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August 7, 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 is an electronic copy of Idaho Power Company's Reply Testimony of Michael J. Youngblood and Reply Testimony of Randy Allphin.

Please contact this office with any questions.

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Office Manager

Attachments

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

**UM 1610**
**PHASE II**

| | |
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| In the Matter of | ) |
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| PUBLIC UTILITY COMMISSION OF OREGON | ) |
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| Investigation into Qualifying Facility Contracting and Pricing. | ) |
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**IDAHO POWER COMPANY**

**REPLY TESTIMONY**

**OF**

**MICHAEL J. YOUNGBLOOD**

**August 7, 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. Are you the same Michael J. Youngblood who previously testified in this docket?**

A. Yes. My witness qualifications are set forth in my Direct Testimony, Idaho Power/600.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to respond to the response testimony filed July 24, 2015, in Phase II of Docket No. UM 1610, by the following parties: Staff, Oregon Department of Energy ("ODOE"), the Renewable Energy Coalition ("REC" or "Coalition"), Community Renewable Energy Association ("CREA"), OneEnergy, Obsidian Renewables, LLC ("Obsidian"), collectively referred to as the Intervenors ("Intervenors"), regarding the Issue List items numbers 3, 4, and 6.

**Q. Please list Issues 3, 4 and 6.**

A. Issue Nos. 3 and 4 are very closely related, and I will address both of them concurrently. They are:

**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?

The other issue I will address is Issue No. 6, which is a question regarding the avoided cost prices paid to a qualifying facility ("QF") during the time when a utility is resource sufficient. The issue is stated as:

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

**Q. Please summarize the parties' positions regarding Issue Nos. 3 and 4.**

A. As I stated in my response testimony, the positions of the parties can be identified as being in agreement with either one of two opposing points of view. Portland General Electric ("PGE"), PacifiCorp d/b/a Pacific Power ("PacifiCorp"), and Idaho Power, collectively referred to as the Utilities ("Utilities"), believe that the capacity contribution modification that was approved in Order No. 14-058 is appropriate, and more closely determines the value of capacity provided by differing QF resource types in determining published avoided cost rates using the proxy method. Staff and the rest of the Intervenors believe that the adjustment methodology adopted by the Public Utility Commission of Oregon's ("Commission") had the "unintended effect" of applying two decrementing adjustments to the capacity payments received by solar QFs during deficiency periods.

**Q. What did the Commission direct regarding the capacity contribution of QF resources in Order No. 14-058?**

A. At the outset, Order No. 14-058, p2, the Commission stated:

- We retain our current methodology for calculating standard avoided cost prices and standard renewable avoided cost prices, with the modification described below.

The Commission went on to direct:

- 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.

With respect to revising the pricing methodology for both standard avoided cost prices and standard renewable avoided cost prices to account for the capacity contribution of different QF resources, Order No. 14-058 provides the following language:

> Capacity Contribution of QF Resources
>
> Currently, no adjustments are made to Standard and Standard Renewable avoided cost prices to account for the actual contribution to capacity made by each QF resource type. To produce more accurate avoided cost estimates, parties propose adjusting the capacity component in standard and renewable avoided cost prices to capture the expected capacity contribution of each QF resource type. For the Standard Method, Staff proposes multiplying the capacity component currently embedded in the method by a "capacity contribution factor," equal to the expected contribution to peak load of the specific QF resource type. The assumed capacity contribution to peak load would be the contribution estimate used in the utility's acknowledged IRP for the specific type of generation (wind, solar, etc.).
>
> For the Standard Renewable Method, Staff proposes adjusting the capacity component implicit in the renewable on-peak price by the incremental capacity contribution of the specific QF resource type relative to the avoided renewable resource. For a wind QF, this would currently result in no change to its renewable avoided cost prices obtained under the current Renewable Method because the next avoidable resource for both PGE and Pacific Power is a wind resource. For solar and baseload QFs, the price adjustment would result in a higher capacity component (and therefore a higher on-peak price) than in the current method. The capacity contribution for each renewable QF resource type used in this adjustment would be the capacity contribution assumed for that resource type in the utility's acknowledged IRP.
>
> We agree on the need to adjust for capacity contribution of each resource type and adopt Staffs proposed method for calculating capacity adjustments, as set forth in Staff/102-103, using input estimates derived from the utility's acknowledged IRP. We direct the parties to address issues regarding calculation methodology in future utility IRPs.

**Q. Why is the Commission's language important with regard to the current debate regarding Issue Nos. 3 and 4?**

A. It is important to note that the Commission first stated that it retained the current methodology for calculating standard avoided cost prices and standard renewable avoided cost prices, with the modification described later. The then-current methodology required by the Commission prior to Order No. 14-058, was for electric utilities to set rates based on the cost of a proxy resource during periods of resource deficiency and on monthly market prices during periods of resource sufficiency. The proxy is a natural gas combined-cycle combustion turbine ("CCCT") proxy resource for standard avoided cost prices, and the next avoidable renewable resource identified in the electric company's Integrated Resource Plan ("IRP") for renewable avoided cost prices. The next avoidable renewable resource in PGE's and PacifiCorp's IRPs are wind resources.

The Commission then went on to direct that the current methodology for calculating standard avoided cost prices and standard renewable avoided cost prices was to be modified to account for the capacity contribution of different QF resources. The intent of the Commission was to make the modification to the then-current methodology, leaving everything else the same.

**Q. Why is it important to note that the modification was made to the then-current methodology?**

A. In its motion for clarification filed April 24, 2014, Obsidian referred to the recognition of a solar QF's capacity contribution as the "first discount," and it does not challenge the appropriateness of recognizing a lower capacity contribution for solar QFs relative to a proxy CCCT. Obsidian refers to the spreading of capacity costs to the on-peak hours as the "second discount" because solar QFs that generate less energy compared to the proxy CCCT receive less in total dollars.

It is important to note that the modification was made to the then-current methodology because of Obsidian's, and now joined by Staff and the other Intervenors, contention that the adjustment methodology adopted by the Commission in Order No 14-058 had the "unintended effect" of applying two decrementing adjustments to the capacity payments received by solar QFs during deficiency periods. But that is not true. The methodology for determining avoided cost prices before Order 14-058 had been in place since 2006 for PGE and PacifiCorp and since 2012 for Idaho

Power. The "pre-14-058" methodology always spread the capacity costs to the on-peak hours. This was not an "unintended second discount." The methodology *intended* to determine the avoided cost for the QF generation *relative to* the CCCT proxy. And it did provide a relative estimate of the costs that were being avoided by the utility when the QF generation was being provided, relative to the CCCT proxy.

What the modification directed by Order No. 14-058 did was to acknowledge the different capacity contributions made by different renewable resources, but all still relative to the CCCT proxy. None of the renewable QF resources to date provide the same capacity value as the CCCT proxy. But some renewable resources provide more value than other renewable resources, and Order No. 14-058 attempted to provide a modification to the existing methodology in order to recognize those differences. A solar generation resource for example, provides more capacity contribution at times when the utility needs it the most, during the peak hours, than does a wind generation resource. And therefore, the methodology provided by Order No. 14-058 provides for a higher avoided cost rate for solar than for wind. However, it is not intended to provide a higher avoided cost rate for solar than for a CCCT proxy unit, because it does not provide the same value as the CCCT generation plant.

**Q. Can you provide a brief example to help explain the concept you just discussed?**

A. Yes, I think I can do so best in reference to the "simplistic example" provided by Obsidian's witness, David Brown toto illustrate his claim of the "double discount." Obsidian/400 Brown/10.

Mr. Brown asks us to imagine that there are two workers doing the same job with the same pay grade. One works full time at 40 hours per week and the other works 20 hours per week. For clarity, I would like to give the workers names. Let's call the employee working 40 hours per week Roxy Proxy, and the part-time employee, Sonny Solar. Mr. Brown argues the objective is proportionate compensation of the two workers, and based on this view he concludes that Sonny Solar should earn half of the total compensation paid to the Roxy Proxy full-time worker. Mr. Brown concludes that accordingly, they should be paid the same hourly wage—one for 40 hours per week and the other for 20.

**Q. Do you agree with Obsidian's conclusion?**

A. No—because I think Mr. Brown has defined "proportionate compensation" too narrowly. By looking only at the total number of hours the two employees are working, he is ignoring the respective ***value*** that these employees provide to the business.

**Q. Please explain**.

A. The result Mr. Brown advocates is exactly the situation that existed ***before Order No. 14-058***. Both of the workers, both the proxy resource and the renewable QF, were paid the same hourly rate. The difference in the total compensation between the two resources was due to the fact that the renewable resource did not provide capacity for the same amount of hours as the proxy resource. Mr. Brown does correctly state the Utilities' position that the hourly wage paid to Sonny, the part-time worker, should be less than the hourly wage paid to Roxy, the full-time worker. But in order to understand the rationale for this position, we need to learn more about Roxy and Sonny.

Roxy is a veteran worker. She has worked long and hard, and continues to provide value today. Roxy is very dependable. Roxy will work day or night, come rain or shine. Roxy will show up to work whenever called. And if there is not work to do, we can call Roxy and she will stay home.

Sonny is young and energetic. He wants to do a good job, but, he doesn't provide as much value as Roxy. Sonny can't work at night, and isn't always as dependable as Roxy. On some days, Sonny doesn't even show up to work. And on other days, even when there is no work to do, Sonny shows up and wants to get paid.

And he gets paid, because there are laws that require us to pay him even if he is not needed at that time.

Granted, I have tried to "creatively" expand upon Mr. Brown's simplistic example. And in doing so, I mean no disrespect at all to Mr. Brown, Obsidian, Staff or any of the other Intervenors. I also want to state that this characterization is solely Idaho Power's, and may or may not represent the views of the other utilities. But I have tried to illustrate the differences between the two workers and in doing so, the differences between the proxy resource and the QF renewable generation. There is absolutely nothing wrong with Sonny. He is great and contributes when he can. He just does not provide the same amount of work ***or*** the same value as Roxy. And therefore, I would pay Sonny a lower hourly wage than I would pay Roxy, and I would only pay Sonny when he showed up to work. In a similar fashion, there is nothing wrong with solar, or wind, or any other renewable resource. They are clean resources that provide value when they generate. However, they are not the same resource as a dispatchable baseload resource such as a gas-fired CCCT. And therefore, they should be paid relative to the proxy unit for the costs that are actually avoided when they generate.

**Q. Returning to the real world, how does this example help explain the concept of capacity contribution of QF resources that was implemented by Order No. 14-058.**

A. As I stated above, the situation before Order No. 14-058 was that both the proxy resource and the renewable QF were being paid the same hourly price, even though the proxy resource could provide more value for the utility than the QF, including the ability to dispatch the resource on an as-needed basis and the ability to provide operating reserve capacity. These benefits are available to the utility in all hours, not just when the resource is generating energy. Order No. 14-058 recognized the disparate value provided by the different resources, and made an adjustment to the Standard and the Standard Renewable avoided cost prices to account for the actual contribution to capacity made by each QF resource type *relative* to the proxy unit.

**Q. In summary, with regard to Issues 3 and 4, should the Commission revise the methodology approved in Order No. 14-058 for determining the capacity contribution calculation for both renewable avoided cost prices (Issue 3) and standard non-renewable avoided cost prices (Issue 4)?**

A. No. As I have stated in my direct testimony, my response testimony, and now in my reply testimony in Phase II of Docket UM 1610, 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 the proxy resource to each resource's contribution to peak from the acknowledged IRP, as directed in Order No. 14-058. To pay for generation that is not generated, or for capacity that is not provided, is contrary to the Federal Energy Regulatory Commission (FERC) definition of avoided cost and harmful to utility customers. For many years, the Oregon proxy methodology has determined an avoided cost rate that was paid only for those peak hours during which the renewable QF was actually generating and delivering energy to the host utility. What the modification in the approved Order No. 14-058 did was to differentiate between the types of QF resources, providing additional value to solar QFs as compared to wind QFs because of the operational characteristics of those different resource types. To modify the methodology now as Staff/Intervenors suggest would increase the avoided cost rate paid to the QF above the avoided cost rate of the proxy resource. As shown in my direct testimony, as well as the previous testimony and briefing on this issue, the proposed changes actually result in compensating a solar QF for capacity at a higher rate than the 100% capacity proxy CCCT. This is not only logically incorrect; it is harmful to the utility’s customers and illegal. The current methodology approved in Order No. 14-058 should be affirmed by the Commission in this proceeding and Staff/Intervenor proposals rejected as requiring payment in excess of avoided costs.

**Q. Mr. Brown provides somewhat lengthy testimony about ELCC. What is Idaho Power's response?**

A. Mr. Brown inappropriately proposes to utilize an entirely different methodology to calculate the capacity contribution of solar QF projects. This issue is not properly before the Commission. As stated earlier in my testimony, the Commission clearly determined in Order No. 14-058 to retain the existing methodology with the only changes being to account for the capacity contribution of different QF resources and wind integration costs. To now bring up, and advocate for an entirely different methodology is contrary to the Commission's Order, Obsidian's clarification/reconsideration request of that Order, and the issues that are before the Commission in this proceeding. Mr. Brown additionally states that all the utilities currently use the ELCC method. Obsidian/400 Brown/2. This is not true. Idaho Power does not use the ELCC method in any supply side resource planning, and it has never been approved as part of the avoided cost methodologies.

**Q. Please summarize the parties' positions regarding Issue No. 6.**

A. Issue No. 6 has to do with whether the market prices used during the Resource Sufficiency Period sufficiently compensate for capacity. As with many of the other issues, the parties' positions have not varied much. And while this issue seems generic in nature, much of the discussion in testimony was directed toward PacifiCorp. The Intervenors were in support of the opening testimony provided by Mr. Kevin C. Higgins which was presented on their behalf, referred to as the Joint QF Parties. Mr. Higgins discusses at length why the market prices used during the resource sufficiency period do not compensate for capacity in the PacifiCorp territory. He states that there are two fundamental reasons for his conclusion: 1) there is a structural problem in the way PacifiCorp's IRP is interpreted for determining QF pricing, and 2) the extraordinarily long sufficiency period indicated by the 2015 PacifiCorp IRP is sending a price signal to prospective QFs that the long-term value of their capacity has no value except for the relatively small premium that may be included in the price of firm energy based on projected market prices. To remedy these two problems, Mr. Higgins suggests the development of an Alternative IRP scenario that re-determined the preferred resource portfolio absent the (assumed) renewable QFs in order to properly value the capacity that QFs would avoid, and that the Commission adopt an interim capacity pricing mechanism for Schedule 37 sales by renewable QFs and zero-emitting QFs until the uncertainty surrounding implementation of Section 111(d) is resolved. Joint QF Parties/100 Higgins/4-6.

ODOE also supports Mr. Higgins' reasoning, however states that the problem with his recommended approach relates to data in a specific IRP, while the data in the next IRP are likely to be different. ODOE believes that without a parallel process to dispute the inputs used in the avoided cost filing associated with the next IRP, there would be no way to update the values. ODOE/900 Carver/8.

Staff agrees with the Joint QF Parties' recommendation to require PacifiCorp to stop basing its avoided cost prices on a resource stack that assume terminating QFs are renewed. However, regarding the recommendation for an interim capacity pricing mechanism, Staff states that FERC has found that an avoided cost rate may not include a "bonus" or "adder" above the calculated full avoided cost of the purchasing utility to provide additional compensation for environmental externalities that are not real costs that would be incurred by the utilities. Staff/600 Andrus/19.

PGE states that no additional payment for capacity is warranted during the sufficiency period and that a capacity payment during the sufficiency period results in prices that exceed the avoided cost of the utility. PGE/700 Macfarlane, Morton/6.

Most of PacifiCorp's response testimony on this issue is in response to the other parties' criticism of its existing practices regarding 'front office transactions' and expenditures for environmental upgrades at existing company-owned coal-fired generation resources during the sufficiency period. PacifiCorp explains that the Joint QF Parties conflate the issues surrounding compliance with Section 111(d) rules and certain planned and potential capital investments at existing coal facilities during the resource sufficiency period to comply with the EPA's Regional Haze rule under the Clean Air Act. With regard to QFs seeking a new contract upon expiration of an existing contract, PacifiCorp believes they should be treated the same as other QFs and avoided cost prices should reflect the utilities then current energy and capacity needs at the time of renewal. PAC/1100, Dickman/19.

**Q. What is Idaho Power's position with regard to Issue 6?**

A. Idaho Power's position regarding whether market prices used during the Resource Sufficiency Period sufficiently compensate for capacity remains unchanged. Idaho Power believes that market prices do compensate for capacity, and in fact, may over-compensate the QF provider. My direct and response testimony provides the support for this conclusion, acknowledging also that this Commission has long differentiated between the calculations of avoided costs for a utility in a resource deficit position from a utility in a surplus position. However, while the Commission has provided a methodology that values capacity based on the market when a utility is in a resource sufficient position, not all commissions maintain the same view. In Idaho Power's Idaho jurisdiction, the IPUC has stated that 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.

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, QFs are compensated for capacity, even though it is not a cost being avoided by the utility. While the Intervenors may believe that market prices do not fairly compensate a QF for capacity during the time of a utility's resource sufficiency, a better question is whether it is really fair to the customer to pay for capacity during the time of resource sufficiency and when additional capacity is not needed. Consequently, Idaho Power's position is that the Commission should make no change to its existing requirements where QFs are paid market rates when the utility is in a surplus position. If any change were to be made, then the QF should not receive any capacity payment for such periods of time when the utility is capacity sufficient.

**Q. Does this conclude your testimony?**

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

**UM 1610**
**PHASE II**

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| PUBLIC UTILITY COMMISSION OF OREGON | ) |
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**IDAHO POWER COMPANY**

**REPLY TESTIMONY**

**OF**

**RANDY ALLPHIN**

**August 7, 2015**

**Q. Please state your name and business address.**

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

**Q. Are you the same Randy Allphin who previously testified in this docket?**

A. Yes. My witness qualifications are set forth in my Direct Testimony, Idaho Power/900.

**Q. What is the purpose of your testimony?**

A. Over the course of Phase II of Docket No. UM 1610, there has been direct testimony filed May 22, 2015 and/or response testimony filed July 24, 2015, by a number of parties including: the Commission Staff, Oregon Department of Energy ("ODOE"), the Renewable Energy Coalition ("REC" or "Coalition"), Community Renewable Energy Association ("CREA"), OneEnergy, Obsidian Renewables, LLC ("Obsidian"), and Gardner Capital Solar Development, LLC ("Gardner Capital" of "Gardner Solar"), collectively referred to as the Intervenors ("Intervenors"), as well as the other two utilities, Portland General Electric ("PGE") and PacifiCorp d/b/a Pacific Power ("PacifiCorp"). The purpose of my reply testimony now is to provide a brief summary of the various parties' positions regarding Issue List items 1, 2, 5, 7, 8, and 9, and then provide a synopsis of Idaho Power's position on each of the same issues.

**Q. What are the issues that you will address in your reply testimony?**

A. I will provide testimony relevant to the following 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 reply testimony.**

A. As stated in both my direct and response testimonies, for many of the identified issues, Idaho Power agrees with the Public Utility Commission of Oregon's ("Commission") current implementation and rules. As this is the last round of testimony to be provided by all parties on these issues, I have tried to structure my reply testimony such that I first identify the other parties' positions on each issue to the best of my understanding, and then I provide a summary of Idaho Power's final position. Even though the Company's position on these issues has remained unchanged, I have restated our position here for clarity; this summary is not intended to supersede the more thorough discussion of the issues provided in earlier rounds of testimony.

**Q. Please summarize the parties' positions regarding Issue 1: Who owns the Green Tags during the last five years of a 20-year fixed price Power Purchase Agreement ("PPA") during which prices paid to the qualifying facility ("QF") are at market?**

A. Obsidian and Gardner Capital have not addressed this issue. The remaining Intervenors argue that QFs should own 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. PGE's position is that the utility should own the Green Tags regardless of the price of purchase during a period of resource deficiency. PacifiCorp's position is that the

Green Tags should go to the utility at the point in time that the resource deficiency period starts through the end of the PPA.

**Q. What is Idaho Power's position with regard to Issue 1?**

A. Idaho Power's position regarding Issue 1 remains unchanged from its direct testimony. That is, 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. For Idaho Power, the Commission has previously determined that the Green Tags or Renewable Energy Credits/Certificates (RECs) are owned by the QF. If the Commission were to determine that Idaho Power owned RECs in the last five years of a Public Utility Regulatory Policies Act of 1978 ("PURPA") QF contract when market prices are in place, Idaho Power would be required under its current approved REC management plan to sell its RECs on a short term basis and return those proceeds as a benefit to Idaho Power customers.

**Q. Please summarize the parties' positions regarding Issue 2: Should avoided transmission costs for non-renewable and renewable proxy resources be included in the calculation of avoided cost prices?**

A. As Staff stated, this issue applies most directly to PacifiCorp, whose avoided proxy resources are generally "on-system." Staff concludes that the Commission should not conclude in this docket that avoided transmission costs can never be included in the calculation of avoided cost prices when the proxy resource is on-system, and that the issue should be addressed on a case-by-case basis. Staff/600 Andrus/6.

OneEnergy did not provide reply testimony, however, has previously stated that as a matter of policy, avoided transmission costs for both non-renewable and renewable proxy resources should be included in calculating avoided cost prices regardless of whether the proxy resource is off-system or on-system. They recommend that the Commission apply a test: if the on-system proxy resource cannot be designated a Network Resource at its full capacity without transmission upgrades and without de-rating or curtailing other Network Resources, the cost of transmission upgrades necessary to make it a Network Resource should be included in avoided cost prices. OneEnergy/400 Eddie/2-3.

PacifiCorp takes issue with, as it characterizes, OneEnergy's implication that the entire cost of the Gateway West transmission project should be included in the standard avoided costs that rely on the Wyoming wind proxy. PacifiCorp states that the Gateway West transmission project should be excluded from avoided costs because the project is not directly tied to the proxy renewable resource and will not be avoided due to the addition of renewable QFs in Oregon. PAC/1100 Dickman/3-4.

CREA maintains that if there is a cost to PacifiCorp of getting the proxy resource to load, and if a QF provides power to load without requiring that transmission cost, then it is only equitable for PacifiCorp to reflect that avoided transmission cost enabled by the QF in the avoided cost rate offered to the QF. CREA/600 Skeahan/6.

**Q. What is Idaho Power's position with regard to Issue 2?**

A. Idaho Power's position on Issue 2 has not changed from what was originally stated in my direct testimony and restated in my response testimony. 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 for Idaho Power as a result.

**Q. Please summarize the parties' positions regarding Issue 5: What is the appropriate forum to resolve litigated issues and assumptions?**

A. Staff recommends that the Commission continue to use its current process requiring the utilities to file updated avoided cost prices within 30 days of acknowledgment of the utility's Integrated Resource Plan ("IRP"). The utilities basically agree with Staff that the current process should not be changed, asserting that parties have the opportunity to challenge assumptions used in the IRP during the public process already in place in developing a utility's IRP. Staff also recommends that the utilities be required to meet minimum filing requirements ("MFRs") when they make their avoided cost filings. Staff/600 Andrus/14.

ODOE proposes that a contested case filed concurrently with the utility's IRP filing, would provide fair and timely resolution of disputed elements of utility avoided cost filings. ODOE/900 Carver/2-3. ODOE believes that load forecast, natural gas prices and other elements integral to setting deficiency dates within four years of the IRP filing should be settled in the IRP acknowledgement order. All other issues related to setting avoided cost rates should be settled in the parallel docket that would be filed at the same time as the IRP. ODOE/900 Carver/6-7.

REC and CREA believe that parties should be provided an opportunity to review, challenge and obtain Commission resolution on all inputs and assumptions before the avoided cost rates become effective. Coalition/500 Lowe/4 CREA/600 Skeahan/9. CREA also supports Staff's proposal for MFRs, but states they do not "believe MFRs alone are sufficient to address our concerns and protect our rights." CREA/600 Skeahan/10. They state that there "still must be a contested case process to challenge the inputs and assumptions to the rates that appear to be unreasonable from a review of the initial filing and the MFRs." CREA/600 Skeahan/10.

**Q. What is Idaho Power's position with regard to Issue 5?**

A. First of all, Idaho Power is not opposed to MFRs requiring the utilities to provide references to the IRP and other sources of the inputs utilized in the annual rate update compliance filings; however, the Company is opposed to turning the annual update compliance filings into contested case proceedings that drag out the rate update process.

Idaho Power continues to maintain that the appropriate forum to resolve litigated issues and assumptions related to 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 or update filing.

Idaho Power's IRPs are prepared to fulfill the regulatory requirements and guidelines established by the Idaho Public Utilities Commission and the Public Utility Commission of Oregon. Idaho Power's resource planning process has four primary goals:

1. Identify sufficient resources to reliably serve the growing demand for energy within Idaho Power's service area throughout the 20-year planning period.
2. Ensure the selected resource portfolio balances cost, risk, and environmental concerns.
3. Give equal and balanced treatment to supply-side resources, demand-side measures, and transmission resources.
4. Involve the public in the planning process in a meaningful way.

What should be noted is that the IRP does not have as one of its goals the setting of avoided cost prices. IRPs are the utility's plan to meet its obligation to meet and serve the demand and energy requirements of its customers.

**Q. What then is the relationship of the utility's IRP in setting avoided cost prices?**

A. The IRP process makes certain assumptions in the determination of the least-cost, low-risk method of meeting its obligation to serve its customers. Those assumptions include the utility's assumptions for a load forecast, natural gas prices, electric price curves, fixed costs and variable operation and maintenance costs of supply side resources, demand-side management resources, heat rates, capacity factors, etc. All of these factors are discussed and debated through the public process of determining the utility's preferred portfolio of near-term and long-term resources needed to meet its obligation to serve its customers' load.

With regard to avoided costs, the federal regulations define avoided cost as: "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F. R. § 292.101(B)(6). Therefore, avoided costs are not one of the items determined in an IRP, but are a result of the costs associated with the utility's determination of the generation or purchased power it would otherwise need, but for the purchase from the QF. CREA's assertion that there "still must be a contested case process to challenge the inputs and assumptions to the rates that *appear to be unreasonable* from a review of the initial filing" CREA/600 Skeahan/10 (emphasis added) and REC's proposal to "de-link planning issues that are not fully vetted and prevent them from being a foundation for avoided cost prices." (Coalition/400 Lowe/13) are unwarranted. The determination of avoided costs cannot be "de-linked" from the IRP process. The Commission has determined that there are approved and acceptable methodologies that must be used to compute a utility's avoided cost rates offered to QFs under PURPA. The Commission has also determined that certain inputs and/or values in the avoided cost determinations will use inputs and/or values from the utility's IRPs. The Commission has also determined that avoided costs will be updated within 30 days of the utility's IRP acknowledgement, and/or on May 1 of each year.

**Q. What does Idaho Power propose as the appropriate forum to resolve disputed issues and assumptions?**

A. As I stated in my direct and response testimonies, for compliance filing purposes, which would include annual avoided cost rate updates, it is important to distinguish between situations where the Commission has previously determined, during the course of a contested proceeding, that the utility should use a value obtained from the utility's IRP for an avoided cost input or purpose and a situation where the Commission has not made such determination, but the utility utilizes a value from its IRP for an avoided cost input. The 30-day, post-IRP acknowledgment avoided cost rate ***updates*** and the annual May 1 ***updates*** are ***compliance filing updates***. We are not formulating a new and entirely different avoided cost methodology. We are updating the existing Commission approved and authorized avoided cost methodologies with more recent and up-to-date inputs. If the Commission has previously determined that the utility is to use an input derived from the IRP in determining the avoided cost rate, then the compliance, or update filing, with regard to that input, should be nothing more than a determination of whether or not the utility used the appropriate input from the IRP. It is not up for debate as to whether or not the input should be used, but whether it is the correct input identified in the utility's IRP.

If parties wish to contest the use of an input that was not previously determined through a contested case, or they desire to contest a methodology or practice with regard to avoided cost rates, the appropriate forum to do so is not during a compliance or rate update filing—where the dispute may unduly delay the implementation of appropriate avoided cost prices. The contesting party, either a QF, Staff, or the utility, should bring the issue to the Commission through an application, petition, complaint, or investigation where the Commission can properly consider the issue through a contested proceeding.

The other parties advocate delaying the implementation of the annual updates, and compliance filings so that contested inputs may be litigated. Adoption of this proposal could result in significant delay in the approval of rate update compliance filings, allowing QFs to obligate the utility and its customers to overpriced and outdated avoided cost rates. If avoided cost rates are increasing, the QF would want those updated rates in place as soon as possible. and with the one-sided obligation to purchase, they would simply wait to obtain the higher rate. However, when rates are decreasing, it would be in the QFs interest to forestall the adoption of the new rates (and obtain the higher rates) by litigating as many inputs as possible. The resulting detriment to customers is exacerbated by the fact the fixed rates are locked in for at least 15 years, and if we know they are outdated and incorrect at the time of contracting, the additional uncertainty and potential variance over the 15-year fixed-rate term becomes even more extreme.

**Q. Please summarize the parties' positions 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. Staff agrees with PacifiCorp that the current method of adjusting the standard avoided cost prices ignores the interdependencies across the seven Federal Energy Regulatory Commission ("FERC") factors, and therefore recommends that utilities be conditionally allowed to use a computer based model to calculate negotiated avoided costs. Staff/600 Andrus/21-22. PGE supports the use of the methodology established in Order No. 07-360, adjusting avoided costs for QF specific characteristics consistent with the seven factors outlined in 18 CFR 292.304(e)(2). However, PGE does support the use of computer modeling for larger QFs because they feel it enables a utility to be more precise with its avoided cost prices, stating that modeling is also a widely accepted practice in other forums like the IRP process. PGE/700 Macfarlane-Morton/9-10.

REC and CREA object to the use of a model-based approach for calculating non-standard avoided cost prices, however, REC does not oppose allowing Idaho Power to use the approach that it currently uses in Idaho.

ODOE supports the current Commission practice for PGE and PacifiCorp to use wholesale prices as the floor for QF prices that are fixed for the first 15 years. ODOE also makes some erroneous statements that "paying market prices to a QF, ratepayers are kept whole" and the "value of power during periods of deficiency is what the utility could sell it for or what it would buy it for, regardless of its decremental costs of generation." ODOE/900 Carver/10.

**Q. Why do you claim ODOE's statements are erroneous?**

A. Once again, I return to the federal regulations definition of avoided cost as: "the incremental costs to an electric utility of electric energy or capacity or both which, *but for* the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F. R. § 292.101(B)(6) (emphasis added). If at any time, a utility is required to purchase the generation output from a QF developer at some pre-determined market rate, and that rate is greater than the cost of generation the utility would provide to serve that load, the ratepayer is not kept whole, but harmed.

**Q. What is Idaho Power's position with regard to the methodology used for calculating non-standard avoided cost prices?**

A. Idaho Power proposes no changes to the methodology and process that has been in place since 2012 for calculating non-standard avoided cost prices, and no changes to the Commission's current authorized avoided cost rate determination for projects over the standard rate eligibility cap for Idaho Power as stated in Schedule 85:

> For Idaho Power, the starting point for negotiations are the avoided costs calculated under the modeling methodology approved by the Idaho Public Utilities Commission for QFs over 10 MW, as refined by the Oregon Commission to incorporate stochastic analyses of electric and natural gas prices, loads, hydro and unplanned outages.

**Q. Why does Idaho Power believe that the current methodology for calculating non-standard avoided cost prices is appropriate?**

A. Idaho Power's currently-approved methodology for avoided cost rates for those QF projects that exceed the standard rate eligibility cap is the incremental cost IRP methodology ("ICIRP"). This methodology has been in place for Idaho Power since approved for use through a contested case proceeding before the Idaho Public Utilities Commission in December 2012. IPUC Order No. 32697, Case No. GNR-E-11-03.

It is important to note that the avoided costs determined by the Oregon proxy methodology using an estimate of costs associated with a fictitious proxy combined-cycle combustion turbine ("CCCT") generation plant are not the costs the utility actually avoids, but only a rough estimate of those costs based upon the fictitious premise. Idaho Power agrees with Staff's testimony which states in reference to the modeling methodology approach, "it is likely to provide a more accurate quantification of the impact of a QF based on its specific characteristics than a generic CCCT calculation with adjustments applied to it. To put it simply, an estimate (the adjustments) overlaid on to a simplified estimate (the avoided CCCT resource) will likely be less accurate than a single complex estimate." Staff/500 Andrus/34.

The ICIRP methodology results in a project specific avoided cost calculation that precisely matches the avoided cost definition of the incremental costs to an electric utility, but for the purchase from the QF. The methodology compares the project's specific hourly generation profile to the utility's resource stack being used to serve load in each hour and assigns the cost of the utility's highest cost displaceable resource operating during the hours that the QF provides generation as the avoided cost. The capacity component of the rate is based upon the generation resource type and the avoided cost of a simple-cycle combustion turbine and added to the energy component derived from the utility's hourly highest cost displaceable resources. The hourly values are accumulated into monthly heavy- and light-load pricing.

Idaho Power is proposing no changes to this methodology as it is currently implemented for its Idaho jurisdiction. In fact, the ICIRP methodology is no more complex, and is just as easy if not easier to understand as the proxy resource methodology. The ICIRP methodology has the additional benefits of more accurately determining the utility's avoided cost for that specific QF resource, more closely matches the definition of avoided cost, and is based upon the utility's actual highest cost displaceable resources and not upon a fictitious surrogate and its associated assumptions. The ICIRP methodology would be a more appropriate methodology to utilize for ***all*** avoided cost pricing, however, the Company is asking here that it simply continue to be authorized to utilize this methodology, the same as that approved for use in its Idaho jurisdiction, for QF projects that exceed the standard rate eligibility cap.

**Q. Please summarize the parties' positions regarding Issue 8: When is there a legally enforceable obligation?**

A. Staff's position is that a legally enforceable obligation ("LEO") is established when a QF tenders an agreement that obligates it to provide power to the utility. Staff/600

Andrus/23. PGE recommends that the Commission set clear criteria for establishing affirmative obligation for a QF to create a LEO. PGE/700 Macfarlane – Morton/11. PacifiCorp proposes that the Commission set criteria for establishing a LEO using the milestone of the QF approving the final draft PPA as contemplated in B(5) on page 10 of Schedule 37, which demonstrates that the QF has provided all required contract inputs and exhibits and signed off on the final draft agreement, and commits PacifiCorp to the agreement for execution. PAC/1300 Griswold/8.

REC states that it believes its position is substantially the same as Staff's. Coalition/500 Lowe/17. CREA stated in its opening direct testimony that it would address the legal issues surrounding this issue in legal briefing. CREA/100 Hilderbrand/17.

Gardner Capital provides background from a developer perspective for the Commission regarding the issue of when a LEO is created and responds to Staff's testimony on this issue. Gardner Solar/200 Benga/2. As I stated in my response testimony, Gardner Capital provides testimony directed primarily to its dispute with Idaho Power. Idaho Power notes that Gardner Capital has a separately filed complaint proceeding pending before the Commission to resolve its issues regarding legally enforceable obligation pertaining to its initial requests for draft contracts, Case No. UM 1733; Gardner Capital's particular issues with Idaho Power are more appropriately addressed in that docket.

**Q. What is Idaho Power's position with regard to Issue 8?**

A. As stated in my direct and response testimonies, this is largely a legal issue that Idaho Power intends to address through legal briefing to the Commission. I am not an attorney and have only offered the Company's position on legally enforceable obligation from my perspective as the Company's PURPA Energy Contracts Coordinator Leader.

To a certain extent Idaho Power agrees conceptually with the principles set forth by Staff, PGE, and PacifiCorp—that absent a fully executed contract—that the QF must obligate itself to the transaction in order to obligate the utility and its customers to the transaction. This is, by necessity, going to be a fact specific, case-by-case determination that is within the sole authority and discretion of the Commission. However, to the extent that the Commission can put some "side boards" on this determination, it will offer guidance and certainty to the parties' contracting process.

A LEO determination is almost exclusively used by the QF to attempt to obligate the utility and its customers to a higher, outdated rate when avoided cost rates have—or are about to—decrease.[1] Staff and PacifiCorp recommend that the contracting process must have progressed to the point of final terms, rates, and conditions, ***and*** that the QF has signed and obligated itself to that transaction, in order to establish a LEO that obligates utility customers to the higher, outdated rates. The Texas Public Utility Commission has defined the type of obligation required by the QF in order to establish entitlement to previously-effective rates by requiring the QF to bring its facility online within 90 days of establishment of the LEO. Similarly, the IPUC has defined the obligation of the QF as requiring it to bring its project online within 365 days of the LEO determination. The IPUC imposed this 365 day definition because avoided cost rates update at least on an annual basis, similar to Oregon. In Idaho, just as in Oregon, the QF can choose an operation date in its contract that is beyond 365 from the date of contracting, however, this is much different than the unilateral establishment of a LEO that will bind customers to previously-effective avoided cost rates. Because we are assured that avoided cost rates will be updated during the

[1] As stated earlier, if prices are increasing as a result of the change, the QF will not seek the LEO to the older, lower rate but instead will elect the higher updated rate.

course of these 365 days, the QF must demonstrate its own obligation by committing to bringing its facility online within that time.

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 LEO unless and until such time as the Commission determines under the particular facts and circumstances applicable to an individual QF, that (a) but for the refusal of the utility to enter into a contract, or a purposeful delay in the contracting process, 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. 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 IPUC for establishment of a LEO under PURPA. Idaho Power and the IPUC have participated in numerous proceedings at the 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. 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. Please summarize the parties' positions 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. As I stated in my response testimony, Issue 9 stems largely from operational aspects relevant to PacifiCorp's system, and not Idaho Power. I will briefly summarize the parties' positions regarding this issue:

- Staff supports a process that reasonably estimates transmission costs for the term of a QF contract, and agrees with the need for additional transparency for QFs early in the process. Staff recommends that language be added to each company's avoided cost schedule that is specific to its situation. Staff/600 Andrus/26, 29.
- PacifiCorp acknowledges that third party transmission costs to move a QF's output from a load pocket to another load area is the responsibility of the QF, and that any costs and benefits of third-party transmission service should be attributed to the individual QF as an adjustment to the avoided cost price. PAC/1300 Griswold/11.

- REC agrees that a QF should pay third-party transmission costs to move a QF's net output from a load pocket to the utility's load, but believes the QF should be allowed to select the type of transmission, as long as it reliably meets the QF's contractual obligations. In addition, existing QFs that have been selling power to the utility should not be required to pay for third-party transmission costs that are incurred for reasons beyond the QF's control. Coalition/500 Lowe/17.
- CREA offers a host of considerations for the Commission to take into account when assigning third-party transmission costs to QFs delivering to load pockets where generation can exceed load that I will not try and summarize here. However, CREA is very concerned that the Commission will adopt what it alleges would be "discriminatory avoided cost rates in violation of PURPA by refusing to increase avoided cost rates to account for transmission costs imposed by an on-system proxy resource and reduction avoided cost rates to account for transmission costs imposed by an on-system QF." CREA/500 Skeahan/21.

**Q. What is Idaho Power's position with regard to Issue 9?**

A. As I stated in my response testimony, 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. Idaho Power's position is generally in alignment with the position of Staff, and reiterates that this cost be allocated to the QF separately from the purchase contract as part of the interconnection and network resource designation process.

**Q. Does this conclude your testimony?**

A. Yes, it does.