**BEFORE THE PUBLIC UTILITY COMMISSION**
**OF OREGON**

**UM 1610 (Phase II)**

In the Matter of

PUBLIC UTILITY COMMISSION
STAFF

Investigation into Qualifying
Facility Contracting and Pricing.

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STAFF BRIEF

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## I. Introduction.

Staff of the Public Utility Commission of Oregon (Staff) has addressed in testimony and in its Prehearing Memorandum the nine issues regarding Commission implementation of the Public Utility Regulatory Policy Act (PURPA) that are presented in Phase II of Docket No. UM 1610. Staff does not repeat all of its arguments regarding these nine issues in this brief, but provides a more limited response to some of the arguments made by other parties.

## II. Additional comments regarding the nine issues presented in Phase II.

### Issue No. 1 Who owns the Green Tags during the last five years of a 20-year fixed price PPA during which prices paid to the QFs are at market?

*Staff position: QFs are not compensated for the Green Tags associated with their generation during the periods when they are paid market-based prices and should therefore own the Green Tags when they are paid market-based prices, even if the utility is forecasted to be renewable resource deficient.*

PacifiCorp and Portland General Electric Company (PGE) continue to assert that they should own Green Tags (hereinafter referred to as Renewable Energy Credits (RECs)) for energy sold under the renewable avoided cost price stream if they are forecasted to be renewable resource deficient at the time of contract execution, even during the last five years of a 20-year contract when qualifying facilities (QFs) are paid market-based prices.[1] Staff disagrees.

Staff has previously explained why the Commission's rationale underlying its decision to allow renewable avoided cost prices supports the conclusion the QF retains ownership of RECs when not compensated for them with resource-

[1] PGE Prehearing Brief 2-3; PacifiCorp Prehearing Brief 2-6.

deficiency-period prices.[2] In this brief, Staff reiterates that its proposed resolution is also supported by equity.

Utilities are held harmless if the QF retains RECs when not compensated for them, even if at the time of contract execution, the utility was forecasted to be renewable resource deficient during the period in question. This is because the utilities do not pay for the RECs and also, have an extended period of time to plan how to acquire other renewable resources during the last five years of a PURPA contract if such acquisition is necessary. Conversely, QFs are harmed if they have to cede ownership of RECs to utilities when the QFs are not compensated for them.

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

*Staff position: If the utility will avoid transmission costs as well as the costs of the proxy resource, the avoided transmission costs should be included in the calculation of avoided cost prices, even if the proxy resource is an on-system resource.*

Staff recommends that the Commission clarify or modify its conclusions in Order No. 14-058 that PacifiCorp will not avoid transmission costs for on-system proxy resources and that avoided transmission costs should not be included in the calculation of avoided cost prices for any PacifiCorp on-system proxy resource. Staff recommends that the Commission conclude that if PacifiCorp's integrated resource plan (IRP) reflects that transmission costs would be avoided along with the cost of the proxy resource, or if a stakeholder makes this showing in the avoided

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[2] Staff Prehearing Memorandum 1-5.

cost review process, PacifiCorp's avoided cost prices for an on-system proxy resource should include avoided transmission costs.

PacifiCorp opposes Staff's recommendation to change the Commission's conclusion in Order No. 14-058 that PacifiCorp will not avoid transmission costs for a proxy resource located on its system. PacifiCorp acknowledges that it may incur transmission costs for a QF resource located on its system if the QF is located in a load pocket.[3] PacifiCorp asserts that PacifiCorp's proxy resources are distinguishable from such QFs because "PacifiCorp's proxy resources are planned, on-system acquisitions that are directly interconnected to PacifiCorp's system and optimally located to load."[4] PacifiCorp explains that "while PacifiCorp could conceivably need to use third-party transmission service rights to deliver a proxy resource to load, such rights would be used in a combination with a variety of other types of existing transmission rights that PacifiCorp already has and uses across its multi-state system in order to optimize the dispatch of its entire resource portfolio."[5]

Notwithstanding PacifiCorp's assurance that its proxy resources are distinguishable from a QF that locates in a load pocket because PacifiCorp's proxy resources will be optimally located so as to never require PacifiCorp to incur incremental transmission costs, Staff recommends that the Commission clarify or modify Order No. 14-058 to provide that transmission costs will be included in the

[3] PacifiCorp's Pre-Hearing Brief 7, 46-55.
[4] PacifiCorp's Pre-Hearing Brief 7.
[5] PacifiCorp's Pre-Hearing Brief 7.

calculation of avoided cost prices if such costs would be avoided, regardless of whether the proxy resource is on- or off-system.

**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?**

*Staff position: The method used to calculate the capacity contribution adjustment for both the Standard Renewable and Non-renewable Avoided Cost prices should be modified so that the capacity payments to QFs are based on the QF resource type's contribution to meeting the utility's peak load.*

Staff agrees with Idaho Power Company's (Idaho Power) description of the capacity contribution adjustment adopted in Order No. 14-058, but disagrees that the calculation obtains the result—payment for capacity commensurate with the QF resource's contribution to peak (CTP)—that was intended by the Commission.[6] Idaho Power explains (as Staff has done) that prior to Order No. 14-058, the capacity costs embedded in avoided cost prices were based on the costs of the proxy resource and was the same for all QFs.[7] Idaho Power explains that even prior to Order No. 14-058, different QFs did not receive the same payments for capacity

[6] Staff testified that a scenario in which capacity payments would be commensurate with the QF resource type's CTP is when the QF resource type's CTP is roughly equivalent to the percentage of the total capacity costs of the avoided resource the QF resource could receive in a year. So if a QF resource type's CTP is 15 percent, capacity payments that are commensurate with this CTP would be equal to about 15 percent of the capacity costs of the proxy resource. (Staff Prehearing Memorandum 7; Staff/300, Andrus/7.)

[7] Idaho Power Company's Prehearing Brief at 11.

because "as a practical matter, the QF would receive a percentage of the total capacity dollars attributed to the proxy plant that was *in proportion to the QF's on-peak capacity factor.*"[8] Idaho Power asserts that the only thing the Commission intended to do in Order No. 14-058 is modify the rate obtained with the pre-Order No. 14-058 methodology (avoided capacity costs x QF on-peak capacity factor) by the QF resource type's CTP. [9]

Staff agrees with Idaho Power that the calculation in Order No. 14-058 decrements the capacity payments received by QFs by multiplying the portion of the avoided cost rate that is for capacity by the QF resource type's on-peak capacity factor, and then multiplying that rate by the QF resource type's on-peak CTP. Staff does not agree with Idaho Power's assertion that the Commission intended to layer two different adjustments on the capacity component of avoided cost prices. Instead, as Staff has said repeatedly since the Commission granted reconsideration of this issue, Staff believes the Commission intended to **replace** the adjustment based on the QF's on-peak capacity factor with an adjustment based on the QF resource type's CTP.

That the capacity calculation adjustment does not do what was intended is apparent from the results obtained under the calculation. The Commission noted that capacity payments to wind QFs under the Standard Renewable Avoided Cost price stream would not change and that capacity payments to solar QFs selecting the Standard Renewable Avoided Cost price stream should increase. [10] This does not

[8] Idaho Power Company's Prehearing Brief 12 (emphasis in original).
[9] Idaho Power Company's Prehearing Brief 11-12.
[10] Order No. 14-058 at 15.

occur. Instead the calculation results in capacity payments for wind and solar QFs that are far below what they received under the previous methodology.[11]

Further, the decreased capacity payments are not what would be expected for payments of capacity that are commensurate with the QF resource type's CTP.[12] On the other hand, capacity payments under the revised capacity contribution adjustment mechanism recommended by the Staff, CREA, REC, and Obsidian in Phase II *could* [13] result in payments for capacity that are commensurate with the QF resource type's CTP. [14] Staff believes that this is the result intended by the Commission.

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

*Staff position: Staff recommends that the Commission continue to use the process outlined in Order Nos. 05-584 and 06-358 and in administrative rules to determine avoided cost prices, but also require utilities to meet minimum filing requirements (MFRs) when they make their avoided cost filings.*

In its order adopting rules implementing PURPA, FERC notes that PURPA requires avoided cost rates that are "just and reasonable to the ratepayers of the utility, in the public interest, and which do not discriminate against cogenerators or small power producers."[15] FERC subsequently explains in that order that under its rules implementing PURPA, avoided cost rates meet all these statutory criteria if the

[11] See Staff Prehearing Memorandum 19-20; Staff/400, Andrus/4-5.
[12] See Staff Prehearing Memorandum 19-20; Staff/400, Andrus/4-5.
[13] The capacity payments the QF would actually receive would depend on how many on-peak hours in which it operated.
[14] See Staff Prehearing Memorandum 19-20; Staff/400, Andrus/4-5.
[15] Fed. Reg. Vol. 45, No. 38, at 12215.

rates equal the purchasing utility's avoided costs.[16] In other words, under PURPA and FERC's rules implementing PURPA, the determination of avoided cost prices must focus on determining what costs the utility may avoid with the purchase from a QF, considering the seven factors in 18 C.F.R. § 292.304(e).

The utility's most recently acknowledged IRP is the best starting point for determining what costs the utility may avoid by purchasing energy and capacity from a QF. And, while Staff recognizes the importance of the IRP to the determination of avoided cost prices, Staff also recognizes that the Commission has previously determined that stakeholders have a process outside of the IRP to challenge inputs into avoided cost prices.[17] Staff supports the continued use of the current process for determining avoided cost prices, with the addition of MFRs.

Under the Commission's current process, utilities file update avoided cost rates within 30 days of IRP acknowledgement.[18] Stakeholders and Staff then have the opportunity to seek suspension of the avoided cost prices to allow additional investigation into whether the prices comply with the Commission's methodologies

[16] Fed. Reg. Vol. 45, No. 38 at 12222 ("Paragraph (a) [of section 292.304] sets forth the statutory requirement that The Commission has . . . provided [in the final rule] that the rate for purchases meets the statutory requirements if it equals avoided costs[.]").
[17] Order Nos. 05-584 and 06-358.
[18] OAR 860-029-0040(4)(a).

for establishing avoided cost prices.[19] If no party asks for additional investigation, the prices will become effective 30 days after the utility filed them.[20]

With the addition of MFRs requiring utilities to identify what inputs they used to calculate avoided cost prices, Staff anticipates the process following the filing of avoided cost prices will be more efficient. Within the last year, Staff asked that avoided cost filings be suspended for PGE, PacifiCorp, and Idaho Power, in part because Staff needed to obtain information from the utilities to identify what inputs the utilities had used to calculate avoided cost prices. The need for additional time to investigate the avoided cost filings would likely diminish if utilities comply with Staff's recommended MFRs.

Staff disagrees that a process that runs concurrently with review of an IRP is appropriate. If the processes are concurrent, stakeholders would use inputs from the IRP before acknowledgment of the utility's resource acquisition plan. And, using concurrent processes would unnecessarily stretch the avoided cost review process over many months.

Staff believes that the avoided cost review process that commences after IRP acknowledgment will appropriately focus on the utility's plan for future resource acquisitions. Staff believes that this review process will generally be expeditious because the purpose of the review is to determine whether the avoided cost prices

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[19] See e.g., Order No. 06-538 at 44 ("We reminded parties [in Order No. 05-584], however, that a utility's natural gas forecasts could be examined and challenged during review of the utility's avoided cost filing. Indeed, we encouraged parties to seek suspension of an avoided cost filing when necessary to address concerns about natural gas forecasts, or any other aspect of a utility's filing.").
[20] OAR 860-029-0040(4)(a).

were calculated in accordance with the Commission's methodologies, not to debate the merits of the methodologies.[21]

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

*Staff position: Staff recommends that the Commission (1) continue using market-based prices during the utilities' resource sufficiency periods, (2) reject the Joint QF Parties' interim capacity pricing mechanism because it is inconsistent with the Commission's implementation of PURPA, and (3) direct PacifiCorp to not assume automatic and continuous renewal expiring QF contracts when determining resource sufficiency/deficiency for avoided cost prices.*

### A. The Joint QFs' interim capacity mechanism.

The Renewable Energy Coalition (REC), Community Renewable Energy Association (CREA), Obsidian Renewables, LLC, and OneEnergy, Inc. (together the "Joint QFs") assert that the Commission should implement for PacifiCorp an "interim capacity mechanism" that increases payment for capacity in sufficiency period avoided cost prices for QFs that are renewable or zero-emitting.[22] The Joint QFs assert this mechanism is warranted to send a "modest price signal that these QFs' capacity has long-term value during this critical time of changing environmental regulations, which are likely to impose *additional* costs of environmental compliance that cannot now be included in rates."[23] Staff recommends that the

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[21] *In the Matter of the Public Utility Commission of Oregon Investigation to Determine if Pacific Power's Rate Revision is Consistent with the Methodologies and Calculations Required by Order No. 05-584,* Order No. 09-427 ("[W]e adhere to the process outlined above, whereby avoided cost methodologies are examined in recurring generic investigations and periodic utility updates are reviewed for compliance with those methodologies.").
[22] REC, CREA, Obsidian and OneEnergy Pre-Hearing Brief 1 fn 1, 2.
[23] REC, CREA, Obsidian and OneEnergy Pre-Hearing Brief 2 (emphasis in original).

Commission reject the Joint QFs proposal because it is inconsistent with PURPA and the Commission's previous orders implementing PURPA.

Under the Joint QFs' proposal for an interim capacity mechanism, renewable and zero-emission QFs would receive additional capacity payments during PacifiCorp's sufficiency period based on the net present value of revenue requirement associated with environmental upgrades at PacifiCorp's coal plants during PacifiCorp's sufficiency period.[24] The Joint QFs explain that sufficiency-period avoided cost prices for renewable and zero-emitting QFs in PacifiCorp territory should include additional payment for capacity because: (1) current rates fail to include actual incremental investments necessary to retain existing capacity resources; (2) the extremely long resource sufficiency periods are likely to be inaccurate because they fail to fully account for future environmental regulations, including the EPA's proposed Section 111(d) green house gas rules; and (3) the actual year of deficiency is undoubtedly inaccurate due to a 12-year period of relying on an uncertain wholesale market. [25]

### B. The interim capacity mechanism is inconsistent with PURPA.

There is no authority for creating a new avoided cost price stream for renewable and zero-emission resources that is based on environmental compliance costs at thermal resources. In Order No. 11-505, the Commission concluded that it had authority to adopt a separate avoided cost price rate for renewable resources, relying on FERC's recent conclusion "that where a state requires a utility to procure a certain percentage of energy from generators with certain characteristics,

[24] Joint QF Parties/100, Higgins/6.
[25] REC, CREA, Obsidian and OneEnergy Pre-Hearing Brief 8-9.

generators with those characteristics constitute the sources that are relevant to the determination of the utility's avoided cost for that procurement requirement."[26] The Commission noted that ORS Chapter 469A requires that electric utilities meet a renewable portfolio standard through the acquisition of RECs associated with qualifying renewable generation resources.[27] The Commission ordered PacifiCorp and PGE to calculate an avoided cost price stream based on costs of a proxy renewable resource and to make renewable avoided cost prices available to QFs when purchases from the QF would enable the utility to avoid the acquisition of a resource that would provide the utility with RECs that could be used to meet the RPS.[28]

There is no portfolio standard or other basis for including costs of improvements to thermal resources in the calculation of sufficiency period Renewable Avoided Cost prices. In the absence of a state procurement policy or other state or federal regulation that limits the resource choices available to the utilities, there is no authority to create an avoided cost price stream for a subset of QFs.

Further, the fact the sufficiency period is longer than it has ever been or that federal regulations, when implemented in the future, will impose costs on the utilities are not reasons to artificially increase the sufficiency period avoided cost

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[26] *In the Matter of Public Utility Commission of Oregon Investigation into determination of resource sufficiency, pursuant to Order No. 06-538,* Order No. 11-505 at 4.
[27] *Id.*
[28] *Id.*

prices. It is also not appropriate to include an additional payment for capacity in the event the utility has underestimated its need for capacity.

The Commission does not address the possibility that a utility's resource acquisition plans may change by including adders or subtractors to avoided cost prices. Instead, the Commission requires utilities to fully update avoided cost prices every two years (after IRP acknowledgment) and update certain inputs every year.[29] The Commission also allows revisions to avoided cost prices after acknowledged IRP Updates or after a significant change in circumstances, such as change in a resource acquisition date. The frequent updates to IRP prices are sufficient protection against incorrect estimates regarding the utility's next resource acquisition.

**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?**

*Staff position: It is not necessary for all three utilities to use the same methodology to determine non-standard avoided cost prices. PacifiCorp and Idaho Power should be allowed to use their proposed model-based methods and PGE should be allowed to continue to use the currently approved methodology. The Commission should establish the utility's wholesale power price forecast for standard contracts as the floor for non-standard avoided cost prices.*

Staff believes the accuracy obtained with PacifiCorp's and Idaho Power's proposed model-based methodologies for non-standard avoided cost prices is a benefit that is not outweighed by any burden associated with the complexity of the models. Staff does recommend that the Commission adopt the recommendation made in the Oregon Department of Energy's testimony and require utilities to use

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[29] Order No. 14-058 at 25.

market-based prices as a floor for non-standard avoided cost prices during both sufficiency and deficiency periods, however, to ensure QFs receive payment for capacity.[30]

Prior to 2005, utilities could (or at least did) use decremental generating costs to determine standard avoided cost prices during sufficiency periods. In Order No. 05-584, the Commission decided that such prices did not sufficiently compensate QFs for avoided capacity and ordered utilities to value "avoided costs when a utility is in a resource sufficient position at monthly on- and off-peak forward market prices as of the utility's avoided cost filing."[31] Although that order applied to the calculation of standard avoided cost prices, the same reasoning supports the use of wholesale prices as a floor in the calculation of non-standard rates."[32]

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

> *Staff position: The Commission's current criteria for a legally enforceable obligation should be modified so a legally enforceable obligation is created when the QF executes a final draft executable contract. The Commission should also allow QFs to establish a legally enforceable obligation earlier in the contracting process if the utility does not comply with its own schedule regarding the contracting process or with state or federal policy.*

Staff recommends that the Commission modify its current requirement that a legally enforceable obligation does not exist unless both the QF and utility have agreed to the terms of the sale in writing.[33] Staff recommends the Commission conclude that a legally enforceable obligation is established once the QF signs the

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[30] Staff Prehearing Memorandum 34-35.
[31] Staff/700, Andrus/11-12.
[32] Staff/700, Andrus/11-12.
[33] See OAR 860-0010(a)-(b).

final draft executable contract provided by the utility, thereby committing itself to sell power to the utility. Staff also recommends the Commission clarify that a legally enforceable obligation can be established prior to the time the final draft executable contract is signed by the QF if the QF can show the utility has failed to comply with its contracting obligations or state or federal policy.

PGE makes a very similar recommendation, but recommends the Commission conclude a legally enforceable obligation is established when the utility presents the QF with the final draft executable contract.[34] PGE also recommends that the Commission not determine in this docket that the avoided cost prices in effect at the time of any impasse between the QF and utility will apply to the QF/utility transaction, but clarify that it (the Commission) will determine the appropriate avoided cost price that should apply when the Commission addresses the question of whether a legally enforceable obligation has been established.[35]

Staff agrees with PGE's recommendation about how the Commission should determine what avoided cost prices apply to a sale under a legally enforceable obligation. As PGE notes, resolving this question on a case-by-case basis should reduce any incentive for parties to submit disputes to the Commission to "lock-in" certain avoided cost prices.[36]

Staff does not agree with all the criteria for a legally enforceable obligation proposed by PacifiCorp and Idaho Power. PacifiCorp recommends that the

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[34] PGE's Pre-Hearing Brief at 10.
[35] PGE's Pre-Hearing Brief 11.
[36] See PGE's Pre-Hearing Brief 11.

Commission establish the following criteria for establishment of a legally enforceable obligation:

- The QF has engaged in an extended course of discussions with PacifiCorp, demonstrating a level of commitment to sell its power.
- The QF has agreed to all terms and conditions of the Oregon form PPA, and has made elections where required by the form PPA, allowing for agreement on the key terms and conditions of the agreement; and
- The QF has provided all material documentation and information required by the Oregon form PPA, with the exception of material that may be deemed ministerial.[37]

PacifiCorp's second and third criteria are consistent with Staff's recommendation the Commission find a legally enforceable obligation has been established when the QF signs the final draft executable contract. In fact, PacifiCorp recommendation is similar to that of Staff and PGE. PacifiCorp recommends that the Commission establish that a legally enforceable obligation has arisen "when the QF approves the final draft power purchase agreement" contemplated in PacifiCorp's schedule for avoided cost pricing and contracting.[38]

Staff does not agree with PacifiCorp's first criteria for an "extended course of discussions." The length of time that is needed to conclude the contracting process should not be an indicator of the QF's commitment to sell energy.

Idaho Power's suggested criterion is a two-part test: (1) has there been an unreasonable refusal or delay by the utility to contract; and (2) Did the QF obligate itself.[39] With respect to the second criteria, Idaho Power recommends that the Commission require the QF to show that it can deliver its output within 365 days of

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[37] PacifiCorp's Prehearing Brief 42.
[38] PacifiCorp's Prehearing Brief 43.
[39] Idaho Power Company's Prehearing Brief 26-27.

the Commission determination of a legally enforceable obligation and that the QF will be subject to penalties for failure to deliver in this timeframe.[40] Staff recommends that the Commission reject Idaho Power's proposed criteria of delivery within 365 days.

Earlier this year, several parties stipulated in this docket that QFs should have up to three years between contract execution and the scheduled commercial on-line date (COD) of a resource, with the possibility for more time under certain circumstances.[41] The brief in support of the stipulation notes that "allowing too little time between execution and the scheduled COD can create a barrier for QFs because QFs generally cannot obtain financing for a new project until after they have executed a PPA. This means that QFs must wait for execution of a standard contract before commencing many of the steps that are necessary to bring a resource on line."[42]

Similarly, too little time between a legally enforceable obligation and the scheduled COD could present a barrier to QFs that must have a binding commitment on the part of the utility to purchase the QFs generation before the QF can obtain financing. Staff believes that 365 days is insufficient time between a legally enforceable obligation and scheduled COD of a QF resource.

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

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[40] Idaho Power Company's Prehearing Brief 27.
[41] UM 1610 Stipulation (filed February 20, 2015).
[42] UM 1610 Brief in Support of Stipulation (February 26, 2015).

*Staff position: The Commission should defer resolution of this issue until Phase III of Docket No. UM 1610, or in the alternative adopt PacifiCorp's proposal as modified by Staff.*

Staff's position regarding third-party transmission costs to move QF output in a load pocket remains as it was in its Pre-Hearing Memorandum. PacifiCorp's proposal to acquire long-term firm transmission for the duration of the standard contract is remarkably unappealing because it requires the QF to pay for transmission for the duration of the contract, even if the circumstances creating the load pocket cease to exist. However, including more flexibility regarding third-party transmission costs in standard contracts is difficult because QFs are entitled to contracts with avoided cost rates calculated at the time the QF incurs the obligation to deliver energy and capacity.[43] Accordingly, Staff recommended the Commission defer this issue to Phase III of UM 1610 to allow parties additional opportunity to find common ground between the inflexible and expensive proposal made by PacifiCorp and proposals by other parties that allow flexibility, but may not be consistent with requirements for standard contracts under PURPA.

Staff believes that CREA's proposals for alternate pricing mechanisms could be explored in Phase III.[44] If the Commission signals that PacifiCorp's proposal is not acceptable, parties may be able to come to agreement on a flexible methodology that allows QFs to bear third-party transmission costs while still allowing the QFs to select the standard contract terms and prices.

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[43] *See e.g.*, CREA's Prehearing Legal Brief 24, *citing* 18 C.F.R. §§292.304(b)(5), (d)(2)(ii).
[44] See CREA's Prehearing Legal Brief 25-28.

If the Commission believes the need for certainty overrides any interest in a compromise resolution to this issue, Staff recommends that the Commission adopt PacifiCorp's proposal with the modifications recommended by Staff in its Prehearing Memorandum.[45] Under Staff's proposal, PacifiCorp would offer a QF located in a load pocket with two options for a contract addendum addressing transmission costs. One option would establish a price for transmission for the entire term of the contract and the other would allow the cost of transmission to be re-set every five years concomitant with PacifiCorp's renewable of its long-term transmission contract. The second option would be available but not mandatory for the QF.

Finally, Staff recommends that the Commission require that PacifiCorp make information on load pockets in its system available to QFs on request.

## III. Conclusion.

Staff recommends that the Commission adopt the Staff's proposed resolutions to the nine issues presented in Phase II.

DATED this 13th day of October, 2015.

Respectfully submitted,

ELLEN F. ROSENBLUM
Attorney General

Stephanie S. Andrus, #925123
Senior Assistant Attorney General
Of Attorneys for Staff of the Public
Utility Commission of Oregon

[45] Staff Prehearing Memorandum 42-43.