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April 29, 2013

***Via Electronic Filing***

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**RE: Docket No. UM 1610 – In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Staff Investigation Into Qualifying Facility Contracting and Pricing.**

Enclosed for electronic filing in the above-captioned docket is Staff's Reply Testimony.

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# PUBLIC UTILITY COMMISSION OF OREGON

## UM 1610

## STAFF REPLY TESTIMONY OF

## ADAM BLESS

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

**April 29, 2013**

CASE: UM1610
WITNESS: ADAM BLESS

# PUBLIC UTILITY COMMISSION OF OREGON

# STAFF EXHIBIT 200

## Reply Testimony

**April 29, 2013**

**Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.**

A. My name is Adam Bless. I am a Senior Utility Analyst for the Public Utility Commission of Oregon. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

**Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.**

A. My Witness Qualification Statement is found in Exhibit Staff/101.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of this testimony is to clarify staff's proposals in our Response Testimony in Staff/100, reply to issues raised by other parties in their Response Testimony of March 18, 2013, and identify issues where staff has modified its position based on other parties' response testimony or information provided at the April 2, 2013 workshop.

**Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?**

A. Yes. In Exhibit Bless/201, we explain in detail how QFs should receive payment for avoided integration costs and should pay for the cost of their own integration.

**Q. HOW IS STAFF'S TESTIMONY ORGANIZED?**

A. Staff's testimony is organized as follows:

Section 1: Avoided Cost Price Calculation Methodology……………….2
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## SECTION I: AVOIDED COST PRICE CALCULATION METHODOLOGY

**Q. WHAT ISSUES REGARDING THE AVOIDED COST CALCULATION ARE ADDRESSED IN THIS SECTION?**

A. In this section we address comments by the Community Renewable Energy Association (CREA), OneEnergy, and the Oregon Department of Energy (ODOE). Specifically, we reply to concerns about our proposal to apply a capacity contribution factor, concerns about our proposed treatment of integration costs, and suggestions that avoided cost payments include adjustments for upgrades to the bulk electricity and gas distribution systems.

**Q. WHAT CONCERNS WERE RAISED BY COMMUNITY RENEWABLE ENERGY ASSOCIATION (CREA)?**

A. CREA recommended continuing the current Oregon Method, with no changes. (CREA/200, Reading/8.) CREA opposed the application of a capacity contribution factor and the proposal for intermittent QFs to pay integration costs. (CREA/200, Reading/23.) CREA advocated a larger “credit” in the avoided cost calculation for avoided electric transmission costs and a credit for avoided costs associated with expansion of the bulk gas transmission system. (CREA/200, Reading/17-19, 24-25.)

**Q. CREA’S CONCERNS WERE IN RESPONSE TO UTILITIES’ OPENING TESTIMONY. HOW DO THOSE CONCERNS RELATE TO STAFF’S PROPOSAL?**

A. CREA raised concerns about Idaho Power's proposal to add a capacity contribution adjustment, and proposals by all utilities to assess integration charges. (CREA/200, Reading/14-17, 23.) Staff addresses these concerns because we also recommend a capacity contribution factor and an integration charge.

**Q. WHAT WAS CREA'S OBJECTION TO A CAPACITY CONTRIBUTION FACTOR?**

A. CREA asserts that basing the capacity of the QF on the proxy resource is a valid comparative approach because in aggregate all QFs in a utility's system provide a "fairly predictable" supply of power to the system, for energy and capacity. (CREA/200, Reading/23.) CREA stated that an adjustment for capacity contribution would add complexity and allow for gaming by the utility. (CREA/200, Reading/4.)

**Q. DOES STAFF AGREE THAT IN AGGREGATE ALL QFS IN A UTILITY SYSTEM PROVIDE A COMPARABLE SUPPLY OF CAPACITY TO THE SYSTEM?**

A. No. Base load QFs can have a capacity contribution that is comparable to the proxy gas turbine plant, but intermittent QFs do not. The capacity contribution of the aggregate of all QFs depends on the mix of base load and intermittent QFs in the system.

**Q. DOES STAFF'S PROPOSAL TO ADJUST AVOIDED COST PRICES FOR CAPACITY CONTRIBUTION ADD COMPLEXITY?**

A. No. As shown in Staff/100 Bless/102, the proposed capacity contribution adjustment adds two columns to the familiar spreadsheet that PGE and PacifiCorp have used to calculate avoided cost price since 2006. Utilities already factor in the capacity contribution to peak load from variable renewable generation in the Integrated Resource Plan (IRP)[1]. The utilities use these capacity contributions to determine the first year of resource deficiency. Staff's proposal does not create a new calculation, but rather it leverages work already done in the IRP.

**Q. DOES ADJUSTING THE AVOIDED COST PRICE FOR CAPACITY CONTRIBUTION ALLOW GAMING BY THE UTILITIES?**

A. No. There is little the utilities can do to game the calculation. The capacity contribution would be consistent with the value used in the IRP for resource acquisition planning. Using the same factor for QF and IRP purposes assures consistency, and maintaining the basic Oregon method with a relatively straightforward modification minimizes any chance for gaming.

**Q. HOW DOES STAFF RESPOND TO PARTIES' COMMENTS ON THE INCLUSION OF INTEGRATION COSTS IN THE AVOIDED COST PRICE?**

A. Staff maintains that it is appropriate to consider integration costs in the avoided cost price. We cover the topic of Integration Costs more fully in Section 2 of this testimony and in Exhibit Bless/201.

**Q. WHAT WAS CREA'S COMMENT ON AVOIDED TRANSMISSION COSTS?**

[1] See Idaho Power 2011 IRP, page 5 and PacifiCorp 2011 IRP, page 87.

A. CREA advocated a larger credit in the avoided cost price for avoided transmission costs. Specifically, CREA proposed increasing avoided costs to include savings from avoided upgrades in bulk electricity and gas transmission systems. (CREA/200, Reading/23-24.) For example, CREA pointed out that PGE's proposed Carty generation plant (a CCCT located at the current Boardman site) will likely require a gas lateral pipeline costing $54 million. (CREA/200, Reading/23-25.)

**Q. DOES STAFF SUPPORT THESE PROPOSALS TO COMPENSATE QFS FOR AVOIDED TRANSMISSION COSTS?**

A. Yes, in principle. In our testimony of March 18, 2013, staff proposed including avoided transmission costs in the avoided cost calculation. (Staff/100 Bless/5) Those costs will depend on whether the avoided resource is inside or outside the utility's balancing authority (BAA).

**Q. DOES STAFF SUPPORT ADDING TO AVOIDED COST PAYMENTS FOR UPGRADES TO THE BULK ELECTRIC AND GAS TRANSPORTATION SYSTEMS?**

A. Only to the extent that the cost of such upgrades is included in the cost of the avoided resource shown in the IRP. The Commission ruled in Order 06-538 that the reasonable proxy resource is the next avoidable resource in the action plan of the IRP. (Order 06-538 at 55). Staff sees no reason to change that decision. If related and supporting gas and electric transmission lines are needed to serve that generating facility, then their capital costs should appear in the IRP. If stakeholders believe the IRP understates the capital cost of the next capacity resource in the Action Plan, the IRP review is the best place to raise that issue.

**Q. HOW WOULD STAFF ADDRESS THE ISSUE OF COMPENSATION TO QFS FOR DEFERRED INVESTMENTS IN THE BULK GAS AND ELECTRIC TRANSMISSION SYSTEMS?**

A. Staff agrees with a recommendation by OneEnergy that the Commission direct the utilities to study the potential costs of needed upgrades to the gas transmission system (OneEnergy/100, Eddie/29.) However, the need for upgrades to bulk gas and electric transmission affects the cost of major generating capacity projects as well as QFs, and has ramifications for long range resource planning in general. Staff maintains that the IRP is the right place to submit these studies.

**Q. SHOULD AVOIDED COSTS ASSOCIATED WITH DEFERRED TRANSMISSION AND DISTRIBUTION INVESTMENTS BE CALCULATED IN THE SAME WAY AS DSM?**

A. No. There is no guarantee that QF power will enable the deferral of transmission and distribution upgrades to the same extent as DSM. DSM happens right at the load, and has its greatest effect precisely when the load is highest. Some QFs, such as CHP, may provide similar benefits, but QFs can also be in remote locations, or outside the utility's BA. Staff's proposal does include credit for avoided transmission cost to the extent known, and staff has proposed capacity adders in the renewable price stream for baseload QFs.

**Q. DID THE OREGON DEPARTMENT OF ENERGY (ODOE) COMMENT ON THE AVOIDED COST CALCULATION METHOD?**

A. Yes. ODOE recommended retaining the current Oregon Method. ODOE's comments were in response to the utilities' opening testimony of February 4th, 2013, and primarily addressed the question of retaining the Oregon Method versus changing to a model based method such as Idaho Power's IRP method or PacifiCorp PDDRR method. (ODOE/100, Carver/2.)

**Q. DO ODOE'S COMMENTS AFFECT THE MODIFICATIONS TO THE OREGON METHOD THAT STAFF PROPOSED IN ITS MARCH 18TH TESTIMONY?**

A. Yes. ODOE addressed three topics that are integral parts of staff's proposal. First, ODOE supported a different method of calculating the capacity credit for intermittent resources, the "ELCC" method. (ODOE/100, Carver/ 7-8.) Second, ODOE stated that wind QFs should be responsible for "…the cost of regulating reserves that utilities incur associated with errors in wind forecasting and with variability before and within the hour, but only for wind resources in the contiguous area where utilities have major wind resources and have procedures for forecasting wind output."(ODOE/100 Carver/9.) Third, ODOE stated that avoided cost prices should not be adjusted for intermittency if the avoided resource is wind. We address concerns regarding wind integration in Section 2 of this testimony.

**Q. DOES STAFF AGREE WITH USING THE ELCC METHOD FOR CALCULATING CAPACITY CREDIT IN AVOIDED COST PRICE?**

A. No. The appropriate capacity credit for use in avoided cost calculations is the one used in the IRP. Consistency requires that a specific wind resource have the same capacity contribution regardless of whether it is a QF or a utility resource. Having two separate methodologies, one for QF resources and one for IRP resources, does not provide this consistency. The appropriate place to debate the use of the ELCC method, the method proposed by CREA (CREA/200 Schoenbeck/5), or other methods is in future utility IRPs.

**Q. WHAT IS STAFF'S RECOMMENDATION REGARDING CAPACITY VALUATION?**

A. The appropriate capacity credit for use in avoided cost calculations is the one used in the IRP. The value used for resource acquisition planning purposes should be consistent with the value used for avoided cost purposes. If utilities' acknowledged action plans are based on contribution to peak load, then the capacity value of QFs should also be based on their contribution to peak load. If the acknowledged action plan is based on some other method, such as ELCC, then that method is the appropriate way to value QF capacity contribution. The underlying principle is that the methods should be consistent. The IRP review is an appropriate place to explore that method.

**Q. HOW WOULD THE PROPOSED CAPACITY ADJUSTMENT AFFECT QF PRICES?**

A. The proposed capacity adjustment affects only the on-peak price, and only during the deficiency period. During the sufficiency period, QFs receive the forward looking market price. It is difficult to determine the portion of the market price that is compensation for energy costs and the portion that is compensation for capacity costs. Given this difficulty, Staff does not propose any adjustment during the sufficiency period. Also, since the off-peak price is primarily composed of energy costs, staff proposes no adjustment to off-peak prices. The proposed capacity adjustment would affect the on-peak price only.

**Q. HOW DOES THE PROPOSED CAPACITY ADJUSTMENT AFFECT QF PRICES DURING THE DEFICIENCY PERIOD FOR THE STANDARD PRICE OPTION?**

The effect depends on the type of QF generation. Wind QFs choosing the standard price would see reduction in on-peak price, compared to the current Oregon Method. The reduction is due to the smaller capacity component in the on-peak price. Base load QFs would see no change from the current Oregon Method. They would receive the full capacity payment. Solar QFs choosing the Standard price stream would see a reduction in on-peak price during the deficiency period, but the reduction would be smaller than the reduction seen by wind QFs.

**Q. HOW DOES THE PROPOSED CAPACITY ADJUSTMENT AFFECT QF PRICES DURING THE DEFICIENCY PERIOD FOR THE RENEWABLE PRICE OPTION?**

Wind QFs choosing the renewable price option would see no change from Order 11-505. The deficiency period price would remain the fixed costs of the next renewable generation in the utility's IRP (assumed to be wind).

Baseload QFs choosing the renewable price would see an increased on-peak price during the deficiency period, because they would receive additional credit for their greater capacity contribution compared with the avoided wind resource.

Solar QFs choosing the renewable price would also see an increase in capacity payment during the deficiency period, but the increase would be smaller than the increase received by baseload QFs.

Table 1 below summarizes the effect of the proposed capacity adjustment.

**EFFECT of CAPACITY ADJUSTMENT on AVOIDED COST PRICES**

**(Affects the Deficiency period price only)**

| QF Resource Type | Standard Price Schedule | Renewable Price Schedule |
|---|---|---|
| **Wind QF** | **Reduction in on-peak price. No effect on off-peak price.** | **No change from Order 11-505** |
| **Base Load QF** | **No change.** | **Increased on-peak price compared to Order 11-505 because of greater capacity contribution compared to avoided wind facility** |
| **Solar QF** | **Reduction in on-peak price, but smaller reduction than wind** | **Increased on-peak price compared to Order 11-505, but smaller increase than for baseload.** |

**Q. DOES STAFF RECOMMEND AN ADDER TO AVOIDED COST FOR DEFERRED CAPACITY INVESTMENTS, AS PROPOSED AT ONEENEGY/100 EDDIE/10?**

A. No. The capacity component currently included in the on-peak avoided cost price already gives QFs credit for avoided utility investments in capacity.

Moreover, staff's proposed modifications to the Oregon method refine that credit by taking into account the different capacity contributions of different types of QFs.

**Q. DOES STAFF SUPPORT A NEW ADJUSTMENT BASED ON THE RESOURCE DEFERRAL VALUATION OF DSM, AS PROPOSED BY CREA AND ONEENERGY?**

A. No. The valuation described in CREA/204 and OneEnergy/201 is for DSM, not QFs. DSM directly reduces capacity investments because it has its greatest effect precisely at the peak times and at the exact location where the load is. Some QFs may have these characteristics, but intermittent QFs located far from load will not.

**Q. DOES THIS POSITION CONTRADICT ORDER 07-360, WHICH DIRECTED PARTIES TO INCORPORATE A LUMPINESS ADJUSTMENT IN NEGOTIATED CONTRACTS?**

A. No, it does not. Such an adjustment makes sense for negotiated contracts precisely because it can be tailored to the exact characteristics of a QF. A standard contract cannot be tailored so specifically.

**Q. IF THE COMMISSION ADOPTS A MODEL-BASED APPROACH SUCH AS IDAHO POWER'S IRP OR PACIFICORP'S PDDRR METHOD, DOES STAFF HAVE A RECOMMENDATION ON WHICH ONE?**

A. Yes. Staff reiterates that the relative transparency and simplicity of the Oregon Method are preferable to the complexity of the IRP and PDDRR methods. Our goal in proposing modifications to the Oregon Method was to compensate QFs more accurately for their capacity contribution, while keeping that simplicity and transparency. However, if the Commission chooses one of the model based approaches, staff recommends the PDDRR method (the two-run model), for many of the same reasons listed at CREA/200 Reading/6.

**Q. HAS STAFF CHANGED ITS RECOMMENDATION REGARDING LEVELIZED RATES BASED ON OTHER PARTIES' TESTIMONY OF MARCH 18, 2013?**

A. No. Throughout this docket, staff has treated the policies of Order 05-584 as the starting point, making changes only when new facts, new circumstances or new developments make it advisable. Order 05-584 includes a detailed history of OPUC policies regarding levelized prices and documents that levelized prices were used prior to UM 1129. (Order No. 05-584 at 7-10.) The Order lists arguments in favor of levelizing prices and counter arguments against levelizing. (Order No. 05-584 at 23-28.) The Order also considered default security requirements to alleviate the risk to ratepayers if levelized prices were authorized. (Order No. 05-584 at 43.) After weighing the arguments, the Commission declined to order levelized prices. (Order No. 05-584 at 28.)

The arguments favoring levelized rates are mostly based on helping projects to obtain financing and repay loans in the early years of the contract. The counter arguments are that these provisions shift risk to ratepayers. These arguments are unchanged from 2005. No party demonstrated fundamental changes in facts or circumstances since 2005 sufficient to warrant changing the policy adopted in Order 05-584.

**Q. WHAT ABOUT THE SPECIAL CASE OF AN EXISTING QFS THAT IS RENEWING ITS CONTRACT AND FACES A NEW SUFFICIENCY PERIOD?**

A. Existing QFs have the option of continuing to provide their output to the same utility or delivering the output to a different utility. Expiring QF contracts should be treated the same as expiring non-QF contracts in IRP planning. Expiring QF contracts do not warrant special treatment and should be paid the same as new QFs.

## SECTION 2: PRICE ADJUSTMENTS FOR SPECIFIC QF CHARACTERISTICS

*Issue 4.A.* *Should the costs associated with integration of intermittent resources (both avoided and incurred) be included in the calculation of avoided cost prices or otherwise be accounted for in the standard contract? If so, what is the appropriate methodology?*

**Q. THE COMMISSION CHOSE NOT TO IMPOSE INTEGRATION COSTS IN DOCKET NO. UM 1129. WHY DOES STAFF PROPOSE TO ALLOW INTEGRATION CHARGES NOW?**

A. The decision not to include integration costs in Docket No. UM 1129 was appropriate given the small amount of data available in 2005. PGE and PacifiCorp did not include integration studies in their IRPs at that time. Wind penetration has increased beyond what was projected in 2005, utilities now include wind integration studies in their IRP, and we now have more data. These new developments warrant the change in policy.

**Q. DOES STAFF PROPOSE ANY CHANGES TO THE TREATMENT OF INTEGRATION COSTS DESCRIBED IN MARCH 18, 2013 RESPONSE TESTIMONY?**

A. Yes. In that testimony, staff stated that avoided integration costs should be added to the avoided cost price, but QFs should pay for the integration costs that they impose on the utility through a separate line item in the contract. On further review, staff now agrees that it is acceptable to “net” imposed wind integration costs and avoided wind integration in the avoided cost calculation if both the QF and the avoided wind resource are in the utility’s BAA. If the QF is located in another BAA, then that BAA must recover its integration costs via the FERC OATT. Exhibit Bless/201 shows, in more detail, how the integration costs are calculated and how they are paid.

**Q. SHOULD QFS BE EXEMPT FROM INTEGRATION COSTS BECAUSE THEY ARE DISTRIBUTED GENERATION, AND THEREFORE CLOSE TO LOAD?**

A. No. There is no requirement that QFs be close to load, and no guarantee that a QF will be. For example, PGE’s load is primarily west of the Cascades, far from the best wind resources.

**Q. CREA AND ONEENERGY CITED A 2007 USDOE STUDY IN STATING THAT QFS PROVIDE BENEFITS THAT OFFSET THEIR INTEGRATION**

**COSTS. DOES THAT STUDY PROVIDE COMPELLING EVIDENCE AGAINST CHARGING WIND QFS FOR INTEGRATION?**

A. No. The referenced study was about distributed generation, not QFs. The two are not the same. The study described benefits from small generators that are close to load, interconnected at local distribution, and dispatchable. (See CREA/200, Reading/26 n. 33.) Some QFs have these characteristics, but not all. These benefits would not apply to QFs located far from load or outside the utility's BAA.

**Q. SHOULD INTERMITTENT QFS BE EXEMPT FROM INTEGRATION COSTS BECAUSE OF GEOGRAPHIC DIVERSITY?**

A. No. Staff modified its recommendation so that integration costs would apply only to wind QFs. The preferred locations for wind generating facilities are those with a good wind resource and access to transmission. This is true for wind plants whether they are QFs or not. There is no reason to assume that future wind QFs will be located in different or more diverse wind regimes from larger wind projects, and wind integration studies do not differentiate wind QFs from the integration costs of the wind fleet as a whole. As explained by RNP, "…wind integration studies determine the balancing reserve requirements for the utilities' entire wind fleets, not simply for QF projects." (RNP/100, Lindsey/10.) Therefore, the place to explore the impact of geographic diversity on wind integration costs is the integration study. That is why staff recommends using the wind integration studies from the IRP as the basis for integration charges assessed to QFs.

**Q. SHOULD QFS LOCATED OUTSIDE THE CONTIGUOUS AREA WHERE THE UTILITY HAS ITS OWN WIND FACILITIES BE EXEMPT FROM PAYING INTEGRATION COSTS?**

A. No. Wind facilities outside the contiguous area where the utility has wind generation may provide some geographic diversity, which can reduce (not eliminate) overall integration cost. But having different policies for wind QFs inside or outside a certain area requires a boundary to show where that area ends. Any such boundary will be arbitrary. The key factors in siting wind facilities remain wind quality and proximity to transmission. These factors apply equally to QF and non-QF wind project. Siting decisions should not be distorted by the desire to avoid integration costs. Moreover, if the QF is contracting with an Oregon utility but is located in another BAA (or BPA), then the Commission has no authority over what that BAA charges for integration.

**Q. WHAT WERE THE MAJOR CONCERNS RAISED BY STAKEHOLDERS REGARDING THE USE OF THE IRP INTEGRATION STUDY?**

A. The major concern was the accuracy of the current integration studies, and identifying the right forum for reviewing the studies.

**Q. IS THE AVOIDED COST FILING THE RIGHT PLACE TO REVIEW WIND INTEGRATION STUDIES?**

A. It is one of many places where the wind integration study needs to be reviewed. Utility wind integration studies need to receive close scrutiny in utility IRP's in order to determine the portfolio of resources with the best combination of cost and risk for ratepayers. Utility wind integration studies need to receive close scrutiny in utility rate cases and annual power cost case in order to determine just and reasonable rates for the utility. Utility wind integration studies need to receive close scrutiny in utility avoided cost filings in order to determine a appropriate avoided cost prices to pay to QFs. No single regulatory proceeding can address all of these issues and all of the ways that the utility wind integration study is used. RNP and others can address the accuracy of the studies in all of these forums.

**Q. DID PARTIES COMMENT ON INTEGRATION CHARGES FOR SOLAR PROJECTS?**

A. Yes. CREA and OneEnergy commented that if the Commission implements integration costs for wind projects, it should not allow the use of a wind integration charge for solar projects. (OneEnergy/100, Eddie/32; CREA/200, Reading/17.) CREA stated that none of the utilities in this docket have provided a solar integration study, and solar is easier to integrate than wind. (CREA/200, Reading/17.) RNP and ODOE also oppose integration charges for solar projects. (RNP/100, Lindsey/8-9; ODOE/100, Carver/10.)

**Q. HAS STAFF MODIFIED ITS POSITION BASED ON THIS COMMENT?**

A. Yes. After reviewing the above testimony, we now support exempting solar QFs from wind integration costs. Solar QF penetration is small enough right now to minimize any potential harm to ratepayers[2].

**Q. WOULD SOLAR PROJECTS STILL RECEIVE PAYMENT FOR AVOIDED INTEGRATION COSTS IN THE AVOIDED COST PRICE?**

A. Yes. If solar QF projects enable the utility to defer acquisition of large scale wind projects, then the avoided cost price legitimately includes the avoided integration costs.

**Q. IS IT FAIR FOR WIND QFS TO PAY INTEGRATION COSTS DURING THE DEFICIENCY PERIOD IF THE AVOIDED RESOURCE IS WIND?**

A. Yes. Staff proposed that QFs be charged for the cost of their own integration, and receive credit for the utility's avoided integration cost. If the QF and the avoided wind resource are in the same BAA, then those costs will cancel out. Adding avoided integration costs to the avoided cost price and having the QF pay for the cost of its own integration does appear redundant in this case. But if the QF and the utility's avoided resource are in different BAA's, then their respective integration costs are different. By considering the avoided and incurred integration costs separately, we assure that the correct integration charges are paid to the correct entities. Only by adhering consistently to this principle do we ensure the ratepayer indifference mandated by PURPA.

[2] This position is supported by footnote 44 OneEnergy/100 Eddie/33

**Q. PLEASE SUMMARIZE STAFF'S RECOMMENDATION**

A. The general principle is that the avoided cost price will include a credit for avoided integration costs, and a deduction for integration costs that the QF imposes on the utility. This principle is consistent with the two basic PURPA mandates requiring that utilities pay full avoided costs while maintaining ratepayer indifference.

**Q. DOES THIS PRINCIPLE APPLY DURING THE SUFFICIENCY PERIOD?**

A. Yes. During the sufficiency period, there is no avoided integration cost. The avoided cost price will contain a deduction for the cost to integrate the QF power. If the QF is in the contracting utility's BAA, the amount of that integration cost will be as shown in the wind integration study in the IRP. If the QF is outside the utility's BAA, then the BAA "hosting" the QF must recover its costs through its tariff. The OPUC has no authority over those costs.

**Q. HOW DOES STAFF'S PROPOSED POLICY APPLY DURING THE DEFICIENCY PERIOD UNDER THE RENEWABLE PRICE STREAM?**

A. During the deficiency period, the utility will add the integration costs of its avoided renewable resource to the avoided cost price, and it will deduct the cost to integrate the QF power. If both the QF and the avoided resource are in the utility's BAA, then their integration costs cancel out and there is no net adjustment to avoided cost price. But if the two are in different BAAs, then credit for avoided integration costs and the deduction for the QFs integration cost will offset each other. The "net" adjustment may be positive or negative, depending on which BAAs applicable integration costs are greater.

**Q. HOW ARE THE APPLICABLE INTEGRATION COSTS DETERMINED?**

A. For a resource in the contracting utility's BAA, the applicable integration costs should be consistent with the IRP. If the resource is in a different BAA, then the PUC has no authority over the integration costs. The BAA where the resource is located will recover integration costs through its tariff.

**Q. HAS STAFF PROVIDED AN EXHIBIT ILLUSTRATING HOW THIS POLICY IS APPLIED?**

A. Yes. Exhibit Bless/201 is a detailed explanation of how integration costs are calculated and handled under the Renewable Price stream.

## SECTION 3: SCHEDULE FOR AVOIDED COST UPDATES

*Issue 3.A: Should the Commission revise the current schedule of updates at least every two years and within 30 days of IRP acknowledgment?*

**Q. PLEASE REVIEW THE DIFFERENT PROPOSALS FOR AVOIDED COST UPDATE SCHEDULES**

A. All parties agree on a complete avoided cost update following each IRP acknowledgement order. In addition, staff proposed an annual update to adjust for natural gas and forward looking electric market prices. Staff suggested an annual update due in March every year. (Staff/100 Bless/20)

PacifiCorp proposed a quarterly adjustment for natural gas and forward looking market prices. (PacifiCorp/100 Dickman/4) Staff considers this too often.

PGE also proposed a complete update following each IRP acknowledgement and an annual update to adjust for natural gas prices, forward looking market prices, and any changes to its avoided resource in an acknowledged annual IRP update.

Idaho Power's proposal was similar, but included an updated resource sufficiency/deficiency determination in the annual update. OneEnergy recommended that the annual avoided cost update also include changes to avoided cost based on the status of the Production Tax Credit (PTC). (OneEnergy/100, Eddie/19.) Since the PTC has expired and been renewed several times since 2000, they suggested that the PTC be considered "expired" for avoided cost purposes if it has been continuously expired for three or more consecutive months. (OneEnergy/100, Eddie/20.) OneEnergy further recommended that the annual update occur after April, when the U.S. Energy Information Agency (EIA) issues its annual energy outlook. (OneEnergy/100 Eddie/10.)

REC opposed having the annual update occur on a fixed date each year. They proposed a complete avoided cost update following each acknowledged IRP, followed one year later by a partial update. REC made this proposal to avoid pancaking rate changes. (Coalition/200, Schoenbeck/14-17.)

**Q. PLEASE COMMENT ON THE REC SUGGESTION TO DEFER THE ANNUAL UPDATE IF AN IRP ACKNOWLEDGEMENT ORDER IS DUE WITHIN 90 DAYS.**

A. REC's suggestion was intended to avoid rate change pancaking, where changes to avoided cost prices happen within months of each other. Staff agrees that rate change pancaking, if it happens regularly, could make it more difficult for a QF to obtain financing from the ODOE Small Energy Loan Program (SELP) or other sources. However, deferring an avoided cost update when the IRP acknowledgement order is due within 90 days is impractical, because we cannot know with certainty when the IRP Order will be issued. Staff believes having annual updates due on a date certain will provide more predictability than the current schedule.

**Q. HOW MIGHT THE COMMISSION REDUCE THE POTENTIAL FOR RATE CHANGE PANCAKING?**

A. ODOE suggested that if the Commission knows that it will issue an IRP acknowledgment order within a few weeks of the annual update, it can issue an order to skip the regularly scheduled filing and rely on the IRP-triggered filing. (ODOE/300, Brockman/4.)

**Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE PRODUCTION TAX CREDIT (PTC)?**

A. Staff supports adding the status of the PTC to annual avoided cost update, and to the complete avoided cost update that will follow acknowledgement of each IRP.

**Q. PLEASE SUMMARIZE STAFF'S RECOMMENDATION IN VIEW OF THE PARTIES' MARCH 18TH RESPONSE TESTIMONY.**

A. Staff recommends a complete update following each IRP acknowledgement. Staff recommends that all three utilities file an annual update on the same date each year. The specific date is not important, but OneEnergy suggested a date shortly after the U.S. EIA issues its annual energy outlook, which typically happens in April. (OneEnergy/100 Eddie/10.) Staff considers this suggestion reasonable. Based on the other parties' comments, staff recommends that the annual update include adjustments for gas price forecast, forward looking electricity market price, changes in the cost and on-line date of the proxy resource taken from the latest *acknowledged* IRP update, and the status of the PTC as described by OneEnergy. Staff supports the ODOE proposal regarding concerns about rate change pancaking (ODOE/300 Brockman/4.)

## SECTION 4: ELIGIBILITY ISSUES

**Q. BRIEFLY REVIEW THE PARTIES' POSITIONS REGARDING THE ELIGIBILITY CAP.**

A. PGE, PacifiCorp and Idaho Power recommended reducing the eligibility cap. All of the non-utility parties supported retaining the cap at 10 MW. Staff supported retaining the cap at 10 MW, but suggested a 3 MW cap in the event that the Commission makes no changes to the Standard (Oregon) method for calculating avoided cost prices. (Staff/100 Bless/37.) OneEnergy proposed separate contract terms for small distributed generation QFs smaller than 3 MW. (OneEnergy/100 Eddie/33-36).

**Q. IS STAFF'S RECOMMENDATION CHANGED BY TESTIMONY THAT OTHER PARTIES SUBMITTED ON MARCH 18$^{TH}$, 2013?**

A. No. Staff maintains its recommendations from its March 18$^{th}$ testimony. However, Staff does wish to address an issue raised by OneEnergy. Specifically, OneEnergy recommends that the Commission clarify that nameplate capacity for solar QFs means AC output, as opposed to the direct output of the solar panels. (OneEnergy/100 Eddie/9.)

**Q. HOW DOES STAFF RECOMMEND THAT THE COMMISSION CLARIFY THE DEFINITION OF SOLAR QF OUTPUT FOR PURPOSES OF ELIGIBILITY FOR THE STANDARD CONTRACT?**

A. Staff recommends using a conversion factor of 0.85 to convert nominal solar panel DC output to AC output for purposes of standard contract eligibility. A factor of 0.85 is consistent with the factor used for the solar feed in tariff. (See Order No. 10-200 at 5; OAR 860-084-0040(2))

**Q. DOES STAFF SUPPORT SEPARATE CONTRACT TERMS FOR QFS SMALLER THAN 3 MW?**

A. No. OneEnergy proposed separate contract terms for QFs smaller than 3 MW in order to encourage distributed generation. (OneEnergy/100, Eddie/4-5.) Staff recognizes the beneficial characteristics of distributed generation, but there is no guarantee that all QFs smaller than 3 MW will truly have those characteristics. The separate contract terms proposed by OneEnergy for QFs smaller than 3MW include the option to choose fixed prices for a 25 year contract term, the option to choose levelized prices, and an adder for system losses. (OneEnergy/100, Eddie/6.) These terms are attractive enough to invite disaggregation, which is a concern to utilities and renewable advocates alike. The Commission has consistently chosen to have one standard contract and one eligibility threshold. Staff recommends continuing that policy. If we create a special class of QFs, it will be harder to avoid creating more special classes in the future. Staff believes the modifications to the avoided cost price proposed in our March 18th testimony (credit for avoided transmission and integration costs, exempting solar QFs from integration charges, and a capacity credit for non-intermittent renewable QFs) will help compensate distributed generation QFs for their true avoided cost, without changing the eligibility cap.

**Q. HAS STAFF MODIFIED ITS POSITION ON THE "SINGLE FACILITY" CRITERIA BASED ON RESPONSE TESTIMONY FROM MARCH 18TH?**

A. Yes. Staff originally recommended retaining the partial stipulation of Order 06-538 in its current form, with no changes. PacifiCorp proposed a change to this stipulation, allowing only independent family or community based projects to have a common passive investor. (PAC/200, Griswold/24). In our testimony on March 18th, we did not comment on this proposal. However, Staff agrees that this proposal could reduce the potential for disaggregation without unduly discouraging legitimately separate projects. For this reason, we now support

PacifiCorp's proposal regarding the limitation on common passive investors as presented at PAC/200 Griswold/24.

**Q. CAN SEPARATE QFS LEGITIMATELY SHARE INFRASTRUCTURE?**

A. Yes. There are legitimate reasons why two QFs would share infrastructure and remain separate projects. Staff would not consider two nearby projects to be a single QF simply because they share infrastructure. Even full size generating facilities owned by different utilities can sometimes share infrastructure.

## <u>SECTION 5: LEGALLY ENFORCEABLE OBLIGATION AND MECHANICAL AVAILABILITY</u>

*<u>Issue 6.B:</u>* *When is there a legally enforceable obligation?*

**Q. PLEASE REVIEW THE PARTIES' RESPECTIVE POSITIONS ON THE LEGALLY ENFORCEABLE OBLIGATION (LEO)**

A. PacifiCorp recommended that the legally enforceable obligation exists at the point in Schedule 37 Step B.5 when the utility sends its final draft PPA to the QF for signature. [3] (PacifiCorp/200 Griswold/30) Staff, in its March 18th testimony, supported that recommendation.

**Q. DID OTHER PARTIES COMMENT ON THE LEGALLY ENFORCEABLE OBLIGATION ISSUE IN THEIR RESPONSE TESTIMONY?**

A. Yes. REC and Exelon (Threemile Canyon) opposed PacifiCorp's proposal, saying that the utility would have too much ability to delay before presenting the final PPA to the QF. (Coalition/400, Lowe/13-19; Threemile Canyon/ 100,

[3] Idaho Power's recommendation on the LEO was substantially the same as PacifiCorp's.

Harvey/35-37.) REC acknowledged that the contracting process can be abused by all parties involved, and recommended that "other changes to the Schedule 37 process are necessary in order to establish a balanced path to creation of a legally enforceable obligation…" (Coalition/100, Lowe/18-19.)

**Q. DID ANY PARTY PROPOSE A DEFINITIVE POINT AT WHICH THE LEO ATTACHES, OTHER THAN PACIFICORP AND IDAHO POWER?**

A. No. In our March 18th testimony, Staff supported the PacifiCorp position. REC stated that the question needs to be considered in the context of the entire contracting process, which is the subject of Phase II of this docket. (Coalition/100, Lowe/16-19.) Three Mile Canyon did not propose a specific point in Schedule 37, but stated that "..a LEO is created when a QF commits itself to the electric utility." (Threemile Canyon/100, Harvey/35-38.) Threemile Canyon and REC both stated that the QF must have some control over the point at which the LEO is created, so that the utility will not delay the process unduly. (Coalition/100, Lowe/18-19; Threemile Canyon/100, Harvey/35-36.) However, neither party named a specific point in the process where the LEO is created.

**Q. WHAT IS STAFF'S RECOMMENDATION, AND WHY?**

A. There should be a clear, unambiguous step in the process that all parties understand to be the point at which the LEO is created. No party has suggested an alternative to the PacifiCorp/Idaho Power proposal. Given the lack of alternative proposals on this matter, Staff recommends the issue be deferred to Phase II where the entire contracting process can be reviewed holistically.

*<u>Issue 6.E:</u>* *How should contracts address mechanical availability?*

**Q. PLEASE REVIEW THE PARTIES' POSITIONS**

A. All three utilities proposed slight changes to their MAG provisions. The most significant points are: PGE agreed to include a planned maintenance allowance of up to 200 hours per turbine per year, which would not count against the facility's overall availability. (PGE/200 MacFarlane-Bettis/2) PacifiCorp proposed to increase its availability requirement to 90% after the second year of operation with a 60 hour per turbine/year allowance for planned maintenance. (PAC/300 Griswold/1.) Idaho Power proposed no changes to its availability guarantee, but proposed a "shortfall energy payment" if the MAG was not met. (Idaho Power/302 Stokes/15-17.) The shortfall energy payment would cover the utility's cost of short term replacement power.

**Q. WHAT WAS STAFF'S RECOMMENDATION?**

A. Staff declined to prescribe a specific mechanical availability percentage, stating that each utility should be allowed to propose a reasonable combination of mechanical availability percentage, planned maintenance allowance, and penalty for failure to meet the guarantee. Staff's major recommendation was that the penalty should not be contract termination, but should be a monetary penalty along the lines of Idaho Power's proposal. (Staff/100 Bless/44-46.)

**Q. HAS STAFF'S RECOMMENDATION CHANGED?**

A. No.

**Q. DOES THIS CONCLUDE STAFF'S TESTIMONY?**

A. Yes.

CASE: UM 1610
WITNESS: ADAM BLESS

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 201

## Exhibit in Support
## Of Reply Testimony

## April 29, 2013

## Explanation of Integration Cost Treatment

This exhibit shows staff's proposed treatment of avoided integration costs that are added to the avoided cost price under the Renewable Price option, or deducted from the avoided cost price to account for the cost of integrating intermittent QF power. As shown in the attached Table, avoided integration costs added to the avoided cost price are based on the BAA where the *Avoided* resource is located. The cost of integrating intermittent QFs is based on the BAA where *QF* is located.

The general principles are:

**Avoided Integration Costs *Added* to the Avoided Cost Price (**integration costs depend on the Balancing Authority Area (BAA) where the *Avoided* Resource is located)**:**

- Under the Standard (nonrenewable) price option, the avoided resource is a CCCT. There are no integration costs to avoid.
- Under the Renewable price option, there are no integration costs to avoid during the sufficiency period.
- During the deficiency period, the avoided resource is presumed to be wind, and the QF enables the utility to avoid costs of integrating that wind. The QF receives an "adder" in its avoided cost price, equal to the integration cost of the *avoided* resource.
    a. If the avoided wind resource is in the purchasing utility's balancing area (BAA), then the adder will be that utility's integration costs, based on the integration study in the utility's IRP.
    b. If the avoided wind resource is in another utility's BAA (or BPA), then the adder will be that BAA's integration charge, as reflected in the purchasing utility's IRP.
    c. If the BAA where the avoided resource is located has integration costs in its OATT, then the purchasing utility's IRP will reference the OATT. The Oregon PUC does not have authority over those costs.
    d. A utility may choose to do all of its own wind integration. If so, QFs selling to that utility under the renewable price stream will see an adder to the avoided cost price, equal to the integration costs in the contracting utility's IRP.
- Because these avoided integration costs are based on the avoided resource, they are added to the avoided cost price and are the same regardless of the QF location or resource type.

**QF Integration Costs Deducted from the Avoided Cost Price** (depend on the BAA where the *QF* is located):

The general principle is that the QF is responsible for the cost of its integration.

- Integration costs depend on the location of the QF, not the avoided resource. Therefore, there is no difference between the Standard and Renewable Price Stream.
- During the sufficiency period, there is no avoided resource. The avoided cost price is the forward looking market price. Utilities may deduct the QF integration costs.
    a. If the QF is located in the contracting utility's BAA (in-system) then the deduction for QF integration costs will be based on the integration study in the utility's IRP.
    b. If the QF is in another BAA (out of system), then the deduction for integration is based on applicable integration charges of the other BAA. The PUC has no authority over that cost.
    c. If the integration cost exceeds the market price, the net avoided cost price will not be lower than zero.
- During the deficiency period, the adjustment to the avoided cost price is the "net" of the avoided integration costs minus the QF's integration costs.
    a. If the QF and the avoided resource are in the same BAA, the integration costs will cancel each other out, leaving no net adjustment.
    b. If the QF and the avoided resource are in different BAAs, then the adjustment to the avoided cost price may be positive or negative, depending on which BAA's integration costs are higher.
    c. For a QF located in a BAA "other" than the contracting utility, that BAA must recover integration costs through its tariff. The Oregon PUC has no authority over those costs.
    d. If the contracting utility does all of its own wind integration, then the applicable integration costs will be those in the integration study in the IRP.

The Table below summarizes the effect of Staff's proposed treatment of integration costs on the avoided cost price.

**Location of Avoided Resource**

| Location of QF | Avoided Resource in Contracting IOU BAA (In-system) | Avoided Resource in Other BAA (Out of System) |
|---|---|---|
| QF in Contracting IOU BAA (In-System) | • No Net Adjustment to Avoided Cost (avoided integration costs and QF integration costs cancel each other) | • Avoided integration costs from utility's IRP[1]<br>• Cost to integrate the QF power taken from the integration study in the utility's IRP.<br>• Adjust the Avoided Cost Price to reflect the difference between avoided integration cost and QF integration cost.<br>• This adjustment may be positive or negative |
| QF in Other BAA (Out of System) | • Add the utility's avoided integration costs to QF price[2]<br>• QF pays "other"BAA integration charges[3] | • Add the utility's avoided integration costs to QF price[4]<br>• QF pays "other" BAA integration charges |

Notes:

1. Integration costs for an Out-of-System Avoided Resource are the integration costs charged by the BAA where the avoided resource is located. OPUC does not have authority over these charges.
2. Integration costs for In-System Avoided Resource are taken from the utility's integration study in their IRP.
3. Integration costs for "out of system" QF set by the QF's host BAA, as shown in that BAA's OATT. The OPUC does not have authority over these charges.
4. Taken from the OATT of the BAA where the avoided resource is located.

CERTIFICATE OF SERVICE

UM 1610

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 29th day of April, 2013 at Salem, Oregon

Kay Barnes

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