McDowell
Rackner &
Gibson PC

WENDY MCINDOO
Direct (503) 595-3922
wendy@mcd-law.com

May 20, 2013

VIA ELECTRONIC AND U.S. MAIL

PUC Filing Center
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97308-2148

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

Attention Filing Center:

Enclosed for filing in docket UM 1610 are an original and five copies of Idaho Power Company's Prehearing Memorandum.

A copy of this filing has been served on all parties to this proceeding as indicated on the attached certificate of service.

Please contact this office with any questions.

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Office Manager

Enclosures

cc: Service List

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.	**IDAHO POWER COMPANY'S PRE-HEARING MEMORANDUM**

I. INTRODUCTION

Pursuant to the May 13, 2013, Prehearing Conference Memorandum issued by Administrative Law Judges ("ALJ") Shani Pines and Traci A.G. Kirkpatrick, Idaho Power Company ("Idaho Power" or "Company") submits this Pre-Hearing Memorandum to the Public Utility Commission of Oregon ("Commission"). The purpose of this docket is 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 I issues identified in ALJ Michael Grant's Rulings of December 21, 2012, and January 30, 2013. These recommendations are primarily intended to create a system that more accurately reflects the true avoided costs of a utility. This ensures that PURPA's strict mandates are satisfied and customers are held indifferent to the Qualifying Facility ("QF") generation. Idaho Power's recommendations are also driven by a desire for consistency across its jurisdictions, which will prevent the opportunity for regulatory arbitrage. Idaho Power recommends:

- **Standard Avoided Cost Prices (Issues 1(a), (b), and (c), 4(c)):** Continued use of the Standard Method, with one modification to account for the capacity contribution of the type of QF resource. Idaho Power proposes that the Commission approve the specific capacity factor values recently approved by the Idaho Public Utilities Commission

McDowell Rackner & Gibson PC
419 SW Eleventh Ave, Ste. 400
Portland, OR 97205

("IPUC"). This proposal is supported by the Renewable Energy Coalition ("Coalition") and conceptually identical to Staff's. The Company recommends rejection of levelized pricing and that existing QFs seeking a new contract continue to receive capacity payments.

- **Negotiated Avoided Cost Prices (Issues 1(a) and 4(c)):** Retain the current Schedule 85 language that authorizes Idaho Power to use the modeling methodology approved by the Idaho Commission, the incremental IRP methodology, which determines the avoided cost of energy by using Idaho Power's power cost model to calculate the incremental cost for each hour of the proposed QF contract term. This proposal is also supported by the Coalition.
- **Renewable Energy Certificates ("RECs") (Issue 2(c)):** QF retention of all RECs under standard contracts and Idaho Power receipt of 50 percent of the RECs under negotiated contracts. This is a modified position for Idaho Power that is consistent with the treatment of RECs in Idaho.
- **Schedule for Avoided Cost Updates (Issue 3):** Annual updates of standard and negotiated rates using updated natural gas and load forecasts.
- **Wind Integration Charge (Issue 4(a)):** Assessment of the costs of integration, consistent with Idaho Power's most recent Wind Integration Study.
- **Standard Contract Eligibility Cap (Issue 5(a) and (c)):** Reduction of eligibility cap for wind and solar QFs to 100 kW.
- **Legally Enforceable Obligation ("LEO") (Issue 6(b):** LEO exists only if the QF signed a draft contract and demonstrated that utility refused to contract or delayed the process.
- **Mechanical Availability Guarantee ("MAG") (Issue 6(e)):** Retention of the MAG at a level consistent with the Company's Idaho standard contracts.
- **Contract Term (Issue 6(i)):** Reduction of the fixed price portion of the contract from 15 to 10 years.

II. ARGUMENT AND RECOMMENDATIONS

A. PURPA Mandates Customer Indifference to QF Transactions.

PURPA requires that rates paid to QFs for their energy and capacity must be just and reasonable, non-discriminatory, and not exceed the utility's avoided cost.[1] "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.[2] In setting this standard, FERC intended that 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."[3] The avoided cost requirement also ensures that QFs are not subsidized at ratepayers' expense.[4]

Similarly, in Order No. 05-584, 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.[5] 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."[6]

In past Commission proceedings, QF developers and the Oregon Department of Energy ("ODOE") have argued in favor of higher avoided cost prices "to ensure that the

---

[1] *See* 16 U.S.C. §§ 824a-3(b), (d).
[2] 18 C.F.R. § 292.101(b)(6).
[3] *So. Cal. Ed. Co.*, 71 F.E.R.C. ¶ 61,269, 62,079 (F.E.R.C. 1995).
[4] *Independent Energy Producers Association v. California Public Utilities Comm'n*, 36 F.3d 848, 858 (9th Cir. 1994).
[5] *Re Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Docket 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 AR 112, Order No. 85-010 at 18 (Jan. 8, 1985).
[6] Order No. 05-584 at 11 (emphasis added).

legislature's goal of renewable resource development is attained."[7] The Commission has consistently rejected this argument. In doing so, the Commission has recognized that "[h]igher rates would make more projects feasible." However, the Commission also recognized that it "has another goal to consider", and "[t]hat goal is to obtain service for ratepayers at reasonable rates."[8]

For Idaho Power, customers have not been held indifferent to QF generation; instead, customers have been harmed. The record in this case demonstrates that avoided cost prices historically have been greater than market prices and forecasts indicate that this trend will continue well into the future.[9] As a result, customers are paying more for QF generation than they would otherwise pay if the Company were purchasing a firm product in the Mid-C market.[10] This differential is substantial—in 2013 customers paid $74 million above market for QF generation and in 2014 customer will pay $70 million above market for QF generation.[11] In total, for the ten year period between 2013 and 2022 this differential is estimated to be $602 million, or a present value of nearly $500 million.[12]

In addition, for Idaho Power QF generation is largely surplus to its customer's needs.[13] This means that the Company is required to sell the surplus QF generation at market, which not only results in a loss when the avoided cost price exceeds the market price, but also results in Idaho Power incurring additional transmission expenses to move the QF generation to market.[14]

The customer harm resulting from PURPA is largely the result of standard avoided cost prices that were determined with little to no regard for the unique operating

[7] *Re Proposed Amendments to Rules Relating to Cogeneration and Small Power Production Facilities*, Docket AR 102, Order No. 84-742 at 3 (Sept. 24, 1984).
[8] Order No. 84-742 at 3.
[9] Idaho Power/200, Stokes/15.
[10] Idaho Power/200, Stokes/15.
[11] Idaho Power/200, Stokes/16-17.
[12] Idaho Power/200, Stokes/17.
[13] Idaho Power/200, Stokes/16.
[14] Idaho Power/200, Stokes/17; Idaho Power/200, Stokes/54.

characteristics of each individual or type of QF project and without regard to the impact of QF development on Idaho Power's system. Idaho Power's recommendations in this case are intended to remedy the past deficiencies in the avoided cost calculation to ensure, to the greatest extent possible, that the avoided cost prices paid to QFs are accurate so that PURPA's strict customer indifference mandate is satisfied.

B. Standard Rates and Contracts (Issues 1(a), (b), (c), and 4(c)).

The Company currently utilizes the Standard Method for determining its standard avoided cost prices. In this case, the Company is recommending only one modification to that method—the separate calculation of the energy and capacity components of the avoided cost price to take into account the different capacity contribution made by different types of QFs.[15] These separate components would be added together into a single price that would be set forth in Schedule 85.[16]

The Company's proposed modification would multiply the avoided cost of capacity based on a combined cycle combustion turbine ("CCCT") plant[17] by the peak-hour capacity factor of the QF resource (base load, hydro, seasonal hydro, wind, and solar).[18] The peak-hour capacity factor accounts for the capacity the QF resource will provide during Idaho Power's peak-hour load period between 3:00 p.m. and 7:00 p.m. in July.[19] The Company proposes calculating the peak-hour capacity factor using the 90th percentile exceedance criterion that is used in the Company's Integrated Resource Plan ("IRP"). Idaho Power' peak-hour demand drives the Company's need for additional capacity and the use of the 90th percentile exceedance criterion means there is a 90 percent probability

---

[15] Idaho Power/200, Stokes/27.
[16] Idaho Power/200, Stokes/27.
[17] This is determined by multiplying the capital costs of a CCCT by the nameplate capacity of the QF and then converting this value to an annual cost. Idaho Power/200, Stokes/27.
[18] Idaho Power/200, Stokes/27.
[19] Idaho Power/200, Stokes/27; Idaho Power/400, Stokes/18.

McDowell Rackner & Gibson PC
419 SW Eleventh Ave, Ste. 400
Portland, OR 97205

that the specific resource type will contribute to serve Idaho Power's peak-hour demand.[20] The peak-hour load planning criteria are more stringent than average load planning criteria because Idaho Power's ability to import additional energy is typically limited during peak load periods.[21] The use of the 90th percentile exceedance value from the Company's IRP will also result in significantly less controversy when avoided cost prices are updated.[22]

In terms of the specific capacity factors that should be used, Idaho Power recommends that the Commission approve the use of the same values that were recently approved by the IPUC in Order No. 32802. This recommendation is supported by the Renewable Energy Coalition.

Adjusting the standard avoided cost price to account for the capacity contribution of the specific type of QF is a straightforward and simple way to account for the "availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods."[23] FERC's regulations specifically state that this factor must be taken into consideration "to the extent practicable."[24] This proposed adjustment is also consistent with 18 C.F.R. § 292.304(c)(3)(ii), which states that the standard prices "may differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies."

The introduction of a capacity contribution adjustment is also consistent with recent Commission orders recognizing the distinctions between base load and intermittent QFs.[25] This adjustment also recognizes the reality of the QF development on Idaho Power's

---

[20] Idaho Power/200, Stokes/27, 41; Idaho Power/400, Stokes/18. This approach was also proposed by PacifiCorp for use in determining the capacity contribution for wind and solar QFs for negotiated avoided cost prices. PAC/100, Dickman/14; PAC/300, Dickman/14.
[21] Idaho Power/400, Stokes/19.
[22] Idaho Power/400, Stokes/19; Staff/200, Bless/4.
[23] 18 CFR § 292.304(e)(2).
[24] 18 C.F.R. § 292.304(e).
[25] *Re Investigation into Resource Sufficiency Pursuant to Order No. 06-538*, Order No. 11-505 at 5 (Dec. 13, 2011).

McDowell Rackner & Gibson PC
419 SW Eleventh Ave, Ste. 400
Portland, OR 97205

system, which consists of overwhelmingly intermittent generators for which a CCCT is not representative.[26]

The Company also supports the proposal to allow an existing QF to receive a capacity payment if the QF chooses to enter into a new PURPA contract when the utility is resource sufficient. The IPUC recently adopted a similar policy. Therefore, in the interests of consistency, and to discourage regulatory arbitrage, Idaho Power supports the proposal *for Idaho Power.*

Additionally, Idaho Power proposes that the Commission not allow a levelized price over the term of the contract. Levelized pricing shifts unreasonable risk from developers onto Idaho Power's customers and experience has demonstrated that levelized pricing is unnecessary for QF development.[27]

C. Negotiated Avoided Cost Prices and Contracts (Issues 1(a) and 4(c)).

Currently, Idaho Power's Oregon Schedule 85 authorizes the Company to use as the starting point for negotiations the same IRP methodology approved by the IPUC. Idaho Power proposes no changes to this authorization. However, the IPUC recently approved modifications to the Company's IRP methodology, which Idaho Power has referred to as the "incremental IRP methodology.[28] In this docket, Idaho Power asks that the Commission specifically approve these modifications for use in Oregon contracts.

The incremental IRP methodology determines the avoided cost of energy by using Idaho Power's power cost model (AURORA[29]) to calculate the incremental cost for each hour of the proposed QF contract term.[30] The highest displaceable incremental, *i.e.*,

---

[26] Idaho Power/200, Stokes/13-14.
[27] Idaho Power/200, Stokes/74; Idaho Power/200, Stokes/76-77; Idaho Power/400, Stokes/23-24.
[28] Idaho Power/200, Stokes/30.
[29] "[T]he AURORA model, which is used to determine the dispatch of utility-owned resources in the incremental IRP methodology, has been used by Idaho Power for years in both the planning and ratemaking processes." Idaho Power/400, Stokes/13.
[30] Idaho Power/200, Stokes/33.

McDowell Rackner & Gibson PC
419 SW Eleventh Ave, Ste. 400
Portland, OR 97205

avoided, cost for each hour is used to create an hourly time series of avoided costs.[31] This time series is then multiplied by the QF's hourly generation profile, the results of which are summed over the heavy and light load hours for each month and then divided by QFs forecast generation.[32] These calculations result in a heavy and light load price for each month of the contract.

The incremental IRP methodology uses the same method to calculate the avoided cost of capacity as the former IRP methodology, except that it uses a simple cycle combustion turbine generator ("SCCT") instead of a CCCT to calculate the avoided cost of capacity.[33] Idaho Power's need for capacity is driven by summertime peak-hour loads, and an SCCT is typically the lowest cost supply-side resource for this type of service.[34] Thus, the fixed cost of an SCCT is more appropriate.[35]

The incremental IRP methodology is an improvement over both the Standard Method and the Company's previous IRP-based methodology. Consistent with FERC's regulations, which require state commissions to consider, to the extent practicable, the factors set forth in 18 C.F.R. § 292.304(e), the incremental IRP methodology incorporates several of the resource-specific characteristics of the proposed QF generation—including the QF's specific generation output profile, a resource specific capacity factor, the timing of anticipated generation, and a capacity credit based on the anticipated amount of capacity provided during Idaho Power's projected peak-load hours.[36] This more

---

[31] Idaho Power/200, Stokes/33. Displaceable incremental costs are limited to (1) incremental costs for Company-owned thermal resources (Bridger, Boardman, Valmy, Langley Gulch, and the gas-fired peakers) that are on-line and operating at above their minimum load level, (2) the incremental cost associated with longer-term firm purchases, and (3) the incremental cost of market purchases as determined by AURORA. Idaho Power/200, Stokes/36.
[32] Idaho Power/200, Stokes/33-34.
[33] Idaho Power/200, Stokes/41.
[34] Idaho Power/200, Stokes/41.
[35] Idaho Power/200, Stokes/41.
[36] Idaho Power/200, Stokes/29.

McDowell Rackner & Gibson PC
419 SW Eleventh Ave, Ste. 400
Portland, OR 97205

sophisticated modeling results in a more accurate avoided cost price and better ensures that customers are truly held indifferent to QF generation.[37]

The former IRP-based methodology, which utilized two AURORA runs—one with the QF and one without—ultimately resulted in an avoided cost price based on AURORA's estimate of future market prices.[38] This resulted in customers assuming an inordinate market risk that they would not have absent the QF transaction.[39]

Unlike the former methodology, Idaho Power's incremental IRP methodology also better embodies FERC's definition of "avoided cost" because it does not determine the avoided costs based on a forecast market price.[40] "Avoided costs" are the incremental costs to an electric utility of energy or capacity or both which, but for the purchase of the qualifying facility or qualifying facilities, such utility would **generate** itself or **purchase** from another source."[41] Under the incremental IRP methodology, the *incremental costs that Idaho Power would have incurred but for the QF generation* is the basis for QF contract pricing.[42] Nowhere in PURPA's avoided cost definition does it provide for the value associated with off-system sales of QF generation.[43] In approving the incremental IRP methodology, the IPUC agreed that the methodology resulted in a more accurate avoided cost price.[44]

---

[37] Idaho Power/200, Stokes/30.
[38] Idaho Power/200, Stokes/34-35.
[39] Idaho Power/200, Stokes/30.
[40] Idaho Power/200, Stokes 34.
[41] 18 C.F.R. § 292.101(b)(6) (emphasis added).
[42] Idaho Power/200, Stokes 34.
[43] Idaho Power/200, Stokes 34. *See also Re Investigation of Avoided Costs and of Cost-Effective Fuel Use and Resource Development*, Docket UM 21, Order No. 84-720, 62 P.U.R.4th 397, 412 (Sept. 12, 1984).
[44] *Commission's Review Of PURPA QF Contract Provisions Including The Surrogate Avoided Resource (SAR) And Integrated Resource Planning (Irp) Methodologies For Calculating Avoided Cost Rates,* Case No. GNR-E-11-03, Order No. 32697 at 21 (Dec. 18, 2012).

D. Environmental Attributes/Renewable Energy Certificates ("RECs") (Issue 2(c)).

Consistent with its Idaho jurisdiction, Idaho Power proposes that the Commission determine, *for negotiated contracts*, that Idaho Power owns half of the RECs associated with the QF energy that it must purchase from QF projects, and *for standard rate contracts*, that the QF owns all RECs. This recommendation differs from the recommendation set forth in Idaho Power's testimony in this case.[45] At the time Idaho Power filed its testimony in this case, the REC ownership issue was still pending in Idaho. Idaho Power's modified recommendation is intended to align Idaho and Oregon, consistent with the Company's approach to most of the issues presented in this case.[46]

E. Schedule for Avoided Cost Updates (Issue 3).

To maintain consistency with its Idaho jurisdiction, Idaho Power proposes that standard rates be updated annually using the natural gas forecast published by the United States Energy Information Administration ("EIA").[47] The update would occur 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.[48]

F. Wind Integration Charge (Issue 4(a)).

Idaho Power proposes to implement an integration charge for any wind QF contracting with the Company. Idaho Power recommends that the Commission authorize Idaho Power to charge the cost of integration to wind QF projects at a level commensurate with the results of the Company's most recent wind integration study.[49]

Transactions with wind QFs result in higher costs to customers because Idaho Power is required to provide additional operating reserves from dispatchable resources

---

[45] *See* Idaho Power/200, Stokes/77-79 (recommending Idaho Power retain all RECs under both negotiated and standard contracts).

[46] *See* Idaho PUC Order No. 32802, Case No. GNR-E-11-03, May 6, 2013 (final order on reconsideration).

[47] Idaho Power/200, Stokes/67.

[48] Idaho Power/200, Stokes/67.

[49] Idaho Power/200, Stokes/67-73. The study is Idaho Power/205.

capable of increasing or decreasing generation on short notice to offset changes in wind generation.[50] Holding additional operating reserves on other dispatchable resources means that the operation of those resources is restricted and they cannot be economically dispatched to their fullest capability.[51] If Idaho Power's customers are responsible for paying for these additional costs, which would not be incurred but for the QF transaction, then customers are not held indifferent.[52]

Although the Commission chose to not assess integration charges for standard contracts in UM 1129, the circumstances now warrant their inclusion. In that docket, the Commission recognized that integration costs increase significantly as the level of wind penetration increases.[53] Since the conclusion of UM 1129 Idaho Power has experienced substantial QF development on its system and a large majority of this QF development has been and continues to be development of intermittent wind generation facilities.[54] Indeed, currently wind constitutes 70 percent of QF nameplate capacity on Idaho Power's system as compared with 44 percent in 2005.[55] This wind development is having significant unintended and detrimental operational and financial impacts on Idaho Power's system and customers.[56] The failure to assess wind integration costs results in significant costs that are borne by Idaho Power's customers and therefore it is now appropriate and necessary to assess integration charges.[57]

Idaho Power's wind integration study provides robust evidentiary support for Idaho Power's proposed wind integration charge[58] and represents the most recent integration cost data available.[59]

---

[50] Idaho Power/200, Stokes/67-68.
[51] Idaho Power/200, Stokes/67-68.
[52] Order No. 05-584 at 11.
[53] Order No. 07-360 at 24-25.
[54] Idaho Power/200, Stokes/45-46.
[55] Idaho Power/200, Stokes/52.
[56] Idaho Power/200, Stokes/45-46.
[57] Idaho Power/200, Stokes/45-46.
[58] Idaho Power/205.

G. Standard Contract Eligibility Cap (Issue 5(a) and (c)).

Idaho Power proposes that the Commission maintain the current eligibility cap of 10 MW for all types of QF projects except for wind and solar. For wind and solar QF's, Idaho Power proposes the Commission lower the eligibility cap to 100 kW or less, which will be consistent with the Company's Idaho jurisdiction so as to prevent regulatory arbitrage.

In UM 1129 the Commission balanced two competing goals—mitigating customer risk caused by the inherent differential between the standard rate and the actual avoided cost rate, and mitigating market barriers to QF development.[60]

With respect to the mitigation of customer risk, Idaho Power's recommendation to lower the eligibility cap for solar and wind QFs will ensure that the avoided cost rate paid by the Company and its customers is specifically tailored to these QFs' unique operational characteristics. This will result in a more accurate avoided cost rate because the rate will specifically consider the individual QF's availability, dispatchability, reliability, and the usefulness of the QFs energy and capacity during system emergencies.[61] These factors are all specifically identified by FERC as factors that state regulatory commissions must take into account, to the extent practicable, when determining the avoided cost of a utility.[62] Because it is now practicable to consider these factors, the Commission should do so. Negotiated rates, based on the Company's incremental IRP methodology, are also less sensitive to gas price volatility, which has historically been the most volatile, and dominant,[63] of all the inputs used to set avoided cost rates.[64]

With respect to the mitigation of market barriers, Idaho Power's experience has shown that as a group, QF developers are highly sophisticated, possess sufficient

---

[59] *See* Order No. 07-360 at 24 ("the utility should use the most recent integration cost data available").
[60] Order No. 05-584 at 16.
[61] Idaho Power/200, Stokes/53-54.
[62] *See* 18 C.F.R. § 292.304(e).
[63] Coalition/200, Schoenbeck/9
[64] Idaho Power/400, Stokes/9-11.

McDowell Rackner & Gibson PC
419 SW Eleventh Ave, Ste. 400
Portland, OR 97205

financial resources to negotiate a PURPA contract, and are willing and able to disaggregate large projects specifically to obtain standard rates.[65] Indeed, of the 27 total wind QFs currently either online or under contract with Idaho Power, only one 3 MW QF was *not* developed by a sophisticated renewable energy development company with years of experience developing renewable projects.[66] Thus, the vast majority of developers contracting with Idaho Power have the economic wherewithal to negotiate a PURPA contract.[67]

Moreover, transaction costs as a percentage of overall development costs have decreased since UM 1129. In Order No. 05-584, the Commission concluded that "10 MW represented a point at which the costs of negotiation become a reasonable fraction of total investment costs."[68] This conclusion assumed that a 10 MW project costs approximately $10 million to develop.[69] The record in *this* case demonstrates that development costs have roughly doubled—meaning that it now takes$10 million to develop a project half that size.[70] Therefore, applying the Commission's reasoning in Order No. 05-584, the eligibility cap should be reduced.

Lowering the eligibility cap will also make it more difficult for large-scale developers to disaggregate their projects into smaller units to improperly take advantage of standard avoided cost prices.[71] Experience has shown that regardless of how carefully crafted the Commission's disaggregation criteria may be, sophisticated developers will find ways to

---

[65] *See also* PAC/200, Griswold/19 ("the Company is now negotiating with well-funded, experienced developers who have successfully developed multiple QF and renewable projects across the country, and hire some of the most skilled technical and legal firms in the country.").
[66] Idaho Power/200, Stokes/61.
[67] Order No. 05-584 at 40 (emphasis added).
[68] Order No. 05-584 at 17 ("We rely, in particular, on the fact . . . that ODOE, which has significant experience with the development of QF projects, indicated that 10 MW represented a point at which the costs of negotiation become a reasonable fraction of total investment costs.").
[69] Order No. 05-584 at 14 ("ODOE represents that at 10 MW, negotiation costs become a relatively small fraction of total $10 million investment costs."); *Id.* at 13 ("PacifiCorp also observes that a 3 MW QF project requirements approximately $3 million in capital costs to construct . . .").
[70] CREA/100, Hilderbrand/4; PGE/100, Macfarlane-Morton/6.
[71] Idaho Power/200, Stokes/45.

McDowell Rackner & Gibson PC
419 SW Eleventh Ave, Ste. 400
Portland, OR 97205

circumvent the rules if there is a significant price difference between avoided costs for standard contracts and negotiated contracts.[72]

In addition, Idaho Power's experience suggests that lowering the eligibility cap will not result in the end of QF development in Oregon. Idaho Power has negotiated six PURPA contracts totaling 200.9 MW of capacity.[73] And even after the IPUC lowered the eligibility cap in Idaho to 100 kW for wind and solar QFs the Company continues to negotiate contracts with wind and solar QFs and continues to receive additional inquiries.[74] Notably, these negotiations occurred without comparable guidelines to those that govern the Oregon negotiation process.[75]

H. Legally Enforceable Obligation ("LEO") (Issue 6(b).

Idaho Power proposes that the Commission conclude that an LEO exists only if both of the following conditions have been met: (1) the QF signs the contract, regardless of whether the utility signs; and (2) the utility has refused to contract or has purposefully delayed the contracting process.[76]

I. Mechanical Availability Guarantee ("MAG") (Issue 6(e)).

Idaho Power recommends that standard contracts continue to include a MAG; however, the Company requests that its current standard contract be modified to more closely align with the performance guarantees contained in Idaho Power's approved Idaho standard contract.[77] Specifically, the contract should include an adjusted MAG for all intermittent QF PPAs to an 85 percent monthly availability standard. If the 85 percent MAG is not achieved, then the monthly price is adjusted with an "availability shortfall price." The Company also proposes a modification for non-intermittent resources to

[72] Idaho Power/400, Stokes/15-16; PAC/200, Griswold/23-24; PAC/400, Griswold/18.
[73] Idaho Power/200, Stokes/63 ("By way of comparison, the Company has executed a total of 61 contracts; approximately 1 in 10 PURPA contracts were negotiated.").
[74] Idaho Power/200, Stokes/63; Idaho Power/400, Stokes/13.
[75] Idaho Power/200, Stokes/64
[76] Idaho Power/200, Stokes/80.
[77] Idaho Power/300, Stokes/2.

McDowell Rackner & Gibson PC
419 SW Eleventh Ave, Ste. 400
Portland, OR 97205

introduce a 90/110% monthly performance standard. A "shortfall energy price" would be applied to deliveries outside of the 90/110 performance band.[78]

J. Contract Term (Issue 6(i)).

Idaho Power proposes that the Commission continue to authorize contracts for up to 20 years. However, Idaho Power proposes that the currently authorized 15-year fixed price portion of the contract be reduced to 10 years.[79] This reduction more equitably shares the market price risk associated with fixed avoided cost prices.[80]

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

Respectfully submitted this 20th day of May, 2013.

MCDOWELL RACKNER & GIBSON PC

Lisa F. Rackner
Adam Lowney

IDAHO POWER COMPANY
Donovan Walker
Lead Counsel
Julia Hilton
Corporate Counsel
1221 West Idaho Street
P.O. Box 70
Boise, Idaho 83707
Attorneys for Idaho Power Company

---

[78] Idaho Power/300, Stokes/2.
[79] Idaho Power/200, Stokes/73.
[80] Idaho Power/200, Stokes/74; Idaho Power/400, Stokes/39.

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document in Docket UM 1610 the following named person(s) on the date indicated below by email addressed to said person(s) at his or her last-known address(es) indicated below.

OPUC Dockets
Citizens' Utility Board of Oregon
dockets@oregoncub.org

RNP Dockets
Renewable Northwest Project
dockets@rnp.org

Daren Anderson
NW Energy Systems Company LLC
da@thenescogroup.com

James Birkelund
Small Business Utility Advocates
james@utiltiyadvocates.org

Will K. Carey
Annala, Carey, Baker, et al., PC
wcarey @hoodriverattorneys.com

Melinda J. Davison
Davison Van Cleve PC
mjd@dvclaw.com mail@dvclaw.com

Loyd Fery
dlchain@wvi.com

Oregon Dockets
Pacificorp, dba Pacific Power
oregondockets@pacificorp.corn

Gregory M. Adams
Richardson & O'Leary
greg@richardsonandoleary.com

Brittany Andrus
Public Utility Commission of Oregon
brittany.andrus@state.or.us

Adam Bless
Public Utility Commission of Oregon
adam.bless@state.or.us

Jay Tinker
Portland General Electric
pge.opuc.filings@pgn.com

Megan Walseth Decker
Renewable Northwest Project
megan@rnp.org

Renee M. France
Oregon Department of Justice
Natural Resources Section
renee.m.france@doj.state.or.us

J. Laurence Cable
Cable Huston Benedict et al.
lcable@cablehuston.com

Stephanie S. Andrus
Department of Justice - Business
Activities Section
stephanie.andrus@state.or.us

Chad Stokes
Cable Huston Benedict et al.
cstokes@cablehuston

R. Bryce Dalley
Pacific Power
bryce.dalley@pacificorp.com

Bill Eddie
One Energy Renewables
bill@oneenergyrenewables.com

J. Richard George
Portland General Electric Company
richard.george@pgn.com

Diane Henkels
Cleantech Law Partners PC
dhenkels@cleantechlawpartners.com

Matt Krumenauer
Oregon Department of Energy
matt.krumenauer@state.or.us

John Lowe
Renewable Energy Coalition
jravenesanmarcos@yahoo.com

G. Catriona McCracken
Citizens' Utility Board of Oregon
catriona@oregoncub.org

Kathleen Newman
Oregonians for Renewable Energy Policy
kathleenoipl@frontier.com
k.a.newman@frontier.com

Irion A. Sanger
Davison Van Cleve
ias@dvclaw.com

Robert Jenks
Citizens' Utility Board of Oregon
bob@oregoncub.org

David A. Lokting
Stoll Berne
dlokting@stollberne.com

Glenn Montgomery
Oregon Solar Energy Industries Association
glenn@oseia.org

Mark Pete Pengilly
Oregonians for Renewable Energy Policy
mpengilly@gmail.com

Peter J. Richardson
Richardson & O'Leary PLLC
peter@richardsonandoleary.corn

Kacia Brockman
Oregon Department of Energy
kacia.brockman@state.or.us

John W. Stephens
Esler Stephens & Buckley
stephens@eslerstephens.com
mec@eslerstephens.com

Kenneth Kaufmann
Lovinger Kaufmann LLP
kaufmann@lklaw.com

Jeffery S. Lovinger
Lovinger Kaufmann LLP
lovinger@lklaw.com

Mike McArthur
Association of Oregon Counties
mmcarthur@aocweb.org

Thomas H. Nelson
Attorney at Law
nelson@thnelson.com

Elaine Prause
Energy Trust of Oregon
elaine.prause@energytrust.org

Toni Roush
Roush Hydro Inc.
tmroush@wvi.com

Donald W. Schoenbeck
Regulatory & Cogeneration Services, Inc.
dws@r-c-s-inc.com

David Tooze
City of Portland — Planning and Sustainability
david.tooze@portlandoregon.gov

S. Bradley Van Cleve
Davison Van Cleve PC
bvc@dvclaw.com

Energy Trust of ORegon
John M. Volkman
john.volkman@energytrust.org

Mary Wiencke
Pacific Power
mary.wiencke@pacificorp.corn

Richard Lorenz
Cable Huston Benedict Haagensen & Lloyd
rlorenz@cablehuston.com

John Harvey
Exelon Wind LLC
John.harvey@exeloncorp.com

Cynthia Fonner Brady
Exelon Business Services Company, LLC
cynthia.brady@constellation.com

DATED: May 20, 2013

Wendy McIndoo

Wendy McIndoo
Office Manager