CASE: UM 1610 PH II
WITNESS: BRITTANY ANDRUS

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 600

# Response Testimony

# July 24, 2015

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

A. My name is Brittany Andrus. My business address is 201 High Street SE. Suite 100, Salem, Oregon 97301-3612.

**Q. Please describe your educational background and work experience.**

A. My Witness Qualification Statement is found in Exhibit Staff/301 and Staff/501.

**Q. What is the purpose of your testimony, and how is it organized?**

A. The testimony below contains Staff's reply to the opening testimony in Phase II of this investigation into qualifying facility (QF) contracting and pricing filed by parties on May 22, 2015. As with Staff's earlier testimony, this testimony is organized around nine issues.

**<u>Issue No. 1:</u> 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?**

**Q. What are the circumstances underlying Issue No. 1?**

A. In 2005, the Commission decided that utilities should offer QFs standard contracts with terms up to 20 years.[1] Because of the speculative nature of forecasted prices for such an extended term, the Commission decided that the fixed-rate portion of a 20-year contract should be 15 years, and that rates paid in the last five years should be based on market prices.[2]

In 2011, the Commission ordered PacifiCorp and Portland General Electric Company (PGE) to offer standard avoided cost prices based on costs of the next avoidable resource in their IRP. The Commission specified that when the utility is renewable resource deficient, renewable avoided cost prices

[1] Order No. 05-584 at 19-20.
[2] Order No. 05-584 at 20.

are based on the costs of the next avoidable renewable resource.[3] During periods of renewable resource sufficiency, avoided cost prices are based on market prices.[4] The 2011 order specified that during periods of resource deficiency, QFs receiving the Standard Renewable Avoided Cost prices must transfer renewable energy credits (RECs) associated with energy sold to the utility, but may keep the RECs during the utility's resource sufficiency periods.[5] At issue now is whether the Commission intended for QFs to transfer RECs to the utility during the utility's renewable resource deficiency periods even when the QF is receiving market-based prices in the last five years of a 20-year standard contract based on Standard Renewable Avoided Cost prices.

**Q. Please describe parties' arguments in favor of requiring QFs to transfer RECs to utilities even when the QFs are receiving market-based prices.**

A. PGE asserts that under the Commission's 2011 order implementing Standard Renewable Avoided Cost prices, QFs must always transfer RECs to the utility during the utility's deficiency period no matter whether the QF is receiving deficiency period prices based on the fixed costs of the next avoidable renewable resource.[6] PGE testifies that the purpose of entering into a standard renewable contract is to obtain the QF's green tags during resource deficiency periods.[7] PGE testifies that "[i]f the utility is entering into a standard renewable PPA and guaranteeing that it will purchase the QF power, the utility

[3] Order No. 11-505 at 19.
[4] Order No. 11-505 at 19.
[5] Order No. 11-505 at 19.
[6] PGE/500, Macfarlane-Morton/4-6.
[7] PGE/500, Macfarlane-Morton/6.

should own the Green Tags regardless of the price of purchase during a period of resource deficiency."[8]

PacifiCorp notes that the Commission decided that QFs should receive market-based prices during the last five years of a standard contract in order to reduce the risk of forecasting prices for a 20-year contract while still facilitating financing for the QF.[9] PacifiCorp asserts that there is no relationship between the Commission's rationale for market-based prices in the last five years of a standard contract and RECs. Instead, REC ownership is related to the utility's resource position.[10] Relying on these points, PacifiCorp asserts that REC ownership must pass to utility's during their resource deficiency periods notwithstanding "a QF's voluntary option to accept market prices during the last five years of a PPA."[11]

**Q. Are PacifiCorp's and PGE's arguments persuasive?**

A. No. PacifiCorp and PGE do not address the rationale underlying the Commission's decision to require Standard Renewable Avoided Cost prices, which is as follows:

> Allowing a renewable QF to choose between [renewable and non-renewable] avoided cost streams is consistent with FERC's ruling that clarified the right of the states to determine the avoided cost associated with utility purchases of energy "from generators with certain characteristics." Renewable QFs willing to sell their output and cede their RECs to the utility allow the utility to avoid building (or buying) renewable generation to meet their RPS requirements. These QFs should

[8] PGE/500, Macfarlane-Morton/6.
[9] PacifiCorp/1000, Griswold/4.
[10] PacifiCorp/1000, Griswold/6-7.
[11] PacifiCorp/1000, Griswold/7.

> be offered an avoided cost stream that reflects the costs that utility will avoid.[12]

The Commission's rationale links the QF's obligation to transfer RECs to the receipt of prices designed to compensate for the value of the RECs.[13] Meaning, the QF is required to transfer RECs to the utility to be eligible for avoided cost prices based on the fixed costs of the next avoidable renewable resource. The QF should not have to transfer its RECs when it is not being compensated for them with payments based on the fixed costs of the next renewable avoidable resource.

**Issue No. 2: Should avoided transmission costs for non-renewable and renewable proxy resources be included in the calculation of avoided cost prices?**

**Q. Please explain this issue.**

A. This issue applies most directly to PacifiCorp whose avoided proxy resources are generally "on-system." PacifiCorp testifies that avoided cost prices should not include avoided costs for "Company-owned infrastructure and third-party rights" to move energy across the Company's multi-state service territory because purchasing from a QF does not allow it to avoid transmission costs.[14] PacifiCorp asserts that this is because "Company-owned transmission infrastructure and contractual rights on third-party systems are needed to operate PacifiCorp's system whether it adds QFs or non-QF resources."[15]

[12] Order No. 11-505 at 9.
[13] See Order No. 11-505.
[14] PacifiCorp/800, Dickman/5.
[15] PacifiCorp/800, Dickman/5.

OneEnergy, LLC (OneEnergy) asserts that there is at least one PacifiCorp proxy resource for which PacifiCorp would incur transmission costs that it may not incur for a resource in a different location. OneEnergy testifies that PacifiCorp's renewable avoided cost prices are based on a proxy wind plant to be located in the "Aeolus wind bubble' in Wyoming.[16] OneEnergy states that it "is widely known that insufficient transmission exists today to get new generation resources from the wind bubble to PacifiCorp load. Recent wind QF agreements with projects in this area have required the QF to accept a reduced purchase price to account for PacifiCorp's curtailment of other Network Resources using the same transmission paths."[17]

**Q. Does Staff agree with PacifiCorp that it could not incur transmission-related costs for its proxy resource that are above and beyond those incurred for any on-system resource?**

A. No. PacifiCorp's testimony that it will never avoid transmission costs with a QF purchase is inconsistent with some of its other testimony. For example, PacifiCorp testifies that it will incur third-party transmission costs for some QFs because they are located in load pockets.[18] Presumably, PacifiCorp would incur the same type of costs if its next avoidable resource is in a load pocket. Further, PacifiCorp testifies that the QF's location impacts the value of the QF's energy and capacity on PacifiCorp's system.[19]

[16] OneEnergy/400, Eddie/2-3.
[17] OneEnergy/400, Eddie/3, *citing* Eddie/1; Response to OneEnergy Data Request 6.1 (OneEnergy/401).
[18] PacifiCorp/1000, Griswold/25-26.
[19] PacifiCorp/800, Dickman/18.

**Q. Does Staff agree with OneEnergy that PacifiCorp's proxy renewable resource is located in a "wind bubble" and that PacifiCorp must acquire additional transmission resources to move energy from the proxy plant to its load?**

A. Staff has not investigated the question sufficiently to opine on the accuracy of OneEnergy's assertions. However, OneEnergy's assertions support Staff's recommendation – the Commission should not conclude in this docket that avoided transmission costs can never be included in the calculation of avoided cost prices when the proxy resource is an on-system proxy resource. Whether there are such avoided transmission costs is a factual question that should be addressed on a case-by-case basis.

**Q. When would this case-by-case examination take place?**

A. It would take place at the same time that the other inputs to avoided cost prices are reviewed, in the process subsequent to the IRP acknowledgment. As with other inputs, the parties should start with the costs shown in the utility's IRP.

**Q. OneEnergy recommends a test for determining whether there are avoided costs for on-system proxy resources. Does Staff agree with this test?**

A. OneEnergy recommends the following test:

> If the on-system proxy resource cannot be designated a Network Resource at its full capacity without transmission upgrades and without a de-rating or curtailing other Network Resources, then the

> cost of transmission upgrades necessary to make it a Network Resource should be included in avoided cost prices.[20]

Staff thinks this test could inform the case-by-case analysis mentioned above, but does not support OneEnergy's recommendation that the Commission order that this test be used to finally determine the question of avoided transmission costs in every case. The Commission should clarify that there may be situations in which avoided transmission costs should be included in the calculation of avoided cost prices when the proxy resource is an on-system resource, and that parties may address the issue on the facts for a particular proxy resource in process following the compliance filings made within 30 days of an acknowledged IRP.

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

**Issue No. 4: Should the capacity contribution calculation for standard non-renewable avoided cost prices be modified to mirror any change to the solar capacity contribution calculation used to calculate the standard renewable avoided cost price?**

**Q. Please summarize the question presented by Issue Nos. 3 and 4.**

A. Under the avoided cost methodology in effect prior to Order No. 14-058 (the "Previous Method"), there was no explicit adjustment to account for the actual value of a QF's capacity contribution. But, there was a practical adjustment

[20] OneEnergy/400, Eddie/2-3.

because QFs were compensated for capacity in proportion to the QF resource type's on-peak capacity factor (the average percentage of nameplate capacity generated during all on-peak hours). So, a QF resource type with an on-peak capacity factor of 27.5 percent could expect to receive annual payments for capacity equal roughly equal to 27.5 percent of the utility's annual avoided capacity costs, which are based on the fixed costs of a combined cycle combustion turbine (CCCT).

In Order No. 14-058, the Commission adopted the Staff proposed capacity contribution adjustment that adjusted payments to QFs based on the QF resource type's contribution to peak. Staff recommended the change because a resource's capacity contribution depends on both the characteristics of the QF resource and the characteristics of the utility system to which the QF is delivering energy and better represents the value of the QF's capacity to the utility.[21]

The question presented now is whether the Commission intended the capacity contribution adjustment to be additive to the already existing on-peak capacity factor "adjustment," or to be a substitute. This ambiguity arises because Staff and other parties believe that the methodology Staff presented as exhibit to Staff's original testimony in Phase I of Docket No. UM 1610 (Staff/102-103), is flawed and does not do what the Commission intended.

Staff intended to propose a methodology that would adjust capacity payments to QF to make them commensurate with the QF resource type's

[21] See e.g., ODOE/800, Broad/6.

contribution to peak. But, the methodology that Staff proposed and that was adopted by the Commission does not do this. Instead, the methodology adjusts payments to QFs based on the QF resource type's contribution to peak and then again for the QF resource type's on-peak capacity factor. The result is payments to QFs that are significantly lower than payments that are commensurate with the QF's contribution to peak.

The utilities, however, believe the methodology in Staff/102-103 is not flawed and does what the Commission intended. The utilities point to the Commission's intention to lower capacity payments to QFs and note that this is what the methodology presented in Staff/102-103 does.

**Q. Is the Commission's intent clear from the language of the order?**

A. It is not sufficiently clear to preclude the parties' dispute. The Commission expressly adopted Staff's proposed methodology and this methodology has the double-discount effect described above. But, the Commission also noted in its order that under the standard renewable avoided cost price stream, the methodology should result in capacity payments to solar and baseload resources that are higher than what they would receive under the current method.[22] This statement indicates the Commission did not intend to adopt a methodology that lowered the capacity payments for these resource types to a fraction of what they received under the previous method.

**Q. How should the Commission resolve this dispute?**

[22] Order No. 14-058 at 15.

A. Staff recommends the Commission return to Order No. 14-058. Staff believes the order is clear that the Commission intended that payments for capacity to QFs should be commensurate with the contribution to peak of the QF resource type. Meaning, if a QF is of a type with a contribution to peak of 12 percent, the Commission intended that the QF could receive payments equal to 12 percent of the utility's annual avoided capacity costs (if it operated consistently with the assumptions used to determine the contribution to peak).

While the utilities are correct that the Commission did intend to address potential for overpayments for capacity in Order No. 14-058, the Commission did acknowledge that the capacity contribution adjustment adopted in the order would increase capacity payments to QFs in some circumstances.[23]

**Q. What do the utilities say in this phase of UM 1610?**

A. PGE merely states that the methodology for the Standard Renewable Avoided Cost prices in Order No. 14-058 is correct and that the methodology for Standard Non-Renewable Avoided Cost prices should remain as is to be consistent with the Standard Renewable Avoided Cost price.[24]

Idaho Power and PacifiCorp both oppose the Proposed Method based on the mistaken belief that Staff's proposed modifications to the capacity contribution adjustments would result in the utilities paying QFs for capacity in hours that QFs do not generate.[25]

PacifiCorp testifies:

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[23] Order No. 15-048 at 15.

[24] PGE/500, Macfarlane-Morton/8.

[25] Idaho Power/800, Youngblood/10, PacifiCorp/800, Dickman/10.

> As with standard renewable avoided costs, the issue of changing the calculation of capacity costs under standard non-renewable avoided cost prices boils down to whether the fixed costs of the CCCT should be spread across on-peak hours and only paid to a QF when it is generating (as has been done for many years), or whether a QF should be paid a fixed amount for capacity regardless of when it generates.[26]

Regarding Staff's proposed modification to the capacity contribution adjustment for Standard Non-Renewable Avoided cost prices Idaho Power testifies,

> Staff assumes that the QF is entitled to all of "those" dollars that the capacity contribution adjustment would be expected to pay the target capacity dollars over the course of a year. If that were true, then taken to the extreme, if a solar QF only generated for one on-peak hour in a year, Staff's capacity contribution adjustment would compensate the QF for the total target capacity dollar amount in one hour, equivalent to a lump-sum capacity payment.[27]

**Q. Are Idaho Power and PacifiCorp's assertions that QFs will be compensated for capacity that they do not provide?**

A. No. The contribution to peak of a resource type is based in part on the on-peak capacity factor of the resource type. So, the contribution to peak is based on an assumption of how many on-peak hours the resource type will operate in a year. Under Staff's Proposed Method, if a QF operates consistently with the assumption regarding operating hours used to calculate the resource type's contribution to peak, the QF should be able to receive payments commensurate with the resource type's contribution to peak. If the

[26] PacifiCorp/800, Dickman/10. See also PacifiCorp/800, Dickman/13 "Proposals to pay a fixed amount to QFs for avoided capacity costs misrepresent the cost of displacing a proxy resource[.]").
[27] Idaho Power/800, Youngblood/10.

QF operates only half as much as is assumed for the QF resource type, the QF could receive only half these payments.

Furthermore, Staff finds the utilities' arguments to the contrary puzzling, particularly because the utilities' mistake has been addressed in previous testimony. More specifically, all three utilities made similar arguments in Phase I of UM 1610, and Obsidian Renewables, LLC, addressed the utilities' mistaken assumption with the following Q&A:

> **Q. Does Obsidian advocate that the capacity payment should be paid as a fixed dollar amount rather than on a per MWh basis?**
>
> A. No. The recommendation in my opening testimony was quite clear that the properly calculated capacity payment should be paid as an adder to the on-peak energy rate consistent with Staff's revised proposal. I am aware, however, that the purchasing utilities attribute to Obsidian, either directly or indirectly, the notion that the capacity payment should be a fixed dollar amount. See PGE/400, Macfarlane/5; Idaho Power/600, Youngblood/15, PAC/600, Duvall/8.
>
> I believe that this is merely a straw-man argument that the purchasing utilities have collectively devised based on a misunderstanding of Obsidian's April 24, 2014 Motion for Clarification.[28]

**Q. Putting aside the utilities' mistaken assumption that QFs will be entitled to a fixed annual capacity payment no matter how many hours in which they generate, are the utilities correct that Staff's proposed modifications to the capacity contribution adjustment will result in overcompensating QFs for capacity?**

A. No. At most, QFs would receive payments for capacity that are commensurate with their contribution to peak, meaning that a QF with a contribution to peak of

[28] Docket UM 1610 Phase I Obsidian/300, Brown/6.

12 percent would receive annual payments roughly equal to 12 percent of the utility's annual avoided capacity costs. Staff disagrees with any assertion that this would "overcompensate" QFs.

In any event, whether Staff's proposed method "overcompensates" QFs or appropriately compensates QFs is the question presented to the Commission. Staff believes the parties are in agreement as to the amount of capacity payments QFs would receive under the Current Method and Staff's Proposed Method. What the parties do not agree on is whether QFs would be "overcompensated" under the Proposed Method. Again, the resolution turns on what the Commission intended in Order No. 14-058. Did the Commission intend for QFs to receive capacity payments commensurate with their contribution to peak, or did the Commission merely intend to reduce the payments the QFs were already receiving to a fraction thereof by multiplying these payments by the QFs contribution to peak.

Staff believes the former. First, as discussed above, the language of Order No. 15-048 noting that capacity payments to certain QF resource types would increase under the Staff proposed methodology supports this interpretation.[29] Second, reducing payments to QFs by applying both discounts results in payments for capacity that have no correlation to the capacity avoided by the utility. This result is arbitrary and not consistent with the rest of the Commission's avoided cost methodologies that are focused on correctly measuring the utilities' avoided costs.

[29] Order No. 15-048 at 15.

**Issue No. 5: What is the appropriate forum to resolve litigated issues and assumptions?**

**Q. What is Staff's recommendation regarding this issue?**

A. Staff recommends that the Commission continue to use its current process, but also require utilities to meet minimum filing requirements (MFRs) when they make their avoided cost filings.

**Q. What is the Commission's current process?**

A. Each utility is required to file updated avoided cost prices within 30 days of acknowledgment of the utility's Integrated Resource Plan (IRP). "Avoided cost filings are subject to suspension and the same investigatory process that any tariff filing may undergo."[30]

**Q. Do other parties recommend a different process?**

A. PacifiCorp recommends that the Commission limit litigation regarding avoided cost price inputs to the IRP process.[31] PacifiCorp argues that there should be no additional process "whereby stakeholders could litigate inputs and assumptions developed in an acknowledged IRP."[32] PacifiCorp asserts that such a process would undermine the collaborative, transparent IRP process, be duplicative and slow the implementation of updated avoided cost prices.[33]

[30] Order No. 05-584 at 36-37. *See also* OAR 860-029-0080(6) ("Any standard rates filed under OAR 860-029-00040 shall be subject to suspension and modification by the Commission.").
[31] PacifiCorp/900, Drennan/10-11.
[32] PacifiCorp/900, Drennan/10.
[33] PacifiCorp/900, Drennan/10-11.

ODOE recommends that the Commission use a separate proceeding that runs concurrently with the IRP to litigate avoided cost prices.[34] ODOE cites to the increasing complexity of the avoided cost prices inputs as the reason for a separate proceeding.[35] ODOE also recommends the Commission require utilities to comply with a MFR that is "sufficiently detailed to ensure that filings demonstrate that the assumptions underlying the avoided cost estimates are reasonable."[36]

Idaho Power asserts that neither the IRP nor an avoided cost "compliance" process is appropriate for litigating disputed issues.[37] CREA testifies that avoided cost prices should be established with a contested case process and that "simply accepting inputs from an IRP into an avoided cost filing without our having appropriate rate-setting procedural safeguards" is not appropriate.[38]

PGE testifies that the current process is sufficient. PGE notes it is willing to provide cites to IRP to improve parties' ability to review avoided cost price filings.[39]

**Q. What is Staff's response to the recommendations of other parties?**

A. PacifiCorp's assertion that inputs to avoided cost prices should not be subject to dispute once an IRP is acknowledged is unworkable. While the Commission has held that the IRP should be the basis for determining what costs a utility

[34] ODOE/ 700, Carver/5-6.
[35] ODOE/700, Carver/6-9.
[36] ODOE/700, Carver/5.
[37] Idaho Power/900, Alphin/4-5.
[38] CREA/500, Skeahan/15.
[39] PGE/500, Macfarlane-Morton/8-9.

would avoid with a QF purchase, limiting stakeholders' ability to contest avoided cost price inputs to the IRP would complicate and lengthen the IRP process.

ODOE's proposal for a concurrent process is not necessary to protect stakeholders' interests. Staff agrees that a concurrent process could hasten implementation of avoided cost price changes following IRP acknowledgment. However, the current sequential process allows the Commission to use the utilities' acknowledged resource plans as the starting point for what costs the utilities will avoid with QF purchases.

Staff believes that Idaho Power's assertion that the avoided cost "compliance process" is not the appropriate place for parties to dispute IRP inputs is based on a misunderstanding of the current process. As already noted, avoided cost prices are subject to "suspension and modification" after they are filed by the utility.[40] Presumably any avoided cost prices filed after suspension and modification would be subject to a compliance process, but the review of the initial avoided cost prices is not a "compliance process." To the extent that Idaho Power asserts that policy issues such as those addressed in this docket are not appropriate for the process following an avoided cost price filing, Staff agrees.

Staff appreciates PGE's offer to include citations to the IRP in the avoided cost filings. This proposal is not a sufficient substitute for Staff's proposed MFRs, however. Finally, Staff believes that CREA's recommendation for a

[40] Order No. 05-584.

contested case process aligns with Staff's recommendation to continue using the process previously ordered by the Commission.

**Issue No. 6: Do market prices used during the Resource Sufficiency Period sufficiently compensate for capacity?**

**Q. Please describe the testimony of other parties on this issue.**

ODOE testifies that whether market prices sufficiently compensate for capacity depends on whether the forecasted market prices in the IRP (and avoided cost prices) reflect the utility's actual practices.[41] ODOE notes that a utility may use Mid-C monthly wholesale power prices in IRP, but if it typically purchases capacity separately from its energy purchases or if it contracts for a longer term at fixed prices, the forecast is unlikely to reflect the costs the utility will actually avoid.[42]

CREA, REC, Obsidian Renewables, and One Energy (hereinafter referred to as "Joint QF Parties"), co-sponsored a witness, Kevin Higgins, who testified that QFs are not appropriately compensated during the sufficiency periods for two reasons.

The first reason is specific to PacifiCorp. Mr. Higgins explains that once a QF contact is included in PacifiCorp's resource stack in its IRP, it remains in the resource stack even after the contract term expires.[43] Accordingly, when a QF negotiates a renewal of the contract, PacifiCorp's avoided cost prices are based on sufficiency/deficiency periods that already assume the existence of

[41] ODOE/700, Carver/10.
[42] ODOE/700, Carver/10.
[43] Joint QF Parties/100, Higgins/7-8.

the contract the QF is attempting to procure. As Mr. Higgins notes in his testimony, “when the purpose of the exercise is to determine the value of QF capacity, the act of assuming that all or a portion of the QF capacity that is being valued simply “shows up” via contract extension improperly predetermines the answer to the valuation question—and will understate the value of the QF capacity.”[44]

Mr. Higgins recommends changing the assumption regarding renewing QF contracts for purposes of establishing avoided cost price to ensure the prices are not based on an artificially extended sufficiency period.[45]

Mr. Higgins’ second recommendation is not specific to PacifiCorp, but is most applicable to that utility because of PacifiCorp’s coal resources. Specifically, Mr. Higgins argues that sufficiency period prices do not adequately compensate renewable QFs in PacifiCorp’s territory for their clean energy given the current risk associated with coal resources and PAC’s investments to retain its coal resources.[46]

To address this concern, the Joint Parties recommend that the Commission implement an “interim capacity pricing mechanism” to attribute some value to the capacity of renewable and zero-emission during PacifiCorp’s sufficiency period until the uncertainty regarding implementation of 111(d) is resolved.[47] Under the mechanism, the value of capacity from renewable and zero-emitting QFs would be determined by the net present

[44] Joint QF Parties/100, Higgins/7.
[45] Joint QF Parties/100, Higgins/8-9.
[46] Joint QF Parties/100, Higgins/5-6.
[47] Joint QF Parties/100, Higgins/12-14.

value of the revenue requirement associated with environmental upgrades that are planned for the sufficiency period.[48]

Q. **Does Staff agree with the Joint QF Parties' recommendation to change the way QF contracts are modeled for purposes of determining avoided cost prices?**

A. Yes. Staff agrees with the Joint Parties' recommendation to require PacifiCorp to stop basing its Standard Renewable and Non-Renewable Avoided Cost prices on a resource stack that assumes terminating QFs are renewed.

**Q. Does Staff agree with the Joint Parties' recommendation for an interim capacity pricing mechanism?**

A. No. Staff is unable to find authority for this proposal in the Public Utility Regulatory Policies Act (PURPA). The Federal Energy Regulatory Commission (FERC) has found that an avoided cost rate may not include a "bonus" or "adder" above the calculated full avoided cost of the purchasing utility to provide additional compensation for environmental externalities that are not real costs that would be incurred by the utilities.[49] But, if the environmental costs "are real costs that would be incurred by utilities," then they "may be accounted for in a determination of avoided cost rates."[50]

Here, the Joint QF Parties recommend the interim capacity pricing mechanism to further the public interest of encouraging investment in

48 Joint QF Parties/100, Higgins/14-17.
49 *So Cal Edison,* 71 FERC 61,269 at 62,080 (2010).
50 *Id.*

renewable and non-emitting resources "while the uncertainty surrounding the implications of 111(d) on the Company's resource planning is being sorted out."[51] This uncertainty is monetized, to some degree, because utilities model potential regulatory futures to determine the least cost portfolio of resources in their IRPs. An adder to avoided cost prices to recognize potential future benefits of renewable non-emitting resources is not permissible.

**Issue No. 7: What is the most appropriate methodology for calculating non-standard avoided cost prices? Should the methodology be the same for all three electric utilities operating in Oregon?**

**Q. Please summarize the issue.**

A. The non-standard avoided cost price methodology in Oregon, which applies to QFs that have a capacity larger than 10 MW, follows the Commission direction in Order No. 07-360. That order directs that the utilities adjust their standard avoided cost prices, which are based on a proxy CCCT and a proxy wind resource for nonrenewable and renewable avoided costs respectively, using the seven factors enumerated in FERC regulations.[52]

**Q. Please describe parties' positions on this issue.**

A. CREA opposes the mandatory use of computer models for establishing non-standard avoided cost prices, stating that their use puts the developer at a disadvantage because the models can be very sophisticated and require significant licensing fees and outside expertise.[53]

[51] Joint QF Parties/100, Higgins/14.
[52] Order No. 07-360 at 15-16.
[53] CREA/500, Skeahan/17.

REC opposes any change to Commission policy, "especially for existing hydro and biomass QFs,"[54] and cites the recommendation of Donald Schoenbeck in Phase I of this docket. REC states that the use of computer models is complex, expensive and prone to disputes, and that it is unnecessary "because there are no benefits in terms of more accurate avoided cost pricing."[55]

PGE supports the continuation of the methodology established in Order No. 07-360, and states that the three utilities should have "flexibility in the implementation of adjustments using the seven FERC adjustment factors."[56], PacifiCorp proposes a modeling based approach using its Generation and Regulation Initiative Decision Tools production cost model because it is more accurate than using the proxy method as the starting point for calculating large QF avoided costs.

Idaho Power requests that the Commission continue its policy of authorizing the same methodology in Oregon as is used for Idaho QFs for those projects exceeding the standard rate eligibility cap. Staff notes that currently the rate eligibility cap is different between the two states.[57]

**Q. What is Staff's position on this issue?**

A. Staff agrees with PacifiCorp that the current method of adjusting the standard avoided cost prices ignores the interdependencies across the seven FERC

[54] Coalition/400, Lowe/21.
[55] Coalition/400, Lowe/22.
[56] PGE/500, Macfarlane – Morton/10.
[57] Order No. 15-999 granting temporary relief by reducing the eligibility cap for Idaho Power standard avoided cost prices for QFs in Oregon to 3 MW or less; Idaho Public Utilities Commission Order No. 32262 lowering the eligibility cap for standard avoided cost prices for QFs in Idaho to 100 kW.

factors, and therefore recommends that utilities be conditionally allowed to use a computer based model to calculate negotiated avoided costs. Staff believes that an accurate accounting for the impacts on individual utility systems can be achieved through the use of the production cost models, which are also used to estimate and set rates for power costs each year. They have been thoroughly vetted by the companies and by Staff.

Staff also agrees with CREA that a level of transparency must accompany this recommendation:

> If allowed, the Commission should adopt rules requiring the IOU to cooperate with the developer in use of the IOU's model to run scenario and sensitivity analysis in a transparent manner reasonably requested by the developer in order to develop a fair and equitable non-standard avoided cost rate.[58]

Staff believes that the base assumptions and inputs to a production cost model as well as a thorough description of the model run(s) needs to be provided to QF developers requesting nonstandard pricing.

Staff does not support a requirement that the methodology be the same for all three utilities because the characteristics of a particular system may not require the same complex modeling as another system.

Staff notes that there are currently two different proceedings underway in which the question of the size of the QF standard eligibility is raised.[59] Staff's position above assumes that the 10 MW eligibility cap is in place. In the event that the cap is lowered, this position may be changed.

**Issue No. 8: When is there a legally enforceable obligation?**

[58] CREA/500, Skeahan/18.
[59] Docket UM 1725 (Idaho Power) and Docket UM 1734 (PacifiCorp).

**Q. What is Staff's position on this issue?**

A. Staff's position is guided by language in the Oregon Court of Appeal's opinion in *Snow Mountain Pine v. Maudlin*, that a legally enforceable obligation is established when a QF tenders an agreement that obligates it to provide power to the utility.[60] Staff concludes that a QF is obligated to provide power when it is subject to penalty for failing to deliver on the scheduled commercial on-line date. Generally, this would occur no sooner than the point in the contracting process between the QF and utility when the QF executes the final draft executable standard contract provided by the utility, which will include a scheduled commercial on-line date and information regarding the QF's minimum and maximum annual deliveries.

As discussed in Staff's opening testimony, PacifiCorp, PGE, and Idaho Power all have similar processes for entering into standard contracts. All require the QF to initiate the standard contracting process by submitting certain information, after which the utilities have 15 days to provide a draft standard contract.[61] The QF may either agree to the terms of the draft contract and ask the utility to provide a final executable contract, or provide comments regarding suggested changes. Thereafter, each utility will provide iterations of the draft standard contract no later than 15 days after each round of comments by the negotiating QF. When then QF indicates that it agrees to all the terms in the draft contract, the utilities have 15 days to forward to the QF a final executable contract.

[60] Staff/500, Andrus/38, quoting *Snow Mount Pine v. Maudlin*, 84 Or App 590, 598-99 (1987).
[61] Staff Exhibit 504.

There is a caveat to Staff's position, however. If the utility does not provide the QF with the required information or documents within the time specified in its tariff, or act consistently with its own schedule or state or federal policies, the QF should have the opportunity to establish a LEO notwithstanding that the QF has not yet executed a final draft executable standard contract.

**Q. What are the positions of the other parties?**

A. PGE and PacifiCorp make recommendations regarding the establishment of a LEO that are similar to Staff's. Both utilities rely on the process established in their schedules for standard contracts (Schedule 37 for PacifiCorp and Schedule 202 for PGE).

PGE recommends that the Commission allow a LEO only when the utility issues to the QF a final executable draft of a contract. [62] PacifiCorp asserts that the QF can establish a LEO when the QF "approves the final draft power purchase agreement as contemplated in B(5) on page 10 of Schedule 37."[63] Idaho Power asserts that a LEO can only be established when (a) under the particular facts and circumstances applicable to an individual QF, a legally enforceable obligation has arisen and, but for the refusal of the utility to enter into a contract, there would be a contract at that particular price and terms and (b) the QF can deliver its electric output within 365 days of such determination.[64]

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[62] PGE/500, Macfarlane-Morton/12.
[63] PacifiCorp/1000, Griswold/19.
[64] Idaho Power/900, Alphin/9.

REC states that a QF should be allowed to establish a LEO if negotiations reach an impasse after QF has complied with the utility's information requirements made a good faith attempt to resolve any dispute regarding information and contract terms.[65]

CREA recommends that the Commission's decision regarding establishment of a LEO be guided by FERC's policies regarding unexecuted transmission agreements.[66]

Gardner Solar states that a LEO should be created when (a) the utility has a current avoided cost determination in place as approved by the Commission; (b) the utility has a contract with terms and conditions for QF purchases that has previously been approved by the Commission; and (c) the QF has submitted to the utility a complete application identifying all relevant parameters for the project.[67]

**Q. How does Staff respond to these positions?**

A. Staff recommends that the Commission reject Idaho Power's suggestion that a LEO can be established only when the scheduled commercial on-line date is within 365 days. Earlier this year, the Commission adopted a stipulation in this docket under which QF always have the option to select a commercial on-line date that is no more than 36 months from the date of contract execution.[68] The Joint Brief in Support of Stipulation notes that "allowing too little time between contract execution and scheduled COD can create a barrier for QFs because

[65] Coalition/400, Lowe/28.
[66] CREA/500, Skeahan/18.
[67] Gardner Solar/100, Benga/7-8.
[68] Order No. 15-130.

QFs generally cannot obtain financing for a new project until after they have executed a PPA.[69] The same barrier applies when the QF's obligation arises from a LEO instead of an executed contract. QFs need more than 12 months after establishing a LEO to bring their resource on line.

Staff also does not agree with Gardner Solar that a QF can create a LEO by submitting a completed request for a standard contract.

Staff thinks the positions of CREA and REC help to illustrate when the QF may be able to establish a LEO in the absence of a final draft executable standard contract.

**Issue No. 9: How should third-party transmission costs to move QF output in a load pocket be calculated and accounted for in the standard contract?**

**Q. What was Staff's position on this issue in opening testimony?**

A. Staff stated its support for a process that reasonably estimates transmission costs for the term of a QF contract, and that requires the utility to provide specific and detailed information regarding the load, generation, and transmission capacity values used in assessing the third party transmission needs. Staff did not propose a specific mechanism.

**Q. Please summarize other parties' positions.**

**A.** CREA first connects the third party transmission costs question issue to Issue 2 stating that,

> The Commission should first correct its determination regarding transmission costs associated with on-system proxy resources as

[69] February 26, 2015 Brief in Support of Stipulation at 3.

described in Issue 2 before it assigns the costs of third party transmission to on-system QFs selling to PacifiCorp.

CREA recommends that PacifiCorp provide more detailed information about potential load pockets in its service territory, to include a map of the specific areas, and monthly peak and minimum loads in each. CREA also states that PacifiCorp should include the amount of new QF capacity that can be accommodated in each of these load pocket areas when the Company updates its Schedule 37, and should state the third-party transmission cost reduction proposed in each. CREA objects to PacifiCorp's proposal to acquire long-term firm point-to-point transmission for each load pocket, when the Company can, at times, redirect its existing long-term firm transmission rights to move QF output. CREA proposes that PacifiCorp offer QFs three alternatives: 1) a fixed reduction to the avoided cost rate for the term of the contract that includes the projected costs of acquiring long-term firm transmission, and an offset for the value of that transmission during times when it is not needed to move that QF's generation; 2) a contract addendum under which the QF would pay for the transmission costs that PacifiCorp incurs; and, 3) a contract addendum providing limited curtailment rights to PacifiCorp, with a provision for the compensation to the QF for lost revenue if the Company cannot adequately support the need for the curtailment event.

REC states that all existing projects should be treated differently from new projects because it is the new projects causing the incremental load pocket problem. REC does not believe that an existing QF for which the contract expires should lose its status as a network resource, noting the potential for contract disputes that could cause a gap between contract agreements. REC also wants to ensure that QFs have the ability to select from a set of options.

ODOE suggests a definition of the term “load pocket,” stating that the term needs to be defined for this docket. ODOE notes that load changes over time can significantly impact a particular load pocket; for example if a data center is sited within it, possibly including on-site renewable energy generation, which could have the effect of either relieving or increasing the need for transmission of the QF generation, depending on the circumstances. ODOE proposes alternatives to address these load pocket profile changes over time, including an annual cost assessment of transmission costs incurred that is trued up via a refund of any overpayments to the QF.

PGE did not propose a specific method to account for third party transmission costs. Idaho Power proposed that third party transmission costs be separated from the power purchase contract, and be incorporated into the interconnection and network resource designation process.

PacifiCorp states that the costs and benefits of third party transmission service should be reflected as an adjustment to the avoided cost price specific to the individual QF, or as a contractual adjustment to billing in the power purchase agreement for that QF.[70] The Company confirms that it purchases long-term firm transmission to move generation out of a load pocket when such transmission is available.

[70] PacifiCorp/1000, Griswold/22.

**Q. What is Staff's position?**

A. Staff agrees with the need for additional transparency for QFs early in the process, and recommends that language be added to each company's avoided cost schedule that is specific to its situation. For PGE and Idaho Power, the language should state the company's process for assessing the potential for a load pocket situation after a QF requests a draft power purchase agreement. In the case of PacifiCorp, Staff views CREA's recommendation for a map of load pockets with monthly peak and minimum loads in each, and the quantity of the QF capacity that can be accommodated in each before incurring third party transmission costs, to be administratively burdensome. Staff does, however, agree that a level of prospective information on load pockets should be made available. For example, for each of the load pockets the Company indicates in its data request response, an annual peak and minimum load could be provided upon request. Staff is not in a position to prescribe the detailed information, but recommends that the Commission direct PacifiCorp to propose a detailed description of the load pocket data it will make available to prospective QFs, and the process by which it proposes to provide it.

With respect to the mechanism for calculating and accounting for the third party transmission costs in a load pocket, Staff agrees with CREA and REC that multiple options should be made available in order for the QF to select the option that is the most cost effective to it, including the option for a narrowly defined curtailment option. Staff recommends that PacifiCorp develop the three options outlined by CREA and make them available in any compliance filing following the conclusion of Phase II of this docket.

Regarding the treatment of existing QFs for which the power purchase agreement expires prior to the execution of a new agreement, Staff does not support requiring the utilities to exempt those QFs from any possible third party transmission cost responsibility resulting from the loss of network resource status. Staff acknowledges REC's concern that a company could leverage this factor in its contract negotiations, but because this issue applies to standard contracts, this potential is limited with respect to the power purchase agreement.

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

A. Yes.