McDowell
Rackner &
Gibson PC

SHARON COOPER
Direct (503) 595-3923
sharon@mcd-law.com

May 22, 2015

VIA ELECTRONIC AND U.S. 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 No. UM 1610 is an electronic copy of Idaho Power Company's Direct Testimony of Michael J. Youngblood and the Direct Testimony of Randy Allphin.

Please contact this office with any questions.

contact this office with any questions.

Very truly yours,

Sharon Cooper
Legal Assistant

Attachments

cc: Service List

Phone: 503.595.3922 Fax: 503.595.3928 www.mcd-law.com
419 Southwest 11th Avenue, Suite 400 Portland, Oregon 97205-2605

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

DIRECT TESTIMONY

OF

MICHAEL J. YOUNGBLOOD

May 22, 2015

Q. Please state your name and business address.

A. My name is Michael J. Youngblood and my business address is 1221 West Idaho Street, Boise, Idaho 83702.

Q. By whom are you employed and in what capacity?

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as the Manager of Regulatory Projects in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. In May of 1977, I received a Bachelor of Science Degree in Mathematics and Computer Science from the University of Idaho. From 1994 through 1996, I was a graduate student in the Executive Masters of Business Administration program of Colorado State University. Over the years, I have attended numerous industry conferences and training sessions, including Edison Electric Institute's "Electric Rates Advanced Course."

Q. Please describe your work experience with Idaho Power.

A. I began my employment with Idaho Power in 1977. During my career, I have worked in several departments of the Company and subsidiaries of IDACORP, Inc., including Systems Development, Demand Planning, Strategic Planning, and IDACORP Solutions. From 1981 to 1988, I worked as a Rate Analyst in the Rates and Planning Department where I was responsible for the preparation of electric rate design studies and bill frequency analyses. I was also responsible for the validation and analysis of the load research data used for cost-of-service allocations.

From 1988 through 1991, I worked in Demand Planning and was responsible for the load research and load forecasting functions of the Company, including sample design, implementation, data retrieval, analysis, and reporting. I was responsible for the preparation of the five-year and twenty-year load forecasts used in revenue projections and resource plans, as well as the presentation of these forecasts to the public and regulatory commissions.

From 1991 through 1998, I worked in Strategic Planning. As a Strategic Planning Associate, I coordinated the complex efforts of acquiring Prairie Power Cooperative, the first acquisition of its kind for the Company in 40 years. From 1996 to 1998, as a part of a Strategic Planning initiative, I helped develop and provide two-way communication between customers and energy providers using advanced computer technologies and telecommunications.

From 1998 to 2000, I was a General Manager of IDACORP Solutions, a subsidiary of IDACORP, Inc., reporting to the Vice President of Marketing. I was directly responsible for the direction and management of the Commercial and Industrial Business Solutions division.

In 2001, I returned to the Regulatory Affairs Department and worked on special projects related to deregulation, the Company's Integrated Resource Plan ("IRP"), and filings with both the Idaho Public Utilities Commission and the Public Utility Commission of Oregon ("Commission").

In 2008, I was promoted to the position of Manager of Rate Design for Idaho Power. In that position, I was responsible for the management of the rate design strategies of the Company, as well as the oversight of all tariff administration.

In January of 2012, I became the Manager of Regulatory Projects for Idaho Power, which is my current position. In this position, I provide the regulatory support for many of the large individual projects and issues currently facing the Company. Most recently that has included providing regulatory support for the inclusion of the Langley Gulch power plant investment in rate base and supporting the Company's efforts to address numerous issues involving Qualifying Facilities ("QF") as defined under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), including the

Company's efforts in previous Oregon dockets, including Phase I of Docket No. UM 1610.

Q. Which issues from the UM 1610 Issues List will you address in your testimony?

A. My testimony responds to UM 1610 Issues List items Nos. 3, 4, and 6. Specifically, my testimony will respond to the following issues:

Issue 3: Should the Commission revise the methodology approved in Order No. 14-058 for determining the capacity contribution adder for solar QFs selecting standard renewable avoided cost prices? If so, how?

Issue 4: Should the capacity contribution calculation for standard non-renewable avoided cost prices be modified to mirror any change to the solar capacity contribution calculation used to calculate the standard renewable avoided cost price?

Issue 6: Do the market prices used during the Resource Sufficiency Period sufficiently compensate for capacity?

Q. What is the purpose of your testimony regarding these specific issues?

A. My testimony provides Idaho Power's position that the Commission should not revise the methodology approved in Order No. 14-058 for determining the capacity contribution adder for solar QFs. An intermittent QF resource like solar or wind does not provide the same on-peak capacity contribution as the combined cycle combustion turbine ("CCCT") proxy resource; therefore, the adjustment approved in Order No. 14-058 is necessary so that customers are not financially harmed. Staff's proposed revision to that methodology would financially harm customers because they would be paying for capacity that was not actually avoided. This outcome would be contrary to the intent and direction of Order No. 14-058, and would constitute an unlawful rate that exceeds the Company's avoided cost—as it exceeds 100 percent of the proxy avoided resource value.

In addition, my testimony will argue that the Commission's directive to use market prices during times when a utility is resource sufficient compensates QFs for capacity and, in fact, may overcompensate the QFs during the resource sufficiency period. By definition, if a utility is capacity surplus, then capacity is not being avoided by the purchase of QF power. To compensate a QF for capacity during a period of resource sufficiency, as market prices do, results in an overcompensation to the QF.

Q. What was the topic of your prior testimony filed in Phase I of this docket, UM 1610?

A. The purpose of my prior testimony was to summarize the methods used by Idaho Power to determine the capacity component of avoided cost rates and to summarize the change directed by the Commission in Order No. 14-058. My prior testimony addressed the calculation of the capacity adder portion of avoided cost rates, which is only applicable in the utility's resource deficiency period when the QF is assumed to avoid a proxy resource under Oregon's surrogate avoided resource, or proxy method. My Response Testimony filed on November 19, 2014, responded to the opening testimony of Commission Staff witness Brittany Andrus and Obsidian Renewables, LLC's ("Obsidian") witness David W. Brown. I reiterated why the Commission-approved methodology for determining the capacity adder for solar avoided cost rates was appropriate and should not be modified. Staff's proposed modification is harmful to customers because it artificially *increases* the avoided cost of capacity rate rather than recognizing the *decreased* contribution to peak as directed by Order No. 14-058.

Q. Why is Idaho Power once again providing testimony on the topic of solar capacity contribution?

A. The Company is providing additional testimony on the topic of solar capacity contribution because of the Commission Ruling issued on March 26, 2015. In that

Ruling, Administrative Law Judges Shani Pines and Traci A.G. Kirkpatrick stated, "We also determine that additional discussion on the solar capacity contribution issue previously briefed by the parties is appropriate. As a result, we include the solar capacity contribution issue in the list of issues to be addressed in the Phase II procedural schedule."

Q. Should the Commission revise the methodology approved in Order No. 14-058 for determining the capacity contribution adder for renewable QFs?

A. Prior to responding to this question, it is important to review exactly what the Commission ordered in Order No. 14-058 and to understand why a revision in the calculation of solar capacity was needed.

Q. What was approved in Order No. 14-058 with regard to the determination of capacity in avoided cost rates?

A. Order No. 14-058 approved a methodology that adjusted both the Standard and the Standard Renewable avoided cost prices in order to account for the capacity contribution made by each QF resource type, as compared to the proxy resource. It is important to note that the Commission's adjustment was intended to reflect the difference between the actual capacity contribution made by the QF *as compared to* the capacity contribution of the proxy resource. It is worth noting that the proxy resource does not reflect the actual costs avoided by the utility but-for the QF generation; it is used only as a surrogate for the actual costs avoided. If the proxy resource's assumed capacity contribution is different than the QF's capacity contribution, then an adjustment should be made. Therefore, for a solar QF an adjustment is made to the proxy rate to account for how much capacity the solar QF provides on-peak, when the Company needs it the most. For Idaho Power, using the same 90 percent exceedance criterion used in its long-term IRP process, the on-peak capacity contribution for a solar QF is 32 percent.

Q. What did the Commission direct regarding the capacity adder in Order No. 14-058?

A. The Commission stated, "We modify the current methodology for calculating standard avoided cost prices and standard renewable avoided cost prices to account for the capacity contribution of different QF resources and wind integration costs." Order No. 14-058, p. 2. The Commission provided additional guidance on page 15 of Order No. 14-058, under the heading, "Capacity Contribution of QF Resources." The Commission differentiates between the Standard Method and the Standard Renewable Method to equate to the Standard prices and Standard Renewable avoided cost prices. The Commission states:

> 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 . . . .

Q. What are the differences between the Standard Method and the Standard Renewable Method for determining avoided cost rates?

A. The main difference between the methodologies is in the proxy that is assumed to be avoided, for purposes of determining avoided costs. For the Standard Method, it is a CCCT. For the Standard Renewable Method for Portland General Electric Company and PacifiCorp, it is the capacity and energy costs of a wind turbine. The capacity adder for renewable QFs other than wind, like solar, that request the Standard Renewable rates is intended to compensate these QFs for the incremental capacity provided beyond the capacity of the wind turbine. This adder is then added to the rates that already include the capacity payment for the proxy wind turbine.

Q. How is the capacity contribution percentage used in modifying the capacity adder portion of the Standard avoided cost rates?

A. For Standard rates, the specific capacity contribution percentage of a QF resource is used to adjust the capacity adder portion of the rate associated with the CCCT proxy resource. This adjustment is made to account for the capacity contribution of each QF resource type as it relates to the proxy resource, as directed for the Standard Method by Order No. 14-058.

Q. Is it appropriate that the capacity adder for a solar QF be a percentage of the Standard avoided cost rate capacity adder?

A. Yes. A QF resource such as solar or wind does not provide the same on-peak capacity contribution as the CCCT proxy resource; therefore, the adjustment is necessary so that customers are not financially harmed. This is the basic change that the Commission ordered for Standard prices in Phase 1 of this proceeding. The Commission, in denying the utilities' requests to lower the standard rate eligibility cap, stated:

> We acknowledge the concerns raised by Idaho Power, Pacific Power, and PGE that the application of our current methodology may result in the utility and its customers offering prices in excess of avoided costs. However, as explained below, we conclude that the utilities' concerns about potential overpayments are best addressed through our decisions to require annual updates to avoided costs. As discussed below, we also address ways to incorporate wind integration costs and resource capacity contributions into standard avoided cost price calculations and standard renewable avoided cost price calculations . . . .

Order No. 14-058, p. 7.

Q. What concerns have been raised regarding the change in the methodology that the Commission ordered in Order No. 14-058?

A. I do not believe there are concerns with the change in the methodology ordered by the Commission in Order No. 14-058. In fact, in Phase I of UM 1610, Obsidian referred to the recognition of a solar QF's capacity contribution as the "first discount," and it did not challenge the appropriateness of recognizing a lower capacity contribution for solar QFs relative to a proxy CCCT. However, Obsidian raised concerns regarding the allocation of capacity costs to the on-peak hours, referring to it as a "second discount" because solar QFs generate less energy compared to the proxy CCCT, and therefore receive less in total dollars.

Q. Does the methodology ordered in Order No. 14-058 truly establish a "second discount" as Obsidian suggests?

A. No.

Q. Would it be appropriate to pay a fixed capacity payment for a solar QF based upon the total dollar amount of the capacity cost for the proxy CCCT?

A. No, not at all. Doing so would financially harm customers because they would be paying for capacity that was not actually avoided. In fact, the proxy method, which is already an inaccurate measurement of the true avoided cost for the utility, is based upon a hypothetical proxy CCCT plant as a surrogate for determining the actual avoided cost. While no methodology is perfect, Idaho Power continues to maintain that a more accurate determination of actual avoided costs is the Incremental Cost IRP ("ICIRP") avoided cost methodology used to establish avoided cost rates for QF projects greater than 10 megawatts ("MW"). Nevertheless, the Standard Method, using the proxy CCCT, is used for Standard avoided cost rates for projects less than 10 MW. The capacity contribution is a way of determining the cost of capacity avoided *as it compares to* the CCCT proxy.

Q. Why is the full value of capacity not avoided by the renewable QF resource?

A. The full value of capacity determined from the generation of the proxy resource is not the same as the estimated generation to be received from the renewable QF resource. Let me be clear, a renewable QF *would* receive the full value of capacity *if* the renewable QF provided the same amount of capacity in all the hours that the surrogate proxy resource provided capacity. But it does not. Therefore, the Commission approved an adjustment to the capacity contribution of a renewable QF in Order No. 14-058. This adjustment accounts for the fact that the renewable QF resource does not provide the same capacity contribution as the surrogate proxy resource.

Q. Should avoided cost prices compensate a QF for capacity when capacity is not needed?

A. No, not at all. The Commission has established that the capacity portion of the avoided cost price is not included during the time when a utility is capacity sufficient. Similarly, if a utility is not capacity deficient during the off-peak hours, then there is no capacity that is being "avoided"; therefore, the capacity portion of the payment should not be included. That is why the avoided cost prices distinguish between on-peak and off-peak prices.

Q. Then, if a QF only generates during the on-peak hours but not in every on-peak hour, should a QF still receive the same total amount of capacity payment as a generator that provides capacity in all on-peak hours?

A. No—otherwise the avoided cost price paid to the QF would have to be inflated during the reduced hours that the QF was generating in order to be equivalent to the same total amount of capacity payment for a generation resource that provided capacity in every hour of the on-peak period. In other words, the QF with reduced on-peak generation would not be compensated at the avoided cost rate, but at some rate more than the cost of the generation that is being avoided. In this scenario, customers would be harmed because they would be paying more than the cost of the capacity of generation being avoided.

Q. Does Staff's proposed change to the methodology approved in Order No. 14-059 better align the avoided capacity costs with the generation that is being avoided?

A. No, not at all. In fact, Staff's proposal can create a mismatch of the costs truly being avoided. Staff's proposed two-step process first determines the value of capacity on a dollars-per-MW basis. Staff calls this the target capacity dollars. The second step of Staff's proposed process is to determine how to pay *those* dollars over the course of a year, the capacity contribution adjustment. This is where the mismatch may be created. Staff assumes that the QF is entitled to all of "those" dollars that the capacity contribution adjustment would be expected to pay the target capacity dollars over the course of a year. If that were true, then taken to the extreme, if a solar QF only generated for one on-peak hour in a year, Staff's capacity contribution adjustment would compensate the QF for the total target capacity dollar amount in one hour, equivalent to a lump-sum capacity payment.

Q. What is the effect of Staff's proposed modification to the methodology the Commission approved in Order No. 14-058?

A. Staff's proposed modification is harmful to customers because it *increases* the avoided cost of capacity rate rather than recognizing the *decreased* contribution to peak as directed by Order No. 14-058. Prior to Order No. 14-058, a QF was compensated for capacity by receiving 100 percent of the capacity cost of the proxy for any deliveries that it would make during heavy load hours. The only change directed by the Commission in Order No. 14-058 was to compensate the QF not at 100 percent of the proxy's capacity cost, but at a *reduced* value commensurate with the solar QF's contribution to peak. The Commission did not direct that the rate be increased due to the fact that the QF may not make deliveries during all heavy load hours. This fact is irrelevant to the determination, and to the change directed by the Commission. Prior to Order No. 14-058, the QF was compensated with 100 percent of the proxy value for all of its heavy load hour deliveries. Subsequent to Order No. 14-058, the QF should be compensated in a way that reflects the relative contribution to peak of the QF compared to the proxy. In Idaho Power's case, with regard to a solar QF, this is 32 percent of the proxy value for all of its heavy load hour deliveries. Staff proposes to inflate the capacity component of the rate that was based upon the proxy's value over all heavy load hours and compress that value into a smaller number of hours representing only the hours the solar QF delivers during heavy load. Thus, the QF, under Staff's proposal, is paid a rate that far exceeds 32 percent of the proxy value, which was directed by the Commission.

In fact, using the numbers from Idaho Power's Schedule 85 prior to the May 1, 2015, annual update, and inputs from Idaho Power's 2013 IRP, in Staff and ODOE's proposed methodology, the solar QF capacity rate actually exceeds the 100 percent proxy value capacity rate for a baseload resource.

Idaho Power's Oregon Avoided Cost Prices
Prior to May 1, 2015, Update

	On-Peak	Off-Peak
Baseload QF	$56.78	$43.16
PV Solar QF	$47.52	$43.16
Staff's Proposed PV Solar QF	$61.32	$43.16

As shown in the table, the baseload QF on-peak rate is $56.78 per megawatt-hour ("MWh"). The approved methodology appropriately reduces that amount for a photovoltaic ("PV") solar QF to $47.52 per MWh, reflecting the reduced contribution to capacity that a PV solar QF provides compared to the CCCT proxy resource. However, calculating the on-peak price using the Staff's proposed methodology would result in a PV Solar QF price of $61.32 per MWh. This is even greater than the on-peak price for a baseload QF. This not only is contrary to the intent and direction of Order No. 14-058, but is also an unlawful rate that exceeds the Company's avoided cost—as it exceeds 100 percent of the proxy avoided resource value.

Q. Should the Commission revise the methodology approved in Order No. 14-058 for determining the capacity contribution adder for solar QFs?

A. No. Idaho Power's Schedule 85 currently implements Order No. 14-058 properly by allocating a capacity payment to solar and wind QFs based upon a reduction from 100 percent of the capacity cost of proxy resource to each resource's contribution to peak from the acknowledged IRP, as directed in Order No. 14-058. This method should be affirmed by the Commission in this proceeding and Staff/Intervenor proposals rejected as requiring payment in excess of avoided costs.

Q. With regard to issue No. 6, do the market prices used during the Resource Sufficiency Period sufficiently compensate for capacity?

A. Yes. It should be noted that the Commission has long differentiated between the calculation of avoided costs for a utility in a resource deficit position from a utility in a surplus position. In Order No. 05-584, p. 26, issued in Docket No. UM 1129, the Commission states:

> We are reluctant to abandon this Commission's long history of differentiating the calculation of avoided costs for a utility in a resource deficit position from a utility in a surplus position. 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.

The Commission went on to adopt Staff's recommendation that QF capacity be valued based on the market. In Order No. 05-584, the Commission adopted the methodology that values avoided costs when a utility is in a resource sufficient position at monthly on- and off-peak forward market prices as of the utility's avoided cost filing. Order No. 05-584, p. 28.

Q. Do the Company's avoided cost prices in its Idaho jurisdiction differentiate upon the utility's position of resource sufficiency or deficiency?

A. Yes. However, the Idaho Public Utilities Commission in Order No. 32697, page 21, when discussing a utility's payment to a QF for capacity, stated:

> In calculating a QF's ability to contribute to a utility's need for capacity, we find it reasonable for the utilities to only begin payments for capacity at such time that the utility becomes capacity deficient. If a utility is capacity surplus, then capacity is not being avoided by the purchase of QF power. By

> including a capacity payment only when the utility becomes capacity deficient, the utilities are paying rates that are a more accurate reflection of a true avoided cost for the QF power.

In Idaho, the capacity portion of the payment is included only when the utility is capacity deficient.

Q. Under the Standard Method, does a QF receive a capacity payment during times when a utility is capacity sufficient?

A. Yes. Under the Standard Method, during times of capacity sufficiency, the QF is paid an on-peak and off-peak market price based upon a forward price curve determined at the time of the Company's avoided cost filing. The on-peak price embeds the value of incremental QF capacity in the total market-based avoided rate.

Q. Do market prices then sufficiently compensate for capacity during the Resource Sufficiency Period?

A. Yes, and in fact, use of on-peak and off-peak market prices during a period that a utility is resource sufficient actually results in the utility overcompensating the QF. Again, referring to the concept of resource sufficiency, in order to fairly compensate a QF during the time of a utility's resource sufficiency, there should not be any compensation for additional capacity. If a utility is capacity surplus, the 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. The avoided cost rates in Idaho Power's Idaho jurisdiction do not include a capacity payment during a period of resource sufficiency. However, in Oregon, they are compensated, even though it is not a cost being avoided by the utility.

Q. Does this conclude your testimony?

A. Yes, it does.

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

DIRECT TESTIMONY

OF

RANDY ALLPHIN

May 22, 2015

Q. Please state your name and business address.

A. My name is Randy Allphin. My business address is 1221 West Idaho Street, Boise, Idaho 83702.

Q. By whom are you employed and in what capacity?

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as the Energy Contracts Coordinator Leader.

Q. Please describe your educational background and work experience with Idaho Power.

A. I graduated in 1982 from Boise State University with a Bachelors of Business Administration. In June 1982, I accepted a position as a Customer Service Specialist with Idaho Power. In 1986, I accepted a position as an Operations Accountant in the Operations and Fuels Management accounting group. My specific responsibilities were accounting for and performing economic analyses of the Company's agreements with Qualifying Facilities ("QF"), as well as fuels and thermal operations and maintenance accounting. In 1998, in addition to the responsibility of performing the accounting and economic analysis of QF agreements, I was also assigned the responsibility of administering all aspects of existing and new QF agreements as the Co-generation and Small Power Production (CSPP) Contract Administrator. In 2010, I was promoted to Senior Energy Contracts Administrator and was assigned two direct reports to manage the large number of Idaho Power QF and other renewable energy agreements. In 2012, an additional employee was added to my team and my title was changed to Energy Contracts Coordinator Leader. I have been involved with accounting, economic analysis, contract administration, and contract negotiations of Idaho Power QF and renewable energy agreements for approximately 31 years. In addition, I was responsible for the initial implementation of Idaho Power's Oregon Solar Photovoltaic ("PV") Pilot Program and currently am assigned supervisory oversight of the administration of that program.

Q. What is the purpose of your testimony in this matter?

A. The purpose of my testimony is to address, on behalf of Idaho Power, several of the issues identified in the UM 1610 Phase II Issues List. There are nine designated issues on the Issues List. Mr. Youngblood provides testimony on behalf of Idaho Power relevant to issue numbers 3, 4, and 6. I will provide testimony relevant to the remaining six issues.

Issue 1: Who owns the Green Tags during the last five years of a 20-year fixed price PPA during which prices paid to the QF are at market?

Issue 2: Should avoided transmission costs for non-renewable and renewable proxy resources be included in the calculation of avoided cost prices?

Issue 5: What is the appropriate forum to resolve litigated issues and assumptions?

Issue 7: What is the most appropriate methodology for calculating non-standard avoided cost prices? Should the methodology be the same for all three electric utilities operating in Oregon?

Issue 8: When is there a legally enforceable obligation?

Issue 9: How should third-party transmission costs to move QF output in a load pocket to load be calculated and accounted for in the standard contract?

Q. Please summarize your testimony.

A. For many of the identified issues, Idaho Power agrees with the Public Utility Commission of Oregon's ("Commission") current implementation and rules, and is not taking a position that differs from the Commission's existing determinations. However, Idaho Power reserves the right to further address these issues in response, reply, and/or rebuttal testimony. Idaho Power discusses some instances below where the Company differs from the Commission's current policies on some of the above-referenced issues.

Q. What is Idaho Power's position regarding Issue 1: Who owns the Green Tags during the last five years of a 20-year fixed price PPA during which prices paid to the QF are at market?

A. My understanding of the current Commission policy is that for standard contracts, which utilize a combined cycle natural gas combustion turbine as the surrogate avoided resource, the Green Tags or Renewable Energy Credits/Certificates (RECs) are owned by the QF. Correspondingly, for *renewable* standard contracts, which utilize the utility's next planned renewable resource acquisition from its Integrated Resource Plan ("IRP") as the surrogate avoided resource, the Green Tags are owned by the utility. With no present renewable portfolio requirement under state or federal law, Idaho Power does not have renewable avoided cost rates, only non-renewable standard and negotiated avoided cost rates in the state of Oregon. Idaho Power is not presently contesting this policy, but reserves the right to address this issue in response, reply, and/or rebuttal testimony.

Q. What is Idaho Power's position regarding Issue 2: Should avoided transmission costs for non-renewable and renewable proxy resources be included in the calculation of avoided cost prices?

A. The Commission's current policy regarding the inclusion of third-party transmission costs depends on whether the proxy resource is an on-system or off-system resource. As indicated on page 17 of Order No. 14-058 from Phase I:

> We affirm the existing policy that if the proxy resource used to calculate a utility's avoided costs is an off-system resource, the costs of third-party transmission are avoided, and are therefore included in the calculation of avoided cost prices. . . .

> If the proxy resource used to calculate a utility's avoided costs is an on-system resource, there are no avoided transmission costs, and thus the costs of third-party transmission are *not* included in the calculation of avoided cost prices. (Emphasis in original.)

Unlike Portland General Electric Company, Idaho Power's proxy resource is and/or is assumed to be located on-system as a designated network resource available to serve load. Similar to the Commission's prior determination for third-party transmission costs, there is no additional avoided transmission expense for a designated network resource proxy generation plant, and there should be no change to current calculations of avoided cost rates as a result.

Q. What is Idaho Power's position regarding Issue 5: What is the appropriate forum to resolve litigated issues and assumptions?

A. From Idaho Power's perspective, this is a straightforward issue with a straightforward answer: The appropriate forum to resolve litigated issues and assumptions related to Public Utility Regulatory Policies Act of 1978 ("PURPA") and avoided costs is in an appropriate docket in front of the Commission specifically opened to resolve such litigated issues and/or assumptions—either at the request of the utility, Staff, or any other party that would initiate such request. The appropriate place to resolve litigated PURPA issues and assumptions is *NOT* the utility's IRP proceeding, or the avoided cost compliance filing. Neither of these types of dockets is set up as a contested case, and past attempts to use these dockets to litigate avoided cost inputs have resulted in confusion and delay.

To illustrate, it is helpful to consider two possible scenarios: (1) the Commission has determined, during the course of a contested proceeding, that the utility should use a value obtained from the utility's IRP for such avoided cost input and (2) the Commission has not made such determination, but the utility utilizes a value from its IRP for an avoided cost input.

Under the first scenario, where in a contested proceeding adopting PURPA policies the Commission has determined that the utility use an input derived from the IRP, the only question for the compliance filing is whether the utility utilized the input identified by the IRP. The compliance filing should not be viewed as an opportunity to contest the use of that input—that opportunity was available to the parties during the course of the Commission's PURPA proceeding in which it determined that the utility use a value or input from the IRP for purposes of avoided cost calculations, or for whatever purpose that value is meant.

Under the second scenario, where the Commission has not made a determination as to the use of particular input, it remains inappropriate for parties to seek to litigate issues they may have with the use of such input in a compliance filing. If a party has issue with a particular input, methodology, or practice with regard to avoided cost rates or the implementation of the utility's PURPA obligations, then those issues should be brought to the Commission through an application, petition, complaint, or investigation where the Commission can properly consider the issue through a contested proceeding and make a decision or ruling as to the proper input, practice, procedure, etc. Allowing parties to litigate contested issues in the context of a compliance filing, or an annual avoided cost update, will unacceptably drag out and delay the proceedings, creating confusion and uncertainty as to the ultimate rates. Certainly, Idaho Power's IRP process is conducted with the advice and consultation of the IRP Advisory Committee and is open to anyone who wishes to participate. However, Idaho Power acknowledges that the IRP process, both the development of the IRP itself as well as the subsequent filing and review by the Commission, is a specific process designed for the IRP and utilized for the utility's resource planning needs—not to establish contested issues/values for PURPA. The appropriate place to determine and resolve litigated issues and assumptions for

PURPA is in a PURPA docket. Furthermore, compliance filings should be limited to just that—compliance.

Q. What is Idaho Power's position regarding Issue 7: What is the most appropriate methodology for calculating non-standard avoided cost prices? Should the methodology be the same for all three electric utilities operating in Oregon?

A. Idaho Power is not requesting any change to the current methodology authorized by the Commission for calculating non-standard avoided cost prices. Idaho Power does not believe that all three utilities need to use the same methodology.

Q. What methodology for calculating non-standard avoided cost prices is currently authorized by the Commission for Idaho Power?

A. 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 Idaho Public Utilities Commission for the Company's Idaho jurisdiction. That methodology is termed the Incremental Cost IRP Methodology. The Commission directed use of that methodology in Order No. 07-360, Docket No. UM 1129 (Appendix A, item 2.a.ii) August 20, 2007. This methodology is set forth in the appropriate section for negotiated rate contracts in the Company's Schedule 85 which states, "The starting point for negotiations is the avoided cost calculated under the modeling methodology approved by 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." Idaho Power Schedule 85, page 10 item 2.a. 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.

Q. Is it important that all three utilities use the same methodology for non-standard avoided cost prices?

A. Idaho Power does not believe it is important that all three utilities use the same methodology for non-standard avoided cost pricing. It is more important that each utility use a methodology that accurately reflects its own unique system, and is compatible with its own unique power supply modeling. For example, Idaho Power's Incremental Cost 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. The non-standard, or negotiated, avoided cost pricing is designed to provide a much more accurate approximation of the utility's actual avoided cost than the proxy resource method employed for standard rates. It takes into account, among several other things, the proposed QF resource's unique hourly generation profile, compares that to the utility's displaceable resources that are operating in any given hour to serve load and establishes an avoided cost approximation that meets the federal definition of avoided cost much more accurately than a proxy resource method such as that utilized for standard avoided cost prices.

Additionally, for Idaho Power, it is much more important that the avoided cost prices, procedures, and implementation be 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. The geographic separation and uniqueness of extreme eastern Oregon, where Idaho Power's Oregon service territory is located, as well as Idaho Power's completely integrated system operations for Idaho and Oregon (with no real distinction in state boundaries), makes consistent pricing methodologies logical, practical, and necessary. The state border is essentially an imaginary line on a map. Wind speeds, solar radiation, and geography do not instantly change depending on which side of this imaginary state line you are on. However, 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 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. 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 Idaho Public Utilities Commission for non-standard avoided cost pricing for PURPA 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.

Q. What is Idaho Power's position regarding Issue 8: When is there a legally enforceable obligation?

A. First of all, this is largely a legal issue that Idaho Power intends to address through legal briefing to the Commission. I am not an attorney and thus offer the Company's position on legally enforceable obligation from my perspective as the Company's

PURPA Energy Contracts Coordinator Leader. Idaho Power has had significant claims, activity, and litigation regarding the issue of legally enforceable obligation under PURPA. Idaho Power proposes the Commission establish legally enforceable obligation standards that are consistent with those that are implemented by the Idaho Public Utilities Commission, and have been examined, tested, and upheld on challenge.

Idaho Power proposes the Commission establish that a QF does not bind the Company and its customers to any particular rate or term in a PURPA QF purchase through a legally enforceable obligation unless and until such time as the Commission determines that (a) under the particular facts and circumstances applicable to an individual QF, a legally enforceable obligation has arisen and, but for the refusal of the utility to enter into a contract, there would be a contract at that particular price and terms and (b) the QF can deliver its electrical output within 365 days of such determination. Further, there must be some evidence of the utility's refusal to contract, or purposeful delay in the contracting process on the part of the utility, before a QF could avail itself of the remedy of creating a legally enforceable obligation to a particular rate or particular terms and conditions absent a signed contract. If the QF believes the utility is refusing to contract, the QF would bring a complaint to the Commission to have the price and terms of a legally enforceable obligation established.

This is the process established and long recognized by the Idaho Public Utilities Commission for establishment of a legally enforceable obligation under PURPA. Idaho Power and the Idaho Public Utilities Commission have participated in numerous proceedings at the Federal Energy Regulatory Commission ("FERC"), the Idaho Supreme Court, and federal district court over the issue of legally enforceable obligation and this rule has been upheld as a lawful implementation of PURPA by the state commission that comports with both state and federal law. To properly implement PURPA, the State must make provision for purchases not only through a signed contract but also by means of a legally enforceable obligation, absent a contract. Idaho's implementation was recently more formally set forth in the Contracting Procedures section of Idaho Power's Idaho Tariff Schedule 73, which provides in subsection 1.d:

> The indicative pricing proposal provided to the [QF] . . . will not be final or binding on either party. Prices and other terms and conditions will become final and binding on the parties under only two conditions:
>
> i. The prices and other terms contained in an ESA shall become final and binding upon full execution of such ESA by both parties and approval by the Commission, or
>
> ii. The applicable prices that would apply at the time a complaint is filed by a Qualifying Facility with the Commission shall be final and binding upon approval of such prices by the Commission and final non-appealable determination by the Commission that:
>
> (a) a "legally enforceable obligation" has arisen and, but for the conduct of the Company, there would be a contract, and
>
> (b) the Qualifying Facility can deliver its electrical output within 365 days of such determination.

Idaho Power proposes that similar provisions for a legally enforceable obligation be incorporated in Idaho Power's Oregon Schedule 85.

Q. Does the Commission currently have any rules related to the issue of a Legally Enforceable Obligation ("LEO")?

A. Yes. Under ORS 758.525(2), a QF may choose an avoided cost price based on either the avoided costs calculated at the time of delivery or the "projected avoided costs calculated at the time the legal obligation to purchase the energy or energy and capacity is incurred." While the statute does not define the time at which the legal obligation is incurred, the Commission's rules do. OAR 860-029-0010(29) defines the "time the obligation to purchase the energy capacity or energy and capacity is incurred" as the earlier of:

> (a) The date on which a binding, written obligation is entered into between a qualifying facility and a public utility to deliver energy, capacity, or energy and capacity; or
>
> (b) The date agreed to, in writing, by the qualifying facility and the electric utility as the date the obligation is incurred for the purposes of calculating the applicable rate.

Q. Is there any Commission precedent applying this rule?

A. Yes. In Order No. 09-439 in Docket UM 1449, a QF larger than 10 megawatts was in the process of negotiating a power purchase agreement ("PPA") with PacifiCorp when PacifiCorp filed to update its avoided cost prices. After the Commission approved PacifiCorp's new prices, the QF filed a complaint requesting that the Commission require PacifiCorp to execute a PPA with the QF that included the previous avoided cost prices in effect during negotiations. In granting PacifiCorp's motion to dismiss the QF's complaint, the Commission found that under OAR 860-029-0010(29)(b) a legally enforceable obligation was not created simply by PacifiCorp's provision of a draft PPA to the QF. The Commission noted that conventional contract law does not apply to QF transactions because they are creatures of statutes and the Commission's rules. Therefore, acceptance of the terms of the draft contract does not constitute an agreement and because the draft contract was not a binding written agreement between the parties, PacifiCorp had not incurred a legally binding obligation.

Q. What is FERC's rationale for the existence of its rule regarding a LEO?

A. FERC's rationale is that the concept of a legally enforceable obligation exists in order to protect a QF against a situation where a utility refuses to contract with the QF.

FERC's rules state that a QF may choose to sell its output to a utility pursuant to a contract or a legally enforceable obligation. FERC has further stated:

> 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.

137 FERC 61006 p. 8.

Q. Does this mean that a QF could simply ask for a draft contract or sign a draft contract and send it to the utility, and by doing so create a "Legally Enforceable Obligation" and bind the utility to a certain rate or certain terms and conditions that may be in effect?

A. No. It is clear that there must be some refusal of the utility to contract, some purposeful delay, or action on the part of the utility seeking to avoid its obligation to purchase under PURPA before a QF may avail itself of the extraordinary remedy of consummating a purchase through a non-contractual, but still legally enforceable, obligation. A QF will typically seek the establishment of a LEO in an attempt to secure a higher avoided cost rate when the state commission approves or puts into place a new lower avoided cost rate for the utility. Consequently, the establishment, or not, of a LEO in this context holds important, meaningful, and potentially very costly consequences for the utility's customers if they are bound to pay a previously effective "grandfathered" avoided cost rate that is no longer reflective of the utility's avoided cost.

Q. Has FERC directed that a state commission cannot limit a LEO to when there is a signed contract?

A. FERC has stated in a series of three nearly identical declaratory orders that the Idaho Public Utilities Commission's orders denying the approval of several PURPA power purchase agreements could not limit the application of a LEO to only such time as both the QF and the utility had fully executed the contract. FERC reasoned that because the concept of a LEO is to guard against the eventuality that a utility may refuse to contract to avoid its obligation under PURPA, that it would frustrate that purpose to limit a legally enforceable obligation to only such time as both the QF and the utility had signed the contract.

Q. Did FERC find the existence of a LEO in any of the above-referenced declaratory orders?

A. No. In fact, FERC acknowledged that the factual determination of whether and when a LEO is created or arises is a determination left to the state commissions, and FERC specifically declined to find that a LEO either existed or not under the facts of any of those particular cases.

Q. Is Idaho Power's recommendation to this Commission consistent with FERC's direction regarding a LEO?

A. Yes. The question of whether and when a LEO exists is within the province of the state commissions. However, FERC has directed that a LEO cannot be limited to those circumstances when both parties sign a contract. Idaho Power's recommendations with regard to a LEO satisfies both FERC's direction that a LEO not be limited to when both parties sign and also leaves the decision as to whether the remedy of a LEO shall be applied in any particular case, and any particular set of factual circumstances, to the discretion of the state commission.

Q. What is Idaho Power's position regarding Issue 9: How should third-party transmission costs to move QF output in a load pocket to load be calculated and accounted for in the standard contract?

A. The Commission determined in Phase I of this proceeding that the costs associated with third-party transmission to move QF output in a load pocket to load must be assigned to the QF in order to comport with PURPA avoided cost principles. Order No. 14-058, p. 22. The Commission, however, went on to state that, "We find, however, that Staff and the parties did not fully address how to calculate and assign the third-party transmission costs that are attributable to the QF. We defer this issue to the second phase of these proceedings." Idaho Power proposes that this cost be allocated to the QF separately from the purchase contract as part of the interconnection and network resource designation process. Idaho Power does not have any existing or proposed QF projects that would require the use of third-party transmission to move the QF generation from a load pocket to load. However, if the Company did have such a situation, it believes that, under existing processes, Idaho Power's load serving operations could adequately assess the third-party transmission cost to the QF through the process of interconnection and network resource designation of the QF.

Q. Does this conclude your testimony?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document on the service list 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.

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

Association of Oregon Counties
Mike McArthur
mmcarthur@aocweb.org

Cable Huston Benedict et al.
Chad Stokes
cstokes@cablehuston

Cable Huston Benedict et al.
Richard Lorenz
rlorenz@cablehuston.com

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

Citizens' Utility Board of Oregon
Sommer Templet
sommer@oregoncub.org

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

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

Loyd Fery Farms LLC
Loyd Fery
dlchain@wvi.com

Cleantech Law Partners PC
Diane Henkels
dhenkels@cleantechlawpartners.com

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

Davison Van Cleve PC
Tyler C. Pepple
tcp@dvclaw.com

Irion A. Sanger
Sanger Law PC
irion@sanger-law.com

PUC Staff -- Department of Justice
Stephanie S. Andrus
stephanie.andrus@state.or.us

Energy Trust of Oregon
Thad Roth
thad.roth@energytrust.org

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

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

Exelon Business Services Company, LLC
Paul Ackerman
paul.ackerman@constellation.com

Lovinger Kaufmann LLP
Kenneth Kaufmann
kaufmann@lklaw.com

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

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

One Energy Renewables
Bill Eddie
bill@oneenergyrenewables.com

Oregon Department of Energy
Diane Broad
diane.broad@state.or.us

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

Oregon Department of Justice
Renee M. France
Senior Assistant Attorney General
renee.m.france@doj.state.or.us

Oregon Solar Energy Industries Association
OSEIA Dockets
dockets@oseia.org

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

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

Pacific Power
Dustin T. Till
dustin.till@pacificorp.corn

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

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

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

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

Energy Trust of Oregon
Betsy Kauffman
betsy.kauffman@energytrust.org

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

CREA
Brian Skeahan
PMB 409
18160 Cottonwood Road
Sunriver, OR 97707
Brian.skeahan@yahoo.com

Renewable Energy Coalition
John Lowe
jravenesanmarcos@yahoo.com

Renewable Northwest
Megan Walseth Decker
megan@renewablenw.org

Renewable Northwest
Renewable NW Dockets
dockets@renewablenw.org

Roush Hydro Inc.
Toni Roush
tmroush@wvi.com

McDowell Rackner & Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205

Richardson Adams, PLLC
Peter J. Richardson
peter@richardsonadams.com

Small Business Utility Advocates
James Birkelund
james@utiltiyadvocates.org

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

Obsidian Renewables, LLC
Todd Gregory
tgregory@obsidianrenewables.com

Richardson Adams, PLLC
Gregory M. Adams
greg@richardsonadams.com

Stoll Berne
David A. Lokting
dlokting@stollberne.com

Obsidian Renewables, LLC
David Brown
dbrown@obsidianfinance.com

Portland General Electric
V. Denise Saunders
Denise.saunders@pgn.com

DATED: May 22, 2015

Sharon Cooper
Legal Assistant

McDowell Rackner & Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205