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October 13, 2015

*VIA ELECTRONIC FILING*

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-1166

Attn: Filing Center

**RE: UM 1610 Phase II—PacifiCorp's Closing Brief**

PacifiCorp d/b/a Pacific Power encloses for filing its Closing Brief in the above-referenced docket.

If you have questions about this filing, please contact Erin Apperson, Manager Regulatory Affairs, at (503) 813-6642.

Sincerely,

R. Bryce Dalley /eaa

R. Bryce Dalley
Vice President, Regulation

Enclosure

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

UM 1610
Phase II

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| In the Matter of<br><br>PUBLIC UTILITY COMMISSION OF OREGON<br><br>Investigation Into Qualifying Facility Contracting and Pricing | PACIFICORP'S CLOSING BRIEF |

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## I. INTRODUCTION

The Public Utility Commission of Oregon (Commission) opened this docket to investigate issues related to electric utilities' purchases from Qualifying Facilities (QFs) under the Public Utility Regulatory Policies Act (PURPA).[1] This brief responds to the arguments raised by the parties to this docket in pre-hearing briefs. PacifiCorp d/b/a Pacific Power will not reiterate all of the points raised in its pre-hearing brief, but will respond to specific arguments raised by Staff and intervenors.

## II. ISSUES

### Issue 1: Who Owns Green Tags During the Last Five Years of a 20-Year Fixed Price PPA During Which Prices Paid to the QF Are at Market?

The parties' disagreement about who owns Green Tags[2] during the last five years of a 20-year fixed price PPA boils down to a disagreement about how to interpret and reconcile the Commission's orders addressing (1) the relationship between Green Tag ownership and utility's renewable resource sufficiency position, and (2) between Green Tag ownership and PPA pricing. PacifiCorp's position, as explained in detail in its Prehearing Brief, is that the critical issue is the first issue: whether a utility is in a renewable resource sufficient or deficient position. Staff and others argue that the key issue driving REC ownership is the second issue: the price actually paid for RECs. PacifiCorp will briefly address the reason it believes that the utility's sufficiency position is the most important factor in this analysis.

[1] The parties to this docket are referred to as follows: PacifiCorp d/b/a Pacific Power ("PacifiCorp," or "the Company"); Idaho Power Company ("Idaho Power"); Portland General Electric Company ("Portland General"); Oregon Department of Energy ("ODOE"); Community Renewable Energy Association ("CREA"); OneEnergy, Inc. ("OneEnergy"); Obsidian Renewables, LLC ("Obsidian"); Renewable Energy Coalition ("REC", and when together with CREA, OneEnergy, and Obsidian, the "Joint QFs"); Gardner Capital Solar Development, LLC ("Gardner"); and Oregon Public Utility Commission Staff ("Staff").
[2] Green Tags are also referred to as "Renewable Energy Credits" or ("RECs").

### A. A Utility's Resource Sufficiency Position at the Beginning of a Contract Should Determine REC Ownership for the Life of the Contract.

The Commission's orders focus primarily on the relevance of a utility's renewable resource sufficiency position at the beginning of a PPA when determining REC ownership.[3] A renewable Schedule 37 PPA is based on PacifiCorp's avoidance of a renewable proxy due to its purchase of the QF output. From the point in time that the deficiency period starts, through the end of the PPA, therefore, a utility should own the Green Tags associated with a QF PPA—consistent with the utility's avoidance of the renewable resource used in developing avoided costs for that PPA.

As PacifiCorp noted in its Prehearing Brief,[4] the fact that the Commission has established a different pricing structure for the certain years of that PPA does not mean the utility's resource sufficiency position has changed during those years, nor does it mean the product sold under the PPA has changed. The five-year market price available to QFs at the end of a 20-year contract term was adopted by the Commission to help limit the potential inaccuracy of avoided-cost forecasts inherent in such long contracts, not to fundamentally alter the nature of the product sold under the contract.

### B. The State Has Discretion to Determine Which Party Owns the RECs Associated with a PPA.

Staff and other parties take the position that because "QFs are not compensated for the Green Tags associated with their generation when they are paid market-based prices," they should therefore own the RECs."[5] ODOE, for example, argues that allowing utilities to keep the

[3] *In re Investigation into Resource Sufficiency,* Docket No. UM 1396, Order No. 11-505 at 1 (Dec. 13, 2011) ("During periods of renewable resource sufficiency, the rate will be based on market prices. During periods of renewable resource deficiency, the rate will be based on the renewable avoided cost of the next utility scale renewable resource acquisition in that utility's IRP. *The renewable resource QF will keep all associated Renewable Energy Certificates (RECs) during periods of renewable resource sufficiency, but will transfer those RECs to the purchasing utility during periods of renewable resource deficiency*.") (emphasis added).
[4] PacifiCorp Prehearing Brief at 3-6.
[5] Staff Prehearing Memorandum at 1.

RECs during the last five years of a PPA "would violate the underlying principles of avoided cost under the federal PURPA statute."[6]

But, as FERC has noted, RECs are creations of a state that exists "outside the confines of PURPA." For that reason, "[t]he contracts for sales of QF capacity and energy, entered into pursuant to PURPA . . . do not control the ownership of the RECs (absent an express provision in the contract)." FERC explained that "[s]tates, in creating RECs, have the power to determine who owns the REC in the initial instance, and how they may be sold or traded; it is not an issue controlled by PURPA."[7]

In other words, the issue of REC ownership is a policy issue for the state, not one necessarily driven by an avoided cost analysis. For these reasons and the reasons explained in its Prehearing Brief, PacifiCorp respectfully requests that the Commission determine that utilities are entitled to the Green Tags associated with a QF contract from the deficiency period forward.

**Issue 2: Should Avoided Transmission Costs for Non-Renewable and Renewable Proxy Resources Be Included in the Calculation of Avoided Costs?**

As PacifiCorp explained in its Prehearing Brief, Issue 2 appears to boil down to a concern over whether PacifiCorp may incur certain "transmission costs" (third-party or other) if it builds an on-system proxy resource, and a corresponding assumption that a QF purchase would necessarily avoid any such transmission costs.[8] Issue 2 can be resolved with a simple Commission clarification: no party demonstrated that a utility would avoid transmission costs when the utility's proxy resource is on-system, and therefore inclusion of such transmission costs in the calculation of avoided cost prices is inappropriate.[9]

Staff and Intervenors assert that there is evidence in the Phase II record that PacifiCorp may have avoided transmission costs for on-system proxy resources. As discussed in more detail in Section A below, these assertions fail to account for the fact that the federal transmission

[6] ODOE Prehearing Memorandum at 3.
[7] *Covanta Energy Grp.*, 105 FERC ¶ 61,004 at P 23 (2003).
[8] PacifiCorp Prehearing Brief at 7.
[9] PacifiCorp Prehearing Brief at 6-8.

planning process, not QF development, will drive PacifiCorp's transmission system upgrade decisions related to proxy resources. Thus, even if transmission costs could conceivably be necessary to accommodate an on-system proxy resource, those costs *will not be avoided due to the addition of Oregon QFs*, so there is nothing to include in the calculation of avoided cost prices.

Further, to the extent the Commission nevertheless wishes to modify its policy in this regard, contrary to the suggestions of Staff and Intervenors, this issue cannot be resolved with a simple policy tweak, saving difficult factual determinations for later.[10] Indeed, as discussed in more detail in Section B below, taking Staff's recommendation and merely leaving open the possibility that transmission costs associated with on-system proxy resources can be included in the calculation of avoided cost prices as a matter of policy[11] vastly oversimplifies the issues that would need resolution in this proceeding in order to support such a determination. PacifiCorp requests that the Commission reject any recommendation that it leave this issue open accordingly. Alternatively, to the extent the Commission wishes to make this policy clarification, PacifiCorp requests that it condition such a clarification on resolution of the complex legal questions, state and federal regulatory policy reconciliation issues, and implementation difficulties that Staff and Intervenors have simply lumped into a "factual" bucket for later, or failed to contemplate altogether.

### A. No Party Has Demonstrated That a Utility Would Avoid Transmission Costs When the Utility's Proxy Resource is On-System

Staff notes that OneEnergy has testified that PacifiCorp would incur transmission costs for at least one proxy resource located in an area of Wyoming that is "widely known" to have insufficient transmission.[12] Staff also claims that there are inconsistencies between different

[10] *See, e.g.,* Staff Prehearing Memorandum at 7-8; OneEnergy Prehearing Memorandum at 5.
[11] Staff Prehearing Memorandum at 8.
[12] Staff Prehearing Memorandum at 6 (citing OneEnergy/400, Eddie/2-3). *See also* OneEnergy Prehearing Memorandum at 6-7. CREA makes a similar assertion, suggesting that excluding transmission costs required to bring generation output from a utility proxy to load undermines the concept of avoided cost. CREA Prehearing Legal Brief at 6.

pieces of PacifiCorp's testimony because: (1) PacifiCorp testified that it needs Company-owned transmission infrastructure and third-party contractual rights to operate its system regardless of whether it adds QFs; and yet (2) PacifiCorp testified that it will incur third-party transmission costs for some QFs because they are located in load pockets, so "[p]resumably, PacifiCorp would incur the same type of costs if its next avoidable resource is in a load pocket."[13]

Staff and Intervenors' inaccurate presumptions display a fundamental misunderstanding of the role of a utility's transmission planning process on this issue. As discussed in detail in PacifiCorp's Prehearing Brief, transmission upgrades that are necessary to accommodate a proxy resource would be identified consistent with federal reliability (including load service) planning requirements.[14] Thus, PacifiCorp will incur the cost of its planned transmission upgrades – including any upgrades identified as necessary to move a proxy resource out of a load pocket should it be located in one—*regardless of QF development*.[15] The reverse is also true. That is, if PacifiCorp modifies its determination of the upgrades identified consistent with federal planning requirements, it will do so in accordance with those federal requirements and, contrary to suggestions by OneEnergy, *regardless of QF development*.[16]

Again, no party has offered any evidence that a utility would avoid transmission costs when the utility's proxy resource is on-system, so there are no transmission costs to include in the calculation of avoided cost prices.[17]

### B. Simply Leaving This Matter Open as a Matter of Policy Vastly Oversimplifies the Issues in Need of Resolution in This Proceeding in Order to Support Such a Determination

Contrary to the suggestions of Staff and Intervenors, this issue cannot be resolved with a simple policy tweak, saving difficult factual determinations for later.[18] Indeed, taking Staff's

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[13] Staff Prehearing Memorandum at 7.
[14] PacifiCorp Prehearing Brief at 7-8. An example of such an upgrade is the Gateway West project.
[15] This is unlike the situation where PacifiCorp must acquire new third-party transmission rights because an Oregon QF decides to site its project in a load pocket where there is no need for generation and no transmission upgrades are otherwise planned consistent with federal planning requirements. PacifiCorp Prehearing Memorandum at 8.
[16] OneEnergy Prehearing Memorandum at 7-9.
[17] PacifiCorp Prehearing Brief at 7-8.
[18] *See, e.g.,* Staff Prehearing Memorandum at 7-8; CREA Prehearing Memorandum at 6.

recommendation and merely leaving open the possibility that transmission costs associated with on-system proxy resources can be included in the calculation of avoided cost prices as a matter of policy[19] vastly oversimplifies the issues that would need resolution in this proceeding in order to support such a determination.

PacifiCorp requests that the Commission reject any recommendation that it leave this issue open accordingly. Alternatively, to the extent the Commission wishes to make this policy clarification, PacifiCorp requests that it condition such a clarification on resolution of the complex legal questions, state and federal regulatory policy reconciliation issues, and implementation difficulties that Staff and Intervenors have simply lumped into a "factual" bucket for later, or failed to contemplate altogether. This includes the test recommended by OneEnergy for determining whether there are avoided transmission costs for on-system proxy resources – a test that Staff believes could inform the determination of avoided cost prices in the Commission's review process for avoided cost price filings.[20]

OneEnergy's recommended test involving an analysis of whether an on-system proxy resource can be designated as a Network Resource at its full capacity fails to account for the role of a utility's federal transmission planning process in the identification of necessary network upgrades as noted above, not to mention appears to confuse the several different types of service (and their associated network upgrade requirements) necessary to interconnect with and deliver QF power, as noted below.

Putting aside these fatal flaws, even if, for the sake of argument, transmission costs associated with accommodating an on-system proxy resource could somehow be avoided by a QF, OneEnergy fails to discuss or offer any solutions to the practically insurmountable hurdles associated with implementing its recommended test. For instance, OneEnergy does not suggest a methodology for accurately estimating whether and to what extent an on-system proxy

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[19] Staff Prehearing Memorandum at 8.
[20] Staff Prehearing Memorandum at 8 (citing OneEnergy/400, Eddie/2-3). REC and CREA also support OneEnergy's recommended test. REC Prehearing Memorandum at 26; CREA Prehearing Memorandum at 6.

resource's future Network Resource designation application, when studied in accordance with PacifiCorp's FERC-required Open Access Transmission Tariff ("OATT") process, may be subject to certain limitations – limitations that will necessarily depend on factors out of PacifiCorp's control, such as third-party transmission service requests pending in the same area at the time of the study. This is just one example of an implementation complication that would need to be addressed in this proceeding if the Commission leaves open the possibility that an on-system proxy resource's transmission costs could be avoided by a QF.

Further, any methodology for determining an on-system proxy resource's transmission costs supposedly avoided by a QF should not be as one-sided as OneEnergy's recommended solution, which focuses only on the transmission costs that may be necessary to accommodate an *on-system proxy resource*, and ignores the transmission costs that may be necessary to accommodate a *QF*.[21]

To that end, OneEnergy's suggestion that a QF imposes no transmission upgrade cost burden on utilities or their customers – like OneEnergy's recommended test involving the costs associated with the Network Resource designation of a proxy resource – confuses several concepts and must be disregarded. For instance, as noted in PacifiCorp's Prehearing Brief, there are different types of network upgrades that may be required to accommodate the different types of service necessary to interconnect and deliver a QF's power (*e.g.*, the request for interconnection service submitted by the QF, the request for designation of the QF's PPA as a Network Resource submitted by PacifiCorp's merchant function, etc.).[22]

The state and federal regulatory policies governing the drivers for and cost allocation of these different types of network upgrades also vary, so clarification of the precise types of network upgrades at issue would be a critical component of any policy determination that an on-system proxy resource's transmission costs could be avoided by a QF. Thus, any such policy must include a mechanism for netting against such costs any transmission costs required to

[21] PacifiCorp Prehearing Brief at 9-10.
[22] *Id.*

accommodate a QF purchase. The determination of such costs would necessarily be made on a QF-by-QF basis, which also raises additional implementation questions about how they would be reflected in standard QF contracts.

For all the reasons discussed above and in PacifiCorp's Prehearing Brief, PacifiCorp urges the Commission to resolve Issue 2 with a simple clarification: no party demonstrated that a utility would avoid transmission costs when the utility's proxy resource is on-system, and therefore inclusion of such transmission costs in the calculation of avoided cost prices is inappropriate.

**Issue 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?**

**Issue 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?**

PacifiCorp addressed Issues 3 and 4 at length in its Prehearing Brief and will not restate its arguments in detail here.[23] In brief, the Company believes the Commission should retain its approved methodology for determining the capacity contribution adder for solar QFs selecting standard renewable avoided cost prices and for standard non-renewable avoided cost prices. As explained in PacifiCorp's Prehearing Brief, the changes sought by Obsidian and Staff would increase the capacity payment to intermittent resources to levels that exceed the actual avoided costs of utilities. Such a result is inconsistent with the Commission's intent, and violates the Commission's precedent and PURPA. Furthermore, any modification to either the renewable or non-renewable avoided cost prices would require the Commission to reconsider issues that have already been decided after extensive briefing and testimony before the Commission.

[23] *See* PacifiCorp Prehearing Brief at 10-14. PacifiCorp also supports Idaho Power's position on this issue. *See* Idaho Power Company's Prehearing Brief at 9-17.

**Issue 5: What Is the Appropriate Forum to Resolve Litigated Issues and Assumptions?**

The existing IRP process is the proper forum for developing and vetting assumptions used in avoided cost prices. As PacifiCorp explained in its Prehearing Brief, the Commission's existing IRP process is appropriate for this purpose.

The relitigation of IRP inputs in a separate forum, or the adversarial litigation of IRP inputs during the IRP process itself, would undermine the IRP process and devalue its ultimate outcome. Moreover, adopting any process that results in protracted litigation over the assumptions and inputs for avoided costs would create additional, extended periods of avoided cost price uncertainty, which would in turn undermine the certainty contemplated by PURPA's requirement for fixed, standard avoided costs and harm utility customers. For these reasons and the reasons stated in its Prehearing Brief,[24] PacifiCorp respectfully requests that the Commission reaffirm its use of the existing IRP process for addressing IRP assumptions and inputs.[25]

**A. Any Minimum Filing Requirements Should Be Carefully Considered and If They Are Adopted, They Should Be Objectively Beneficial to the Process of Determining Avoided Cost.**

Like PacifiCorp, Staff supports continuation of the existing process for addressing contested inputs and assumptions. Staff recommends, however, that the Commission require utilities to make Minimum Filing Requirements (MFRs) in support of their filings.[26] PacifiCorp does not strongly oppose this recommendation, but would ask the Commission to carefully determine whether MFRs are actually necessary and whether they will meaningfully add to the process. If the Commission ultimately decides to adopt MFRs, the Commission should ensure those MFRs are carefully crafted and actually add value to the process rather than simply increase administrative efforts and costs.

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[24] PacifiCorp Prehearing Brief at 14-22.
[25] The follow-up process of compliance review should also be retained.
[26] Staff Prehearing Memorandum at 21.

## B. Delays in Approval of Avoided Cost Updates Harm Utility Customers.

As a more general matter, PacifiCorp notes the potential harm to customers when avoided costs filings are suspended for any significant period of time. Approval of avoided cost filings might well be further delayed each year if the Commission were to adopt some of the recommendations in this docket from parties that seek significant additional opportunities to contest a utility's avoided cost filing.

As Mr. Griswold explained, PacifiCorp has historically experienced a rush of QF activity to lock in older avoided cost rates when PacifiCorp updates its avoided costs and those costs are going down. PacifiCorp would ask the Commission to consider what a delay in avoided cost approval means to utility customers in this context. If a *utility rate filing* is suspended, the effect is generally to protect customers from rate increases until those rate increases are thoroughly reviewed and approved.[27] In other words, the purpose of the suspension of a utility rate filing is to protect customers. By contrast, if an *avoided cost update filing* is suspended, that suspension does not protect customers. To the contrary, it gives QFs an opportunity to rush in and sign long-term contracts for avoided cost pricing that is empirically outdated and wrong. The longer the delay in the avoided-cost approval process, the more a utility's customers will be saddled with inaccurate and inflated costs for decades. Commission-approved avoided cost prices are generally recoverable by a utility in retail rates, so the primary harm from this delay is harm to utility customers. PacifiCorp respectfully asks the Commission to consider this customer harm when considering the addition of any additional procedures, adversarial or otherwise, to the avoided-cost approval process.

[27] ORS 757.215.

**Issue 6: Do the Market Prices Used During the Resource Sufficiency Period Sufficiently Compensate for Capacity?**

Paying market prices to QFs during the Resource Sufficiency Period appropriately compensates QFs for their capacity.[28] PacifiCorp will not repeat the arguments made in its Prehearing Brief[29] here, but will simply summarize as follows:

- The Commission determined in Order No. 05-584 that market prices during sufficiency periods adequately compensate QFs for capacity. The Commission's order is still accurate and no evidence suggests it should be revisited.

- Proposals to add the costs of environmental upgrades to avoided cost fail for a number of reasons, including the fact that (1) the proposals address costs that cannot be avoided by the purchase of QF power; (2) some identified upgrades may not actually be needed, making them inappropriate to include in avoided cost pricing under FERC precedent so holding; and (3) these proposals fail to account for loss of benefits such as access to low-cost base load generation and operational benefits which are factored into the Company's IRP when evaluating the benefits of pursuing environmental upgrades.

- Renewing QFs should not be entitled to capacity payments as part of contract renewals; the most current avoided cost information should be applied to new contracts, consistent with the customer indifference standard.

- Potential inaccuracies in IRP assumptions regarding resource sufficiency do not warrant imputation of additional capacity payments; inaccuracies cut both ways.

Staff and PacifiCorp appear to be mostly aligned on these issues. Staff argues in its Prehearing Memorandum, however, that PacifiCorp should "stop basing its Standard Renewable and Non-Renewable Avoided Cost prices on a resource stack that assumes never-ending QF contracts."[30] This appears to be a response to the Joint QFs assertion that PacifiCorp's sufficiency period should be extended because its IRP inappropriately assumes that QF contracts will be renewed upon the expiration of their term.[31] As explained in PacifiCorp's Prehearing Brief, however, PacifiCorp believes the Joint QFs' argument misstates the assumptions made in PacifiCorp's IRP. If the Commission adopts Staff's and the Joint QFs' recommendation on this

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[28] *See* PAC/800, Dickman/13-16; PAC/1100/Dickman/10-19; PAC/1400, Dickman/4-6.
[29] PacifiCorp Prehearing Brief at 23-29.
[30] Staff Prehearing Memorandum at 32.
[31] *See* Joint QF Parties/100, Higgins/8-9; *see also*, Staff/600, Andrus/19. REC testifies that the IRP and PacifiCorp's planned resource acquisitions "have historically been inaccurate." Coalition/500, Lowe/7-8.

issue, the Commission should ensure the requirement is made in an even-handed and symmetrical way.

As Mr. Dickman explained, until the Company's 2015 IRP is acknowledged, the 2013 IRP is still the basis for Oregon standard avoided cost rates. Between the preparation of the 2013 IRP and the recently filed 2015 IRP, the Company executed contracts with QFs totaling more than 800 MW of nameplate capacity.[32] Since the time the 2015 IRP inputs were finalized, the Company executed additional contracts with QFs totaling more than 300 MW of additional nameplate capacity.[33] Because the demarcation of the deficiency period for standard avoided cost prices can only be updated when an IRP is acknowledged, the timing of the sufficiency period is already out of date. Thus, if the Commission determines that the Company's preferred portfolio should be updated to account for122 MW of small QF terminations, the 1100 MW of new QF contracts should also be accounted for to accurately reflect the Company's more updated capacity needs.

In short, the Commission's determination that market prices during sufficiency periods adequately compensate QFs for capacity remains correct today. Short-term firm market purchases contribute to meeting PacifiCorp's firm obligations to serve load, which ensures the Company has sufficient capacity to maintain reliability at a reasonable cost. Paying a QF for the avoided cost of firm market purchases is the equivalent of paying a QF the costs the Company would incur to purchase energy and capacity "but for" the addition of a QF. This is the textbook definition of avoided cost. FERC recognized as much in its landmark Order No. 69, in which FERC discussed how a QF might be compensated for its contribution to a utility's capacity needs. FERC concluded that, if a utility was not planning to acquire a new generation resource for some time, but in the meantime was relying on firm market purchases to meet its energy and

[32] PAC/1100, Dickman/17.
[33] *Id.*

capacity needs, the appropriate compensation for a QF prior to acquisition of the new resource was simply the cost of the avoided firm market purchase.[34]

**Issue 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?**

PacifiCorp urges the Commission to adopt the PDDRR Method[35] for the calculation of PacifiCorp's non-standard avoided costs. PacifiCorp currently uses the PDDRR Method in Utah, Wyoming, and Idaho to calculate non-standard avoided costs. PacifiCorp believes that Oregon utilities should be allowed to employ different production cost models or tailor specific adjustments to match their unique cost structure. Staff agrees with this assertion and supports PacifiCorp's request to use the PDDRR Model to calculate its non-standard avoided cost.

PacifiCorp has used the GRID model to calculate net power costs across its service territory since 2002, subjecting the model to over a decade of rigorous scrutiny by regulators and intervenors. It is used to calculate net power costs in PacifiCorp's annual Oregon TAM filings and to produce avoided cost prices under the PDDRR Method for QF projects in Utah, Idaho, and Wyoming.[36] It is a more accurate way of determining avoided costs than the Proxy Method, and should be adopted here. PacifiCorp will not repeat the arguments in its Prehearing Brief, but instead will make a few additional points in response to various parties' prehearing briefs.

**A. Computer Models Are Critical and Necessary Tools for Valuing Energy and Capacity in Today's Energy Market.**

Some parties argue that the PDDRR methodology is too complex for developers to understand and analyze. REC, for example, asks the Commission to "reject PacifiCorp's

[34] Order No. 69, *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Pub. Util. Regulatory Policies Act of 1978,* 45 Fed. Reg. 12,214, 12,226 (1980) ("Order No. 69") ("A utility's generation expansion plans often include purchases of firm power from other utilities in years immediately preceding the addition of a major generation unit. If a qualifying facility contracts to deliver power, for example, for a one year period, it may enable the purchasing utility to avoid entering into a bulk power purchase arrangement with another utility. *The rate for such a purchase should thus be based on the price at which such power is purchased, or can be expected to be purchased,* based upon bona fide offers from another utility.") (emphasis added).
[35] PDDRR stands for "Partial Displacement Differential Revenue Requirement."
[36] *Id.*

computer modeling approach," because of its complexity.[37] But computer models are critical to the energy industry today. These models are the tools that allow market participants to understand and value energy and capacity in the increasingly complex and efficient energy markets. When PURPA was passed in 1978, there were no well-developed market hubs, no tools for determining locational- or site-specific pricing, no efficient dispatch tools like those that exist today as a result of the growth of wholesale markets.[38] Since then, the energy industry has become increasingly complex and *efficient.* This level of complexity allows for, among other things, the efficient dispatch of resources, the integration of renewable resources, and the use of energy imbalance markets to efficiently and quickly deploy resources across wide geographical areas. These tools have allowed organized markets in the United States to understand that the value of energy and capacity can vary greatly from location to location and can, in fact, be priced accordingly. Utilities are expected to use such tools to efficiently manage their systems every day. To ask utilities to determine avoided cost pricing for long-term QF contracts in 2015 without access to comparatively simple "computer modeling" tools that allow the value of that energy and capacity to be captured accurately is extremely problematic and fails to reflect the state of the energy industry today.

PacifiCorp must take thousands of megawatts of QF power onto its system under *standard* avoided cost pricing, pricing that takes few locational or QF-specific factors into account. This is so even though the actual value of a specific QF's power may, in fact, vary significantly from the standard pricing to which that QF is entitled under the Company's Schedule 37, and even though that deviation may be easily measured using today's energy market tools. Yet these variations will generally not be reflected in standard contracts at all. Thus, standard QFs across PacifiCorp's six-state system have historically had little or no accuracy in their price signals, and therefore little or no incentive to site generation in areas

[37] REC Prehearing Memorandum at 11-14.
[38] *See, e.g., Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 681-683 (2000) (discussing the rise of competitive wholesale energy markets in light of FERC Order 888).

where power is actually needed or transmission is available. This means avoided-cost pricing is distorted for many of these QFs. These smaller QFs argue,[39] on the one hand, that they are able *in the aggregate* to provide significant system benefits that require them to receive compensation, such as displacing planned resource acquisitions (even, they argue, large thermal resources). Yet they argue, on the other hand, that their entitlement to *standard* avoided cost pricing is harmless because their small size minimizes the need for QF-specific factors to be taken into account in their avoided costs. But inaccuracies in small QF PPAs—like the purported benefits of such PPAs—also have an aggregate effect and constitute a large amount of inefficiently priced long-term power PPAs on PacifiCorp's system.

In the end, PacifiCorp is already in the situation where it must use cumbersome, inaccurate methods to develop avoided costs for QFs up to 10 MW. PacifiCorp believes it is important that it be permitted to use modern, efficient tools to develop avoided costs for large, non-standard QFs in order to send a more efficient price signal for at least one subset of Oregon QFs.

### B. PacifiCorp Agrees that Developers Should Have Access to and Assistance with the GRID Model, But Believes Formal Rules May Be Cumbersome and Unnecessary.

Staff agrees with PacifiCorp that the GRID model is an appropriate tool for developing non-standard avoided cost, but recommends the Commission adopt rules requiring the IOUs to work cooperatively with QFs, and "to run scenario and sensitivity analysis in a transparent manner reasonably accessible to the developer in order to develop a fair and equitable non-standard avoided cost rate."[40] As PacifiCorp explained in its Prehearing Brief, the Company is willing to provide QFs with assistance in understanding the model and their avoided costs.[41] In

[39] Standard QFs in Oregon, which can be up to 10 MW, are not particularly small when measured against FERC's 100 kW default threshold. In fact, given the Commission's small QF threshold, PacifiCorp is only aware of a handful of non-standard QFs in Oregon. Until this threshold is modified, standard QF pricing, with all of its economic inefficiencies, drives PacifiCorp's aggregate PURPA cost burden in the state.
[40] Staff Prehearing Memorandum at 34.
[41] PacifiCorp Prehearing Brief at 36.

fact, PacifiCorp has made the model available at no cost to developers and intervenors in other states, and has agreed to provide assistance and training to those wishing to use it.[42]

That said, some developers may want to understand avoided cost calculations in detail, while others are comfortable with the Company's calculations with some lesser level of review. For this reason, the Company would recommend the Commission simply order utilities to make their models available to QFs who wish to use it, and provide assistance and training upon QF request. Any disputes over avoided cost calculations could be brought to the Commission under the existing dispute resolution processes. A rigid set of rules may require utilities and QFs to take steps neither party wants or needs to take in the negotiation process. If the Commission does adopt rules addressing the GRID model and avoided cost, PacifiCorp would recommend those rules allow for various outcomes that work well for different developers with different levels of interest in examining avoided cost calculations.

### C. Using Wholesale Power Price Forecast to Set a Floor for Avoided Cost Pricing Distorts the PDDRR Model Without Cause and Could Harm Customers.

ODOE argues that if the PDDRR method is adopted, the Commission should set a floor for avoided cost at the wholesale power price forecast used to set standard avoided costs.[43] Staff agrees with ODOE's recommendation.[44] PacifiCorp does not believe the Commission should distort the PDDRR methodology in a manner that prevents the methodology from yielding economically valid results. As PacifiCorp explained in its testimony,

> [T]he benefit of using a production dispatch model is that system resource constraints are accounted for, such as transmission capacity, rather than making the simplifying assumption that QF energy always displaces market purchases or facilitates additional market sales during the sufficiency period.[45]

This means that the model may, in some instances, yield an avoided cost below market forecasts—*if avoided cost is actually below market forecasts.*

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[42] PAC/1100, Dickman/20.
[43] ODOE Prehearing Memorandum at 9.
[44] Staff Prehearing Memorandum at 34-35.
[45] PAC/1400, Dickman/6-7.

While the circumstances that yield avoided costs lower than market may not currently exist in Oregon, and while they may never exist for more than a small number of QFs, different conditions prevail in other parts of the Company's service territory and may someday exist in Oregon, as well. As transmission systems become more constrained, as QFs continue to site in areas without utility load needs, and as the PURPA must-take obligation in such areas increasingly becomes a stressor on a utility's ability to move power where it is needed, power can become trapped and the value of QF power can in certain instances dip below market or even—as FERC concedes—become *negative* in certain areas.[46] In order to avoid customer harm, it is critical that as many QFs as possible receive appropriate price signals regarding their siting decisions and the associated value of their power. In short, the PDDRR methodology should work to yield accurate avoided cost pricing results, whatever those result may be, because accurate price signals are critical for maintaining customer indifference to the purchase of QF power.

Not only is ODOE's "floor" recommendation problematic for the reasons noted above, it is also simply a solution without a problem. If a QF's power is, in fact, able to reach a market hub—as ODOE argues is currently the situation in Oregon—the PDDRR methodology will reflect this fact and price the power accordingly. No artificial "floor" is needed. If, however, a QF's power cannot reach a market hub because of transmission constraints, or if the value of the power is affected by legitimate operational or dispatch reasons due to the QF's siting decision, the PDDRR methodology should reflect this economic reality, as well. A methodology should be accurate under all circumstances; it should not be distorted or constrained from yielding

[46] *See, e.g., Idaho Wind Partners 1, LLC,* 140 FERC ¶ 61,219, at P 37 (2012) (describing scenarios where, for operational reasons, avoided costs may be very low or even negative, and noting that these negative avoided costs are presumed as a matter of law to be factored into PURPA contracts) (citing Order No. 69, 45 Fed. Reg. at 12,227-12,228). Moreover, FERC recently addressed operational issues caused by transmission constraints in PacifiCorp's service territory and noted that, although PURPA prohibits PacifiCorp from curtailing QFs to address transmission problems caused the involuntary addition of QFs to constrained areas, PacifiCorp could instead address the issue economically by taking transmission constraints into account when calculating a QF's avoided cost. *Pioneer Wind Park I, LLC,* 145 FERC ¶ 61,215 at fn 79 (2013). ODOE's recommendation would render this proposed solution impossible even when circumstances make it legitimate and economically accurate to price QF power at below market.

accurate results simply because a party believes the facts that would support certain outcomes do not currently exist.

## Issue 8: When Is There a Legally Enforceable Obligation?

### A. PacifiCorp Supports Staff's Position Regarding LEO Formation

PacifiCorp supports Staff's position on this issue, which is consistent with PacifiCorp's recommendation.[47] According to Staff, the Commission should hold that a legally enforceable obligation is created when the QF executes the final draft executable contract. Staff also suggests that a QF should be permitted 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 state or federal policy.[48]

As noted previously, FERC's general policy is to defer to the states on the question of when a LEO arises.[49] In the context of QF "commitment," many states have required QFs to make specific showings before they can be viewed as "unequivocally committed" to selling to the utility, such as a date certain for delivery of energy and capacity, guarantees that a QF will protect utility customers from harm if the project fails, evidence of permits, site acquisition, QF certification, and/or evidence that the QF is pursuing interconnection in a reasonable manner consistent with its commercial delivery date.[50] Staff's recommendation provides clear guidance for determining when a QF "commits" to selling power to the utility in order to establish a LEO.

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[47] Staff Prehearing Memorandum at 35-40; PacifiCorp Prehearing Brief at 36-46.
[48] Staff Prehearing Memorandum at 35.
[49] *See West Penn Power Co.,* 71 FERC ¶ 61,153, 61,495 (1995).
[50] *See, e.g.,* Tex PUC Subst. R. 25.242(f)(1)(B) (QF must be within 90 days of power delivery to establish a LEO); *Public Serv. Co. of Okla.,* 115 P.3d 861, 873 (Okla. 2005) (finding a LEO was created where QF made significant progress in the development of its project, including attempting to obtain environmental and other necessary permits, securing contracts for natural gas, transportation, construction, and operations and maintenance, including site studies, plant design, and negotiations with vendors for these services, to demonstrate project viability). *See also In re Appeal of Pub. Serv. Co. of N.H.,* 539 A.2d 275, 295 (N.H. 1988) (requiring QF to demonstrate there is a reasonable expectation that the project will be on-line by the date specified and to demonstrate the economic viability of its project over its life before a LEO is created); *South River Power Partners, L.P. v. Penn. Pub. Util. Comm'n,* 696 A.2d 926, 931 (Pa. Commw. Ct. 1997) (requiring QF to demonstrate it has the ability to carry out its responsibilities, including substantial action "to acquire the necessary permits, site development approval, construction plans, and financing" before a LEO is created). *See e.g., Armco Advanced Materials Group v. Pennsylvania PUC,* 579 A.2d 1337 (1990)("A LEO does not exist . . . when the qualifying facility has not yet obligated itself to deliver power and remains free to walk away from the negotiations without liability.").

## B. REC Misstates PacifiCorp's Testimony About the QF Contracting Process

PacifiCorp disagrees with a number of statements made by REC about the QF contracting process. While there have certainly been QF disputes on occasion, particularly when avoided costs are changing, QF PPAs are generally signed without issue within a 90-120 day window.[51] Nevertheless, REC asserts that utilities regularly obstruct QF contract formation, stating, for example, that, "despite the Commission's intention to eliminate negotiations, PacifiCorp believes that the contract negotiation process necessarily requires some level of back and forth negotiations."[52] REC calls this a "violation of the Commission's [standard QF] policy."[53]

REC's use of Mr. Griswold's statement is extremely misleading. The "negotiations" to which Mr. Griswold was referring are the *very timelines and processes* built into the Company's Schedule 37. These procedures are not only permitted, but required. They ensure that a utility and a QF engage in some back and forth to exchange critical details about a QF's generation facility, information about interconnection, information about legal compliance, and other key project details such as milestone dates and minimum energy deliveries.[54] For example, a QF may propose a minimum delivery of zero MWh for a solar project which is clearly an unacceptable minimum for a solar project and requires some back and forth "negotiations" on what the appropriate minimum generation level should be. Mr. Griswold's insistence that a QF and a utility interact is both common-sense and critical to a utility's ability to do appropriate due diligence on a project attempting to lock in a long-term obligation.[55] Some level of communication is positive for utilities, their customers, and legitimate QFs, not, as REC asserts, a "violation of the Commission's [standard QF] policy."[56]

REC also criticizes PacifiCorp for modifying Schedule 37 PPAs in some instances, suggesting that PacifiCorp is imposing onerous or inappropriate terms on QFs. This is also

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[51] As Mr. Griswold explained, the contracting process ordinarily takes 90-120 days, unless avoided cost prices are changing. PAC/1000, Griswold/8.
[52] REC Prehearing Brief at 18.
[53] *Id.*
[54] PAC/1300, Griswold/8-10.
[55] PAC/1000, Griswold/18.
[56] REC Prehearing Brief at 18.

misleading. PacifiCorp has, at times, modified the terms and conditions of Schedule 37 PPAs, but only in minor ways, in ways that reflect actual QF characteristics, or to accommodate specific QF requests. For example, Mr. Griswold testified that PacifiCorp has modified standard PPAs for reasons such as the industry's replacement of a market index (a point of reference in a Schedule 37 PPA), to accommodate restrictions on insurance and indemnification to allow public agencies to comply with Oregon law; and to address requests by multiple QFs for shared interconnections, among others.[57] The fact that PacifiCorp may need to modify a standard PPA from time to time does not mean the utility is failing to work cooperatively with QFs or to honor its PURPA obligations. Moreover, Mr. Griswold explained that the Company remains ready to sign standard QF PPAs even if its proposed modifications are refused.[58] In short, REC has made a number of statements about PacifiCorp's testimony on this issue, including those noted above, that PacifiCorp believes are misleading and inaccurate.

### C. The Filing of a Complaint Should Not Automatically Give Rise to a LEO

REC argues that a QF should be able to unilaterally trigger a LEO (and lock in avoided cost prices on the cusp of a price revision) by claiming there are disputed contractual terms. This could be problematic, as the Commission may find itself deluged with complaints when avoided cost prices are changing as QFs attempt to lock in old pricing. As PacifiCorp noted in its Prehearing Brief, this construct would give QFs an incentive to find disputes in order to lock in stale prices, even before a QF had met its own obligations to create a LEO. Rather than allowing a QF to unilaterally "lock in" avoided cost prices with a LEO claim before entering into the dispute resolution process, the Commission should simply determine the appropriate avoided cost price that should apply when a dispute is filed under the Schedule 37 or Schedule 38 dispute resolution process.

[57] PAC/1300, Griswold/9.
[58] *Id.*

### D. The Commission Has a Great Deal of Discretion to Determine When a LEO Arises.

CREA spends a significant amount of time in its brief addressing the applicability or non-applicability of a recent Fifth Circuit case, *Exelon Wind I, LLC v. Nelson*, 766 F.3d 380 (5th Cir. 2014), arguing that the case does not apply here.[59] For clarity, Mr. Griswold mentioned *Exelon Wind* for the simple proposition that the state has a great deal of discretion in determining when a LEO arises. FERC has agreed with this general proposition; the Fifth Circuit took the point a step further by overruling a FERC order addressing LEOs on the ground that FERC had overstepped its bounds. "[U]nder the cooperative federalism scheme created by PURPA," the court stated, "it is the PUC, rather than FERC, that defines the parameters for when a Qualified Facility may form a Legally Enforceable Obligation."[60] PacifiCorp is not arguing that *Exelon Wind* overrules any specific FERC or Oregon PUC order; the case simply reinforces the proposition that the Commission has great latitude under the law to make a decision about when a LEO arises.

### Issue 9: How Should Third-Party Transmission Costs to Move QF Output in a Load Pocket to Load Be Calculated and Accounted for in the Standard Contract?

PacifiCorp proposes procuring long-term firm point-to-point transmission for the entire term of a PPA when third-party transmission is needed to move QF output from a load pocket to PacifiCorp's load. The Company proposes handling these transmission costs on an individual QF basis through an addendum to the QF's PPA. PacifiCorp addressed this issue in detail in its Prehearing Brief,[61] and will simply respond here to one Staff recommendation.

As an initial matter, Staff believes PacifiCorp's proposal is consistent with PURPA. Staff explains that PacifiCorp's proposal "provides the QF with a fixed price that is known at the time of contracting and does not allow PacifiCorp to curtail the QF's generation when transmission is

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[59] ("*Exelon Wind.*") *See* CREA Prehearing Legal Brief at 18 ("PacifiCorp appears to argue that a recent Fifth Circuit decision undermines FERC's LEO rule.").
[60] *Exelon Wind,* 766 F.3d at 396.
[61] PacifiCorp Prehearing Brief at 46-55.

unavailable."[62] Moreover, Staff, explains, "no other proposal submitted in this process regarding recovery of costs for third-party transmission is consistent with PURPA. . . ."[63] PacifiCorp appreciates Staff's careful attention to this issue, the details of which have at times been difficult to address with clarity in light of misunderstandings by a number of parties about the applicable FERC and state rules and how they intersect on this issue.

Staff makes one recommendation that PacifiCorp would like to address. Staff is concerned with the challenges posed by the fact that a load pocket is dynamic and that information about a load pocket is not easily accessible, making it difficult to know at times when third-party transmission costs may be incurred. PacifiCorp explained the legal and operational constraints involved in providing contemporaneous information about transmission availability in its Prehearing Brief and will not repeat them here.[64] In short, however, the Company is prevented from providing a "map" of load pocket constraints for a number of legal and factual reasons stemming primarily from FERC's separation of functions and federal transmission policies.

Staff is concerned about the challenges posed by load pockets, however, and acknowledging that a five-year commitment is required to obtain renewal rights for a long-term point-to-point transmission contract, Staff suggests that PacifiCorp could offer a QF located in a load pocket two options for a contract addendum: 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 reset every five years "concomitant with PacifiCorp's renewal of its long-term contract."[65]

PacifiCorp does not object strongly to this recommendation, but notes that it could raise a number of thorny issues unless it is accompanied by clear guidance from the Commission. If a QF signs a 20-year PPA, but the third-party transmission contract is for only five years, the QF

[62] Staff Prehearing Memorandum at 40.
[63] *Id.*
[64] *See, e.g.,* PacifiCorp Prehearing Brief at 48-50.
[65] Staff Prehearing Memorandum at 43.

may benefit from a reassessment of transmission issues upon renewal, as Staff suggests it might, but the QF might also find that its transmission costs *increase* upon renewal. PacifiCorp is concerned that a QF with a 20-year obligation to sell power to PacifiCorp might not be particularly happy if its transmission costs were to increase during the term of the PPA, which could potentially lead to QF complaints and litigation. To avoid unnecessary disputes, if the Commission requires PacifiCorp to offer QFs a five-year renewal option, it should simultaneously make clear that if a QF chooses a five-year renewal option, the QF assumes any and all risk of transmission price changes during the term of the PPA, and that PacifiCorp will be held harmless from consequences of this election. In other words, both the potential upside and the potential downside of this election will fall to the QF.

Staff also suggests that the resolution of this issue might be deferred to Phase III. PacifiCorp believes the resolution to this issue is a fairly straightforward one that need not be deferred any longer. The cleanest and best solution is for PacifiCorp to obtain a firm, point-to-point transmission contract to move QF output out of a load pocket for the term of the PPA, the costs of which would be reflected in a PPA addendum. A transmission contract for the full term of a PPA provides certainty that a five-year contract cannot. If the Commission would prefer the QF have the option to purchase transmission for a five-year term, however, this is a workable solution, so long as the Commission clarifies that PacifiCorp and its customers will bear no risk or liability for any consequences of the QF's election.

## III. CONCLUSION

PacifiCorp respectfully requests that the Commission adopt the proposals contained herein.

Respectfully submitted this 13th day of October, 2015.

By: ____________________________

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