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	)

OPENING TESTIMONY OF

JOHN R. LOWE

ON BEHALF OF

THE RENEWABLE ENERGY COALITION

May 22, 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 of this proceeding?

A. Yes. My position and job responsibilities have not changed.

Q. On whose behalf are you appearing in this proceeding?

A. I am testifying on behalf of the Coalition.

Q. What are the Coalition's interests in this proceeding?

A. As explained in my testimony in Phase I, the Coalition's members own and operate non-intermittent qualifying facilities ("QFs") in the five states of Oregon, Idaho, Washington, Utah, and Wyoming. Many of the Coalition's members are non-profits while others are small companies and individuals. The revenues obtained from power sales by the Coalition's members are typically reinvested and provide benefits to their local communities.

The Coalition's primary goal is to ensure fair and reasonable contract terms, conditions, processes, and avoided cost rates for all projects and ratepayers. The Coalition recognizes that PURPA must work to benefit all interested parties, including the utilities, ratepayers, and new and existing QFs of various sizes.

The Coalition's interests in this proceeding include assuring that the unique interests of existing projects are considered. Existing QFs are those projects that are producing and selling power to the interconnected utility. Some of these projects have been operating since the mid 1980s, and most are small hydroelectric projects. These existing projects face many of the same difficulties associated with new projects, including unexpected avoided cost rate changes, low prices, one-sided standard contract terms, etc.

Existing QFs also face some unique challenges that are often not adequately considered since most regulatory revisions to PURPA at the state level occur with a new project perspective. Existing projects must enter into a replacement power purchase agreement ("PPA") when their current PPA expires. This always means that their new PPA starts during a term that includes an initial and sometimes extensive period of very low resource sufficiency period prices. Most existing projects have been operating for years, and may require upgrading of their equipment and facilities, including interconnections. New interconnection agreements are often required. There can be significant costs involved in addressing these needs or requirements. Throughout this testimony, I point out some of specific problems facing existing projects, and how the Commission should take reasonable steps to ensure that they continue to operate and provide benefits to ratepayers and their communities.

Q. What issues are addressed in your testimony?

A. My testimony addresses the remaining issues in Phase II of this investigation into QF pricing and contracting. The most important issues from the Coalition's perspective are:

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

- 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 recommendations on these issues.

A. The most important aspect of the question regarding the appropriate forum to resolve disputed avoided cost rates is that parties deserve **a forum** to review and challenge the rates. The Commission should ensure that interested parties have a fair and full opportunity to address and challenge avoided cost rate inputs and assumptions. While much of the basis for avoided costs are derived from utility Integrated Resource Plans ("IRPs"), those plans typically do not address QF issues nor do they provide an adequate opportunity to do so.

Reliance upon the IRP for non-controversial inputs and assumptions may be reasonable, but the current process does not provide parties an opportunity to submit testimony or obtain resolution of key issues. The Commission should either expand the IRP process to adequately address QF issues, or limit the IRP's influence and impact upon avoided cost rates.

The market prices that are used to set avoided cost rates do not adequately compensate QFs, especially existing projects, for the capacity value they provide to the utilities. The importance of resource sufficiency pricing has increased in just the last couple years as the utilities have gone from no or short to very long sufficiency periods. Failing to fix the inaccurate resource sufficiency pricing could have major long-term impacts, including potentially shutting down some existing projects and halting the development of cost effective new QF generation.

The Commission should continue its current approach for calculating non-standard avoided cost prices. The current process uses the utilities' Commission-approved avoided cost rates for QFs 10 megawatts and under, and then allows the utilities to make specific revisions to ensure they accurately reflect project specific characteristics. The utilities have failed to establish that this process is flawed, or that using a different approach would result in more accurate avoided cost rates. In addition, the current process provides benefits to all parties because it simplifies and reduces costs during an already difficult and complex negotiating process.

A QF should be allowed to create a legally enforceable obligation after making a good faith effort to provide a utility with all reasonable information and committing itself to sell power at then effective avoided cost rates. The current contract completion process allows the utilities to impose or request unreasonable restrictions and conditions or otherwise delay the process. The process should be made more fair and balanced so that a QF is not required to agree to inappropriate or problematic terms or conditions simply to ensure that it is not paid lower avoided cost rates. I propose specific revisions to the PacifiCorp's rate schedule that will require the QF to negotiate in good faith, but allow them to "lock in" avoided cost rates if there are legitimate disputes that cannot be resolved before an avoided cost rate change is effective. Similar changes should be made to Idaho Power Company's and Portland General Electric Company's rate schedules.

I agree in principle that QFs should be required to pay for the additional third party transmission costs that they impose upon their interconnected utility, and that QFs should be paid for any transmission costs they cause their utility to avoid. Existing QFs that have been operating for years are included their utility's resource plans and are considered network resources. Therefore, existing QFs should be "grandfathered" and not be required to pay third party transmission costs that are the result of the creation of a load pocket. PacifiCorp does not appear to agree with this principle; however, the company has not made a specific proposal on this issue. I plan to provide more detailed testimony on this issue later in the proceeding.

Q. Are there issues on the Phase II issues list that you are not addressing in detail at this time?

A. Yes. There are three additional issues in this phase of the proceeding, which include:

- 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?

My testimony makes preliminary recommendations and observations on these issues, but the Coalition will review the testimony of other parties before making final recommendations.

Q. Are there other issues that you are not addressing at this time, but plan on addressing in the future?

A. Yes. The Phase I order establishing an issues list included interconnection process issues that the ALJ concluded would be addressed in Phase II. The parties in Phase II agreed that interconnection issues should be addressed in this or a separate docket following the completion of Phase II. The issues include but are not limited to whether PPAs can include conditions that referencing the timing of interconnection agreements and milestones, and whether QFs have the ability to elect a larger role for third party contractors. These are critical issues for the Coalition and its members; however, the

Coalition and other parties decided that these issues should be addressed at a later date.

Another issue is that Oregon's administrative rules regarding PURPA are outdated and need to be revised. The parties have agreed that these rules should be revised after the Commission establishes its PURPA policies in Phase II. Again, these are important issues, but should be addressed later.

It makes more sense to revise the PURPA rules and interconnection standards after the Commission and the parties have had the benefit of a final order regarding these Phase II issues.

Finally, Idaho Power and PacifiCorp recently made filings to radically alter the Commission's policies regarding contract term and size threshold for eligibility for standard rates. As these filings were only recently made, I am not addressing them in this testimony; however, I may address them in a subsequent round of testimony.

Q. Are there any other witnesses testifying on behalf of the Coalition?

A. Yes. Kevin Higgins is testifying on behalf of the Coalition, as well as the Community Renewable Energy Association, Obsidian Renewables, and OneEnergy. Mr. Higgins is addressing the issue of whether avoided cost prices during the sufficiency period adequately compensate QFs for the capacity value they provide to the utilities.

Q. Do you have any observations regarding PURPA issues in the Northwest at this time?

A. Yes, although this could be a lengthly commentary, I will limit such commentary to one single observation. In the past fews years the utilities have been exposed to rising tide of PURPA obligations potentially, according to them, creating both operational concerns and significant ratepayer cost exposure. The result has been a constant proliferation of state regulatory proceedings for several years, primarily in Idaho and Oregon, in which the utilities have attempted to minimize the claimed or potential damages. In addition, the attack on PURPA in the Northwest has now risen to the federal level with utility efforts to set aside the basic PURPA purchase offer obligation. Regardless of their intentions, this broad sweeping effort is having a negative impact on a large number of local community based existing projects whose continued existence may be at risk. Efforts by interested parites going forward would be well-served to correct the implementation of PURPA, rather than allow approaches and policies that have the practical impact of eliminating it.

APPROPRIATE FORUM FOR DISPUTED AVOIDED COST INPUTS AND ASSUMPTIONS

Q. How frequently are avoided cost rates set?

A. My understanding is that Oregon law requires updates every two years. Current Commission policy allows the utilities to file after the Commission acknowledges the utility's IRP, and to file an annual update each May 1. This results in at least annual updates, and can result in two updates during a single year when the IRP has been acknowledged. Also, while the Commission has stated it disfavors further updates, the utilities can (and in the past have) filed additional updates. Therefore, the Commission's current policy allows more frequent updating of avoided costs than required by law and the Commission's past practices.

The Coalition supports updating avoided costs on an annual basis to ensure that the rates are accurate, and to reduce the incentive for the utilities to file updates at times other than scheduled in the Commission's rules and policies. QFs often plan their interconnection and contract negotiation process based the Commission established schedule for avoided cost updates, and unplanned updates can cause significant harm to the QFs. In addition, unplanned updates can result in unnecessary and costly litigation that diverts the parties and the Commission from more important business.

Q. What is the current manner in which avoided cost rates are set?

A. Avoided cost rates are based on inputs and assumptions that are drawn from the utilities' IRPs, gas and market price forecasts, methodologies approved by the Commission, and other factors. After the utilities' file avoided cost rates, the rates typically go into effect without interested parties having an opportunity to challenge the inputs, assumptions, or methodologies. The utilities control the entire process of developing inputs and assumptions, and there is little to no opportunity for QFs or the Commission to determine if the rates are just and reasonable or accurately represent the utilities' avoided costs.

Q. Please describe your understanding of the substantive standards for setting avoided cost rates?

A. I am not a lawyer; however, I have worked in this industry my entire career and I am familiar with the Commission's policies and obligations.

- First, avoided costs are supposed be the additional cost to an electric utility of energy and capacity that the utility would generate itself or purchase from another source but for purchasing power from a QF. Essentially, avoided cost rates are supposed to be the costs that the utility would incur if it did not purchase power from the QF.

- Second, avoided cost rates can be tailored to the operational characteristics of the QFs. For example, Oregon has a standard renewable avoided cost rate, adjusts the capacity payment under standard rates during the resource deficiency period for intermittent resources, and has specific negotiation factors for QFs above 10 MWs. Idaho also ensures that existing QFs that renew their contracts are paid for the capacity they provide to the utility during the sufficiency period.

- Third, the avoided cost rates paid to QFs must be "just and reasonable" to both QFs and ratepayers.

- Fourth, the rates paid to QFs must be sufficient to encourage the production of generation, which means that they can be no lower than the utility's avoided costs.

Q. Are there problems associated with relying upon the IRP to determine the inputs and assumptions for avoided cost rates?

A. Yes. The main problems are that the IRP does not: 1) discuss or focus on QF or avoided cost issues; and 2) provide an opportunity to challenge inputs or assumptions that will directly affect avoided cost prices.

Q. What is the purpose of an IRP?

A. A utility's IRP proceeding evaluates the utility's resources considering risk and uncertainty in order to create a portfolio of resources that best forecasts the expected costs and risks for the utility and its customers. The end result of the IRP is an "action plan" that must be consistent with the long-range public interest.

The purpose of this plan is not to establish, and generally does not even discuss or mention, avoided cost rates. QFs are generally only mentioned in terms the utility's existing resource portfolio, and there is no consideration or evaluation of the impact that the IRP will have on QFs and avoided cost rates. Therefore, the key components and issues in the IRP that will have a direct impact on avoided cost rates are typically not addressed by the utility or the Commission during the development or review of the IRP.

Q. Can you provide an example of an important QF issues that are not considered in IRPs?

A. Yes. One of the most important aspects of avoided cost rates is the change from a resource sufficiency to resource deficiency period. Resource sufficiency is when the utility is considered to have sufficient resources to meet its needs without building new capital intensive thermal or wind generation. Resource sufficiency avoided cost rates are based on market purchases. Resource deficiency is when the utility next plans to build new thermal or wind generation. Resource deficiency avoided cost rates are based on the costs of a new thermal or wind generation resource, and are typically higher than resource sufficiency prices.

Currently and in the past the price differential between resource sufficiency and deficiency prices was large; however, there were short or no resource sufficiency periods. For example, PacifiCorp has had periods of no resource sufficiency and past periods could be just a few years. Coalition/401, Lowe/1 (PacifiCorp Supplemental Response to REC data request ("DR") 3.1); Coalition/402, Lowe/3 (Excerpt from PacifiCorp Brief in Docket No. UM 1129). Currently, however, by the use of wholesale market purchases and aggrressive demand side management targets, PacifiCorp's resource sufficiency periods extends until 2024, and they are proposing a sufficiency period of 2028 in their 2015 IRP. PacifiCorp 2015 IRP at 2 (showing a 2028 sufficiency period). Therefore, in the past QF avoided costs had only a few years of very low prices, and now they may experience extremely long periods of very low prices.

The Commission's current policy is to use the IRP to establish the resource sufficiency and deficiency demarcation. The IRP, however, only formally acknowledges an Action Plan that is only a few years out, and does not focus on the more distant years. For planning purposes, there is no need to accurately identify whether the utility will acquire a new thermal resource in 2024, 2026 or 2028 because all the years are outside of the Action Plan. All parties acknowledge that there is considerable uncertainty in the years outside of the Action Plan. The utility will complete a new IRP well before it has to make a decision regarding new resource acquisitions. This makes sense as a pure planning document because it provides the utilities with flexibility to change their resource acquisition decisions. This approach does not waste the Commission's or stakeholder time in precisely setting a specific resource acquisition date that will be irrelevant for planning purposes.

However, accurately identifying the resource sufficiency and deficiency demarcation has a huge impact on avoided cost rates. When resource sufficiency periods were short, the impact of inaccurate resource sufficiency and deficiency demarcations was less important. While the difference between a 2024 and 2028 resource sufficiency and deficiency demarcation can be almost irrelevant for planning purposes, there is a huge impact on QFs and can make the difference between an economic and uneconomic project.

This is especially true when put in context with the term of contract allowed for fixed published prices. QFs are able to enter into contracts with fixed prices for fifteen years. If the sufficiency period extends to about fifteen years, then QF contracts will only receive a couple to no years of capacity payments. Since the QFs do not receive capacity payments when they renew their contracts, this means that they may **<u>never</u>** receive capacity payments, even though they will actually provide capacity to the utilities.

It is likely that the utilities' current long resource sufficiency periods will prove to be even more inaccurate than in the past. Long term utility resource planning is inherently risky, especially when there is not rigorous analysis to support the later dates. We are in a very uncertain time with the future of carbon regulation. It is questionable that PacifiCorp will be able to maintain its existing coal fleet. While it is appropriate for PacifiCorp to retain flexibility in its long term planning given the uncertainties of carbon regulation, it is inappropriate to set avoided cost rates based on resource sufficiency periods that are very likely to be erroneous.

Q. Are there more examples of important inputs and assumptions that are set in the IRP that are important for QFs?

A. Yes. There are numerous critical assumptions in the IRPs, including gas price forecasts, forward market prices, availability of tax credits, resource capacity values, etc. The assumptions and inputs selected by the utilities can sometimes have a very small impact on the Action Plan and do not warrant careful review for planning purposes, but can have major impacts on avoided cost rates. Gas price forecasts used for avoided cost prices determination, for example, are similar to those used for planning purposes. This is because of the desire to have consistency between the IRP and avoided cost prices. Despite this attempt to be consistent, and granting that there are some discussions of gas prices in the planning process, ultimately the utility has complete control over which gas forecast is used in the plan and subsequently in avoided cost pricing.

Q. Does the current IRP process provide stakeholders an opportunity to challenge and obtain a Commission decision on these critically important issues?

A. No. First, the IRP is developed by the utility, which controls all the assumptions and inputs. Stakeholders are provided some opportunity to comment and make suggestions, but ultimately the utility controls the entire process. The second key aspect is that it is not a contested case in which parties can submit testimony, challenge evidence, or obtain a Commission resolution of key issues.

The current IRP process is appropriate to develop the utility's plan for future resource acquisitions. This process, however, does not provide interested parties an opportunity to challenge or obtain any resolution regarding key issues that will impact avoided cost rates.

One example of this is the issue of the capacity value of solar resources. This is a good example because I do not have an opinion regarding what the correct solar resource capacity value is. In a number of proceedings, parties have claimed that the value of PacifiCorp's solar capacity is too low. The issue was raised in PacifiCorp's last IRP and the plan was acknowledged without resolution of the solar capacity issue. This resulted in the current avoided costs based on an input that was controversial, but was never ruled upon by the Commission. PacifiCorp is now proposing a higher solar capacity value in its current IRP. Therefore, the current avoided cost rates include the lower solar capacity value that both PacifiCorp and the solar QFs agree is too low. I do not know which capacity value is correct, but parties should have the ability to review and obtain Commission resolution of these types of issues before avoided cost rates go into effect.

Q. Will these issues become bigger problems in the future?

A. Yes. As explained above, longer sufficiency periods, use of capacity values, production tax credits, and gas price forecasts are all issues that will be more important than in the past because changed assumptions can result in significantly different rates. Simply put, the longer the resource sufficiency period, the more significant some these issues become and must be considered in context with other PURPA implementation policies, such as contract term and levelization of prices.

Q. How can these problems be remedied?

A. There are two options. First, the Commission could expand the IRP process to include all reasonable considerations of QF issues and so that parties have an opportunity to challenge the assumptions and inputs related to avoided cost prices. Second, the Commission could de-link planning issues that are not fully vetted and prevent them from being a foundation for avoided cost prices. The second solution should be combined with a longer and automatic post-filing proceeding to review avoided cost updates.

Q. Please explain what you mean by an expanded IRP process.

A. The Commission could allow interested parties to review, formally challenge, and obtain resolution of avoided cost rate inputs and assumptions within an IRP docket, or in a separate and parallel proceeding. By parallel and separate proceeding, I mean a docket that has the same schedule as the IRP Commission review process, but would be limited to obtaining Commission resolution of only those major issues that result in a change in avoided cost rates. Many issues in the IRP have no impact on avoided cost rates, and the Commission would not need to resolve any issue that does not change the prices. For example, this would include resolution of the resource sufficiency periods, but not transmission investments unrelated to avoided cost prices.

An expanded IRP process has the advantage of relying upon an existing process that is already conducting a limited review of many of the same issues. The IRP Commission review process also has a long schedule that allows sufficient time to analyze all issues related to avoided cost rates. In addition, conducting avoided cost review in or simultaneously with the IRP Commission review process would also reduce the possibility of the Commission acknowledged IRP having inputs or assumptions that depart from those used to set avoided cost rates. Finally, if the inputs and assumptions are addressed in an expanded IRP Commission review process, then there would be less of a need to review the utilities' actual avoided cost filings. This could result in quicker and less controversial approvals of avoided cost rates.

Q. Please explain what you mean by an expanded post-filing process.

A. Currently, the utilities develop their IRPs and control the assumptions, inputs, recommendations, and Action Plan. Then, the Commission issues an order acknowledging at pleast part of the IRP. The utilities' then file avodied cost rates after acknowledgement of the IRP, and/or make an additional filing on May 1. The utilities avoided cost rates are typically approved with little substantive review or analysis, and the parties do not have much of an opportunity to challenge the assumptions and inputs that are derived from the IRP and other sources.

The Commission could continue to review and approve the justness and reasonableness of the utility's inputs, assumptions, calculations, and methodologies related to avoided cost rates at the time the new avoided cost filings are made. The additional process would be to ensure that parties have an opportunity to conduct discovery, review, and challenge all aspects of the filings. I expect that most avoided cost rate filings could be approved without needing any Commission resolution, if the utilities were responsive to stakeholders concerns in the IRP, fully support their assumptions, and inputs, respond to discovery requests, and comply with previous Commission guidance.

The avoided cost rate updates should be consistent with prior Commission methodologies and include inputs, assumptions, calculations, and methodologies from the utility's most recently acknowledged IRP. The utility should be allowed to depart from the most recently acknowledged IRP, but must identify and explain the change.

The utility should have the burden to establish that the rates are just and reasonable for both QFs and ratepayers, including the reasonableness of all inputs and assumptions. The utility unilaterally selects these inputs and assumptions, and should be required to establish that they are correct, just, and reasonable.

Similar to rates paid by consumers, consistency with specifically acknowledged parts of the IRP 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 plan should not be relevant for any aspect of the IRP that was not specifically acknowledged by the Commission. There is no reason that any inputs or assumptions (whether in an IRP or not) should have any presumption of reasonableness, and consistency with the IRP is only relevant if the Commission has acknowledged the specific issue. 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.

A more thorough review can better ensure that avoided cost rates are just, reasonable, and accurate. An expanded post-filing process has the advantage of clearly separating the IRP from avoided cost rates. Unless the Commission makes a clear break and separation between the IRP and avoided cost rates, QFs will need to aggressively participate in both the IRP and the avoided cost filing to ensure that they do not miss their opportunity to raise issues. For example, if inputs and assumptions from the IRP have a presumption of reasonableness, then QFs will need to challenge their reasonableness in both the IRP process and the Commission review of the plan. This could result in the waste of stakeholder and Commission resources under the current process in which avoided cost rate issues are not normally a part of the IRP process.

Q. What is your recommendation?

A. In the end, either or both an expanded IRP or post-filing process may be acceptable if the parties have a fair opportunity to challenge disputed inputs and assumptions. The expanded IRP Commission review process is likely a better option because it provides more time, allows avoided cost rates to become effective more quickly, and reduces the likelihood that there would be inconsistencies between the IRP and avoided cost rates. I understand, however, that the Commission may not want to have a more detailed review of inputs and assumptions in or concurrent with the IRP Commission review process, and an expanded avoided cost process may be acceptable. The key aspects are that the utilities' unilaterally chosen assumptions and inputs should not have any presumption of reasonableness and the parties should have sufficient time and ability to review the avoided cost rates.

Q. Do you have any other suggestions on the issue of inputs and assumptions?

A. Yes. The Commission should establish minimum filing requirements for avoided cost rate update filings. I have attached a short list of items that the utilities should include in any update filing. This will benefit all the parties by reducing the need to conduct discovery, and allow a quicker review and approval of the avoided cost rate updates. Exhibit Coalition/403 includes my recommended minimum filing requirements.

Q. Please summarize your minimum filing requirements.

A. These include basic information that QF parties and likely staff would need to review the reasonableness and accuracy of the utilities' avoided cost rate filings. This includes support for the resoruce sufficiency and deficiency demarcation, gas price forecasts, resource sufficiency prices, and the assuptions and inputs related to wind and thermal resource costs. Some of this information is already included in the utilities' IRPs, and some of the filing requirments merely request that the utitlites identify where the information came from. This is particularly important if the utilities have departed from the IRP. Just a cursory review of the filing requriements demonstrates the numerous inputs and assumptions that need to be verified and reviewed, which supports a more extensive forum for the parties to analyze the avoided cost rate assumptions and inputs.

CAPACITY VALUE DURING THE RESOURCE SUFFICIENCY PERIOD

Q. You previously explained what the difference and importance of the resource sufficiency period is. Do these rates adequately compensate QFs for the capacity value they provide?

A. No. Kevin Higgins will be addressing this issue in detail; however, it is my opinion that avoided cost rates during the resource sufficiency period do not adequately compensate QFs for the capacity value they provide to their utilities and ratepayers. Existing QFs in particular are under compensated for the value they provide to ratepayers and utilities.

Q. Resource sufficiency prices are based on market purchases. Have the utilities historically only acquired market purchases during the sufficiency period?

A. No. It is my understanding is that both PacifiCorp and PGE have acquired thermal and large market purchases during the resource sufficiency periods. This means that the utilities resource acquisitions have not always matched their sufficiency and deficiency periods. I am not questioning the prudence or appropriateness of the utilities acquiring these resources during the sufficiency period. I believe that utilities should not be constrained by or prevented from purchasing economic resources during dates identified as “sufficiency” in IRPs. Utilities should be able to purchase least cost and least risk resources when appropriate. I want to emphasize that I believe it is appropriate for the utilities to have the flexibility to acquire low cost resources outside of their planning periods; however, this has the practical result of having undercompensated QFs during this period.

Q. How does this process impact QFs?

A. It harms QFs to set avoided cost rates based on sufficiency periods that have historically been inaccurate and are likely to be inaccurate in the future. The utilities are allowed to select long resource sufficiency periods, which results in long periods of low prices. Then the utilities can acquire thermal or other capacity resources during these periods in which QFs are only paid for market energy. If the sufficiency periods were more accurate, then the QF contracts would have included more capacity payments. Future avoided cost rates are also reduced because acquiring new resources has the practical impact of moving the next sufficiency period out.

Q. Is this issue more important now than in the past?

A. Yes. As discussed above, the utilities' IRPs are proposing long sufficiency periods. PacifiCorp has proposed that it will not acquire new thermal resource until 2028 or a wind resource until at least 2035. PacifiCorp 2015 IRP at 2. Given pending climate change related regulations, it appears unlikely that PacifiCorp will be able to retain its entire coal fleet and it might need to acquire a new natural gas resouce before 2028 or renewable resources before 2035. PacifiCorp is essentially deferring any serious consideration of its long term resource needs into future IRPs, which is likely to result in inaccurately long resource sufficiency periods for QFs. We know that the sufficiency periods are likely to be too long, but we just do not know how inaccurate they will be.

Q. Is this a more important issue for existing projects?

A. Yes. Small existing QFs are often included in the utilities' IRP as existing capacity resources, just like the utilities' own thermal and renewable resources. As these capacity resources are already included in the utility's load and resource balance, they cannot be considered surplus power. The fact that these renewing QFs are planned to continue to operate results in benefits to the utilities and ratepayers. When they enter into new contracts, existing QFs are treated as new QFs, which means that they are not compensated for the capacity value that the utilities and ratepayers continue to receive. Essentially, the utilities plan on these resources to provide capacity, but the QFs are not paid for this capacity.

Q. Are you proposing a fix to these problems at this time?

A. The Coalition is sponsoring Mr. Higgins' testimony to more accurately calculate resource sufficiency prices at this time, which recommends an alternative IRP run related to existing QFs. When making its decision in this case, the Commission should consider that resource sufficiency periods have been historically inaccurate and existing QFs provide uncompensated benefits to the utilities.

The better and more accurate fix for existing QFs would be for the Coalition to adopt the same solution as the Idaho Public Utilities Commission: paying existing QFs for capacity during the resource sufficiency period. As explained earlier, the utilities include small existing QFs in their IRP planning portfolios and the vast majority do not have the ability to enter into contracts with other entities. These small existing QFs should be treated like other long-term resources, and continue to be paid capacity when they renew their contracts.

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

Q. What are non-standard avoided cost prices?

A. QFs 10 MWs and below can elect to sell power at published, pre-approved avoided cost rates. QFs above 10 MWs do not have this option, and their rates are negotiated, based on criteria established by the Commission.

Q. Do believe there should be any change in Commission policy on this issue?

A. No. The utilities have not demonstrated that any changes are warranted, especially for exisiting hydro and biomass QFs.

Q. Did the Coalition address this issue in Phase I?

A. Yes. The Coalition retained Donald Schoenbeck to address this issue. Mr. Schoenbeck provided detailed recommendations and in-depth analysis. The Coalition continues to support the recommendations made by Mr. Schoenbeck in Phase I. Upon advice of counsel, I have been informed that this information remains in the record in this proceeding, and the Coalition does not need to repeat all the points made in any aspect of our Phase I testimony.

Q. Please briefly summarize Mr. Schoenbeck's recommendations from Phase I.

A. Mr. Schoenbeck: 1) explained how the current non-standard avoided cost rate negotiation process works; 2) detailed the difference in avoided cost rates that can be expected under both methods; and 3) identified problems with PacifiCorp's and PGE's proposed approaches.

Q. Please summarize the current non-standard avoided cost rate negotiation process.

A. The current negotiation process for large QFs starts with the standard Commission approved avoided cost rates for projects 10 MWs and under. The Commission then allows the utilities to make specific adjustments to account for FERC approved factors to modify these avoided cost rates. The utilities are only allowed to use the Commission approved methodologies and approaches to account for specific FERC factors, and are not allowed to make adjustments for any other factor, unless specifically approved by the Commission. <u>Re Investigation Relating to Electric Utility Purchases from QFs</u>, Docket

No. UM 1129, Order No. 07-30 at 15-29 (Aug. 20, 2007). The Commission specifically concluded that a "utility should not make adjustments to standard avoided cost rates other than those approved by the Oregon Commission and consistent with these guidelines." Id. at 16 and Appendix A at 3.

Q. Please summarize the difference in avoided cost rates using the Oregon approved methodology and the utilities' proposed computer modeling approach.

A. Mr Schoenbeck was a consultant with decades of experience with utility computer models and energy markets, and his conclusions were that the two methods could produce similar avoided cost rates, if the computer models were properly run. Coalition/200, Schoenbeck/8-12.

Q. What was Mr. Schoenbeck's and what is your current recommendation?

A. That the utilities should not be allowed to use their computer modeling approaches. While the overall prices of correctly using both methods should not be significantly different if done accurately and fairly, the computer modeling method is far more complex, expensive, and prone to disputes. As the Commission is aware from utility rate proceedings, computer model inputs and assumptions are subject to a certain degree of discretion and there can be significant factual disputes. Use of computer model to verify the utilities' assumptions and inputs can be very expensive, even for large QFs. Major costs to a QF of using the model include obtaining the computer models, potential disputes regarding confidential material, hiring consultant to run them, and additional negotiations and disputes that can occur when using a non-transparent method. Coalition/200, Schoenbeck/8-11. Very few large QFs go through this expensive and time consuming process. Coalition/402, Lowe/20-21 (PacifiCorp Response to Coalition DR 7.24).

Essentially, the computer modeling approach should not be used because there are no benefits in terms of more accurate avoided cost pricing, and there are significant harms in terms of higher costs and the potential for abuse by the utilities.

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

Q. What is the issue regarding legally enforceable obligations?

A. A QF has the right to receive a legally binding offer to establish a power sale to a utility pursuant to a contract or a legally enforceable obligation. While the Commission has attempted to streamline and reduce the opportunities for difficulties in the QF contract completion and negotiation process, the process sometimes results significant disputes between the QF and a utility. This is especially true when the avoided cost prices are expected to drop or lower prices already have been filed with the Commission.

Once discussions regarding purchase contract reach an impasse due to the utility's unreasonable delays, requirements or refusal to complete execution of a contract, a QF has the legal right to assure its commitment to sell power to the utility under then current prices and contract terms, and create a legally enforceable obligation. The QF should then be paid those then current rates, even if the contract is not finalized. In this testimony, I propose specific revisions that would allow a QF to create a legally enforceable obligation.

Q. Please explain what exactly is meant by a "legally enforceable obligation"?

A. QFs can sell their net output pursuant to a contract or a "legally enforceable obligation." 18 CFR § 292.304(d); Order No. 69, FERC Stats. & Regs. ¶ 30,128, 45 Fed. Reg. 12,214 at 12,224 (1980). A legally enforceable obligation is broader than simply a contract between an electric utility and a QF, and may exist without a contract. The concept of a legally enforceable obligation is intended to ensure that a QF can require a utility to purchase its power even if the utility has refused to enter into a contract.

A QF can enter into a legally enforceable obligation by committing itself to sell power to an electric utility. Cedar Creek Wind, LLC, 137 FERC ¶ 61,006 at P. 36, 39 (2011); Snow Mountain Pine Co., 734 P.2d 1366, 1371, 84 Or. App. 590 (Or. App. 1987). A utility cannot refuse to sign a contract so that a later and lower avoided cost is applicable. In other words, a legally enforceable obligation allows a QF to "lock in" current avoided cost rates, especially when a utility is delaying or otherwise imposing unreasonable terms and conditions.

Q. Why is this important?

A. Utilities can delay the negotiation process, request unreasonable information, or impose unduly burdensome restrictions or requirements. These problems can be exacerbated because there is unequal negotiating experience and resources between the QF and a utility. This is especially true for small QFs that rarely negotiate these types of contracts, and have limited knowledge of PURPA, avoided cost matters, and power markets.

Q. Did you address this issue in Phase I?

A. Yes. I explained in more detail the roadblocks and obstacles that utilities often raised during the contract negotiation and completion process. Coalition/100, Lowe/13-16. These include contract pre-requisites, requests to complete the interconnection and transmission process, refusal to sign or complete final contracts, and a lack of willingness to complete or begin the contract process if price changes are in progress. As I explained, all the obstacles provide an opportunity for abuse and the Commission should make changes to better protect QFs. Coalition/100, Lowe/13-14.

These delays and negotiation problems are particularly harmful when there is an upcoming avoided cost rate change. Utilities should not be allowed to refuse to sign a contract, delay the process, request inappropriate information, or impose unreasonable restrictions so that a later and lower avoided cost rate applies. The Commission should establish clear policies that, when negotiations stall or are delayed, a QF enter into a legally enforceable obligation by committing itself to sell power to an electric utility. In addition, a QF should not loose its avoided cost prices after there is an agreement regarding or the QF has committed itself to the fundamental contract and price terms, or the QF is simply waiting final approvals from management.

Q. How has the Commission attempted to streamline this process?

A. The Commission has established rules, policies, standard contracts, and rate schedules to facilitate and direct the process by which a QF can enter into a contract to sell its net output. <u>Re Investigation Relating to Elec. Util. Purchases from QFs</u>, Docket No. UM 1129, Order No. 05-584 at 6-12, 16 (May 13, 2005). The Commission has concluded that there should not really be a negotiation process, as the purpose of having approved standard contacts and schedules is to have rates, terms and conditions that a QF can elect without any negotiation. <u>Id.</u> at 12. In other words, the goal is "eliminate negotiations . . ." <u>Id.</u> at 16.

Q. Has the Commission approved process been consistently followed?

A. No. In my experience, there is often a need for significant negotiations, most of which are unnecessary. The utilities do not always follow these rules and requirements, and they can unnecessarily delay the process or impose their own requirements in violation of the Commission's policy. For example, while a small QF has the right to insist on the

Commission approved contract terms and conditions, PacifiCorp believes that it can require, and it has recently been requiring, QFs to agree to non-standard terms and conditions in order to obtain a standard contract. Coalition/402, Lowe/9-19 (PacifiCorp Responses to Colaition DR 7.14, 7.15, 7.16 and 7.17). Therefore, PacifiCorp operates as if it does not need to comply with the Commission's policy that QFs can elect to use the standard contracts without modifications.

Q. What are the QFs options when a utility imposes unreasonable terms or conditions?

A. The QF can either agree to the utilities' unreasonable terms or conditions, or file a complaint. A complaint is an expensive and time consuming process that can delay when the QF can sell power to the utility. Therefore, in addition to the costs of the complaint and the uncertainty regarding the outcome, there can be significant lost sales when a complaint is filed. This is especially a problem when there is a pending rate decrease. The only economic option is often to sign the contract with unreasonable terms or conditions.

Q. What are your specific recommendations to make the process more fair?

A. A QF should be allowed to create a legally enforceable obligation if the QF is unable to resolve outstanding issues after providing required information and negotiating in good faith with a utility. The utilities' standard avoided cost rates have established negotiation processes, and a QF should be required to make a good faith effort to follow and comply with this process. For example, QFs should not be allowed to simply fill out and sign a draft contract in order to establish a legally enforceable obligation. QFs should be required to provide complete information so that the utility can prepare a draft contract. Assuming the utility timely provides a draft contract, then the QF should be required to make a good faith attempt to resolve any disputes regarding information, contract terms and conditions, etc.

A QF should be allowed to commit itself to sell power to the utility at then current rates if negotiations reach an impasse after the QF complies with these initial requirements. The QF could then file a complaint to resolve the dispute, or continue negotiations with the utility on disputed non-price provisions, without having to worry about a pending price change. Removing the risk of the QF losing then current avoided cost rate will dramatically reduce the pressure on a QF's to agree to an unreasonable or illegal contract in order to avoid a price reduction.

Q. Can you provide more specificity regarding your recommendation?

A. Yes. I have attached a revised version of PacifiCorp's Schedule 37 as an example. Schedule 37 requires that the QF provide PacifiCorp with specific information in order to obtain a project specific draft contract. It is reasonable to require the QF to provide certain minimum information. The utility should not be allowed to impose additional or more stringent requirements. Under Schedule 37, the draft contract must be provided in fifteen business days after complete information is provided, although often there is no reason why it should not be provided earlier.

PacifiCorp can (and should be allowed) to request reasonable additional or clarified project information that is necessary for the preparation of a final draft contract. If PacifiCorp has not requested additional or clarified information when it provides the draft contract, then the QF can request a final contract. More common, PacifiCorp will request additional or clarified information. There can be disputes regarding contract terms in the draft contract, the reasonableness of project specific information, or other issues that are difficult to resolve.

My recommendation is that a QF should be able to create a legally enforceable obligation by committing itself to sell power under then current rates if there are unresolved disputes fifteen business days after PacifiCorp has provided (or should have provided) a draft contract. In my experience, the QF and the utility will typically spend far more time exhaustively attempting to resolve any disputes. Sometimes it is clear that there are intractable disputes, especially if there is an upcoming rate change. After committing itself to sell power, the QF can then file a complaint, or continue negotiations on the disputed terms or conditions, without risk that they will loose the then current avoided cost rates. Contract terms and conditions would be those ultimately agreed to or deemed reasonable by the Commission after a dispute resolution or complaint proceeding.

My recommendation also affords protections to the utilities from last minute efforts of QFs attempting to lock into prices before they change. This includes, for example, a minimum time prior to a price change that a proper and complete request for a contract be received by the utility. These and other approaches are all part of a revised contracting process that results in resolution of the legally enforceable obligation issue.

Specifically, my recommendation prevents QFs from attempting to form a legally enforceable obligation until they have provided information, received a draft contract and requests for additional information, and attempted to resolve the outstanding issues. It is also reasonable for QFs because it ensures that they are not pressured into agreeing to unreasonable terms, conditions, or requirements merely because they are afraid of losing their right to higher avoided cost rates.

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

Q. What is meant by third-party transmission costs in a load pocket?

A. The Commission has explained that PacifiCorp's entire service territory is non-contiguous, and interconnected in places by third-party transmission. This is called by PacifiCorp as "load pockets" and third-party transmission must be used to get the QF power to PacifiCorp's loads. The Commission determined in Phase I that the costs of third-party transmission should be paid by QFs, but left the implementation of a methodology or specific manner for payment to Phase II. <u>Re Investigation into QF pricing and contracting</u>, Docket No. UM 1610, Order No. 14-058 at 21-23 (Feb. 24, 2014).

Q. What is your recommendation on this issue?

A. I support in concept the idea that QFs should pay for and be credited third party transmission costs. A summary of my recommendations are:

- Existing and operating projects should be treated differently than new projects because the system was designed and built with existing projects in mind. Existing projects are included in the utilities' IRPs, and the utilities plan on their continued operation without the need for additional transmission purchases.

- Principles of cost causation also support "grandfathering" existing projects so that they do not pay for new third party transmission. PacifiCorp currently needs to purchase third party transmission because new QFs are locating in "load pockets." But for these new projects, this issue would never have come to the Commission.

- Any QF that is required to pay for third party transmission costs should be provided complete and accurate information regarding the extent of the transmission constraints and the cost of the transmission.

- Finally, the Commission should ensure that QFs have the ability to select the most cost effective option available. These include purchasing non-firm transmission, agreeing to lower avoided cost rates, curtailment of power, etc.

Q. Has PacifiCorp made a proposal on this issue?

A. No. My testimony identifies the broad principles that the Commission should use to resolve this issue, and makes some specific recommendations. Since we do not know what PacifiCorp's specific proposal will be, I will likely provide responsive testimony on this issue later in this proceeding.

Q. Please explain how QF transmission issues are treated?

A. In the transmission world, QFs are considered "network" resources of PacifiCorp's commercial operations. Network resources include those that are owned, purchased, or leased by PacifiCorp and using network transmission service. PacifiCorp's merchant operations makes a request with its transmission operations, and after the request is approved, the QF resources are supposed to be treated like any other PacifiCorp resource (which may or may not need third party transmission).

Q. How are existing projects generally treated?

A. Existing QFs already have network resource status, and they continue to have that status when their contracts renew. The majority of the members of the Coalition are small QFs that do not have any other economic opportunities to sell power, and they essentially are required to renew their contracts or stop operating.

Q. What do you understand to be PacifiCorp's position regarding existing projects?

A. PacifiCorp agrees that existing projects will continue to be treated as network resources if they renew their contracts before the expiration of a new contract; however, the Company states that they will loose their network resource status if they renew afterwards. Coalition/401, Lowe/3 (PacifiCorp Response to Coalition DR 7.5). Therefore, existing projects are at risk being required to new transmission studies and third party transmission costs if their contracts expire.[1]

PacifiCorp also intends to charge existing and already operating QFs third party transmission costs if their area becomes a load pocket. Coalition/401, Lowe/5 (PacifiCorp Response to Coalition DR 7.7). Therefore, if new generation develops in the system or there is a loss of load, then the existing QFs will be required to pay for third party transmission costs that they did not cause.

PacifiCorp does not appear to be willing to allow non-firm or other forms of transmission. Coalition/401, Lowe/6-8 (PacifiCorp Responses to Coalition DR 7.8, 7.9 and 7.10). PacifiCorp appears to want to require QFs to pay for the most expensive form of transmission, even if lower cost solutions are available to the QFs and the company.

Q. Do you agree with PacifiCorp's views regarding existing projects network resource status?

A. Only in part. I agree that a QF should retain its network resource status if it renews its contract, and that a QF should loose its network resource status if it decides not to enter into a contract because it will no longer sell power.

I disagree with the company that a QF should loose its network resource status if their contract expires, and they do not enter into a new contract because of a dispute with the utility. There can be numerous potential interconnection and contract related disputes that would prevent a QF from signing a new contract with a utility. The QF should not be forced to choose between signing a harmful contract or interconnection agreement, and losing its network resource status. The utility should not be able to use the threat of loss of network resource status as negotiating tool to extract concessions from the QF.

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[1] I am distinguishing between transmission and interconnection costs. QFs already must re-negotiate their interconnection agreements and may be subject to new interconnection costs. They currently are not subject to the risk of paying transmission costs.

I recommend that a QF retain its network resource status if it signs a new contract, or communicates that it intends to continue selling power to the utility, but has not signed a new contract because a disagreement over the terms of the contract, interconnection agreement, or other relevant issue.

Q. Do you agree with PacifiCorp that existing projects should be required to pay for third-party transmission in a load pocket?

A. No. Existing QFs have been part of PacifiCorp's electric system for years, many going back to the 1980s or earlier. PacifiCorp has planned, developed, and operated its distribution and transmission system based on the assumption that these QFs have been and will continue to operate. All of these QFs also purchase station service power from PacifiCorp, which can be a significant power source for very small QFs. Existing QFs should not be required to pay for new third party transmission costs that they did not cause to occur because of new QFs, other utility generation, or load loss.

Q. Do you believe that all projects should be able to have options other than the acquistion the most expensive form of third-party firm transmission?

A. Yes. The Commission should require that PacifiCorp merchant make every reasonable effort to acquire the lowest cost transmission or other alternative. In addition, the Commission should adopt specific methodologies and guidelines to protect QFs.

An important point in this analysis is that the business relationship in these negotiations is between PacifiCorp merchant and PacifiCorp transmission and a third party transmission provider. The QF is not a direct party to the negotiations between PacifiCorp merchant and transmission. PacifiCorp generally does not want to purchase power from QFs, which means that you have PacifiCorp merchant negotiating on the behalf of QFs that the company does not want on its system in the first place.

There are other options available that are lower cost that purchasing firm transmission for the QF's entire net output. For example, a QF could agree to non-firm transmission or have its net output curtailed when transmission is unavailable. Bonneville Power Administration ("BPA") is a major transmission provider in the region, and they do not have a Federal Energy Regulatory Commission approved Open Access Transmission Tariff. BPA may be willing to work out lower cost arrangements during limited times when PacifiCorp needs third party transmission.

The Commission should adopt strict guidelines and/or methodologies that require PacifiCorp to take all reasonable actions to acquire the least cost solution.

Q. What types of information would QFs need to analyze the costs, benefits, and responsibilities related to the acquisition of third party transmission?

A. I am not entirely sure exactly what is needed, as this is a new issue. However, PacifiCorp should be required to provide the QFs with all data regarding the availability or lack of availability of transmission on its system. In addition, the QF should be able to direct PacifiCorp to ask for all reasonable information from any third party transmission provider regarding availability of transmission and associated costs, and PacifiCorp should share this information with the QF. These communications, information and/or requirement sharing should be addressed in PacifiCorp's applicable tariffs for QFs.

<u>GREEN TAGS</u>

Q. What is your position on who should own Green Tags during the last five years of a twenty-year PPA?

A. Oregon's policy is that a QF can retain its Green Tags or renewable energy certificates when it makes PURPA sales. A renewable QF eligible under Oregon's renewable portfolio standard can sell both the net output and the renewable energy certificates

("RECs") to a utility and obtain a different, renewable avoided cost rate. When making sales based on the renewable avoided cost rate, the QF retains the RECs during the resource sufficiency period when avoided cost rates are based on market purchases, and the QF transfers the RECs to the utility during the time period in which the avoided cost rates are based on a renewable proxy resource. During the last five years of a 20-year fixed price PPA, the QF is paid market rates by the utility, and I see no reason why a QF should be required to transfer the RECs to the utility during this time period.

My understanding is at least some of the Oregon utilities believe the RECs should be transferred to the utilities during the last five years of a twenty-year PPA. I am unsure what creative arguments the utilities may raise to justify this position, and I will review their arguments and potentially respond in the next round of testimony.

OTHER ISSUES

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

A. Yes. I agree in principle that avoided transmission costs should be credited to QFs, and QFs should have to pay for additional third party transmission costs. The Coalition will review the testimony of other parties on this issue, and the Coalition may provide responsive testimony or address the issue in legal briefs.

Q. Do you have a position on whether 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?

A. Not at this time. The Coalition will review the testimony of other parties on this issue, and the Coalition may provide responsive testimony or address the issue in legal briefs.

CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1610

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

EXHIBIT COALITION/401

PACIFICORP RESPONSES TO DATA REQUESTS

May 22, 2015

UM 1610/PacifiCorp
April 27, 2015
REC Data Request 3.1 – 1st Supplemental

REC Data Request 3.1

Since 2005, please identify the resource sufficiency/deficiency period in the Company's avoided cost rates.

1st Supplemental Response to REC Data Request 3.1

Further to the Company's response to REC Data Request 3.1, the Company provides the following supplemental information:

Please refer to the table below, which has been updated to reflect the deficiency period stated in the 2013 Integrated Resource Plan (IRP) Preferred Portfolio (Table 8.7).

Year	Deficit Year
2005	2010
2006	2010
2007	2012
2008	2012
2009	2014
2010	2014
2011	2014
2012	2016
2013	2016
2014	2024
2015	2024

UM 1610/PacifiCorp
April 27, 2015
REC Data Request 7.4

REC Data Request 7.4

Please confirm that existing qualifying facilities currently selling power to PacifiCorp are Network Resources. If not, please explain.

Response to REC Data Request 7.4

Confirmed.

UM 1610/PacifiCorp
April 27, 2015
REC Data Request 7.5

REC Data Request 7.5

For existing qualifying facilities that are located in a "load pocket" and have a current power purchase agreement, please explain:

(a) whether these qualifying facilities would lose their Network Resource status if they enter into a new power purchase agreement before or by the last day of their current power purchase agreement; and

(b) whether these qualifying facilities would lose their Network Resource status if they enter into a new power purchase agreement after the last day of their current power purchase agreement.

Response to REC Data Request 7.5

(a) No, existing qualifying facilities (QF) would not lose their Network Resource status if they enter into a new power purchase agreement (PPA) before or by the last day of their current PPA.

(b) Yes, Network Resource status runs coterminous with the term of a PPA.

UM 1610/PacifiCorp
April 27, 2015
REC Data Request 7.6

REC Data Request 7.6

For existing qualifying facilities that are located in a "load pocket" and have a current power purchase agreement, please explain whether the qualifying facility can enter into a new power purchase agreement without being required to pay for the costs of third party transmission.

Response to REC Data Request 7.6

No, per Public Utility Commission of Oregon (OPUC) Order No.14-058 in this docket, the qualifying facility (QF) located in a load pocket is required to pay for any cost of moving excess generation out of the load pocket to load.

UM 1610/PacifiCorp
April 27, 2015
REC Data Request 7.7

REC Data Request 7.7

For existing qualifying facilities that are located in a "load pocket" and have a current power purchase agreement, please explain whether existing qualifying facilities will be "grandfathered" or will need to pay for third party transmission costs when generation output in the load pocket increases over time.

Response to REC Data Request 7.7

If the qualifying facility (QF) was located in the load pocket that did not have an excess generation issue (i.e., sufficient load to absorb the generation) and the load in the load pocket increased, there would be no need to acquire transmission service because there is no excess generation from the QF.

If the QF was located in the load pocket and is already paying for third party transmission due to an excess generation issue created by the QF and the load in the load pocket increased sufficient to absorb 100 percent of the QF load, then PacifiCorp merchant would not renew the point-to-point (PTP) transmission when the transmission service agreement expired. At the time of the QF power purchase agreement (PPA) renewal, any excess generation conditions in the load pocket would be identified during the QF's update of its interconnection. If the study showed sufficient load then there would be no need to acquire transmission service because there is no excess generation from the QF.

UM 1610/PacifiCorp
April 27, 2015
REC Data Request 7.8

REC Data Request 7.8

For qualifying facilities that are located in a "load pocket" and are seeking to enter into a new power purchase agreement, please explain whether these qualifying facilities can purchase third party non-firm transmission.

Response to REC Data Request 7.8

Transmission service is the responsibility of PacifiCorp merchant as the customer of the transmission provider and not the qualifying facility (QF).

UM 1610/PacifiCorp
April 27, 2015
REC Data Request 7.9

REC Data Request 7.9

Please assume that PacifiCorp will allow, or a regulatory body requires PacifiCorp to allow, qualifying facilities that are located in a "load pocket" and are seeking to enter into a new power purchase agreement to purchase third party non-firm transmission. Does PacifiCorp believe that a pricing adjustment to the qualifying facility's avoided cost rates should be made to reflect that the transmission is "non-firm."

Response to REC Data Request 7.9

Transmission service is the responsibility of PacifiCorp merchant as the customer of the transmission provider and not the qualifying facility (QF).

UM 1610/PacifiCorp
April 27, 2015
REC Data Request 7.10

REC Data Request 7.10

If he answer to data request 7.9 is yes, should the pricing adjustment different depending on the expected availability of the non-firm transmission?

Response to REC Data Request 7.10

Please refer to the Company's response to REC Data Request 7.9.

UM 1610/PacifiCorp
April 27, 2015
REC Data Request 7.14

REC Data Request 7.14

For Oregon standard qualifying facilities, does PacifiCorp agree that it cannot require a qualifying facility to agree to contract changes, amendments, revised terms or addendums that have not be approved by the Oregon Public Utility Commission? If not, please explain.

Response to REC Data Request 7.14

No. The standard contract approved by the Public Utility Commission of Oregon (OPUC) has allowances in it to make changes without filing for approval as requested by either party. For example, the qualifying facility (QF) can request incremental nameplate capacity upgrades as a result of changes in their equipment that do not need approval by the OPUC.

UM 1610/PacifiCorp
April 27, 2015
REC Data Request 7.15

REC Data Request 7.15

Please identify all qualifying facilities that PacifiCorp has proposed a “jury trial waiver” addendum, attachment or other provision.

Response to REC Data Request 7.15

Jury trial waiver became a formal Company requirement as of May 21, 2012, and PacifiCorp began adding the requirement to qualifying facility (QF) power purchase agreements (PPA) on a forward basis and when an older QF PPA was amended. Please refer to Attachment REC 7.15.

Counterparty	Jury Trial Waiver Language	Notes
AG Hydro	No	
Albany, City of	No	
Ballard Hog Farms Inc	Yes	
Bear Creek Solar	Yes	Addendum A
Bell Mountain (Jake Amy)	No	
Bell Mountain Hydro (Ted Sorenson)	No	
Beryl Solar	Yes	
Biomass One, L.P.	No	
Birch Creek Hydro	No	
Black Cap II (Obsidian Renewables)	Yes	Addendum A
Bly Solar	Yes	Addendum A
Blue Mountain Power Partners, LLC	Yes	
Buckhorn Solar	Yes	
Buffalo, City of	No	
Bureau of Land Management - Rawlings Office	Yes	
C Drop Hydro	Yes	Added in 1st Amendment (July 3, 2014)
Cameron A. Curtis	No	
Cargill, Inc.	No	
CBG Portland	No	
CDM Hydro	No	
Cedar Valley	Yes	
Chevron USA Inc.	Yes	
Chopin Wind	Yes	Addendum A
COID - Juniper Ridge	No	
COID - Siphon	No	
Commercial Energy Management	No	
Cottonwood Lower	No	
Cottonwood Upper	No	
Deschutes Valley Water District	No	
Dorena Hydro	No	
Douglas County - Galesville Dam	No	
Douglas County Forest Products	No	
Draper Irrigation Company	No	
Dry Creek	No	
eBay, Inc	Yes	Appendix A
EBD Hydro, LLC	No	
Evergreen BioPower LLC	Yes	Added in 1st Amendment (4/25/2013)
ExxonMobil Production Co.	Yes	Added in 1st Amendment (12/9/13)
Falls Creek H.P. Limited Partnership	No	
Farm Power - Misty Meadow	No	
Farmers Irrigation District (FID)	No	
Finley Bioenergy, LLC	No	
Foote Creek II, LLC	Yes	
Foote Creek III, LLC	Yes	

George DeRuyter and Sons Dairy LLC	Yes	Appendix A
Georgetown Irrigation Company	No	
Granite Peak Solar	Yes	
Greenville Solar	Yes	
GrowPro, Inc.	No	
Harold Foster and Robert Walker - Bogus Lower Cold Springs	No	
Harold Foster and Robert Walker - Bogus Upper Cold Springs	No	
Hill Air Force Base	No	
Ivory Pine (Obsidian Renewables)	Yes	Addendum A
J Bar 9 Ranch	No	
Kennecott Utah Copper LLC (Refinery)	Yes	
Kennecott Utah Copper LLC (Smelter)	Yes	
Lacomb Irrigation	No	
Laho Solar	Yes	
Lake Siskiyou (Box Canyon)	No	
Latigo	Yes	
Lower Valley Energy, Inc.-Culinary/Swift Creek (Upper/Lower)	Yes	
Loyd Fery	Yes	
Luckey, Paul	Yes	
Mariah Wind, LLC	Yes	Addendum X
Marsh Valley Hydro & Electric Company	No	
Meadow Creek - Five Pine	No	
Meadow Creek - North Point	No	
Middlefork Irrigation District	No	
Milford Flat Solar	Yes	
Mink Creek Hydro fka Robert Fackrell	No	
Monroe Hydro, LCL	No	
Mountain Energy	No	
Mountain Wind Power II LLC	Yes	
Mountain Wind Power LLC	Yes	
Nichols Gap Limited Partnership (Eagle Point)	No	
Nicholson Sunnybar Ranch	No	
North Fork Sprague	No	
Odell Creek- Jim Jans	No	
OJ Power	No	
OM Power 1, LCL	No	
OR Windfarm - Big Top LLC	No	
OR Windfarm - Butter Creek Power, LLC	No	
OR Windfarm - Four Corners Windfarm LLC	No	
OR Windfarm - Four Mile Canyon Windfarm LLC	No	
OR Windfarm - Oregon Trail Windfarm LLC	No	
OR Windfarm - Pacific Canyon Windfarm LLC	No	
OR Windfarm - Sand Ranch Windfarm LLC	No	
OR Windfarm - Wagon Trail LLC	No	
OR Windfarm - Ward Butte Windfarm LLC	No	
Oregon Environmental Industries, LLC	No	

Oregon Institute Technologies	No	
Oregon State University	No	
OREM Wind Family, LLC	Yes	Addendum X
Pavant Solar	Yes	
Pioneer Wind Park I, LLC	Yes	
Portland Water Bureau	No	
Power County Wind Farm North	No	
Power County Wind Farm South	No	
Preston, City of	No	
Res-AG oak Lea	No	
REUT Origination Fiddlers Canyon 1	Yes	
REUT Origination Fiddlers Canyon 2	Yes	
REUT Origination Fiddlers Canyon 3	Yes	
REUT Origination Manderfield	Yes	
REUT Origination Milford 2	Yes	
REUT Origination Quichapa 1	Yes	
REUT Origination Quichapa 2	Yes	
REUT Origination Quichapa 3	Yes	
REUT Origination South Milford	Yes	
REUT Quichapa 1	Yes	
REUT Quichapa 2	Yes	
REUT Quichapa 3	Yes	
Roseburg Forest Products - Dillard	Yes	
Roseburg Forest Products - Weed	No	
Roseburg LFG Energy, LLC	No	
Rough & Ready Lumber Company	No	
Roush Hydro, Inc	Yes	
Santiam Water Control District	No	
Shiloh Warm Springs Ranch Partnership	Yes	Added in 3rd Amendment 2/4/2014)
Slate Creek Hydro	No	
Spanish Fork Wind Park 2, LLC	Yes	
Sprague River (Obsidian Renewables)	Yes	Addendum A
St. Anthony Hydro	Yes	
Stahlbush Island Farms	Yes	Addendum A
Sunnyside Cogeneration Associates	No	
Swalley Irrigation District	No	
TATA Chemicals (Soda Ash)	Yes	
Tesoro Refining and Marketing Company	Yes	
Thayn Ranch Hydro (Green River)	No	
Three Sisters Irrigation District	Yes	Addendum A
Threemile Canyon Wind	Yes	Added in 10th Amendment 9/26/13
TMF BioFuels	No	
Utah Red Hills Solar	Yes	
Warm Springs Hydro, LLC	Yes	Addendum A
Wasatch Integrated Waste Management	Yes	
Weber County, State of Utah	No	
Yakima Tieton (Cowiche)	Yes	Appendix A
Yakima Tieton (Orchards)	Yes	Appendix A

REC Data Request 7.16

Please identify all qualifying facility power purchase agreements that include a "jury trial waiver" addendum, attachment or other provision.

Response to REC Data Request 7.16

Please refer to the Company's response to REC Data Request 7.15.

UM 1610/PacifiCorp
April 27, 2015
REC Data Request 7.17

REC Data Request 7.17

For each Oregon standard qualifying facility power purchase agreements since 2008, please identify all contract changes, addendums, attachments or other provisions that have not been specifically approved by the Oregon Public Utility Commission.

Response to REC Data Request 7.17

Please refer to Attachment REC 7.17.

QF	COD	Jury Waiver	Contract Year Definition	Insurance	Minimum volumes
Adams Solar Center, LLC	Apr-30-2017	X			
AG Hydro	Dec-31-2013		X		
Bear Creek Solar Center, LLC	Apr-30-2017	X			
Big Top LLC	Aug-01-2009				
Bly Solar Center, LLC	Apr-30-2017	X			
Butter Creek Power LLC	Aug-01-2009				
C Drop	May-03-2012	X			X
CBG Portland	Mar-31-2015	X			
Central Oregon Irrigation District (Juniper Ridge)	Oct-04-2010				
Chopin Wind, LLC	Jun-30-2016	X			
City of Albany, Dept of Public Works	Jan-20-2009				
City of Astoria	Feb-10-2015	X			
City of Portland, Portland Water Bureau	Nov-01-2012				
Dorena Hydro	Dec-11-2014				
EBD Hydro	Apr-30-2013				
Elbe Solar Center, LLC	Apr-30-2017	X			
Evergreen BioPower	Nov-05-2007	X			X
Ewauna Solar, LLC	Sep-30-2015	X			
Farm Power Misty Meadow	May-06-2013				
Finley Bioenergy (Finley Buttes)	Dec-25-2007				
Four Corners Windfarm LLC	Sep-11-2009				
Four Mile Canyon Windfarm LLC	Sep-11-2009				
Mariah Wind	Sep-01-2015	X			
Monroe Hydro	Apr-01-2015				
Obsidian Renewables LLC - Beatty Solar	Dec-31-2016	X			
Obsidian Renewables LLC - Black Cap Solar II	Dec-31-2016	X			
Obsidian Renewables LLC - Ivory Pine Solar	Dec-31-2016	X			
Obsidian Renewables LLC - Sprague River Solar	Dec-31-2016	X			
OM Power I	Nov-30-2013				

Oregon Environmental Industries	Jan-17-2007				
Oregon Institute of Technology	Apr-09-2010			X	
Oregon State University	Nov-12-2010			X	
Oregon Trail Windfarm LLC	Aug-01-2009				
Orem Family Wind	Sep-01-2015	X			
Pacific Canyon Windfarm LLC	Aug-01-2009				
RES Ag- Oak Lea	May-22-2012				
Roseburg Landfill Gas (Roseburg South Gate)	Dec-20-2011				
Rough & Ready Lumber	Mar-21-2008				
Sand Ranch Windfarm LLC	Jan-08-2009				
Stahlbush Island Farms	Jun-24-2009	X			
Swalley Irrigation District	Apr-23-2010				
Three Sisters Irrigation District	Aug-22-2014	X			
Threemile Canyon Wind I LLC	Sep-01-2009	X			
TMF Biofuels (Three Mile Digester)	Dec-31-2012				
Wagon Trail LLC	Sep-01-2009				
Ward Butte Windfarm LLC	Sep-01-2009				
Warm Springs Hydro, LLC	Aug-31-2015	X			

Exhibit A Modified for Solar	Addendum A Clarification of PPA Terms	Addendum B Transmission Service	Addendum L - Losses and Metering	Change in Security type	1st Amendment Incremental generation
X		X			
X					
	X		X		
X					
	X		X		
X		X			
				X	
X					
					X
	X		X		
	X		X		
	X				
X					
X					
X					
X					

	X		X		
	X		X		
	X		X		
	X				
	X		X		
	X		X		

REC Data Request 7.24

For each power purchase agreement identified in response to data request 7.23, please identify whether:

(a) the qualifying facility requested a copy of the company's power cost or other model;

(b) whether a copy of the model was provided to the qualifying facility;

(c) whether any of the qualifying facility's analysts, consultants, employees or agents signed a confidentiality agreement; and

(d) the name of the analysts, consultants, employees or agents.

Response to REC Data Request 7.24

The Company objects to this request as not reasonably calculated to lead to the discovery of admissible evidence, and as requesting information not maintained in the ordinary course of business. Without waiving these objections, the Company responds as follows:

Please refer to the table provided below:

Qualifying Facility (QF)	**(a)**	**(b)**	**(c)**	**(d) (*)**
Biomass One, L.P.	No	No	No	
Roseburg Forest Products, Dillars	No	No	No	
Blue Mountain Power Partners LLC (Champlin)	No	No	No	
Enterprise Solar LLC	No	No	No	
Escalante Solar I LLC	No	No	No	
Escalante Solar II LLC	No	No	No	
Escalante Solar III LLC	No	No	No	
Kennecott Refinery	No	No	No	
Kennecott Smelter	No	No	No	
Pavant Solar LLC	No	No	No	
Pavant Solar II LLC	No	No	No	
Sunnyside Cogeneration Associates	No	No	No	
Tesoro Refining and Marketing Company	No	No	No	
Utah Red Hills Renewable Park	No	No	No	
Granite Mountain Solar East LLC	No	No	No	
Granite Mountain solar West LLC	No	No	No	
Iron Springs Solar LLC	No	No	No	
Latigo Wind	No	No	No	
Chevron Wyoming Wind QF	No	No	No	
ExxonMobile Production Company	No	No	No	
Foote Creek II LLC	No	No	No	
Foote Creek III LLC	No	No	No	
Mountain Wind 1	No	No	No	
Mountain Wind 2	No	No	No	
Pioneer Wind Park I LLC	Yes	Yes	Yes	**Employees:** Aleathia Hoster, Christine Mikell, Andrew Fales

Qualifying Facility (QF)	**(a)**	**(b)**	**(c)**	**(d) (*)**
Tata Chemicals (Soda Ash) Partners	No	No	No	

(*) The requested information is only provided where known to the Company.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1610

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

EXHIBIT COALITION/402

EXCERPT FROM PACIFICORP BRIEF

May 22, 2015

HARD COPY OF 12-22-04 FAX

RECEIVED
DEC 2 7 2004
Public Utility Commission of Oregon
Administrative Hearings Division

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 1129

In the Matter of

PUBLIC UTILITY COMMISSION OF OREGON

Staff's Investigation Relating to Electric Utility Purchases From Qualifying Facilities

OPENING BRIEF OF PACIFICORP

PacifiCorp (or the "Company") hereby submits its opening brief in this proceeding.

INTRODUCTION

The Commission's challenge in this case is to balance the inherent tension between the Public Utility Regulatory Policies Act of 1978's ("PURPA") mandate to promote the development of qualifying cogeneration and small power production facilities ("QFs"), while at the same time ensuring ratepayer neutrality. PURPA provides that a utility is not required to pay more than its avoided costs for QF purchases. 18 CFR § 292.304(a)(2). Avoided costs refer to the costs the utility would have incurred to purchase energy and capacity but for the QF purchase. *Id.* § 292.101(b)(6). These provisions make clear that ratepayers cannot be forced to pay more for QF power than for power acquired from other resources.

Ensuring ratepayer neutrality is not only a PURPA mandate; it is inherent in the Company's basic responsibility to ensure low-cost, reliable power supply to its ratepayers. PacifiCorp's position throughout this proceeding has focused on ensuring that ratepayer neutrality is preserved. Much of what may be perceived by some as utility hostility to QF development is better understood as utilities seeking to ensure that ratepayer neutrality is maintained.

To the extent QFs are developed in a manner that is economic *vis a vis* the utilities' other resource alternatives, then everybody wins: (1) the developer gets a guaranteed

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where individual deviations from those requirements are appropriate. A one-size-fits-all decision may inhibit QF development if it prevents utilities from working with QFs to fashion customized solutions. On this issue, Staff agrees that a case-by-case approach is appropriate. (Tr 268-69.)

If the Commission decides to prescribe specific types and levels of security, PacifiCorp's preference is that the Commission approve the types and levels outlined in Ms. Wessling's testimony. Other alternatives that were presented by Staff include (1) performance bonds in lieu of project development security, (2) a right of future offset in lieu of default security and (3) a mechanical availability guarantee. (Staff/800, Morgan/3-5; Tr 158-59.) PacifiCorp would consider the combination of these mechanisms as reasonable if the Commission rejects PacifiCorp's proposal.

F. Issue No. 4: Avoided Cost Methodology

PacifiCorp supports retention of the current methodology for calculating avoided costs. Certain parties, notably Simplot/Sherman Country, are advocating that the Commission adopt the SAR method currently in use in Idaho.[2] However, the SAR methodology has several inherent problems and should not be adopted.

A principal problem with the SAR methodology is that it produces a single $/MWh price that applies to all QF generation regardless of season or time of day. Thus, unlike the current volumetric pricing model used in Oregon, the SAR methodology would spread capacity benefits across all hours and would not differentiate between peak and off-peak hours. (PacifiCorp/100, Widmer/20.) PacifiCorp (along with Staff and PGE) opposes the elimination of volumetric pricing, which would remove incentives for QFs to deliver during peak hours. (*See* Staff/700, Chriss/9.) Because QFs under standard contracts are not required to adhere to firm hourly delivery schedules, the Company cannot rely on them in the

[2] Idaho Power asks that it be allowed to continue to use the SAR methodology for administrative convenience and parity with its Idaho operations. PacifiCorp does not oppose Idaho Power's request to be treated differently on this issue.

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same manner as other firm capacity. However, the Company does receive a capacity benefit to the extent the QFs deliver during peak hours. The Commission should preserve the current volumetric pricing structure, because it aligns the payment of capacity benefits with periods in which the QF is providing capacity-type benefits. The Utah Commission recently adopted peak and off-peak pricing for QFs in Docket No. 03-035-T10.

Another significant problem is that the SAR method, as recently modified by the Idaho Commission, no longer considers a resource surplus period. In other words, the SAR method assumes the utility is perpetually capacity deficit and awards full capacity benefits even when the utility may be capacity surplus. (PacifiCorp/100, Widmer/22.) The result is that ratepayers are being charged for excess QF capacity at the same time as the utility may be backing down less expensive resources to accommodate the QF generation.

The rationale for abolishing the surplus period is that additional stimulus is needed for QFs during the early years, when utilities are most likely to be surplus. A common complaint from QFs is that utilities always show an initial surplus period. This is not true. In the case of PacifiCorp, the current avoided costs (adopted in September 2001) reflected an immediate deficit and included full capacity payments during the first year. (PacifiCorp/100, Widmer/23.) Similarly, the Company's November 2003 avoided cost filing (suspended pending this proceeding) recognized immediate summer capacity deficits in 2004-06 and included corresponding capacity benefits (growing to a full deficit situation with full capacity payments in 2007). (*Id.*)

In any event, it is entirely appropriate for utilities to be predominately surplus as they will constantly be acquiring resources necessary to serve incremental load growth. Any suggestion that the utilities use the surplus period to thwart QF development is simply untrue and is not supported by the evidence in the record. It would be bad policy if utilities were encouraged not to adequately plan and construct new resources, as a means of elevating the first year avoided cost prices for QFs. (Tr 76.)

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To illustrate the magnitude of surplus period issue, consider the following: The Idaho SAR method assumes that the proxy plant will operate at a 92% capacity factor, regardless of whether the utility needs the additional energy. Using the Company's November 2003 avoided cost filing and assuming the acquisition of 10, 25, and 100 MW of QF generation, the impact would be approximately \$3.5 million, \$8.8 million and \$35.1 million respectively over a three year period. (PacifiCorp/100, Widmer/24; PacifiCorp/104, Widmer/1.) As these figures indicate, removing the sufficiency period has potentially significant impacts for retail electric customers.

Staff advocates several alternatives that would address the issue of lower QF payments during surplus periods, while avoiding overcompensation to QFs for unnecessary capacity. Staff suggests that utilities could make a capacity payments during surplus periods in an amount equal to the market value of the excess capacity being received from the QF. Staff further endorses levelization with respect to such capacity benefits. The effect would be to spread later term capacity benefits across any early-term surplus period. Alternately, Staff proposes that utilities offer market pricing options, where the QF receives an established hourly index price for each delivered MWh. (*Id.*) Between the two options, the Company feels that the market pricing option would better reflect the value of capacity over the contract term. However, PacifiCorp would accept either proposal over elimination of the surplus period.

G. Issue No. 5: Applicability Of Oregon PURPA Regulations

Senate Bill 1149 rendered the Oregon PURPA statute inapplicable to electric utilities (PacifiCorp and PGE) that satisfy public purpose obligations under ORS 757.612. When this change was implemented, the Oregon PURPA regulations, OAR chapter 860 Division 29, were also amended so as not to apply to PacifiCorp and PGE.

PacifiCorp agrees with Staff that it would be appropriate for the Commission to open a rulemaking procedure to adopt rules that implement federal PURPA. Presumably, such

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1610

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

EXHIBIT COALITION/403

MINIMUM FILING REQUIREMENTS

May 22, 2015

UM 1610 Minimum Filing Requirements

The minimum filing requirements will be discussed in the application accompanying the avoided cost compliance filing, and the filing will also contain all work papers (including files in electronic format with formulae intact) supporting the rates in the compliance filing.

Minimum Requirements to be discussed in the application:

1. Resource Sufficiency/Deficiency Demarcation

    a. include demarcation year for standard and renewable rates

    b. include discussion of basis for demarcation, including the year when the utility is energy deficient, capacity deficient, and the year the utility plans to acquire a major non-renewable or renewable resource for duration of 5 years and 100 MW or greater in size

    c. provide citation to pages of the last Commission-approved IRP supporting the dates provided in subsection b., or provide complete explanation for the utility's proposed dates if the dates do not rely on the last Commission-approved IRP

2. Gas Price Forecast

    a. include description of the source of the gas price forecast and the forecast's assumptions regarding PTC/ITC and carbon costs/taxes, and discuss the basis for any differences in the source used in the avoided cost compliance filing from the source used in the last compliance filing

    b. in or attached to the application, include a complete copy of the gas price forecast used in calculation of the standard rates, and all source documents regarding the forecast

    c. provide a complete explanation of the basis for the utility's use of the gas price forecast, and any differences from the gas price forecast in the last Commission-approved IRP

    d. provide a comparison of the proposed gas forecast to the most recent EIA and Northwest Power and Conservation Council gas forecast

3. Sufficiency Period Prices

a. provide a description of the source of the sufficiency period prices and the source's assumptions regarding PTC/ITC and carbon costs/taxes, including market hubs used for market price projections, with forward price curves relied upon, and any adjustments or blending ratios made thereto in order to develop the avoided cost prices

b. provide the assumed cost of third-party point-to-point transmission (in $/kW/month and $/MWh delivered) and the capital cost for network transmission upgrades on the utility's system to deliver the avoided resource electricity to load; provide information and explanation supporting the cost assumptions; if no such costs are included in the rates, provide a description of the steps taken to confirm that the existing infrastructure will be adequate

4. Standard Rates Deficiency Period Resource

a. provide details on the resource type, geographic location, nameplate capacity, and annual capacity factor of the avoided resource

b. identify the location(s) of the of source of natural gas to supply the resource, and provide the assumptions used in the rates for costs to interconnect to and upgrade the existing natural gas infrastructure and costs of gas transmission and storage necessary to deliver gas from the source to the location in a. at adequate firmness and explain the basis for the assumptions

c. provide the assumed heat rate for the resource and adjustments made to the assumed heat rate to account for elevation and temperature and cooling method at the location in a.

d. provide the assumed cost of interconnection facilities for the avoided resource and an explanation of the basis for the assumption

e. provide the assumed cost of third-party point-to-point transmission (in $/kW/month and $/MWh delivered) and the capital cost for network transmission upgrades on the utility's system to deliver the output to load; provide information, explanation, and calculations supporting the cost assumptions; if no such costs are included in the rates, provide a description of the steps taken to confirm that the existing infrastructure will be adequate

f. provide a description of the federal, state, and local taxes that are in effect to be assessed to projects of this type at the time of the filing in the location described in section a., and provide the assumptions used in the avoided cost rate calculation in the filing

g. provide the capacity contribution value used to calculate the rates for solar and wind resource types, and the page numbers of the last Commission-approved IRP that support the assumptions; or provide complete explanation of the basis for the utility's assumptions if they do not rely on the last Commission-approved IRP

5. Renewable Rates Deficiency Period Resource

a. provide details on the resource type, geographic location, nameplate capacity, and annual capacity factor of the avoided resource

b. for the assumed annual capacity factor of the resource, provide an explanation of how the assumption is reasonable given the location in a., and provide the underlying assumptions regarding mechanical availability, annual hours of curtailment by the transmission provider(s), and annual MWh of energy curtailed

c. provide the assumed cost of interconnection facilities for the avoided resource and an explanation of the basis for the assumption

d. provide the assumed cost of third-party point-to-point transmission (in $/kW/month and $/MWh delivered) and the capital cost for network transmission upgrades on the utility's system to deliver the output to load; provide information and explanation supporting the cost assumptions; if no such costs are included in the rates, provide a description of the steps taken to confirm that the existing infrastructure will be adequate

e. provide a description of the federal, state, and local taxes that are in effect to be assessed to projects of this type at the time of the filing in the location described in section a., and provide the assumptions used in avoided cost rate calculation in this the filing

f. provide the capacity contribution value used to calculate the rates for solar and wind resource types, and the page numbers of the last Commission-approved IRP that support the assumptions; or provide complete explanation of the basis for the utility's assumptions if they do not rely on the last Commission-approved IRP

g. identify any tax benefits (e.g., PTC, ITC, grants in lieu of credits) relied upon in the calculation of the rates, and provide the page numbers of the last the Commission-approved IRP that support the assumptions; or provide complete explanation of the basis for the utility's assumptions if they do not rely on the last Commission-approved IRP

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1610

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

EXHIBIT COALITION/404

REVISED SCHEDULE 37 (REDLINE AND CLEAN)

May 22, 2015

B. Procedures

1. The Company's approved generic or standard form power purchase agreements may be obtained from the Company's website at www.pacificorp.com, or if the owner is unable to obtain it from the website, the Company will send a copy within seven days of a written request.

2. In order to obtain a project specific draft power purchase agreement the owner must provide in writing to the Company, general project information required for the completion of a power purchase agreement, including, but not limited to:

   (a) demonstration of ability to obtain QF status;
   (b) design capacity (MW), station service requirements, and net amount of power to be delivered to the Company's electric system;
   (c) generation technology and other related technology applicable to the site;
   (d) proposed site location;
   (e) schedule of monthly power deliveries;
   (f) calculation or determination of minimum and maximum annual deliveries;
   (g) motive force or fuel plan;
   (h) proposed on-line date and other significant dates required to complete the milestones;
   (i) proposed contract term and pricing provisions as defined in this Schedule (i.e., standard fixed price, renewable fixed price);
   (j) status of interconnection or transmission arrangements;
   (k) point of delivery or interconnection;

3. The Company shall provide a draft power purchase agreement when all information described in Paragraph 2 above has been received in writing from the QF owner. Within 15 business days following receipt of all information required in Paragraph 2, the Company will provide the owner with a draft power purchase agreement including current standard avoided cost prices and/or other optional pricing mechanisms as approved by the Public Utility Commission of Oregon in this Schedule 37.

4. If the owner desires to proceed with the power purchase agreement after reviewing the Company's draft power purchase agreement, it may request in writing that the Company prepare a final draft power purchase agreement. In connection with such request, the owner must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft power purchase agreement. If the owner and the Company are unable to resolve any disputes or disagreements, 15 business days after the draft power purchase agreement should have been provided, the owner can commit itself to sell power under then current rates and its proposed contract terms and conditions. After making such a commitment, the owner will be eligible to receive the avoided cost rates currently in effect in this rate schedule.

5. Within 15 business days following receipt of all information requested by the Company in this paragraph 4, the Company will provide the owner with a final draft power purchase agreement.

6. After reviewing the final draft power purchase agreement, the owner may either prepare another set of written comments and proposals or approve the final draft power purchase agreement. If the owner prepares written comments and proposals the Company will respond in 15 business days to those comments and proposals.

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7. When both parties are in full agreement as to all terms and conditions of the draft power purchase agreement, the Company will prepare and forward to the owner within 15 business days, a final executable version of the agreement. Following the Company's execution a completely executed copy will be returned to the owner.

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Deleted: Prices and other terms and conditions in the power purchase agreement will not be final and binding until the power purchase agreement has been executed by both parties.

B. Procedures

1. The Company’s approved generic or standard form power purchase agreements may be obtained from the Company’s website at www.pacificorp.com, or if the owner is unable to obtain it from the website, the Company will send a copy within seven days of a written request.

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(g) motive force or fuel plan;
(h) proposed on-line date and other significant dates required to complete the milestones;
(i) proposed contract term and pricing provisions as defined in this Schedule (i.e., standard fixed price, renewable fixed price);
(j) status of interconnection or transmission arrangements;
(k) point of delivery or interconnection;

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7. When both parties are in full agreement as to all terms and conditions of the draft power purchase agreement, the Company will prepare and forward to the owner within 15 business days, a final executable version of the agreement. Following the Company's execution a completely executed copy will be returned to the owner.