BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PHASE II

UM 1610

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

RESPONSE TESTIMONY OF

JOHN R. LOWE

ON BEHALF OF

THE RENEWABLE ENERGY COALITION

July 24, 2015

INTRODUCTION

Q. Please state your name and address.

A. My name is John R. Lowe. I am the Executive Director of the Renewable Energy Coalition (the "Coalition"). My business address is 12040 SW Tremont Street, Portland, Oregon 97225.

Q. Are you the same John Lowe who previously testified in Phase I and II of this proceeding?

A. Yes.

Q. What issues do you address in Phase II?

A. My testimony addresses all the remaining issues in Phase II of this investigation into qualifying facility ("QF") pricing and contracting. My Phase II testimony focuses on the following issues:

- What is the appropriate forum to resolve disputed inputs and assumptions?
- 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?
- When is there a legally enforceable obligation?
- Whether the market prices used during the resource sufficiency period sufficiently compensate for capacity?
- 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?

My testimony also reaffirms the Coalition's position and/or supports the positions of other parties on the following issues:

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

- Should the capacity contribution calculation for the 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?

Q. Before addressing each of the specific issues, do you have any overall comments?

A. Yes. There has been an unprecedented number of filings and proceedings related to the Public Utility Regulatory Policies Act ("PURPA") in this and other states. The utilities are attempting to take advantage of what may be a short-term and inflated amount of solar QF development to dismantle PURPA. My testimony assumes that Idaho Power and PacifiCorp's proposals in UM 1725 and UM 1734 to change the contract term, and reduce size thresholds are rejected. The Commission would need to revisit and revise many of the issues under consideration in this proceeding if any aspect of Idaho Power's and PacifiCorp's requests are approved.

<u>APPROPRIATE FORUM FOR DISPUTED AVOIDED COST INPUTS AND ASSUMPTIONS</u>

Q. Why is this issue important for the Coalition?

A. The avoided cost inputs and assumptions determine the prices that QFs are paid for their power sales to Oregon investor owned electric utilities. It is critically important for the economic survival of QFs that these prices be accurately set so that they are appropriately paid for all of the capacity and energy that they provide to the utilities. Similarly, avoided cost rates need to be accurately set to ensure that ratepayers are held harmless when a utility purchases power from a QF instead of building its own generation resources. Given the importance of accurately setting the avoided cost rates, there should be a forum for QFs, Staff, and other interested parties to address and challenge avoided cost rate inputs and assumptions.

Q. Please summarize the testimony of the parties you are responding to regarding this issue.

A. There are a variety of different proposals regarding how the inputs and assumptions should be reviewed and approved. On one side are Staff, Oregon Department of Energy ("ODOE"), the QF parties, and Portland General Electric Company ("PGE") that believe there needs to be an opportunity to review, challenge, and obtain Commission resolution of avoided cost rate issues. These parties disagree about when and where avoided cost rates should be addressed, but they all agree that they should be an opportunity to dispute what inputs and assumptions the utilities decide to use. On the other side are PacifiCorp and Idaho Power, which to greater or lesser degrees, believe that there are some issues that Staff, QFs, and other interested parties should not have the ability to address or challenge, at least before the avoided cost rates go into effect.

The parties positions on this issue are:

- Commission Staff: All inputs and assumptions should be reviewed in a compliance filing after the annual update or Commission acknowledgement of a utility's integrated resource plan ("IRP"). Staff/500, Andrus/25-26.

- ODOE: All inputs and assumptions should be reviewed in a separate proceeding that runs parallel with (meaning at the same time as) the utility's IRP. ODOE/700, Carver/5-6.

- Idaho Power: Certain inputs and assumptions should be reviewed in a separate PURPA proceeding, and there should not be any substantive review in an IRP or compliance filing. Assumptions and inputs that have never been reviewed by the Commission should not be subject to challenge in a compliance filing, but interested parties should be required to file a separate application, petition, or other pleading to these challenge inputs or assumptions after avoided cost rates change. Idaho Power/900, Allphin/4-6.

- PacifiCorp: Inputs and assumptions should be based on the utilities' acknowledged IRP, but parties should not have the ability to challenge and obtain a Commission decision on the reasonableness of any inputs or assumptions. The utility and not the Commission ultimately sets the avoided cost rates. PAC/900, Drennan/12.

- PGE: Inputs and assumptions should be based on the IRP; however, parties should have the opportunity to challenge them in a subsequent proceeding. PGE does not identify the standard upon which the Commission would rule on disputed inputs and assumptions, including the importance of consistency or inconsistency with the inputs and assumptions used in the IRP. PGE/500, MacFarlane-Motion/8.

- Community Renewable Energy Association ("CREA"): 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. CREA/500, Skeahan/14-15.

- REC: 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. A separate proceeding at the time of the IRP is preferable, but an expanded post-filing compliance proceeding is also acceptable if properly structured. Coalition/500, Lowe/16-17.

Q. Are any of the proposals by the other parties acceptable?

A. Yes. Staff and ODOE have made the most clear and specific proposals, both of which could ultimately provide interested parties an opportunity to challenge the utilities' avoided cost rates. They meet the essential requirement that parties be provided a forum to raise their issues and obtain Commission resolution prior to the rates becoming effective.

A general approach like ODOE's that reviews the avoided cost rates in a separate proceeding at the same time as the IRP is the best solution. ODOE's recommendation would reduce the possibility that there will be inconsistency between avoided cost rates and the IRP. Even if there is no legal presumption of reasonableness, the Commission may be reluctant to issue an order in avoided cost rate proceeding that is different from what the utility included in an acknowledged IRP. Also, reviewing the avoided cost inputs and assumptions in a separate proceeding would reduce the time needed to review the actual avoided cost rate filings, which would result in more expeditious proceeding of compliance filings.

Staff's approach is also acceptable, but the importance of the utility's acknowledged IRP would need to be clarified. Staff's approach ensures that the utilities have the burden of proof to demonstrate the reasonableness of the inputs and assumptions, but does not explain the role of the inputs and assumptions used from an acknowledged IRP. As I explained in my opening testimony, consistency with specifically acknowledged part of the plan may be evidence in support of reasonableness when approving the avoided cost rates, but it should not be a guarantee that the rates will be approved. Consistency with the IRP should not be relevant for any aspect of the IRP that was not specifically acknowledged by the Commission. Any party should be allowed to challenge the utility's reliance on the acknowledged IRP, or the utility's deviations from the most recently acknowledged IRP.

Q. Are any of the proposals by the other parties unacceptable?

A. Yes. PacifiCorp's recommendation that inputs and assumptions from the IRP should be used, but that parties cannot review, challenge, or obtain a Commission order regarding their reasonableness is unacceptable. PacifiCorp's position is essentially that it ultimately has the unilateral choice to set avoided cost rates. This means that the Commission itself would be taken out of the process of reviewing the inputs and assumptions.

PacifiCorp's position would be a departure from Commission precedent and any reasonable public policy. The Coalition will also address in legal briefs whether PacifiCorp's approach is consistent with the law. PacifiCorp's approach that it and only it is the arbiter of avoided cost issues is an example of the utility's approach to many PURPA matters, including contract negotiation and implementation. PacifiCorp often takes extreme positions that puts QFs in the position of agreeing to unreasonable demands, or being subject to harmful delays and/or expensive litigation.

Idaho Power's proposal that parties cannot challenge certain inputs and assumptions before the avoided cost rates become effective also is unacceptable. Idaho Power recommends that inputs and assumptions that have not been reviewed in a separate PURPA proceeding cannot be challenged before the avoided cost rates become effective. Idaho Power's proposal would require parties to file their own petition or application to challenge the inputs and assumptions. While the avoided cost rates are being challenged, the QFs would need to make sales at potentially illegal prices. Avoided cost rate inputs and assumptions should never go into effect without Staff and interested parties having the ability to raise their concerns and obtain a Commission order on all disputed issues.

Q. REC recommends that minimum filing requirements be used. Do other parties address the issue of minimum filing requirements?

A. Yes. Staff also requests that the Commission require the utilities to include minimum filing requirements, and PGE states that it will provide citations to its IRP with its avoided cost rate filing. The information requested in Staff's minimum filing requirements is generally acceptable, and should be the minimum information provided with the utility's avoided cost rate filings. PGE's proposal to reference its IRP is welcome and appreciated because it can be difficult identify where specific inputs and assumptions came from. I also have been made aware that PGE generally provides well supported and detailed information in its power cost rate proceedings. PGE's proposal, however, is insufficient because the IRP is not the only source of information for avoided cost rate inputs and assumptions. In addition, simple citations may not provide sufficient information to understand the basis for the input or assumption. Therefore, the minimum filing requirements attached to my opening testimony and/or Staff's should be used.

CAPACITY VALUE DURING THE RESOURCE SUFFICIENCY PERIOD

Q. Do the resource sufficiency prices adequately compensate QFs for the capacity value they provide to the utilities and ratepayers?

A. No. Kevin Higgins addressed this issue for the Coalition and other QF parties in opening testimony. The utilities and Commission Staff propose to maintain the current avoided cost rate methodology that only pays QFs the value of market purchases, rather than the full capacity value that QFs provide to the utilities and ratepayers. For example, PacifiCorp witness Brian Dickman supports setting resource sufficiency prices solely on market purchases. PAC/800, Dickman/14-16.

Q. Do you agree with Mr. Dickman that PacifiCorp will only rely upon market purchases for its capacity needs during the sufficiency period identified in its IRP?

A. No. As explained in the Coalition's opening testimony, PacifiCorp will also be relying upon QFs to provide capacity, and will be making expensive investments in retaining its existing thermal plant capacity. For example, PacifiCorp is currently planning on the availability of 255 MWs of QFs to meet its system peak. PacifiCorp 2015 IRP at 62. These QFs have been causing, and those that renew their contracts will continue to cause, PacifiCorp to avoid capacity costs. Not paying capacity to these existing QFs contributes to the risk of more capacity being needed if projects do enter into new PPAs following the expiration of their current contracts.

PacifiCorp's approach also fails to recognize that its current IRP plans to acquire a new combined cycle combustion turbine in 2027 or 2028 is likely to be inaccurate (2013 IRP Update and 2015 IRP). PacifiCorp's planned resource acquisitions have historically been inaccurate, especially during the longer-term. For example, in 2008

PacifiCorp did not "plan" on acquiring a new thermal resource until 2012. However, PacifiCorp acquired the 520 MW Chehalis plant in 2008. PacifiCorp's resource needs identified in its current IRPs may be even more inaccurate. PacifiCorp's actual resource acquisitions could significantly change if its IRP assumptions prove inaccurate, including but not limited to: 1) changes in Washington's or Oregon's renewable portfolio standard ("RPS"); 2) PacifiCorp joining the California Independent System Operator; 3) the adoption of a federal RPS; 4) adoption of a state or federal carbon tax; 5) the adoption of EPA's Section 111(d) rules; 6) closure of part or all of coal generation facilities; 7) the inability to capture the high levels of demand side management; and 8) the lack of availability of power in the wholesale market. Most of these policies could result in a reduction in coal generation, and an increase in renewables, baseload gas, and peaking gas generation well before 2027. Therefore, PacifiCorp is likely to acquire significant capacity resources during its alleged resource sufficiency period.

Q. Has PacifiCorp raised similar arguments in other states?

A. Yes. PacifiCorp has made similar proposals to regarding resource sufficiency prices in many of the states that the company operates. For example, PacifiCorp's avoided cost rates in Washington currently include a kilowatt hour energy rate and a kilowatt month capacity payment. On behalf of PacifiCorp, Mr. Dickman is proposing to eliminate the kilowatt month capacity payment, and only pay QFs energy rates in Washington.

The Washington Utilities and Transportation Commission ("Washington Commission") staff strongly opposes PacifiCorp's proposal. The Washington Commission Staff points out that during the resource "sufficiency" period as defined by PacifiCorp, the company is in fact capacity deficit and will acquire capacity. The

Washington Commission Staff also recognizes that PacifiCorp plans on existing QFs renewing their contracts and providing capacity that they are not compensated for. Relying upon information provided by the Northwest Power and Conservation Council, the Washington Commission Staff also criticizes PacifiCorp for reliance upon the wholesale power market. The Washington Commission Staff notes that the Northwest Power and Conservation Council proposes a market premium risk adjustment for valuing conservation resources because of concerns regarding the resources available in the wholesale market. Ultimately, the Washington Commission Staff proposes that capacity during the alleged resource sufficiency years should be based on Washington's methodology for valuing incremental capacity for the purposes of the Washington RPS reporting. The Washington Commission Staff proposes a $4.58 kilowatt month capacity payment, which is an increase from the current about $2.50 Washington kilowatt month capacity payment. This proposal results in a larger capacity payment than Kevin Higgins has recommended in this proceeding.

THE MOST APPROPRIATE METHODOLOGY FOR CALCULATING NON-STANDARD AVOIDED COST PRICES

Q. Why is this issue important for the Coalition?

A. The Coalition believes that the avoided cost rates for all QFs, including those above 10 MWs that must negotiate their rates, be just and reasonable for both the utility and the QF.

Q. What are the positions of the other parties on this issue?

A. Staff and the utilities recommend that each utility be allowed to select an their own methodology to set negotiated avoided cost rates. Therefore, PGE would continue to use the current Commission approved process for negotiating avoided cost rates that starts with the utility's approved rates for smaller QFs and adjusts them using specific Commission-approved factors. PacifiCorp and Idaho Power, however, would be able to use their own computer models to calculate large QF avoided cost rates. Staff supports this approach on the grounds that the utilities' power cost models have been successfully used in rate cases. PacifiCorp supports this approach because it will be able to use the computer modeling approach set the avoided cost rates will be lower than the current Commission-approved approach. Idaho Power supports this approach because it is what is used in its Idaho jurisdiction.

Q. Do you agree with PacifiCorp?

A. No. As explained in my testimony in both Phase I and II, and Don Schoenbeck's testimony in Phase I, PacifiCorp should not be allowed to use its computer model to set avoided cost rates for large QFs. PacifiCorp's proposal will not result in more accurate avoided cost rates, but will instead increase costs (and a variety of other problems including potential complaints) during an already difficult and complex negotiating process.

This responsive testimony only addresses new issues identified by PacifiCorp in Phase II. For example, Mr. Schoenbeck's earlier testimony refutes PacifiCorp's biased and inaccurate comparison of the differences in standard avoided cost prices and its computer model. The fact that experts cannot even reach agreement regarding how the computer model would adjust avoided cost rates in an investigation that has lasted for years demonstrates how difficult using the computer model can be. Adopting PacifiCorp's approach will result in QFs either simply accepting inaccurate avoided cost rates, or expending considerable resources investigating and challenging PacifiCorp's decision and assumptions.

As previously explained in testimony, the Federal Energy Regulatory Commission ("FERC") has identified seven factors that may be taken into account when setting avoided cost rates, and the Commission adopted a method to account for these factors in Order No. 07-360. Negotiated rates for large QFs start with the standard avoided cost rates for smaller QFs, with adjustments based on Commission approved methodologies or contract provisions to account for these factors. PacifiCorp disagrees with this approach, and wants to use its power cost model to estimate the value of these seven factors and other potential adjustments. The justifications provided by Staff witness Lisa Schwartz and adopted by the Commission in Order No. 07-360 to not use a computer model are even more relevant today when PacifiCorp is doing everything in its power to legislatively repeal or administratively neuter PURPA.

Q. PacifiCorp states that it should be allowed to make adjustments related to issues not on FERC's list of seven factors. PAC/800, Dickman/21. Do you agree?

A. No. First, in UM 1129 when the Commission adopted its current approach, Staff's legal position was that the seven factors identified by FERC was an all inclusive list and that other factors could not be taken into account. E.g., Staff's Opening Brief Phase II, Track II at 15. Second, allowing PacifiCorp the opportunity to create new factors to lower avoided cost prices without the Commission's review and approval of how those factors will impact avoided cost rates simply provides the company with too much discretion.

Q. PacifiCorp states that only two of the seven FERC factors are accounted for. PAC/800, Dickman/20-21. Do you agree?

A. No. Order No. 07-360 addresses most of these factors through modeling adjustments or contract provisions. The only two factors not accounted for by Order No. 07-360 are: 1) the individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and 2) the smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities. Both of these factors should increase rather than decrease avoided cost rates, and the Commission allowed the QF and utility to account for these factors if they could agree upon a practical and reasonable way.

Q. PacifiCorp states that it should be allowed to use as current as possible information to update whatever inputs and assumptions it desires when using the computer modeling approach, including inclusion of proposed QF PPAs. PAC/800, Dickman/23-26. Do you agree?

A. No. The same reasons for allowing limited annual updates support requiring PacifiCorp to only use Commission-approved or acknowledged inputs and assumptions, plus the limited set of factors (gas and market prices forecasts, and updated information about the production tax credit). Annual updates, plus a potential additional update after acknowledgement of an IRP allows frequent avoided cost rate changes. Annual updates also ensure that parties have an opportunity to review and the Commission an opportunity to approve the inputs and assumptions used in setting avoided cost rates. Similar policies should apply to setting large QF avoided cost rates, regardless of whether they are part of a computer model or the Commission’s current approach.

Parties and the Commission will not have the ability to independently review unproven changes, inputs, and assumptions, including whether the company’s forecast of proposed QF PPAs is reasonable. Referencing testimony in its UM 1734 filing, PacifiCorp justifies updating for proposed QF PPA because it has received a large number of new solar QF PPA requests and has entered into a large number of QF contracts. PAC/800, Dickman/23-26. In UM 1734, Obsidian Renewables witness David

Brown demonstrated that few QFs that request PPAs or even enter into PPAs actually are constructed. Mr. Brown's specific numbers match my experience in that the attrition between QF contract or pricing requests and operational projects under contract is extremely high. Therefore, PacifiCorp should not be allowed to reduce avoided cost rates based on inflated numbers of possible QFs that are unlikely to ever generate electricity. This is an example of, if allowed to use its computer model, PacifiCorp will creatively attempt to think up new factors that will result in lower avoided cost rates below its actual avoided costs.

Q. Do you agree with Staff on allowing PacifiCorp to use its computer model?

A. No. Staff supports allowing PacifiCorp to use a computer modeling approach because it could be more accurate, and that PacifiCorp's computer model has been reviewed and vetted in rate cases. Staff/500, Andrus/34-35. This is a change in Staff's position, because in UM 1129 Staff recommended that each avoided cost rate adjustment factor be specifically identified using a Commission-approved methodology to facilitate and prevent abuse in the negotiation process.

While I am not an expert in computer models, Staff's reference to the use of computer models in utility rate cases supports continuation of the current approach and not using those models to set avoided cost rates. First, PacifiCorp's computer model was designed to estimate power costs, and not set avoided cost rates for a specific project. Second, PacifiCorp's computer model has been subject to frequent litigation with modeling adjustments proposed by Staff and intervenors. Intervenors have retained (sometimes with intervenor funding) expensive experts to review and analyze the computer model. PacifiCorp has only two large QFs above 10 MWs in Oregon, and the risk of potentially inaccurate avoided cost rates does not warrant the additional expense and controversy in the avoided cost negotiation process.

Q. Do you agree with Idaho Power on this issue?

A. I do not oppose allowing Idaho Power to use the approach that it currently uses in Idaho. The Commission has at times treated Idaho Power differently from PacifiCorp and PGE because its Oregon operations are a small portion of its overall service territory. Specifically, the Commission previously allowed Idaho Power to use its own computer model to set large QF avoided cost rates and in UM 1129 the Commission held that "Idaho Power, however, may use the modeling methodology approved by the Idaho Public Utilities Commission for deriving avoided costs that serve as the starting point for negotiations with large QFs under a legally enforceable obligation." Order No 07-360 at 13. In addition, Idaho Power does not have any QFs above the current size threshold for standard contracts and rates, so this issue may be purely academic as it relates to Idaho Power (assuming the Commission rejects Idaho Power's request to lower the size threshold for wind and solar in UM 1725). If the Idaho Public Utilities Commission, however, approves changes in the company's current modeling approach, Idaho Power should be required to obtain approval to use the new model in Oregon. The Commission should not delegate complete responsibility for the methodology for setting large QF avoided cost rates to another regulatory body.

<u>WHEN IS THERE A LEGALLY ENFORCEABLE OBLIGATION?</u>

Q. Why is this an important issue for the Coalition?

A. With annual avoided cost filings this issue is may be even more significant than when there were fewer avoided cost fillings. With annual filings there simply is no time for delays in the contracting process without potentially subjecting a proposed project to superseded and often lower prices.

Since utilities often delay the negotiation process, request unreasonable information, or impose unduly burdensome requirements they can use this shorter filing cycle in conjunction with uncertainty over when a legally enforceable obligation is created to their advantage. The utilities can also be openly hostile to QF development because they do not earn a return on power purchases from third parties. Small QFs are often taken advantage of because they rarely negotiate these types of contracts, and have limited knowledge of PURPA, avoided cost matters, and power markets. The Commission needs to ensure that there are fair and balanced policies to protect QFs, and the right of a QF to legally obligate itself to sell power at then current avoided cost rates is a necessary tool to prevent utility abuses.

My previous testimony in Phase I and II, and Don Schoenbeck's testimony in Phase I addressed this issue and has rebutted most of the arguments raised by the utilities in Phase II. Essentially, the utilities want to continue to have the right to delay the negotiation process without allowing QFs to enter into a legally enforceable obligation. This testimony responds to new arguments raised by Idaho Power and Staff.

Q. Idaho Power proposes that a QF cannot legally obligate itself unless it can deliver the power in 365 days. Idaho Power/900, Allphin/9. Do you agree?

A. Absolutely not. This is a thinly veiled proposal to prevent most QFs from entering into a legally enforceable obligation. Both new and existing QFs often need to upgrade and invest in interconnection and/or network upgrades to be able to sell their electricity. The interconnection process can take well over a year. For example, PacifiCorp recommends that a QF plan on at least a year and a half to complete the process. Delays can cause the process to last even longer. QFs often must first enter into a PPA to obtain financing for both the interconnection and facility construction. This means that the end of the interconnection process and actual commercial operation date is not known until after the PPA is signed. Therefore, the QF may not know if it can, or be physically able to deliver power, in one year when it is ready to legally obligate itself to sell power. Essentially, Idaho Power is proposing a condition precedent to obtaining a legally enforceable obligation that is simply impossible for many QFs to meet.

I agree, however, that there should be some limitation on when a QF can enter into a legally enforceable obligation. Earlier in Phase II of this proceeding, the active parties agreed that a QF should have a reasonable amount of time before contract execution and commercial operation date. The parties agreed that QFs should have the right to select a period of up to three years, with the possibility of additional time. In the brief in support of the stipulation, Staff explained that allowing too little time between contract execution and delivery can create a barrier for QFs because they "generally cannot obtain financing for a new project until after they have executed a PPA. This means that QFs must wait for execution of a standard contract before commencing many of the steps that are necessary to bring a resource on line." Brief in Support of Stipulation at 3. This also applies to existing projects, especially those that need to re-invest in interconnection and generation technology. In this situation I see no substantive difference between a legally enforceable obligation and a contract execution, and a QF should be to commit itself via a contract or legally enforceable obligation three years before power deliveries are scheduled to occur, and potentially longer under unique circumstances.

Q. Staff proposes that a legally enforceable obligation can be entered into if a utility does not meet all deadlines in the contract negotiation process. Staff/500, Andrus/41. Do you agree?

A. Yes. Staff's recommendation that a QF can show it has legally obligated itself if the utility has not meet all the deadlines is reasonable and consistent with my recommendation. Staff's proposal also requires the QF to provide the information required by the utility's tariff or standard form contract. While not entirely clear, I interpret this as allowing the QF to create a legally enforceable obligation if the utility requests information, or proposes contract changes that are unreasonable. Therefore, I believe Staff and the Coalition's positions to be substantially the same.

<u>HOW SHOULD THIRD-PARTY TRANSMISSION COSTS TO MOVE QF OUTPUT IN A LOAD POCKET BE CALCULATED AND ACCOUNTED FOR?</u>

Q. Why is this issue important for the Coalition?

A. The Commission has ruled that QFs should be responsible for third party transmission costs to move a QF's net output from a load pocket to the utility's load. While I agree that a QF should pay these costs, there is a wide variety of options to move this power and the QF should be allowed to select the type of transmission, as long as it reliably meet's the QF's contractual obligations. In addition, existing QFs that have been selling power to the utility, and that the utility has planned on their continued operations should not be required to pay for third party transmission costs that are incurred for reasons beyond the QF's control.

The issue primarily impacts PacifiCorp, and PacifiCorp's testimony on this issue is very disappointing in the paucity of information provided. The Commission directed the parties to propose a method "to calculate and assign the third-party transmission costs that are attributable to the QF." Order No. 14-058 at 22. PacifiCorp, however, focused its testimony on discussing why the QF should pay for third party transmission costs and explaining its practices. Although it is not entirely clear, PacifiCorp appears to want to require QFs to use only the most expensive option for obtaining third party transmission costs: long term firm point to point transmission ("LTF PTP"). In addition, PacifiCorp ignored the issue of third party transmission and costs for existing QFs when entering into a replacement PPA, a key issue for the Coalition. The CREA was the only party that made specific and concrete proposals on this issue, and I largely agree with their recommendations. I also respond to broad points raised by the ODOE and the Commission Staff on this issue.

Q. Do you agree that PacifiCorp should always purchase LTF PTP to transmit a QF's net output to load?

A. No. PacifiCorp admits that there are more cost effective options for QFs. PAC/1000, Griswold/26. Load pocket issues may only occur during certain times of the year, and there is no need to require a QF to pay for expensive transmission for the entire year to only address a limited and discrete problem. This could include a use of facilities agreement with Bonneville Power Administration, and/or conditional or short term firm transmission. Alternatively, a QF should be able to agree to limited curtailment of power deliveries for those few events in which generation exceeds load in the load pocket. A QF should have the option of using LTF PTP, but not required to do so when other alternatives are available. These recommendations are consistent with those presented by CREA and ODOE. CREA/500, Skeahan/23-24; ODOE/800, Broad/12.

Q. Do you agree that the costs of third party transmission should be set at the time the PPA is entered into?

A. No. PacifiCorp appears to be proposing that the specific allocation of third party transmission costs should be resolved at the time of contract execution. PAC/1000, Griswold/21-22. The existence and amount third party transmission costs, and options to address the need to transmit the power, may not be known or capable of calculation until after interconnection and transmission studies have been completed and negotiations with third party transmission owners entered into. Therefore, the standard contract should require the QF to pay for third party transmission costs, but provide the QF with the option to select the specific method after the costs and need for third party transmission are determined.

Q. Does Staff address the load pocket issue?

A. Only briefly. Staff appears to be planning on reviewing the specific proposals by the parties and making a recommendation or proposal later in the case. Staff/500, Andrus/42. Staff, however, recommends that the utility be required to provide specific and detailed information regarding the load, generation, and transmission capacity values used, and the basis for calculating the amount and cost of third party transmission. Id. CREA also proposes specific informational needs and requirements by PacifiCorp to provide information to QFs. CREA/500, Skeahan/21-22. I agree with these recommendations, and they should be expanded. The utility should be required to provide this information not only in the contract negotiation process, but also during the contract implementation process. Disputes may occur after contracts are signed, and the QFs should have the right to verify the need and costs of any third party transmission acquired (or that may be acquired) on its behalf.

Q. Do you agree with ODOE's recommendation that load pocket costs be updated as changes occur? ODOE/800, Broad/17-21.

A. Only if it is an option. A QF should be able to agree to short term arrangements that are updated as third party transmission costs increase or decrease. Some QFs, however, desire certainty or need know their costs in order to obtain financing, and should have the right to enter into long-term contracts with a reasonable estimate of expected third party transmission costs. In addition, the issues related to the dynamic changes to the existence of a load pocket remain unaddressed. Load additions or reductions as well as generation addition or reductions impact on party obligations, processes, and notices could create significant problems.

OTHER ISSUES

Q. Do you have a position on the remaining issues in the case?

A. Yes. The remaining issues in the case include who owns the Green Tags, avoided transmission costs for the proxy resource, and capacity contributions. As explained in my opening testimony, the QF should own Green Tags during the last five years of a PPA in which the QF is only paid market prices. In addition, the Coalition supports the positions of Staff and the QFs on the issue of capacity contributions, and the position of other QFs on the issue of avoided transmission costs for proxy resources. These issues have been adequately developed in the testimony of other parties, and there is no need for additional responsive testimony on behalf of the Coalition on these issues.

CONCLUSION

Q. Does this conclude your testimony?

A. Yes.