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September 2, 2015

VIA ELECTRONIC MAIL

PUC Filing Center
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088

Re: UM 1610 – In the Matter of OREGON PUBLIC UTILITY COMMISSION, Investigation into Qualifying Facility Contracting and Pricing

Attention Filing Center:

Attached for filing in the above-captioned docket is an electronic copy of Idaho Power Company's Prehearing Brief.

Please contact this office with any questions.

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Office Manager

Attachments

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 1610 – PHASE II

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Investigation into Qualifying Facility Contracting and Pricing.	**IDAHO POWER COMPANY'S PREHEARING BRIEF**

I. INTRODUCTION

Pursuant to the March 26, 2015, ruling issued by Administrative Law Judges (ALJ) Shani Pines and Traci A.G. Kirkpatrick, Idaho Power Company (Idaho Power or Company) submits this Prehearing Brief. The Public Utility Commission of Oregon (Commission) opened Phase II of this docket to address various issues related to Oregon's implementation of the Public Utility Regulatory Policies Act of 1978 (PURPA). This brief summarizes the Company's position on the Phase II issues identified in the UM 1610 Phase II Issues List attached to the ALJ's March 26, 2015, Ruling.

II. PROCEDURAL BACKGROUND

In Order No. 12-146, the Commission ordered that a generic docket be opened to investigate issues related to electric utilities' purchases from qualified facilities (QFs) under PURPA. This general investigation was docketed as UM 1610.[1]

Following testimony and briefing on the issues identified for Phase I, the Commission issued Order No. 14-058, resolving certain issues and identifying others for further investigation in Phase II.[2] Thereafter, Obsidian Renewables (Obsidian) filed a Motion for Clarification of Order No. 14-058, regarding the Commission disposition of Issue 2A—

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[1] *Re Application to Revise Methodology Used to Determine Standard Avoided Cost Prices*, Docket Nos. UM 1590 and 1593, Order No. 12-146 at 1 (Apr. 25, 2012).

[2] *Re Investigation Into Qualifying Facility Contracting and Pricing*, Docket No. UM 1610, Order No. 14-058 (Feb. 24, 2014).

"Should there be different avoided cost prices for different renewable generation resources?"[3] As explained in greater detail in section IV.B, Order No. 14-058 introduced a modification to the calculation of avoided cost prices "to account for the capacity contribution of different QF resources."[4] Based on Staff's recommendations for further input from interested parties to clarify the solar capacity payment issue raised by Obsidian, the ALJ granted the motion for clarification and set a schedule for testimony and briefing on the solar capacity payment issue separate from the other issues to be addressed in Phase II.[5] Following testimony and briefing focused on the solar capacity payment issue, however, the Commission ultimately determined that "additional discussion on the solar capacity contribution issue previously briefed by the parties is appropriate," and added the solar capacity contribution issue to the final docket UM 1610 Phase II Issues List.[6]

The following parties filed testimony on one or more of the Phase II issues: Idaho Power, Commission Staff (Staff), Oregon Department of Energy (ODOE), Portland General Electric (PGE); PacifiCorp dba Pacific Power (PacifiCorp), Gardner Capital Solar Development (Gardner Capital), the Renewable Energy Coalition (REC), the Community Renewable Energy Project (CREA), OneEnergy Inc. (OneEnergy), and Obsidian. REC, CREA, OneEnergy, and Obsidian filed both individually and jointly as the "Joint QF Parties" (Joint QFs).

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[3] *Re Investigation Into Qualifying Facility Contracting and Pricing*, Docket No. UM 1610, Obsidian's Motion for Clarification (Apr. 24, 2014).

[4] Order No. 14-058 at 2.

[5] *Re Investigation Into Qualifying Facility Contracting and Pricing*, Docket No. UM 1610, ALJ Ruling (June 10, 2014) (granting Obsidian's Motion for Clarification).

[6] *Re Investigation Into Qualifying Facility Contracting and Pricing*, Docket No. UM 1610, ALJ Ruling (Mar. 26, 2015).

III. SUMMARY OF IDAHO POWER'S POSITIONS ON PHASE II ISSUES

In support of its positions on the Phase II issues, Idaho Power has provided Direct, Response, and Reply testimony of its witnesses Michael Youngblood and Randy Allphin.[7] As explained by Messrs. Youngblood and Allphin, and further discussed in this brief, Idaho Power's positions on the Phase II issues are rooted in its primary responsibility to protect its customers by ensuring that the Commission's implementation of PURPA does not harm Idaho Power's customers. Idaho Power's recommendations are also driven by a desire for consistency across its jurisdictions, which will prevent regulatory arbitrage. Idaho Power's positions can be summarized as follows:

- **Issue 1: Ownership of Green Tags.** Idaho Power currently has no renewable portfolio requirement under state or federal law applicable in the state of Oregon. The Commission has previously determined that the Green Tags or Renewable Energy Credits/Certificates (RECs) are owned by the QF. Idaho Power is not currently challenging this previous ruling. However, if Idaho Power were to become subject to renewable portfolio requirements it reserves the right to review the circumstances at that time a take the appropriate action deemed necessary to protect the interests of its customers.
- **Issue 2: Avoided Transmission Costs.** The Commission has previously determined that Idaho Power's proxy resource is and/or is assumed to be located on-system as a designated network resource available to serve load. Idaho Power's proxy resource remains an on-system network resource with no avoided transmission expense to serve Idaho Power load. Consequently there should be no change to the current calculations to include avoided

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[7] *See* Direct Testimony of Michael Youngblood (Idaho Power/800) and Randy Allphin (Idaho Power/900); Response Testimony of Michael Youngblood (Idaho Power/1000) and Randy Allphin (Idaho Power/1100); Reply Testimony of Michael Youngblood (Idaho Power/1200) and Randy Allphin (Idaho Power/1300).

transmission costs for Idaho Power. **Issue 3: Calculation of Solar Capacity Contribution Adder for Renewable Avoided Cost Prices.** Idaho Power believes that the Commission should adhere to its methodology adopted in Order No. 14-058 for both Renewable and Non-Renewable standard avoided cost rates. However, because Idaho Power does not maintain Renewable avoided cost rates, the Company will not provide argument specific to this issue.

- **Issue 4: Modification of the Capacity Contribution Component for Non-Renewable Avoided Cost Prices.** The Commission should adhere to the methodology it adopted in Order No. 14-058, which adjusted both the Non-Renewable and Renewable standard avoided cost prices to produce more accurate avoided cost estimates in order to account for the *actual* capacity contribution made by each QF resource type when measured against the proxy resource. When compared to previous and proposed approaches to calculation of avoided capacity, the currently approved methodology results in the closest approximation of the utility's *actual avoided capacity costs as measured with reference to the proxy combined-cycle combustion turbine plant (CCCT).* The Commission should reject the alternative methodologies proposed by other parties, all of which would result in unreasonable avoided cost prices in excess of the utility's actual avoided capacity costs.
- **Issue 5: Appropriate Forum for Dispute Resolution.** The appropriate forum to resolve litigated issues and assumptions related to avoided costs is in a specific complaint or other proceeding brought to address such issues. Such disputes should not be litigated in avoided cost compliance or Integrated Resource Planning (IRP) proceedings, which are time sensitive and are not designed as contested case proceedings. Alternatively, if the Commission

determines that such disputes should be litigated in avoided cost compliance or IRP dockets, then the Company proposes that QFs requesting standard contracts during the pendency of these proceedings be restricted to only the new avoided costs under review, subject to true-up.

- **Issue 6: Market Prices in Resource Sufficiency.** The Commission should make no change to its existing requirements, which provide that QFs are paid market rates when the utility is in a resource sufficient position. Such prices already more than compensate QFs because when utilities are in a resource-sufficient position they cannot avoid capacity costs by purchasing QF power, and yet on-peak market prices embed capacity costs.
- **Issue 7: Non-Standard Avoided Cost Prices.** The Commission should retain its current approach, which directs Idaho Power to use the modeling methodology approved by the Idaho Public Utilities Commission (IPUC)—the incremental IRP methodology—which determines the avoided cost of energy by using Idaho Power's power cost model (AURORA) to calculate the incremental cost for each hour of the proposed QF contract term.
- **Issue 8: Legally Enforceable Obligation.** In the absence of a signed contract a legally enforceable obligation may arise between a utility and QF when a QF can demonstrate that: (1) there has been an unreasonable delay or refusal to contract by the utility; and (2) the QF has sufficiently obligated itself to the particular transaction at those particular rates.
- **Issue 9: Third Party Transmission Costs.** Idaho Power currently does not incur any third party transmission costs to move QF electricity to load. For Idaho Power these costs would be identified and included in the existing Generation Interconnection process and studies and any identified costs required to enable interconnection and designation of the QF as an Idaho

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Power network resource would be paid by the QF through that process. These costs would not be part of the avoided cost calculation, but for Idaho Power part of the separate Generation Interconnection process, which is the appropriate treatment for these costs. Idaho Power proposes no changes to the current process.

In the discussion that follows, Idaho Power presents its position on Issues 3-8, without further discussion of Issues 1, 2, and 9 which do not impact Idaho Power or its customers.

IV. APPLICABLE LAW

Congress passed PURPA in 1978 to encourage conservation, reliability, and efficiency in the delivery and generation of electricity, with equitable rates for electric consumers.[8] Section 210 of PURPA introduced the now-familiar requirement that utilities "must-purchase" power from certain QFs.[9] In order to ensure that this new requirement did not prejudice utility ratepayers, Congress expressly provided that the prices paid to QFs by electric utilities ***must not exceed the incremental cost to the utility of alternative electric energy, defined as "the cost to the electric utility of the electric energy which, but for the purchase from such [QF], such utility would generate or purchase from another source."***[10] This latter concept, which is at the heart of many Phase II issues, is referred to as the utility's "avoided cost."[11]

The Federal Energy Regulatory Commission (FERC) rules implementing Section 210 further clarify that "avoided cost" is the cost that the utility would have paid for the capacity and energy obtained from the QF if the utility had purchased the capacity and energy from another source or generated the power itself.[12] In setting this standard, FERC intended that

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[8] 16 U.S.C. § 2601.

[9] 16 U.S.C. § 824a-3.

[10] 16 U.S.C. § 824a-3(d).

[11] *See* 16 U.S.C. §§ 824a-3(b), (d).

[12] 18 C.F.R. § 292.101(b)(6).

utility customers should be neither helped nor harmed by the utility's purchase of QF power, and, in fact, should remain "indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives."[13] The avoided cost requirement also ensures that QFs are not subsidized at ratepayers' expense.[14]

Although PURPA is a federal law implemented by FERC, state commissions have authority to implement the Section 210 must-purchase obligation, including the establishment of "avoided cost" prices. State commissions have considerable discretion to determine a method for calculating avoided costs, and to set criteria for creation of a legally enforceable obligation between a QF and a utility. A recent Memorandum of Agreement between FERC and the IPUC described the respective state and federal roles as follows:

> PURPA establishes a program of cooperative federalism. The FERC is required to issue regulations to give effect to federal policy, as set by Congress in the statute, to encourage small power production development. State regulatory authorities, such as the Idaho PUC, are responsible for implementing the FERC's regulations, and may do so in a manner that accommodates local conditions and concerns so long as the implementation is consistent with PURPA and the FERC's PURPA regulations.[15]

For the past three decades, this Commission has consistently articulated and demonstrated a strong commitment to this model of "cooperative federalism" and the implementation of PURPA in a manner that achieves PURPA's goals without prejudice to utility ratepayers:

- In 1984, QF developers argued in favor of higher avoided cost prices "to ensure that the legislature's goal of renewable resource development is attained."[16] The Commission rejected this argument by acknowledging that, while "[h]igher

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[13] *So. Cal. Ed. Co.*, 71 F.E.R.C. ¶ 61,269, 62,079 (F.E.R.C. 1995).

[14] *Independent Energy Producers Association v. California Public Utilities Comm'n*, 36 F.3d 848, 858 (9th Cir. 1994).

[15] *See* Memorandum of Agreement between FERC and the Idaho Public Utilities Commission dated December 24, 2013 (https://www.ferc.gov/legal/mou/mou-idaho-12-2013.pdf).

[16] *Re Proposed Amendments to Rules Relating to Cogeneration and Small Power Production Facilities*, Docket No. AR 102, Order No. 84-742 at 3 (Sept. 24, 1984).

rates would make more projects feasible," the Commission "has another goal to consider" and "[t]hat goal is to obtain service for ratepayers at reasonable rates."[17]

- In 2005, the Commission noted that one of its fundamental objectives under PURPA is to accurately price QF power to ensure that customers remain indifferent to QF generation.[18] The Commission emphasized that it has "consistently interpreted its PURPA mandate to be the adoption of policies and rules that promote QF development, using among other tactics, accurate price signals and full information to developers, *while ensuring that utilities pay no more than avoided costs.*"[19]

- In its 2014 order in Phase I of this docket, the Commission's ruling was "grounded in the policies that we articulated in previous orders addressing these issues," such as to "provide maximum economic incentives for development of QFs while insuring that the costs of such development do not adversely impact utility ratepayers who ultimately pay these costs."[20]

- More recently, in Order No. 15-199, the Commission stated that its task in implementing PURPA is to "balance our duty to 'create a settled and uniform institutional climate for QFs in Oregon,' while ensuring 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."[21]

As explained in greater detail below, Idaho Power's positions on the Phase II issues require the Commission to again weigh these competing interests and strike the proper balance.

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[17] Order No. 84-742 at 3.

[18] *Re Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Docket No. UM 1129, Order No. 05-584 at 11 and 19 (May 13, 2005); *Re Adoption of Administrative Rules Relating to Cost-Effective Fuel Use and Resource Development*, Docket No. AR 112, Order No. 85-010 at 18 (Jan. 8, 1985).

[19] Order No. 05-584 at 11 (emphasis added).

[20] Order No. 14-058 at 3 (quoting 18 C.F.R. § 292.101).

[21] *Re Applications to Lower Standard Contract Eligibility Cap and to Reduce the Standard Contract Term, for Approval of Solar Integration Charge, and for Change in Resource Sufficiency Determination*, Docket No. UM 1725, Order No. 15-199 (June 23, 2015) (quoting ORS 758.515(3)(b) and Order No. 14-058 at 3 citing Order No. 05-584 at 6; 16 U.S.C. § 824a-3(a) – (b), 18 C.F.R. § 292.101 *et seq.* (lowering the eligibility cap for Idaho Power's standard contracts from 10 to 3 MW on a temporary and interim basis in order to protect Idaho Power and its customers from entering into "substantial long-term contracts that exceed the company's actual avoided costs").

V. DISCUSSION OF ISSUES

Issue 4: The Commission Should Retain the Order No. 14-058 Methodology for Calculating Capacity Payments for Non-Renewable Avoided Cost Rates because this Approach Achieves a More Accurate Approximation of a Utility's Actual Avoided Capacity Costs in Comparison to a CCCT Proxy.

FERC's rules implementing PURPA are explicit that the avoided cost price paid to a QF must compensate it for energy, capacity, or both, which "but for" the purchase from the QF, such utility would generate itself or purchase from another source.[22] No party disputes that QFs should be compensated for avoided capacity. The issue is rather how to quantify the value of the capacity that a utility avoids when it purchases power from a QF.

1. *Utility Capacity Payments to QFs Should Compensate for the Actual Avoided Capacity Costs Attributable to that Particular Resource.*

FERC's rules state that an avoided cost rate satisfies PURPA and FERC's own rules if the rate equals the avoided costs determined after consideration of certain factors, including "the availability of capacity or energy from a QF during the system daily and seasonal peak periods," as well as the QF's dispatch ability and reliability.[23] Although FERC has left it to the States to select a methodology for calculating avoided capacity costs,[24] it recognizes that the value of the capacity costs avoided by a utility should *increase* when a QF "can provide energy to a utility during peak periods when the electric utility is running its most expensive generating units" and, conversely, should *decrease* if the "demonstrated reliability" of the QF makes it less valuable to the utility. [25]

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[22] 18 C.F.R. § 292.101(6); *Small Power Production and Cogeneration Facilities: Regulations Implementing Section 210 of the Public Utility Regulatory Policy Act of 1978,* Order No. 69, 45 Fed.Reg. 12,214, FERC Stats & Regs., Regs. Preambles 1977-1981 ¶ 30,128 (Feb. 19, 1980) (hereinafter "Order No. 69").

[23] 18 C.F.R. § 292.304(e)(

[24] Order No. 69 at 12226,

[25] *Id.*

2. ***The Avoided Capacity Cost Methodology Established in Order No. 14-058 More Accurately Values QF Capacity.***

With Order No. 14-058, the Commission modified the traditional avoided cost proxy methodology to more appropriately reflect the actual capacity contribution of wind and solar QFs.[26] The Commission explained its reasons for doing so as follows:

> 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 . . . .
>
> 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.[27]

In order to fully understand the Commission's direction and intent, it is important to note the specific language in the Order. The Commission intended to adjust "the capacity component in standard and renewable avoided cost prices."[28] In this way, they intended to produce more accurate avoided cost estimates to account for the *actual contribution to*

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[26] Order No. 14-058 at 2.

[27] *Id.* at 15 (emphasis added).

[28] *Id.*

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capacity made by each QF resource type. The *capacity component* was already an established part of avoided cost prices.[29] The capacity component is added to the energy component to determine the avoided cost on-peak price, while the off-peak price only contains the energy component of the calculation. The capacity component of the avoided cost price was always a part of the then current methodology, and the Commission specifically stated in Order No. 14-058, that they retained the current methodology for calculating standard avoided cost prices and standard renewable avoided cost prices, with the modifications described in the Order.[30] The modification only adjusted the capacity component of the avoided cost price by multiplying the capacity component embedded in the existing method by a "capacity contribution factor," equal to the expected contribution to peak load of the specific QF resource type.[31] No other change to the calculation was ordered.

Prior to Order No. 14-058, Idaho Power and the other utilities established the capacity component of the avoided cost prices paid to QFs using the following method: (1) Estimating the annual cost in dollars of the capacity-related portion of a CCCT, otherwise referred to as the proxy resource; (2) Convert the annualized cost of capacity to a dollar-per-megawatt-hour rate ($/MWh) by dividing the annual capacity-related costs by the product of the number of on-peak hours in a year and the on-peak capacity factor of the proxy resource.[32] For example, Idaho Power's annualized cost of capacity of $66,200/MW-yr ($66.20/kW-yr) divided by the product of the number of on-peak hours in a year and the on-peak capacity factor of the proxy resource (4,862 on-peak hours X 100 percent on-peak capacity factor of the proxy CCCT) results in a capacity component of the avoided cost price of $13.62/MWh. It is to this number, the capacity component of the avoided cost price, that Order No. 14-

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[29] *See e.g.* Order No. 05-584 at 26.

[30] Order No. 14-058 at 12.

[31] *Id.* at 15.

[32] Staff/400, Andrus/4

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058 directed the parties to multiply a "capacity contribution factor" equal to the expected contribution to peak load of the specific QF resource type.

As correctly noted by the Commission, prior to Order No. 14-058, no adjustments were made to "avoided cost prices to account for the actual contribution to capacity made by each QF resource type".[33] In other words, prior to Order No. 14-058, all QFs received the same capacity component determination ($13.62/MWh in our example) included in the on-peak avoided cost price for every on-peak hour of generation, without any modification to reflect the actual capacity contribution to peak load avoided by that particular QF. To be clear, not all resources ever received the same annual capacity payment using the prior method, because the QF would receive an on-peak avoided cost price *only for energy actually delivered* by the QF during on-peak hours. As a practical matter, the QF would receive a percentage of the total capacity dollars attributed to the proxy plant that was *in proportion to the QF's on-peak capacity factor.*

Under Order No. 14-058, the Commission revised the methodology to adjust the capacity component portion of the avoided cost price, in order to ensure that a utility's capacity payments to a QF took into account not just the QF's output over all peak hours (as the existing method already did), but also the QF's contribution to peak load (CTP). Accordingly, the Order directed the utility to multiply its $/MWh capacity component currently embedded in the method by a "capacity contribution factor", equal to the expected CTP of the specific QF resource type. The order stated that the assumed CTP would be the contribution estimate used in the utility's acknowledged IRP for the specific type of generation (wind, solar, etc.). In Idaho Power's case, the current CTP determined in the 2013 IRP for a wind QF is 3.9 percent and for a solar QF is 32 percent. These CTP percentages are multiplied times the capacity *component for the proxy resource, in direct*

[33] Order No. 14-058 at 15.

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compliance with the Commission's direction in Order No. 14-058.[34] Thus, under Idaho Power's current Schedule 85, the 2016 capacity component of the on-peak avoided cost price for a wind QF is $0.53/MWh and for a solar QF is $4.36/MWh, which represents 3.9 percent and 32 percent of the capacity component for the proxy resource ($13.62/MWh), respectively. This means that rather than a QF receiving 100 percent of the capacity contribution to peak load of the proxy resource, as it did before Order No. 14-058, it instead receives a lower capacity payment commensurate with its particular CTP.

The avoided cost prices that result from this method are, not surprisingly, lower than previous prices. Indeed, the Commission's stated goal was to "produce more accurate avoided cost estimates" that would "capture the expected capacity contribution of each QF resource type."[35] The method adopted by the Commission in Order No. 14-058 results in more accurate avoided cost estimates based on the value of capacity of the proxy resource actually avoided by the QF generation.

3. *Payments for Avoided Capacity Should Be Based on the Value of Capacity Actually Avoided by the QF Resource.*

As a policy matter, the Commission's direction in Order No. 14-058 is consistent with PURPA and FERC's direction that avoided cost prices be established based on the capacity value of a particular resource as compared to the proxy resource, taking into consideration both the resource's CTP and its annual capacity factor (CF). In fact, to disregard either aspect of a QF's capacity value would be inconsistent with basic principles of sound utility resource planning. When a utility is evaluating a resource for planning purposes, it does not consider *only* how much the resource can contribute at the utility's hour of peak load,

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[34] *Id.* (adopting 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).

[35] *Id.* The Commission's observation that "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" is not to the contrary, because it related only to the capacity adder in Standard Renewable contracts, for which the proxy plant is a wind resource with a lower capacity contribution than solar.

nor does it consider *only* what percentage of its nameplate capacity the resource will contribute during all hours in a year. Both aspects of capacity are critical to a utility's assessment of the value of the resource to that utility's operating system. There is no reason to consider only one or other (CTP or CF) when assigning value to the capacity a utility avoids by purchasing from a QF.

In order to fully understand the Commission's direction and intent in Order No. 14-058, it is helpful to review the two different aspects of "capacity" that are considered when acquiring a generation resource. In the case of setting standard non-renewable avoided cost rates, that generation resource is the proxy CCCT. As described below, the capacity value of a given resource is measured by both its **capacity factor** and its **contribution to peak**.

Capacity Factor: The capacity factor of a resource is the ratio of its *actual output* over a period of time to its *potential output* if it were possible for it to operate at full nameplate capacity over that same period of time.[36] Basically, it is the measure of how much energy that resource is expected to produce over a given period of time, and is represented as a percentage of plant capacity.

Contribution to Peak: The CTP of a resource is also stated as a percentage, but it refers to the percentage of the resource's nameplate capacity that it provides at the utility's *hour* of peak load.[37] For example, a load-following power plant, such as a CCCT proxy resource, with a nameplate capacity of 300 MW that can generate 300 MW at the hour of a utility's peak load has a CTP of 100 percent because it contributes 100 percent of its nameplate capacity at peak load. An intermittent renewable resource such as a solar PV

[36] Idaho Power/600, Youngblood/7.

[37] Calculation of CTP is not at issue here. In Order No. 14-058, the Commission directed the utilities to use the CTP for each resource type that they use for purposes of planning, which is fixed in each utility's acknowledged IRP.

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project, with a nameplate capacity of 100 MW that generates 32 MW at the utility's hour of peak load has a CTP of 32 percent.

In his reply testimony, Mr. Youngblood illustrates this principle with reference to two hypothetical workers—Roxy Proxy and Sonny Solar.[38] In this hypothetical, Roxy Proxy is a full-time employee who works 40 hours per week, and Sonny Solar works 20 hours per week. If Roxy and Sonny had comparable levels of productivity during their hours worked, it would be logical for them to be paid the same hourly wage. In the hypothetical scenario, however, Sonny Solar does not perform at the same productivity level as Roxy Proxy. For purposes of illustration, the following paragraph expands on the hypothetical to focus on the relative productivity of the two workers.

Roxy and Sonny work at The Corner Deli, where they assemble perishable lunches for delivery all over Portland. In the Deli's kitchen, the hours between 10 AM and noon are the lunch rush and, during those peak hours, Roxy assembles 100 lunches per hour. Sonny doesn't work every lunch rush and, when he does, he only assembles 32 lunches per hour. Roxy is paid a higher hourly wage than Sonny; both are valued employees, but Roxy's compensation is commensurate with her efficiency and contribution during those peak hours. Common sense dictates that this is just and reasonable, assuming that Sonny will be similarly compensated if and when he increases his productivity. In this hypothetical, establishing Roxy and Sonny's hourly wage based on productivity is akin to setting the capacity price for QFs based on CTP. The fact that Roxy and Sonny get paid for the hours they work is akin to paying QFs for on-peak output (CF). True, Sonny makes less than half of what Roxy makes, even though he works exactly half as many hours as Roxy does. But there is nothing inherently unfair about this reality; Sonny is paid a fair wage for his work.

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[38] Idaho Power/1200, Youngblood/5-7.

4. *Arguments by Staff, ODOE and Joint QFs Do Not Address Both Contribution to Peak and Capacity Factor, as Correctly Required by the Commission's Order*

The position now taken by Staff, ODOE, and the Joint QF's is that the methodology adopted by the Commission in Order No. 14-058 is flawed because it results in a "double discount" to the capacity price paid to QFs. The parties assert that the problem with the method adopted by the Commission in Order No. 14-058 is that it calculates a capacity payment taking into account the QF's CTP, "but then effectively discounts this rate again by applying it only to the hours of full capacity production."[39] To correct this supposed flaw in the Order No. 14-058 methodology, the parties assert that if the capacity payment is to be discounted to reflect QF's CTP, then the capacity component of the avoided cost rate should be calculated by spreading the total fixed capacity cost of the proxy resource over only the QF's assumed MWh of on-peak operation. Stated simply, the parties assert that, if the capacity component is adjusted using the CTP reduction, the actual capacity factor of the QF as compared to the proxy resource should no longer apply. Staff explains that otherwise, "it is impossible for an intermittent resource that cannot operate in all those hours to receive *all of the capacity dollars to which it is entitled.*"[40] Staff and the parties have forgotten, however, that the whole purpose of the proxy method is to establish an estimation of avoided costs as compared to the proxy resource, so that QFs can be compensated for the energy and capacity that the utility actually avoids generating or purchasing *because of power it purchases from a QF.* There is no presumption underlying Order No. 14-058—or PURPA

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[39] Obsidian/400, Brown/5. In his direct testimony, David Brown states that "if you are paid 20 percent of the value of capacity on 20 percent of the high load hours then you end up with only 20 percent of 20 percent, or only 4 percent of the total capacity dollars. I believe, and Staff has since confirmed, that this double discount was not intentional and was simply an inadvertent math error." Idaho Power respectfully disagrees with Staff, ODOE, and the Joint QFs that Staff's methodology adopted in Order No. 14-058 was in error, but nonetheless addresses the merits of the issue.

[40] Staff/400, Andrus/4.

for that matter—that a QF is allowed to receive compensation for capacity or energy that the QF does not enable the utility to avoid.

Idaho Power takes issue with the parties' characterization of the Order No. 14-058 methodology as instituting a "double discount" because both words introduce misconceptions that cloud the issue—these are not "discounts" and nothing is being done twice. The word "discount" implies a reduction from the actual cost or value of something; modifying the capacity component of the avoided cost rate to be commensurate with a QF's actual capacity contribution to peak load achieves a better estimation of the actual cost or value being avoided and should not be viewed as a discount.

The word "double" implies that the methodology involves repeating the same calculation twice, which is simply not the case. As pointed out above, capacity factor and capacity contribution to peak load involve two different aspects of capacity, both of which must be considered in determining the actual capacity value of a resource. The methodology prior to Order No. 14-058 already accomplished the appropriate adjustment due to the capacity factor of a renewable QF resource such as wind or solar, as they are compared to the CCCT proxy resource. And no modification to the determination of the capacity component of the avoided cost price was ordered, in fact, it was explicitly ordered that no other changes to the QF pricing was to occur.[41] The modification directed in Order No. 14-058 to adjust the capacity component in standard and renewable avoided cost prices was explicitly made to produce more accurate avoided cost estimates to capture the expected capacity contribution of each QF resource type.[42]

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[41] Order No. 14-058 at 12.

[42] *Id.* at 15.

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5. ***PURPA Prohibits the Commission from Requiring Utilities to Pay QFs Prices that Exceed Actual Avoided Costs***

Moreover, Staff's proposed modification to the capacity calculation from Order No. 14-058 as applied to Idaho Power actually *increases* the avoided cost rate as compared to the proxy resource rather than recognizing the decreased contribution to peak as directed by the Order. Staff, ODOE and the Joint QFs proposed changes to the capacity contribution directed by the Commission in Order No. 14-058 would result in avoided cost rates for Idaho Power that exceed the avoided cost rates of the baseload CCCT proxy resource being avoided. In fact, using the numbers from Idaho Power's Schedule 85, and inputs from Idaho Power's 2013 IRP, in Staff and ODOE's proposed methodology, the on-peak avoided cost rate for a solar QF, which has a contribution to peak load of 32 percent, actually exceeds the on-peak avoided cost rate of the baseload CCCT proxy resource, which assumes a contribution to peak load of 100 percent. This not only is contrary to the intent and direction of Order No. 14-058, but also results in an unlawful rate that exceeds the Company's avoided cost—as it exceeds 100 percent of the proxy avoided resource value.[43]

Consequently the Commission should reject the "clarification" and proposed adjustments of Staff the QF parties. The direction from Order No. 14-058 is lawful, clear, and correct, resulting in a better estimation of avoided costs and protecting utility customers from overpaying for PURPA resources. The Commission should affirm its determination in Order No. 14-058 as to the contribution to peak of solar resources.

Issue 5: The Appropriate Forum to Resolve Litigated Issues and Assumptions relating to PURPA and Avoided Costs is in a Commission Docket Opened Specifically to Address Such Issues.

Idaho Power agrees that QFs must have a forum to challenge inputs to avoided cost prices. However, the process of litigating inputs should not be allowed to derail or hold up

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[43] Idaho Power/700, Youngblood/12 (currently approved solar on-peak avoided cost rate, Schedule 85 = $47.52/MWh; currently approved baseload on-peak avoided cost rate, Schedule 85 = $56.78/MWh; proposed Staff/ODOE solar on-peak avoided cost rate = $61.32/MWh).

either the IRP, or the utilities' annual avoided cost filings. Neither of these processes are set up as contested cases, and both are time-sensitive; moreover, past attempts to use these dockets to litigate avoided cost inputs have resulted in confusion and delay. This delay is detrimental to utility customers, particularly when avoided cost rates are adjusting downward as they have for the past several adjustments. Instead, Idaho Power believes that disputes over inputs to the avoided cost calculations should be resolved in complaint or investigative dockets, opened specifically to review these inputs—either at the request of the utility, Staff, or any other party that wishes to initiate such request.

Staff asserts that that the avoided cost filing is an appropriate forum to resolve disputed issues, pointing to Commission orders in which Commission has encouraged parties to seek suspension of avoided cost filings to address concerns regarding inputs.[44] Idaho Power disagrees. Avoided cost compliance filings are time-sensitive and often involve a price change of considerable interest to QFs and the utility. Indeed, over the past several years, new filings have generally involved significant decreases to avoided cost prices. And, in Idaho Power's experience, a new filing with lowered avoided cost prices will frequently trigger QFs to make immediate requests for new standard contracts, in an attempt to lock in the old prices before the new ones are approved. A policy allowing QFs to use the avoided cost filings to challenge inputs could provide them with the incentive and opportunity to drag out those processes as long as possible, thereby delaying approval of the new prices. For these reasons, the Commission should not permit parties to litigate contested issues in the context of a compliance filing or an annual avoided cost update. Compliance filings should be limited to just that—compliance.

Rather, the appropriate place to determine and resolve litigated issues and assumptions for PURPA is in a PURPA docket. If a party has issue with a particular input,

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[44] Staff/500, Andrus/28.

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methodology, or practice with regard to avoided cost rates or the implementation of the utility's PURPA obligations, that issue should be brought to the Commission through an application, petition, complaint, or investigation so that the Commission can properly consider the issue through a contested proceeding and make a decision or ruling on the issue.

Alternatively, if the Commission decides that avoided cost compliance filings are an appropriate forum for resolving such disputes, Idaho Power requests that the Commission take action to insure that customers are not harmed by any delay in approving the new avoided costs. Specifically, the Commission should order than any request for contracts made after the new avoided cost filing is made should be considered as eligible for the new prices, as filed. These new prices would be subject to "true-up" consistent with those ultimately approved by the Commission

Issue 6: Market Prices Used During the Resource Sufficiency Period Sufficiently Compensate QFs for Capacity.

The Commission has long differentiated between the calculation of avoided costs for a utility in a resource deficit position from a utility in a resource sufficient, or surplus, position. In Order No. 05-584, the Commission stated:

> The historical differentiation is based on recognition that a utility's avoided costs differ depending on the resource position of the utility. In a period of resource deficiency, the historical calculation of avoided costs has included both the variable and fixed costs of a planned resource in order to reflect the actual deferral or avoidance of that resource. In a period of resource sufficiency, however, the historical calculation of avoided costs has included only the variable costs of operating an existing resource, reflecting the inability of a resource sufficient utility to defer or avoid a resource when QF generation is committed.
>
> We remain convinced that the accurate calculation of avoided costs requires differentiation when a utility is in a resource sufficient position versus a resource deficient position.[45]

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[45] Order No. 05-584 at 26.

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In short, the Commission has recognized that during times of resource sufficiency, the utility cannot avoid capacity costs by purchasing QF power.

In implementing its policy, the Commission adopted Staff's recommendation and ordered that avoided costs for utilities in a resource sufficient position be set at monthly on- and off-peak forward market prices[46] Some parties argue that the use of market prices under-compensates QFs during times of resource sufficiency.[47] However, the contrary is true.

The use of the on-peak market price embeds the value of incremental QF capacity in the total market-based avoided cost rate, and therefore the QF receives compensation for capacity even when the utility is resource sufficient.[48] If a utility is capacity sufficient, capacity is not being avoided by the purchase of QF power; therefore, the utility and its customers are not avoiding any capacity costs during that time. Thus, market prices more than compensate QFs during times of resource sufficiency.

Issue 7: For Non-Standard Cost Contracts, Each Utility Should Use an Avoided Cost Methodology that Best Suits its Unique System; for Idaho Power, this is the IRP Methodology Approved by the Commission.

Since at least 2007, the Commission has directed Idaho Power to use the same methodology for non-standard avoided cost prices, for those projects that exceed the standard rate eligibility cap, as that which is approved for use by the IPUC for the Company's Idaho jurisdiction.[49] That methodology is termed the Incremental Cost IRP Methodology (IRP Methodology). The IRP Methodology is set forth in the appropriate section for negotiated rate contracts in the Company's Schedule 85 as follows: "The starting point for negotiations is the avoided cost calculated under the modeling methodology approved by

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[46] *Id.*

[47] *See* Joint QF Parties/100, Higgins/4-6; ODOE/900, Carver/8, Staff/600, Andrus/19.

[48] Idaho Power/1200, Youngblood/10-12.

[49] *Re Investigation Related to Electric Utility Purchases from Qualifying Facilities*, Docket No. UM 1129, Order No. 07-360 at Appendix A, item 2.a.ii (Aug. 20, 2007).

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the Idaho Public Utilities Commission for QFs over 10 MW, as defined by the Oregon Public Utility Commission to incorporate stochastic analyses of electric and natural gas prices, loads, hydro and unplanned outages."[50] This language was most recently approved for Schedule 85 in July 2014, as part of the Company's compliance filing from Order No. 14-058 in Phase I of this proceeding.[51] Idaho Power sees no need to depart from this methodology and requests that the Commission continue to direct Idaho Power to use its IRP methodology for calculating avoided costs.

As explained in greater detail in the testimony Mr. Allphin, Idaho Power does not believe it is important that all three utilities use the same methodology for non-standard avoided cost pricing.[52] For example, Idaho Power's IRP Methodology uses the same AURORA power supply modeling of its Company-owned resources and system that is utilized for its IRP purposes as well as for the annual Power Cost Adjustment in Idaho and the Annual Power Cost Update in Oregon, so it is both efficient and more accurate for Idaho Power to use this methodology for calculating avoided costs.

Additionally, for Idaho Power, it is more important that the avoided cost prices, procedures, and implementation are consistent between its Idaho and Oregon jurisdictions than to have those processes, procedures, and implementation be aligned with the other utilities in the state of Oregon.[53] State jurisdictional PURPA regulations are different by state and it is relatively simple for a proposed project to locate its project in the state which has the more favorable PURPA regulations. Idaho Power has seen great interest in and activity from solar and wind projects seeking to benefit from these jurisdictional differences to the detriment of Idaho Power customers in both states who share in the Company's PURPA

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[50] Idaho Power Schedule 85, page 10 item 2.a.

[51] *Re Application to Update Schedule 85 Qualifying Facility Information*, Docket No. UM 1730, Order No. 15-204 (June 23, 2015).

[52] Idaho Power/900, Allphin/7.

[53] Idaho Power/900, Allphin/7.

power supply expenses. For example, a recent PURPA QF project physically located in the state of Idaho took extreme measures to establish eligibility for an Oregon standard PURPA contract by attempting to wheel its power to Idaho Power's system in Oregon rather than enter into an Idaho PURPA contract because the project determined that the Oregon standard PURPA contract, avoided costs, and other PURPA regulations were more favorable than the Idaho PURPA rules and regulations.[54] Different PURPA QF rules and regulations and avoided cost values in Idaho and Oregon encourage projects to relocate just across the border to the more favorable state, and the increased purchase power costs are shared by all Idaho Power customers.

Idaho Power requests that the Commission continue to authorize the use of the same methodology approved by the IPUC for non-standard avoided cost pricing for QFs that exceed the standard rate eligibility cap to be used as the starting point for negotiations, as specified in the currently approved Schedule 85.

Issue 8: The Commission Should Adopt the Clear Criteria Proposed by Idaho Power Regarding When, Outside of an Executed Contract, a Legally Enforceable Obligation Arises Between a QF and a Utility.

FERC precedent dictates that a utility may incur a legally enforceable obligation to purchase QF output at a set avoided cost price: (1) where the utility and QF execute a contract governing the terms of the agreement; or (2) in the case where a utility unreasonably refuses to contract with the QF, where the QF obligates itself to sell to the utility under specifically defined terms and conditions. In essence, FERC has directed that where a utility has unreasonably frustrated the QF's ability to contract, and the QF has done what is necessary to obligate itself, a sort of "constructive contract" will arise between the QF and utility. For the purposes of this brief, we will use the term LEO to refer to this constructive contract.

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[54] *Tumbleweed Energy II, LLC v. Idaho Power Co.*, Docket Nos. UM 1552 and 1553, Order No. 12-083 (Mar. 13, 2012).

As a practical matter, a dispute over the existence of a LEO generally arises when the Commission has approved or is about to approve new standard avoided cost prices that represent a significant decrease from the old prices, and the QF claims to have a right to previous, higher avoided costs rates, despite the fact that the QF and utility have not executed a contract. For this reason, the Commission's determination as to the specific circumstances giving rise to a LEO will have significant consequences for both the QFs and utility customers.

Idaho Power proposes that the Commission establish that a QF does not bind the Company and its customers to existing standard contract terms and/or conditions through a LEO unless and until:

- "But for" the refusal of the utility to enter into a contract, there would be a contract at a particular price and terms;
- The utility's refusal or conduct was purposeful and intended to prevent or delay the utility's commitment to purchase power from the QF, in violation of PURPA;
- The QF can deliver its electrical output within 365 days of the Commission's determination; and
- The QF will be subject to the penalties specified in the Standard Contract for failure to deliver its energy within that 365-day timeframe.

The following discussion details the legal basis and rationale for Idaho Power's position.

1. *The Commission Has Discretion to Determine What Facts Create a Non-Contract Legally Enforceable Obligation in Oregon.*

The phrase "legally enforceable obligation" in the context of PURPA is a phrase found in FERCs regulations, 18 C.F.R. § 292.304, *Rates for purchases*, in subsections (b) (5) and (d) (2). The portion relevant to the issues in this proceeding states:

> (d) *Purchases "as available" or pursuant to a legally enforceable obligation*. Each qualifying facility shall have the option either:

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> (1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or
>
> (2) To provide energy or capacity pursuant to a ***legally enforceable obligation*** for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:
>
> (i) The avoided costs calculated at the time of delivery; or
>
> (ii) The avoided costs calculated at the time the obligation is incurred.[55]

Upon enacting the above regulation, FERC stated: "Use of the term 'legally enforceable obligation' is intended to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility merely by refusing to enter into a contract with the qualifying facility."[56] FERC has further explained:

> Thus under our regulation, a QF has the option to commit itself to sell all or part of its electric output to an electric utility. While this may be done through a contract, if the utility refuses to sign a contract, the QF may seek state regulatory authority assistance to enforce the PURPA-imposed obligation on the electric utility to purchase from the QF, and a non-contractual, but still legally enforceable, obligation will be created pursuant to the state's implementation of PURPA.[57]

FERC, has not defined what conditions give rise to an LEO. Rather, FERC has ruled, "It is up to the States, not [FERC], to determine the specific parameters of individual QF power purchase agreements, including the date at which a legally enforceable obligation is incurred under State law."[58] Determining what establishes an LEO under Oregon law is the issue before the Commission.

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[55] 18 C.F.R. § 292.304(d).

[56] Order No. 69 at 12,224 (Feb. 25, 1980).

[57] *Cedar Creek Wind LLC*, 137 F.E.R.C. ¶ 61,006 at 8 (2011).

[58] *New PURPA 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, 119 F.E.R.C. ¶ 61,305 at ¶ 139 (2007) ("[I]t is the state regulatory authorities (or non-

2. *Idaho Power Endorses a Modified Version of Staff's Recommendation*

Both Idaho Power and Staff opening testimony presented a thorough and accurate summary of how Oregon has handled this issue to date, including a review of relevant case law and rulemaking history.[59] Idaho Power sees no reason to repeat that information here. The bottom line is that the Idaho Power agrees with Staff that the Commission should allow QFs the opportunity to establish a non-contractual LEO, but Idaho Power recommends that the Commission limit this relief to circumstances in which the QF demonstrates that the utility has unreasonably refused or delayed execution of a contract and the QF obligated itself to sell under specific terms and conditions.

Specifically, Idaho Power recommends that the Commission require a QF to make the following showings in order to establish a non-contractual LEO:

(1) Has there been an unreasonable refusal or delay by the utility to contract?

Regarding this factor, the Commission should require the QF to show that:

- The utility's refusal or conduct was purposeful and intended to prevent or delay the utility's commitment to purchase power from the QF, in violation of PURPA.[60] On this point, the Commission should look to whether the utility's refusal or delay was on one hand reasonable and justified by the circumstances or the result of an understandable oversight or on the other hand was specifically intended to frustrate the QF's legitimate rights under PURPA.
- "But for" the refusal of the utility to enter into a contract, there would be a contract at a particular price and terms. This factor could only be satisfied if the QF has provided the utility with all of the information required for a contract, and has clearly evinced its intent to be obligated—including its willingness to provide a specific amount of energy under specific terms and conditions. An initial request for a contract can never satisfy this criterion.

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regulated utilities) that determine whether and when a legally enforceable obligation is created, and the procedures for obtaining approval of such an obligation.").

[59] Idaho Power/900, Allphin/8-13; Staff/500, Andrus/36-39.

[60] *Id.*; *see also Grouse Creek Wind*, 142 F.E.R.C. ¶ 61,187 at 40 (2013) (quoting *JD Wind* 1, LLC, 129 F.E.R.C. ¶ 61,148 at 29 (2009) ("a QF, by committing itself to sell to an electric utility, also commits the electric utility to buy from the QF; these commitments result either in contracts or in non-contractual, but binding, legally enforceable obligations.").

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(2) Did the QF obligate itself?

Regarding this factor, the Commission should require the QF to show that:

- It can deliver its electrical output within 365 days of the Commission's determination,[61] and
- It will be subject to the penalties specified in the Standard Contract for failure to deliver its energy within that 365-day timeframe.[62] In order for a QF to actually obligate itself, it must have something to lose if it defaults on its obligation.

Each of these criteria are supported by—if not required by—PURPA and applicable federal and state precedent referenced above.

Idaho Power notes that a determination as to whether a LEO has arisen, in the absence of a written contract, will require a detailed, case-by-case review of the facts presented. However, by adopting Idaho Power's proposed criteria for establishing a non-contractual LEO, the Commission would go a long way towards creating a "'settled and uniform institutional climate for qualifying facilities in Oregon' while ensuring that electric utilities 'purchase power from QFs at rates that just and reasonable to the utility's customers, in the public interest, and that do not discriminate against QFs.'"[63]

VI. CONCLUSION

For the reasons set forth above, the Commission should adopt Idaho Power's recommendations to reduce the likelihood of future customer harm and ensure that PURPA

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[61] IPUC Order No. 33197 at 4-5, Case No. IPC-E-14-24; IPUC Order No. 33048 at 5-6, Case No. AVU-E-14-03; *Power Resource Group, Inc. v. Public Utility Commission of Texas*, 73 S.W.3d 354 (Tex. 2002); *Power Resource Group, Inc. v. Klein*, No. A-03CA-762-H, slip op. at 12 (W.D.Tex. Feb. 18, 2004); *Power Resource Group, Inc. v. Public Utility Commission of Texas*, 422 F.3d 231 (5th Cir. 2005) *cert. denied*, 547 U.S. 1020, 126 S.Ct. 1583, 164 L.Ed.2d 301 (Mar. 20, 2006) (upholding state Commission's exclusive authority to determine parameters of legally enforceable obligation including a requirement that a proposed QF project be online within 90 days of establishing a legally enforceable obligation).

[62] *Snow Mountain Pine v. Maudlin*, 84 Or App 590, 598-99 (1987).

[63] Order No. 15-199 at 6 (quoting Order No. 14-058 at 3 and Order No. 05-584 at 6).

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is implemented in Oregon in a way that ensures, to the greatest extent possible, customer's indifference.

Respectfully submitted this 2nd day of September, 2015.

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