consistently demonstrate an ability to meet these levels of guaranteed availability after excluding hours lost to force majeure and scheduled maintenance. Pacific Power also proposes revising its definition of availability in standard QF contracts to allow 60 hours per year for scheduled wind turbine maintenance, instead of the current

240 hours. Pacific Power indicates that the company's recent experience demonstrates that this change is reasonable.

CREA: Although CREA agrees with Threemile that a MAG is unnecessary in standard contracts, should the Commission continue to authorize a MAG, CREA urges the Commission to adopt Pacific Power's proposed MAG language for all three electric utilities. CREA argues that Pacific Power's proposed 90 percent availability requirement is reasonable for small QFs, particularly when compared to PGE's 95 percent requirement.

2. Resolution

We agree with Staff that the MAG language in standard contracts should address three requirements: 1) an overall mechanical availability percentage; 2) a planned maintenance allowance that is not counted with regard to the overall availability percentage; and 3) a specified penalty for the failure to meet the overall guarantee.

We adopt Pacific Power's proposal to institute a 90 percent overall guarantee for wind QF contracts, starting in contract year three for new contracts, and starting in year one for contracts that are renewed or supersede a contract with another utility. We are persuaded by Pacific Power's representation that experience demonstrates the ability of wind QFs to meet these levels of guaranteed availability, and CREA's concurrence that the requirements are reasonable.

We adopt Staff's proposal to allow 200 hours of planned maintenance per turbine per year that would not count towards calculation of the overall guarantee. PGE also proposed 200 hours on a turbine-by-turbine basis. We conclude this planned maintenance allowance is reasonable in context of the total range that was proposed by the parties, and in context of the other requirements of the MAG.

With regard to the penalty for a failure to meet the aggregate annual mechanical availability percentage, we reject PGE's proposal that the contract be terminated for failure to meet the prescribed availability limit in a given year. We generally agree with Staff's proposal that the penalty should be based on the costs of replacement power for the shortfall in output from the qualifying facility. We direct the parties in Phase II of these proceedings to develop a methodology for calculating such net replacement power costs. We also direct the parties to address whether and under what circumstances should contract termination occur for persistent failure to meet availability limits set forth in standard contracts in Phase II.

We reject all other MAG recommendations made by the parties.

I. Levelization: Should QFs have the option to elect avoided cost prices that are levelized? (Issue 1B)

1. Parties' Positions

Utilities are not currently required to levelize contracts, but they have the ability to negotiate levelization with individual QFs. In docket UM 1129, the Commission declined to adopt a proposal to levelize prices. CREA, REC, and OneEnergy favor levelization; Staff, Pacific Power, PGE, and Idaho Power oppose adoption of levelized pricing.

CREA, REC, and OneEnergy: CREA, REC, and OneEnergy argue in favor of levelization, arguing that FERC endorses levelized pricing to match more closely the schedule of debt service of a facility. During periods with a lengthy surplus period, levelization would allow QFs to build smaller increments of capacity on the system during that surplus period while leaving ratepayers indifferent over the life of the contract. Required sufficiency periods would stop small community QF projects in Oregon, unless there is levelized pricing. The parties argue QFs should be able to elect tilted rates, to make QF projects more financeable while maintaining a price-signal for the utility's sufficiency period.

Staff: Staff argues levelization benefits QFs by improving their ability to obtain financing and repay loans in the early years of a contract, but the cost of that benefit is increased risk borne by ratepayers, which is inconsistent with PURPA.

Pacific Power: Pacific Power argues levelization in avoided cost pricing introduces additional customer risk in the early years of a QF's PPA, when payments are higher than they would be under non-levelized pricing. Pacific Power states levelization also undermines accuracy, because it causes avoided costs payments to diverge from a utility's avoided cost price stream for that year, and it makes billing and security unnecessarily complex.

PGE: PGE states that, while FERC has allowed states to implement avoided cost rates with levelization, PGE strongly believes levelization is not appropriate as it shifts risks to utility customers. PGE states the Commission fully addressed this issue in Order No. 05-584, and there are no new reasons to change it.

Idaho Power: Idaho Power states levelized pricing represents a loan from Idaho Power's customers to the QF in the early years of the contract (when the contract rate exceeds avoided costs) with the expectation that the QF project will pay back the customer loan in the back half of the contract (when the contract price is less than avoided costs). Idaho Power notes that the loan carries risk and potential customer harm, such as when a levelized contract defaults.

2. Resolution

In light of the adjustments to avoided cost methodology that we adopt in this Order, we find it unnecessary to adopt parties' proposals to levelize rates. As the electric utilities point out, levelization results in the QF project receiving energy rates in the early years of a QF contract that are higher than the actual avoided costs of energy. In its testimony, Idaho Power provides evidence that contracts with QFs that contain levelized rates place the risk of QFs' default on ratepayers; when a QF defaults on their long-term QF agreement prior to the full term of the agreement, ratepayers do not recoup the early-year overpayments.[47] We decline to adopt mandatory levelization of rates.

J. Remaining Issues

As we stated at the outset, the parties took the opportunity to offer comments on a broad range of issues. However, we take up and implement only those issues that both provide persuasive reasons to depart from our previous orders addressing QF pricing, and provide new information to support the requested change.

V. ORDER

IT IS ORDERED that:

1. The Issues List adopted by ALJ ruling on October 25, 2012 is re-adopted and attached to this Order as Appendix A.

2. Within sixty days of the date of this order, each electric utility will file by application, and serve upon all parties to these proceedings, revised standard contract forms that set forth standard rates, terms and conditions that are consistent with the resolutions made in this order.

3. The revised standard contract forms shall become effective 30 days after the date of filing, unless otherwise suspended by the Oregon Public Utility Commission. Prior to the effect date, the standard contract forms shall be considered initial offers.

4. Each electric utility will also file revised tariffs that implement the resolutions made in this order.

5. On May 1 of this and each subsequent year, each electric utility will file an update to avoided cost prices consistent with the resolutions made in this order.

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[47] *See* Idaho Power/200, Stokes/74-77.

6. A subsequent phase of these proceedings will be opened to address Phase II issues.

Made, entered, and effective FEB 24 2014.

Susan K. Ackerman
Chair

John Savage
Commissioner

Stephen M. Bloom
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

Appendix A
Issues List – UM 1610

1. Avoided Cost Price Calculation

   A. What is the most appropriate methodology for calculating avoided cost prices?
      i. Should the Commission retain the current method based on the cost of the next avoidable resource identified in the company's current IRP, allow an "IRP" method-based on computerized grid modeling, or allow some other method?
      ii. Should the methodology be the same for all three electric utilities operating in Oregon?

   B. Should QFs have the option to elect avoided cost prices that are levelized or partially levelized?

   C. Should QFs seeking renewal of a standard contract during a utility's sufficiency period be given an option to receive an avoided cost price for energy delivered during the sufficiency period that is different than the market price?

   D. Should the Commission eliminate unused pricing options?

2. Renewable Avoided Cost Price Calculation

   A. Should there be different avoided cost prices for different renewable generation sources? (*for example* different avoided cost prices for intermittent vs. base load renewables; different avoided cost prices for different technologies, such as solar, wind, geothermal, hydro, and biomass.)

   B. How should environmental attributes be defined for purposes of PURPA transactions?

   C. Should the Commission amend OAR 860-022-0075, which specifies that the non-energy attributes of energy generated by the QF remain with the QF unless different treatment is specified by contract?

3. Schedule for Avoided Cost Price Updates

   A. Should the Commission revise the current schedule of updates at least every two years and within 30 days of each IRP acknowledgement?

   B. Should the Commission specify criteria to determine whether and when mid-cycle updates are appropriate?

   C. Should the Commission specify what factors can be updated in mid-cycle? (*such as* factors including but not limited to gas price or status of production tax credit.)

   D. To what extent (if any) can data from IRPs that are in late stages of review and whose acknowledgement is pending be factored into the calculation of avoided cost prices?

Appendix A
Issues List – UM 1610

E. Are there circumstances under which the Renewable Portfolio Implementation Plan should be used in lieu of the acknowledged IRP for purposes of determining renewable resource sufficiency?

4. Price Adjustments for Specific QF Characteristics

A. Should the costs associated with integration of intermittent resources (both avoided and incurred) be included in the calculation of avoided cost prices or otherwise be accounted for in the standard contract? If so, what is the appropriate methodology?
B. Should the costs or benefits associated with third party transmission be included in the calculation of avoided cost prices or otherwise accounted for in the standard contract?
C. How should the seven factors of 18 CFR 292.304(e)(2) be taken into account?

5. Eligibility Issues

A. Should the Commission change the 10 MW cap for the standard contract?
B. What should be the criteria to determine whether a QF is a "single QF" for purposes of eligibility for the standard contract?
C. Should the resource technology affect the size of the cap for the standard contract cap or the criteria for determining whether a QF is a "single QF"?
D. Can a QF receive Oregon's Renewable avoided cost price if the QF owner will sell the RECs in another state?

6. Contracting Issues

A. Should the standard contracting process, steps and timelines be revised? (Possible revisions include but are not limited to: when an existing QF can enter into a new PPA and the inclusion of conditions precedent to the PPA including conditions requiring a specific interconnection agreement status.)
B. When is there a legally enforceable obligation?
C. What is the maximum time allowed between contract execution and power delivery?
D. Should QFs smaller than 10 MW have access to the same dispute resolution process as those greater than 10 MW?
E. How should contracts address mechanical availability?
F. Should off-system QFs be entitled to deliver under any form of firm point to point transmission that the third party transmission provider offers? If not, what type of method of delivery is required or permissible? How does method of delivery affect pricing?
G. What terms should address security and liquidated damages?

Appendix A
Issues List – UM 1610

H. May utilities curtail QF generation based on reliability and operational considerations, as described at 18 CFR §292.304(f)(1)? If so, when?

I. What is the appropriate contract term? What is the appropriate duration for the fixed price portion of the contract?

J. What is the appropriate process for updating standard form contracts, and should the utilities recently filed standard contracts be amended by edits from the stakeholders or the Commission?

7. Interconnection Process

A. Should PPAs include conditions that reference the timing of the interconnection agreement and interconnection milestones? If so, what types of conditions should be included?

B. Should QFs have the ability to elect a larger role for third party contractors in the interconnection process? If so, how could that be accomplished?