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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 Prehearing Brief

PacifiCorp d/b/a Pacific Power encloses for filing its Prehearing 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/kw

R. Bryce Dalley
Vice President, Regulation

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1610
Phase II

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Investigation Into Qualifying Facility Contracting and Pricing	PACIFICORP'S PRE-HEARING BRIEF

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 pre-hearing brief sets forth PacifiCorp d/b/a Pacific Power's (PacifiCorp or Company) legal position on the issues identified in the parties' Phase II stipulated issue list and a summary of the factual support for each position.[2]

As this Commission and state regulators across the country have stated time and time again, under PURPA's original intent, retail customers should be indifferent to the purchase of QF power.[3] FERC has likewise affirmed the need to ensure customer indifference to utility purchases of QF power, noting that, in enacting PURPA, "[t]he intention [of Congress] was to

[1] *In re Idaho Power Co.'s Application to Revise the Methodology Used to Determine Standard Avoided Cost Prices,* and *In re Request to Revise Standard Contract Avoided Cost Prices Paid to Qualifying Facilities Under Schedule 85,* Dockets UM 1590 and UM 1593, Order No. 12-146 (Apr. 25, 2012). For purposes of this brief, the parties to this docket are referred to as follows: 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] ALJ Ruling Establishing Issue List (Mar. 26, 2015).
[3] *E.g., In re Staff's Investigation Relating to Electric Util. Purchases from Qualifying Facilities,* Docket No. UM 1129, Order No. 05-584 at 11 (May 13, 2005) (Commission has recognized PURPA's customer indifference standard since 1981).

make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives."[4] Indeed, PURPA's legislative history makes clear that PURPA was intended to encourage cogeneration and small power production, but it was not intended to provide subsidies to QFs.[5]

Under PURPA, then, customers must remain indifferent to or unaffected by QF contracts. As this Commission understands, avoided cost rates are not the only terms to a PURPA contract. Indeed, both avoided costs and other terms and conditions of PURPA contracts affect whether retail customers remain indifferent to the purchase of QF power. The Company takes certain positions in this docket because it believes those positions are critical to maintaining customer indifference, and, if adopted by the Commission, would allow the Commission to properly implement PURPA while avoiding exposing customers to unnecessary risk.

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?

Green Tags should be awarded to the utility at the beginning of the resource deficiency period identified in the utility's most recently acknowledged Integrated Resource Plan (IRP) at the time the power purchase agreement (PPA) was executed.[6] The utility should then retain ownership of the Green Tags throughout the remainder of the PPA term.[7] Stated another way, 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

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[4] *Southern Cal. Edison Co., et al.*, 71 FERC ¶ 61,269 at 62,080 (1995) *overruled on other grounds, Cal Pub. Util. Comm'n*, 133 FERC ¶ 61,059 (2010).

[5] *See* Conference Report on PURPA, H.R. Rep. No. 1750, 95th Cong., 2nd Sess. 97-98 ("The provisions of this section are not intended to require the rate payers of a utility to subsidize cogenerators or small power producers."); *Indep. Energy Producers Ass'n, Inc. v. California Pub. Utilities Comm'n*, 3 6 F.3d 848, 858 (9th Cir. 1 994) ("If purchase rates are set at the utility's avoided cost, consumers are not forced to subsidize QFs because they are paying the same amount they would have paid if the utility had generated energy itself or purchased energy elsewhere.")

[6] Green Tags are also referred to as "Renewable Energy Credits" or "RECs."

[7] *See* PAC/1000, Griswold/4-7.

end of the PPA, PacifiCorp should own the Green Tags associated with the PPA, consistent with its avoidance of the renewable resource used in developing avoided costs in the PPA.

The Commission's policy regarding Green Tag ownership turns on a utility's resource sufficiency position.[8] The fact that a QF is in the first, tenth, or fifteenth year of a 20-year PPA has no bearing whatsoever on whether a utility is resource sufficient or deficient. Similarly, the fact that the Commission has established a specific pricing structure for the last five years of a 20-year PPA has no bearing on a utility's resource position. The five-year market price available to QFs at the end of a 20-year contract term is a policy adopted by the Commission to balance competing interests regarding the accuracy of avoided-cost forecasts; it is not an indication that a utility is projected to be in a resource sufficient position. Consequently, the fact that the Commission has ordered utilities to pay QFs market prices during the last five years of a 20-year contract should have no bearing on the ownership of Green Tags. PacifiCorp respectfully requests the Commission determine that utilities are entitled to the Green Tags associated with a QF contract from the deficiency period forward.

A. The Commission Should Uphold Its Own Precedent and Conclude that Ownership of Green Tags Is Determined by Resource Sufficiency.

The Commission previously determined that QFs retain ownership over Green Tags during resource sufficiency periods, and that utilities are entitled to Green Tags during resource deficiency periods.[9] The Commission has reinforced the idea that ownership of Green Tags is tied to resource sufficiency or deficiency and the deferral of resource acquisition. For example, in Order No. 11-505, the Commission stated, "[we] agree with PGE that the renewable QF should be paid the market price throughout the *renewable resource sufficiency period*—even if

[8] *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).
[9] *Id.*

the utility is non-renewable *resource deficient.*"[10] Similarly, the Commission also noted that, "[we] are not persuaded that the utility purchase of unbundled RECs signals the start of a renewable resource deficiency period."[11]

In other words, once the resource sufficiency "switch is flipped" to a resource deficiency period, the utility is entitled to the Green Tags, without any further consideration of pricing issues. If the Commission had intended otherwise, it presumably would have stated as much.

B. Pricing Issues During the Five-Year Period at the End of a 20-Year QF Contract Are the Byproduct of the Commission's Balancing of Interests that Have No Bearing on Ownership of Green Tags.

Various parties cite to portions of Commission Order No. 11-505 for the proposition that the Commission intended for QFs to retain Green Tags during the final five-years of a 20-year contract term.[12] This pricing construct, however, was created by the Commission to balance competing interests and, in the Commission's view, to provide QFs with financing certainty. It does not undermine or change the Commission's prior rulings that ownership of Green Tags is driven by the resource sufficiency/deficiency demarcation.

The portion of Commission Order No. 11-505 cited by several parties states as follows:

> Allowing a renewable QF to choose between the two avoided cost streams is consistent with FERC's ruling that clarified the right of the state 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 be offered an avoided cost stream that reflects the costs that [the] utility will avoid.*[13]

As the emphasized text indicates, the goal of avoided cost pricing is to allow utilities to purchase output and Green Tags that will allow them to avoid building additional generation that can meet RPS requirements, while balancing those interests against the financial needs of the

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[10] *Id.* at 9 (emphasis added).
[11] *Id.* at 6 (emphasis added).
[12] *See* ODOE/700, Carver/2-3; CREA/500, Skeahan/7-10; Staff/500, Andrus/2-6.
[13] Order No. 11-505 at 9 (emphasis added). (cited at CREA/500, Skeahan/8; Staff/500, Andrus/5; Staff/600, Andrus/3-4; ODOE/900, Carver/1-2 (citing Staff testimony for the same proposition)).

QF. This effort to balance competing needs is further supported by the Commission's original order adopting a 20-year maximum contract term. There, the Commission stated:

> [W]e acknowledge that 20 years is a significant amount of time over which to forecast avoided costs. Indeed, divergence between forecasted and actual avoided costs must be expected over a period of 20 years. *Given our desire to calculate avoided costs as accurately as possible, and the testimony of several parties that avoided costs should not be fixed beyond 15 years*, we are persuaded that standard contract prices should be fixed for only the first 15 years of the 20-year term. Tariffs and standard contract terms should provide that, in the event a QF opts for a standard contract with a 20-year term, the QF must take one of the market pricing options that we address later in this order for the final five years of the contract.[14]

In other words, the market prices associated with the last five years of a 20-year QF PPA are related entirely to a balancing of interests between the accuracy of avoided-cost pricing and the interest a QF may have in electing a long, 20-year contract term. It is unrelated to the sufficiency/deficiency demarcation the Commission has deemed relevant to Green Tag ownership. Finally, the Commission stated in Order 05-584:

> [E]stablishing an appropriate maximum term for standard contracts *requires us to balance two goals.* A primary goal in this proceeding is to accurately price QF power. We also seek, however, to ensure that QF projects that are deemed eligible to receive standard contracts have viable opportunities to enter into a standard contract. To achieve this latter goal, it is necessary to ensure that the terms of the standard contract facilitate appropriate financing for a QF project. Consequently, we agree . . . that our *fundamental objective* is to establish a maximum standard contract term that enables QFs to obtain adequate financing, *but limits the possible divergence of standard contract rates from actual avoided costs.*[15]

Contrary to other parties' assertions, the Commission's attempt to balance competing interests when adopting a 20-year contract term does not demonstrate any intention to confer ownership of Green Tags to one party versus another based on the pricing in the PPA. In fact, the language above suggests that the Commission's avoided cost pricing structure was adopted with the intent of balancing competing interests and providing QFs with financing certainty, not to address

[14] Order No. 05-584 at 20 (emphasis added).
[15] *Id.* at 19 (emphasis added).

Green Tag ownership during periods when QFs, for reasons *unrelated to resource sufficiency,* receive market prices.

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?

Issue 2 can be resolved with a simple Commission clarification: no party demonstrated that a utility would avoid transmission costs (third-party or other) 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.

The scope of Issue 2 was originally limited to whether *third-party* transmission costs associated with a proxy resource should be included in avoided cost prices.[16] The Commission issued a clear ruling on this issue, stating, as relevant here, that "[i]f the proxy resource used to calculate a utility's avoided costs is an on-system resource, there are no avoided transmission costs, and thus the costs of third-party transmission are *not* included in the calculation of avoided costs prices. This is the situation for Pacific Power."[17]

After the issuance of Order No. 14-058, certain intervenors and Staff have continued to raise questions about the meaning of this Commission conclusion, asking whether the Commission intended to hold that:

- No party demonstrated that PacifiCorp would avoid transmission costs when the proxy resource is on its system, and therefore inclusion of transmission costs in the calculation of avoided cost prices is not appropriate; or

- Even if PacifiCorp would avoid transmission costs associated with an on-system proxy resource by purchasing QF energy, it is not appropriate to include avoided transmission costs in the calculation of avoided cost prices when the proxy resource is an on-system resource.[18]

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[16] *See In re Investigation into Qualifying Facility Contracting and Pricing*, Docket No. UM 1610, Order No. 14-058 at 16 (Feb. 24, 2014).
[17] *Id*. at 17 (emphasis in original).
[18] *See* Brief in Support of Stipulation Re: Issues List, Docket No. UM 1610 at 6 (Feb. 26, 2015).

In other words, intervenors and Staff appear to have moved beyond the issue of whether *third-party* transmission costs associated with an *off-system* proxy resource should be included in avoided cost prices. Rather, the crux of the current concern appears to be based on belief that 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 such transmission costs.[19]

As is discussed in more detail in Issue 9, it is true that if a QF chooses to site its project in a "load pocket" on PacifiCorp's system, then PacifiCorp may need to arrange for new third party transmission service in accordance with its Open Access Transmission Tariff (OATT) rules (*e.g.*, request and pay for a new point-to-point contract on a third-party system) in order to be able to move that QF power out of the load pocket. However, PacifiCorp's proxy resources are not similarly-situated.

PacifiCorp's proxy resources are planned, on-system acquisitions that are directly interconnected to PacifiCorp's system and optimally located to load.[20] This means 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 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.[21] For example, these rights could be on PacifiCorp-owned transmission infrastructure or on third-party systems, and they could be governed by a variety of different types of transmission agreements (*e.g.*, OATT service agreements, legacy transmission agreements, etc.).[22] In addition, use of the PacifiCorp-owned infrastructure could be part of PacifiCorp's existing system, or it could be associated with a transmission upgrade identified consistent with, for example, federal reliability (including load

[19] *Id.*
[20] *See, e.g.*, PAC/800, Dickman/4.
[21] *See, e.g.*, PAC/800, Dickman/5; PAC/1100, Dickman/5.
[22] *Id.*

service) planning requirements.[23] An example of such a planned upgrade is PacifiCorp's Gateway West project mentioned by several parties to this proceeding.[24]

Importantly, PacifiCorp would maintain and use these existing transmission rights, as well as proceed with any transmission upgrades that are consistent with federal transmission planning policies, *regardless of whether it adds QF or non-QF resources*. Stated differently, the Gateway West project is not directly tied to PacifiCorp's proxy resource(s) and will not be avoided due to the addition of Oregon QFs.[25] Thus, unlike the situation where PacifiCorp must acquire new third-party transmission rights because an Oregon QF chooses 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, on-system proxy resources do not require *incremental* third-party transmission service arrangements. As a result, the addition of a QF does not allow PacifiCorp to avoid an on-system proxy resource's third-party transmission cost, and most certainly not a transmission system upgrade planned consistent with federal requirements,[26] and should not be included in PacifiCorp's avoided costs.

As noted above, PacifiCorp believes the Commission can resolve Issue 2 by clarifying that no party demonstrated that a utility would avoid transmission costs (third-party or other) when the utility's proxy resource is on-system, and therefore inclusion of such transmission costs in the calculation of avoided cost prices would not be appropriate.

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[23] *See, e.g.*, PacifiCorp's Transmission Tariff, Attachment K; *Transmission Planning and Cost Allocation by Transmission Owning and Operating Pub. Utils.*, FERC Order No. 1000, 76 Fed. Reg. 49,842 (Aug. 11, 2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012).

[24] As Mr. Dickman noted, the intended purposes of Gateway West include alleviating existing transmission constraints, improving the ability to deliver energy from all existing resources to load, enabling more efficient dispatch of system resources, improving the performance of the transmission system, improving reliability and enabling access to a diverse range of new resource alternatives over the long-term. PAC/1100, Dickman/4 (citing PacifiCorp's 2015 IRP, Vol. 1, pp. 50-51).

[25] *Id.*

[26] OneEnergy and CREA seem to imply that the entire cost of the Gateway West project should be included in avoided costs, displaying a fundamental misunderstanding of the drivers behind the Gateway West project and, even more fundamentally, a utility's transmission planning process. *See, e.g.*, OneEnergy/400, Eddie/3-4; CREA/500, Skeahan/11-12.

To the extent the Commission wishes to reexamine this issue in the future, a firm legal basis (including consideration of PURPA's "but-for" causation test for avoided cost and any applicable FERC OATT requirements and transmission pricing policies), and a clear methodology for accurately defining, calculating and reflecting such costs in avoided costs would need to be established in an appropriate proceeding before such costs were included in avoided costs. PacifiCorp attempted through its testimony to respond to some of the ideas and questions raised in this regard, but it does not believe the record currently supports the adoption of a policy requiring PacifiCorp (or any utility) to calculate and reflect non-third-party transmission costs in avoided costs. Such a policy, even if deemed appropriate, would require consideration of many important issues, such as:

- What types of "transmission costs" would be addressed?[27] The cost of the proxy resource's interconnection facilities? What are the costs of network upgrades that may be required as a result of the proxy resource's interconnection? What are the costs of network upgrades that may be required as a result of the transmission service arrangements made to deliver the proxy resource to load? Are there other types of transmission costs?[28]

- In addition to the potential role of the IRP, would PacifiCorp's OATT study process also be taken into account in any "transmission cost" estimations? This would be particularly important if certain types of network upgrades are at issue, as PacifiCorp follows FERC-mandated OATT study processes to estimate, among other things, network upgrades required to accommodate different types of transmission service and the associated costs.

- Would the methodology take into account whether a QF PPA requires PacifiCorp to incur the same type of "transmission costs" a QF believes it is helping to avoid elsewhere? For example, are there interconnection facilities or network upgrades required for the QF's interconnection and/or transmission arrangements? If so, even assuming the "transmission costs" associated with the proxy resource can be clearly defined and estimated in an accurate manner, has the utility necessarily avoided such costs because of the addition of the QF? What if the "transmission costs" necessary

[27] As a general matter, the testimony filed by all parties on Issue 2 is unclear about what types of "transmission costs" are at issue. This would be a critical issue to clarify because, depending on which transmission costs are involved, the methodology would need to take into account, for example, any relevant state and federal transmission pricing policies. *See, e.g.*, *Inquiry Concerning the Commission's Pricing Policy for Transmission Servs. Provided by Pub. Utils. Under the Federal Power Act*, 59 Fed. Reg. 55,031 (Nov. 3, 1994) (FERC Transmission Pricing Policy).

[28] And if the proxy were located near an area of load growth, would deferral of the proxy actually result in deferral of the need to build transmission to serve load in the area?

to accommodate the QF purchase exceed those that the utility would incur to accommodate the proxy resource?

- How would this necessarily QF-specific analysis (heavily dependent on, for example, where the QF chooses to site its project and precisely when it comes online) be appropriately reflected in standard contracts?

Again, however, PacifiCorp believes the Commission can resolve Issue 2 by simply clarifying that no party demonstrated that a utility would avoid transmission costs (third-party or other) when the utility's proxy resource is on-system, and therefore inclusion of such transmission costs in the calculation of avoided cost prices would not be appropriate at this time.

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?

The Commission should retain its approved methodology for determining the capacity contribution adder for solar QFs selecting standard renewable avoided cost prices. 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.

A. The Commission-Approved Methodology for Determining the Capacity Contribution Adder and Obsidian's Motion for Clarification.

In Order No. 14-058, the Commission developed a "capacity contribution adder" to address the fact that, up to that point in time, "no adjustments [were] made to Standard and Standard Renewable avoided cost prices to account for the *actual contribution* to capacity made by each QF resource type."[29] The Commission adopted the capacity contribution adder proposed by Staff and others, which was intended "to produce more accurate avoided cost estimates."[30]

In Order No. 14-058, the Commission adopted Staff's proposal to modify the standard avoided cost prices to account for the actual contribution to capacity made by each QF resource

[29] Order No. 14-058 at 15 (emphasis added).
[30] *Id.*

type.[31] For the Standard Method, the Commission adopted Staff's proposal to multiply the capacity component embedded in the method by a "capacity contribution factor" equal to the expected contribution to peak load of the specific QF resource type.[32] According to the Commission, the assumed capacity contribution to peak load would be the contribution estimate used in the utility's acknowledged IRP for the specific type of generation (wind, solar, etc.).[33] For the Standard Renewable Method, the Commission adopted Staff's proposal to adjust the capacity component implicit in the renewable on-peak price by the incremental capacity contribution of the specific QF resource type relative to the avoided renewable resource. This did not change the method for wind QFs, but for solar and base load QFs, it resulted in a higher capacity component (and on-peak price) than was calculated in the then-current method.[34]

After Order No. 14-058 was issued, Obsidian filed a motion for clarification claiming that applying the capacity adder on a dollars-per-megawatt-hour basis resulted in an inadvertent "double discount" of the capacity payment to a solar QF.[35] According to Obsidian, the avoided cost paid to a solar resource should not be discounted simply because the solar QF has a relatively low capacity factor and does not generate the same amount of energy as the capacity resource. Specifically, Obsidian argued that the capacity adder should be paid as based on the number of on-peak hours during which a solar project *may* operate, rather than depend on the QF's actual energy output. According to Obsidian's motion, "Obsidian seeks clarification that the discounted Capacity Adder calculated pursuant to the methodology [proposed by Mr. Bliss] will be paid to an eligible Renewable Solar QF Resource for all on-peak hours, and will *not be limited only to those peak hours in which the resource actually delivers output to the purchasing utility*."[36]

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[31] *Id.*
[32] *Id.*
[33] *Id.*
[34] *Id.*
[35] Obsidian Renewables LLC's Motion for Clarification, Docket No. UM 1610 (April 24, 2014).
[36] *Id.* at 6 (emphasis added).

These arguments boil down to a proposal that the solar capacity adder should be paid as a fixed dollar amount and that each solar QF should receive the fixed dollar amount regardless of its actual output during on-peak hours.[37]

B. The Commission Correctly Addressed this Issue in Order No. 14-058.

The Commission correctly addressed the capacity contribution issue in Order No. 14-058, and its decision there should not be revisited. The methodology at issue is for standard avoided costs, which involve simplified calculations and prices that apply to all QFs that meet standard avoided cost eligibility requirements. Standard avoided costs during the deficiency period are equal to the cost of a proxy resource, and they are intended to reflect the "actual deferral or avoidance of that resource."[38] The Commission-approved adjustment to capacity contribution results in an appropriate discount for intermittent resources, and does not "double discount" capacity costs for solar QFs; rather, it pays the QF for resources actually avoided by the utility.[39]

By contrast, Obsidian's proposal would pay a solar QF for deferral of a base load resource the solar QF does not actually avoid because the QF would be paid a fixed amount for capacity regardless of whether the QF actually provides the generation needed to offset the resource. Obsidian's proposal would also pay a solar QF for proxy benefits that a solar resource simply does not provide.[40]

Staff argues that if the capacity costs are spread over the on-peak generation of the avoided thermal resource, a solar QF will be undercompensated because it is expected to be available for fewer hours than the avoided resource.[41] This is not an unintended consequence, but a representation of the costs actually avoided by the Company. It is correct to base avoided costs on the characteristics of the resource that is being avoided (here, a Combined Cycle Combustion Turbine, or CCCT), rather than on the characteristics of the QF.[42] The fact that a solar QF is

[37] PAC/800, Dickman/7.
[38] PAC/800, Dickman/8 (citing Order No. 05-584 at 26).
[39] *Id.* at 8-9.
[40] *Id.* at 8.
[41] Staff/500, Andrus/17-20.
[42] PAC/1100, Dickman/7-8.

available for fewer hours than the avoided resource compels a lower payment.[43] The proxy thermal resource provides several benefits to the utility that are not provided by a solar QF, including the ability to dispatch the resource on an as-needed basis and the ability to provide operating reserve capacity.[44] These benefits are available to the Company in all hours, not just when the resource is generating energy.

Fixing the amount of capacity adder dollars paid to a solar QF incorrectly assumes that the solar QF can fully replace a renewable proxy and a portion of a CCCT, and fails to recognize the benefits lost if a CCCT is actually displaced. Under Staff's proposal, a solar QF would receive payment for the entire value of the displaced capacity even though the QF would provide generation only, essentially ignoring the value that a gas plant provides, given its ability to be dispatched, hold reserves, and integrate intermittent energy.[45] Adopting Staff's approach would inflate standard renewable avoided costs and move the method further away from actual avoided costs.

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?

As explained above, PacifiCorp strongly disagrees with the assertion that the proposed changes should be made to the capacity contribution calculation for either renewable or non-renewable avoided cost prices. The changes sought by Obsidian and Staff would result in capacity payments to QFs that are greater than those that would be paid to equivalent base load generation.[46] Furthermore, any modification to either the renewable or non-renewable avoided

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[43] *Id.* at 8.
[44] The capacity costs of a proxy CCCT provide several benefits to the utility that are not provided by an intermittent solar QF, including the ability to dispatch the resource on an as-needed basis and the ability to provide operating reserve capacity. The Company is required to have sufficient contingency reserves available within 10 minutes to ensure reliable service in the event of unexpected generation or transmission outages. The Company is also required to have sufficient generating capacity available to compensate for moment-to-moment changes in the load and resource balance on its system. Combined cycle plants can ramp over most, if not all, of their dispatchable range within 10 minutes and thus have significant reserve carrying capability. PAC/1100, Dickman/8.
[45] *See*, *e.g.*, PAC/1100, Dickman/8-9.
[46] *See* PAC/800, Dickman/10.

cost prices would require the Commission to reconsider issues that have already been decided after extensive briefing and testimony before the Commission.

Additionally, if the Commission were to consider adopting the proposal proffered by Obsidian and Staff, then the avoided cost methodology that has been in place since at least 2006 would be fundamentally undermined. PacifiCorp believes the more prudent course is for the Commission to uphold its determinations in Order No. 14-058 and make no changes to the renewable and non-renewable avoided cost rates. For these reasons, as well as those described above, any proposal to change the capacity contribution calculation for non-renewable avoided prices should also be rejected.

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. The Commission has repeatedly concluded that utilities should rely on inputs and assumptions developed in an acknowledged IRP when setting avoided cost prices. The Commission's existing IRP process is appropriate for this purpose. Utility IRPs are developed through a well-established, robust, and transparent process with opportunity for input and challenges from Commission Staff and stakeholders, as well as meaningful review by the Commission. Using the IRP process to determine critical avoided cost inputs, along with the Commission's existing process for compliance review of utility avoided cost updates, provides a robust, legally appropriate, and—importantly—relatively expeditious process for determining standard avoided costs.

Other parties ask the Commission to add additional opportunities for parties to challenge IRP assumptions and avoided cost inputs used in standard prices. PacifiCorp views these requests as problematic. The relitigation of IRP inputs in a separate forum, or the adversarial litigation of IRP inputs during the IRP process itself, could undermine the IRP process and devalue its ultimate outcome.[47] Moreover, utility avoided costs must be updated regularly to ensure they are as accurate as possible, and protracted litigation over the assumptions and inputs for these 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. PacifiCorp respectfully requests that the Commission reaffirm its use of the existing IRP process for addressing IRP assumptions and inputs.[48]

A. Use of the IRP in Development of Avoided Cost.

The Commission has tied avoided costs to least cost planning (the precursor to IRP) since 1992. In Order No. 92-1793, the Commission "consolidate[d] the avoided cost process with least-cost planning schedule."[49] That order imposed the obligation now found in OAR 860-029-0040(4)(a) to file avoided cost updates within 30 days of IRP acknowledgement.[50]

The Commission has repeatedly affirmed that IRP inputs, which are subject to stakeholder and Commission review, are appropriate for use in developing standard avoided costs. As the Commission stated after the first phase of this docket:

> Calculation of each utility's standard avoided costs begins with the utility filing an IRP for a 20-year planning horizon, as required every two years. Utilities' avoided cost methodologies were designed to capture the avoided costs actually realized by the utility when it purchases power from a QF, and are intended to be simple and clear, with inputs and assumptions taken from IRPs that are subject to stakeholder review.[51]

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[47] ODOE recommends that avoided cost and the IRP issues be adjudicated in the same IRP docket. REC recommends expanding the IRP process to allow parties to formally challenge avoided cost inputs and assumptions within the IRP docket. Staff recommends that resource sufficiency/deficiency determinations made in the IRP process should be subject to challenge in avoided cost updates. Idaho Power recommends that a PURPA docket be opened when there are disputed inputs. PGE, like PacifiCorp, recommends maintaining the current Commission policy wherein utilities use inputs from their last acknowledged IRP as the basis for avoided cost prices.
[48] The follow-up process of compliance review should also be retained.
[49] Order No. 92-1793 at 2.
[50] At the time, the obligation was codified in OAR 860-029-040(a) and stated, "[e] ach public utility shall file with the Commission, within 30 days of Commission acknowledgment of its least-cost plan pursuant to Order No. 89-507, to become effective 30 days after filing, standard rates for purchases from [QFs]."
[51] Order No. 14-058 at 12.

As PacifiCorp witness Mr. Ted Drennan explains, many items incorporated in the IRP and reviewed in the IRP planning process are critical to avoided cost prices.[52] These IRP inputs include, among other things, resource sufficiency period, fuel forecasts, capacity contribution rates, and wind integration costs as well as the cost and performance of specific resources.

B. <u>The IRP Process Is a Robust One.</u>

The IRP process is a robust and open process that provides ample opportunity for interested parties to influence IRP inputs and assumptions. When the Commission established the state's least-cost planning requirements in 1989, it required utilities to include "[s]ignificant public and other utility involvement in plan preparation."[53] Indeed, since that time, the Commission's IRP process has increasingly developed into a robust, well-vetted process. The IRP process is governed by guidelines requiring extensive public input. For example, guideline 2a of the Commission's IRP guidelines states as follows:

> The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.[54]

As a practical matter, the Company spends a significant amount of time soliciting input on its IRP, even before the IRP is drafted. The public process for an IRP is initiated up to a year prior to filing each IRP. During this time, the Company hosts public input meetings and workshops where participants offer comments, recommendations, and generally influence key planning assumptions. For example, before beginning its 2015 IRP, the Company held a

[52] *See* PAC/900, Drennan/5; PAC/1200, Drennan/3-4.
[53] *See* Order No. 89-507 (Apr. 20, 1989).
[54] *See In re Investigation into Resource Planning,* Docket No. UM 1056, Order No. 07-002 at Appendix A at 2 (Jan. 8, 2007).

workshop to solicit feedback on potential improvements to the IRP process itself.[55] In June 2014, the Company met with Oregon IRP stakeholders to discuss any item of their choosing related to the IRP.[56] The Company held seven public input meetings jointly in Portland and Salt Lake City via teleconference, and it hosted two technical workshops.[57]

Participants involved in the IRP process have the opportunity to review and influence the Company's IRP model assumptions, studies, methodologies, and results by attending any of these meetings and workshops, or by providing direct feedback to the Company, even in the early stages of IRP development. And, as will be discussed, the IRP process provides additional, more targeted opportunities for challenging IRP inputs once the IRP is before the Commission.

C. The IRP Process Provides Sufficient Opportunity for Parties to Challenge IRP Assumptions.

Some parties complain that the IRP process fails to provide sufficient process for challenging standard avoided cost inputs derived from the IRP. For example, REC claims that the current IRP process does not "provide stakeholders an opportunity to challenge and obtain a Commission decision" for IRP assumptions.[58] CREA argues that "interested parties should have the opportunity to fully review avoided cost rates and the myriad of assumptions that are behind those rates."[59] PacifiCorp disagrees.

As noted above, the IRP process provides ample opportunity for the public to influence key IRP planning assumptions. Once the IRP is filed, there are additional, specific opportunities for Commission Staff and parties to file comments, concerns, and recommendations.[60] Once the IRP is filed with the Commission, the IRP acknowledgement process allows parties to file comments with the Commission—often several rounds of comments, in which intervenors may

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[55] The workshop was held September 23, 2013. *See* Appendix B of PacifiCorp's 2015 IRP, Volume II, page 30 for further discussion. PacifiCorp's 2015 IRP can be found at http://www.pacificorp.com/es/irp.html.
[56] The Oregon-specific state meeting was held on June 26, 2014. *See* Appendix C of PacifiCorp's 2015 IRP, Volume II, page 59.
[57] *See* Appendix C of PacifiCorp's 2015 IRP for further details on the public input process.
[58] Coalition/400, Lowe/12.
[59] CREA/500, Skeahan /14.
[60] Order No. 07-002, Appendix A at 3 (Guideline 3c).

express concerns with any assumption or input—and to participate in additional workshops and public meetings. Intervenors also have an opportunity to serve the utility with interrogatories or data requests to obtain information related to IRP assumptions.[61] Following the comment period, Staff presents its recommendation memorandum to the Commission, at which point the Commission is required to consider the comments and recommendations provided by others when considering whether to acknowledge an IRP.[62] In short, the IRP regulatory schedule affords intervenors multiple opportunities to comment on all aspects of the IRP and to raise concerns about specific assumptions or inputs.

D. Relitigation of IRP Assumptions Would Undermine the Significance of the IRP.

The Company believes the IRP process provides ample opportunity for parties to challenge IRP inputs and assumptions, but just as importantly, the Company has a number of concerns about the adoption of an adversarial process for litigating IRP inputs. The IRP is a well-established, highly valued process that serves a number of useful roles in Oregon utility regulation. PacifiCorp is concerned that a fundamental purpose of the IRP—the development of long-term resource planning decisions and Commission acknowledgement of those decisions—could be undermined by adversarial litigation of IRP inputs either in the IRP itself, or in a separate, avoided-cost-focused forum.

For example, if a separate forum for litigation of IRP inputs were adopted, parties would know they have an opportunity to target specific IRP inputs that separate, more focused forum, and might be incented to skip participation in the broader IRP process itself in favor of the more targeted forum. Given the importance of obtaining input into the IRP when the Company's long-term plans are actually being developed, any disincentive for parties to participate in the IRP

[61] Parties generally take full advantage of this opportunity. As of June 30, 2015, PacifiCorp had received 127 such requests for the 2015 IRP from Oregon parties alone. This number does not include subparts to those data requests. In the 2013 IRP, the Company responded to 435 data requests from Oregon parties, including thirteen Bench Requests. *See* PAC/1500, Drennan/3-4.

[62] Order No. 07-002 (Guideline 3d).

process could have negative effects on the overall IRP process and the planning outcomes themselves.[63]

Moreover, any separate, adversarial litigation of IRP inputs could undermine the openness that has characterized the IRP process. In effect, utilities would be asked to openly and publicly discuss assumptions and methodologies with other parties, knowing that they will be forced to turn and litigate and defend those *very* same issues again in an adversarial proceeding, with potentially the same parties.[64] This would stifle open discussion. Open discussion of utility planning decisions would also be stifled if Oregon contested-case procedures, or other adversarial procedures, applied to the Company's selection of IRP inputs during the IRP process itself. If the Commission were to adopt an adversarial process to allow litigation of IRP inputs during the IRP process, the discussion of IRP decisions would no longer be free and open; information would be shared through prefiled testimony and cross-examination, with *ex parte* rules in effect. The handling of long-term, resource-planning decisions through a contested-case process would seem contrary to the open process the Commission envisions.

Relitigation of IRP inputs in a separate proceedings could also undermine the utility's planning itself If parallel (or consecutive) IRP and avoided cost processes were adopted, they could result in different conclusions about the *same* IRP inputs, after examination of the *same* issues, data, and assumptions.[65] This would undermine the integrity of the IRP acknowledgment process and the utility's IRP itself. For example, utilities could have one resource sufficiency/deficiency demarcation developed in the IRP used to guide resource procurement activities, but a different demarcation for avoided cost prices.[66] There are numerous planning assumptions (*i.e.*, load forecasts, changes to existing resource availability and capacity ratings, generator operating costs, capacity contribution values, etc.) that influence the type, timing, and

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[63] PacifiCorp is concerned that parties could leverage a second process to slow down updates of avoided cost process. *See* PAC/900, Drennan/11-12.
[64] *Id.*
[65] PAC/1200, Drennan/6-7.
[66] See PAC/900, Drennan/6. The Commission has concluded that "the IRP process [is] the appropriate venue for determining when a utility is resource sufficient or deficient." Order No. 11-505 at 5.

location of future resources in the IRP. If any of these assumptions were modified in a parallel proceeding, then the Company's resource portfolio used for avoided cost pricing would almost certainly be modified, as well, and would immediately be out of alignment with its Commission-approved resource procurement plan.[67]

Finally, relitigation of IRP inputs in a separate forum (or in parallel with the IRP itself) could undermine the significance of the Commission's IRP acknowledgement and throw its meaning into disarray. If the Commission acknowledged a utility's IRP, but later held after an adversarial process that a specific IRP input should be changed, would the Commission acknowledgement still be meaningful? What would that Commission acknowledgement mean when the utility later sought rate recovery of resources that were part of an acknowledged IRP that was later undermined by a separate avoided-cost proceeding? Would the results of the contested-case proceeding be *res judicata,* and would they then trump the results of the Commission's IRP acknowledgement proceeding? A utility's IRP and resource-planning issues should be decided in one forum, with one set of procedures: the current IRP process.

Given the importance of the IRP planning process and the importance of Commission review and acknowledgement of that plan, PacifiCorp believes that introducing litigation and adversarial-type procedures into the IRP process for purposes of developing avoided costs is a case of the tail wagging the dog. The Commission's current process for avoided-cost approval is based on sound policy decisions, is supported by Oregon law, and should be retained.

E. Current Avoided Cost Proceedings Provide QFs with Sufficient Legal Process.

A number of intervenors nevertheless argue they are entitled to additional process to litigate the IRP's avoided cost pricing inputs and assumptions. As noted above, the additional process requested by these parties is extremely problematic. It is also unnecessary under Oregon law.

[67] See PAC/1200, Drennan/3.

In 2009, various parties sought to expand the Commission's avoided-cost approval process to include an investigation or hearing to address certain avoided-cost issues. The Commission concluded that Oregon law did not require it to conduct an investigation or hearing to determine the reasonableness of avoided costs, and the Commission declined to conduct one.[68] The Commission also affirmed the policies behind its existing avoided-cost approval process.

The Commission explained that the avoided-cost approval process was best left a fairly streamlined one. It noted that Oregon's avoided-cost approval process relies on occasional generic investigations to determine what methodologies should be used to value a utility's avoided costs (a methodology that currently relies heavily on IRP inputs), followed by utility compliance filings, which are simply reviewed for compliance with the approved methodologies. The Commission then explained that, as a policy matter, this streamlined compliance process helps ensure that avoided costs are just and reasonable to QFs and to customers of the public utilities, while providing certainty to developers by allowing an expeditious review and updates of avoided cost rates.[69] For these reasons, the Commission should reaffirm its avoided-cost approval process in this docket, as well.[70]

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[68] The legal framework for establishing avoided cost is governed by the statutory framework set forth in ORS 758.505 to 758.555. Importantly, this is *not* the same framework established by ORS 757.210, which establishes the framework for utility rate cases. *See In re Investigation to Determine if Pacific Power's Rate Revision Is Consistent with the Methodologies and Calculations Required by Order No. 05-584,* Docket No. UM 1442, Order No. 09-427 (Oct. 28, 2009) ("ORS 757.210 does not apply to the review and approval of rates *paid* by utilities to QFs, which is governed by the separate statutory framework set forth in ORS 758.505 to 758.555. Under these provisions, electric utilities are required to update their avoided costs at least every two years. Although the Commission must review and approve the filings, the legislature has not mandated an investigation or hearing to determine the reasonableness of those rates. Rather, we are charged with the obligation to ensure that rates paid to QFs are just and reasonable under the overarching goals of PURPA.") (emphasis in original) (footnote omitted).

[69] As the Commission is aware, even this process, which the Commission intended to be fairly streamlined, can be contentious and challenging to administer. And as the Commission has noted, one of the Commission's primary stated goals in implementing PURPA has been to adopt policies and rules that promote QF development through accurate and timely price information about a utility's avoided costs. Relitigating issues already decided in other forums would frustrate this goal, as it could potentially result in lengthy, highly adversarial proceedings that would only cause uncertainty regarding QF rates. Order No. 09-427 at 3-4.

[70] The "Minimum Filing Requirements" (MFR) recommended by certain parties cost inputs are also unnecessarily duplicative and burdensome. Some parties even seek "minimum" filing requirements unrelated to the calculation of avoided cost. *See* PAC/1200, Drennan/13. IRP inputs are already reviewed as part of the robust IRP process. Requiring extensive MFRs (especially those requiring new analysis) will lead to additional litigation in the avoided cost dockets. This will prolong the avoided cost process with no tangible benefits. *Id.*

F. Protracted Litigation of Avoided Cost Prices Has the Potential to Significantly Harm Utility Customers.

Finally, undermining the expeditious review of avoided cost rates can be harmful to customers, particularly when avoided cost prices are going down. The longer the delay in the approval of avoided costs, the more likely QFs will be able to lock in inaccurate rates to the detriment of utility customers. For example, when the Company filed its avoided cost updates in April 2014, the Company received numerous new PPA requests seeking to lock in the old prices as quickly as possible, before the Commission approved the updated prices.[71] As PacifiCorp witness Bruce Griswold explains, some QFs simply downloaded the Company's Schedule 37 PPA from PacifiCorp's website, executed the form PPA, submitted it to PacifiCorp (without any prior contact with the Company), then argued that they had locked in the old rates for the term of a standard contract.[72] Notably, these QFs were not just seeking to lock in these stale avoided cost prices for a year or two, they were seeking to lock in payments for a period of fifteen years. Nor were they seeking to lock in rates that were arguably accurate; they were seeking to lock in rates that were stale and incontrovertibly too high. Any additional delay in the existing approval process for avoided cost pricing would only exacerbate this problem.[73]

G. Conclusion.

For the reasons discussed above, the IRP is the preferred forum to consider issues and assumptions that are fed into the avoided cost filings. It is a well-vetted and transparent process that allows for input from stakeholders and the Commission. Allowing parties to litigate IRP inputs and assumptions in avoided-cost contested cases would disrupt the IRP's usefulness by potentially unwinding the selection and timing of lowest-cost/least-risk resources, the resource sufficiency/deficiency demarcation, and the utility action plan, and would stifle the IRP process itself.

[71] PAC/900, Drennan/12.
[72] *Id.; see also* PAC/1000, Griswold/8-11.
[73] For these same reasons, requests to suspend and investigate avoided cost updates should be heavily scrutinized prior to granting such suspensions, especially following acknowledgement of an IRP. *See* PAC/1200, Drennan/10.

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.[74] The Commission has addressed this issue in the past and determined that paying market prices to QFs during the sufficiency period adequately accounts for capacity.[75] The Commission need not revisit its prior determination.

A. <u>The Commission's Pricing Methodology and Prior Determinations Regarding Compensation for Capacity.</u>

In Order No. 05-584, the Commission established a bifurcated system of avoided cost pricing, which, during deficiency periods, requires the use of historical calculations of avoided costs that takes into account both variable and fixed costs of a planned resource.[76] During sufficiency periods, however, the Commission determined that utilities should "use monthly on- and off-peak forward market prices . . . to calculate avoided costs when . . . in a resource sufficient position."[77]

In adopting this bifurcated methodology, the Commission resolved many of the same arguments now being presented to the Commission.[78] Specifically, the Commission discussed whether market prices during sufficiency periods adequately compensated QFs for capacity. The Commission's order, which is still accurate today, stated as follows:

> We conclude that the basis of differentiation should not be whether the capacity is valued *at all*, but *how* it is valued. [(emphasis in original)] When in a period of resource sufficiency, PGE and PacifiCorp have historically calculated avoided costs based only on the variable costs of operating existing generating resources. *Staff and several other parties,* however, challenged the lack of capacity payment to QFs when a utility is in a resource sufficient position, *arguing that QF capacity has at least some value to utilities at all times and that this value should be compensated for*. When a utility is in a resource sufficient position, we adopt Staff's recommendation that *QF capacity be valued based on the market. . . .* [We] adopt the methodology that values avoided costs when a utility is in a

[74] *See* PAC/800, Dickman/13-16; PAC/1100/Dickman/10-19; PAC/1400, Dickman/4-6.
[75] Order No. 05-584 at 27-28.
[76] Order No. 05-584 at 26.
[77] *Id.* at 2.
[78] *Id.* at 26-27.

> resource sufficient position at monthly on- and off-peak forward market prices as of the utility's avoided cost filing. *We agree with Staff that this approach embeds the value of incremental QF capacity in the total market-based avoided cost rate.* We find this valuation mechanism to be appropriate given the likelihood that a utility will address probable gaps between increasing demand and actual resources, in the absence of incremental QF capacity, with purchases of energy and capacity on the market.[79]

In other words, Order No. 05-584 makes clear that the Commission carefully considered whether market prices sufficiently compensate QFs for capacity during times of resource sufficiency. It appropriately concluded that they do.

No party to this proceeding has raised any argument that warrants revisiting this conclusion. In fact, the Commission stated in Order No. 05-584, that it would remain open to reconsidering its decision on this issue, "[t]o the extent that a party can provide *evidence regarding the market pricing of capacity.*"[80] The record in this proceeding contains no such evidence, and therefore, the Commission's prior determinations should stand.

B. Market Prices During the Resource Sufficiency Period Adequately Account for Capacity.

To the extent the Commission elects to reconsider its prior conclusion, however, PacifiCorp believes that the use of market prices during resource sufficiency periods continues to adequately compensate QFs for capacity.

PacifiCorp's on- and off-peak market prices include a "blend of prices from markets across its system . . . to calculate the market prices paid during the sufficiency period[s]."[81] This blend of prices uses PacifiCorp's latest official forward price curve (OFPC) to develop the most accurate and up-to-date avoided cost prices possible.[82] The OFPC takes into account forward prices of electricity from various market sources and includes a model-based forecast of prices

[79] *Id.* at 27-28 (emphasis added, except as otherwise noted).
[80] *Id.* at 28 (emphasis added). CREA challenges the use of market prices during the sufficiency period, arguing that that the resource plan in the Company's IRP is a "matter between PacifiCorp and the Commission," failing to recognize the Commission's orders requiring avoided costs to be based on the utility's Commission-acknowledged IRP. CREA/600, Skeahan/11.
[81] PAC/800, Dickman/14.
[82] *Id.* at Dickman/15.

for region-wide loads, resources, and market conditions.[83] As Mr. Brian S. Dickman explains, the Company's IRP calls for Front Office Transactions, or short-term market purchases, to balance the Company's capacity needs.[84] The OFPC, therefore, represents PacifiCorp's best and most complete projection of what it would pay in the market to secure delivery of firm power, which could be relied upon to satisfy PacifiCorp's capacity requirements.[85]

C. Response to Other Parties' Arguments.

Various parties propose alternative methodologies for calculating capacity payments to QFs during periods of resource sufficiency. The Joint QFs argue the Commission should adopt an interim QF capacity pricing proposal based on planned environmental upgrades at existing generation facilities.[86] In addition, the Joint QFs[87] and REC[88] both raise issues regarding the accuracy and sufficiency of the IRP planning process for determining avoided cost rates during the sufficiency period.[89] These alternative methodologies are flawed and provide no sound basis for a change in Commission policy.

1. Sufficiency Period Environmental Upgrades.

The Joint QFs argue for an interim QF capacity pricing proposal based on planned environmental upgrades at existing generation facilities that provide PacifiCorp with capacity.[90] The Joint QFs' witness, Mr. Higgins, argues that such interim pricing is appropriate while the

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[83] *Id.*
[84] PAC/800, Dickman/15-16 (explaining that in the 2013 IRP, short-term firm market purchases rise to over 1,400 MW in 2023, the last year before a new major thermal resource is added, and over 1,000 MW in 2024, despite the planned addition of a 423 MW combined cycle unit and 432 MW of wind capacity in that year).
[85] *Id.*
[86] *See* Joint QF Parties/100, Higgins/14-17. As noted in FN. 1 above, the term "Joint QFs" is used to refer to the joint parties that sponsored the brief filed by Kevin Higgins, which include REC, CREA, OneEnergy, and Obsidian.
[87] *See* Joint QF Parties/100, Higgins/10-13; Joint QF Parties/200, Higgins/8-10.
[88] *See* Coalition/500, Lowe/7-8.
[89] Staff agrees with Pacific Power that paying market prices to QFs during the sufficiency period appropriately compensates the QF for capacity. Staff/500, Andrus/30-31. ODOE argues that whether market prices appropriately account for capacity depends on actual purchasing practices of a utility. ODOE/700, Carver/10. Pacific Power does not currently utilize the types of transactions that would, in ODOE's opinion, render market prices during the sufficiency period inaccurate. PAC/1100, Dickman/11. Pacific Power therefore assumes that ODOE supports its position on this issue.
[90] *See* Joint QF Parties/100, Higgins/14-17; Joint QF Parties/200, Higgins/4-9.

Environmental Protection Agency (EPA), federal government, and states figure out how to implement EPA's 111(d) regulations.[91] This proposal would use the costs associated with environmental upgrades to PacifiCorp's generation facilities to determine "the projected per-kW revenue requirement associated with . . . capacity retention" in order to "value the capacity contribution from renewable QFs and zero-emitting QFs."[92]

This proposal fails for a number of reasons. First, the proposal relies on costs that cannot be avoided. The Joint QFs imply that environmental upgrades at specific coal plants in Utah, Wyoming, Colorado, Montana, and Arizona can be avoided by renewable and non-emitting QFs in Oregon. In fact, all of the upgrades listed by the Joint QFs are for compliance with the Regional Haze Rule intended to improve the air quality and visibility in national parks and wilderness areas in the proximity of the emitting resource.[93] PacifiCorp cannot avoid these compliance costs simply by adding Oregon QFs. In fact, construction of several of the upgrades listed by the Joint QFs are already underway, underscoring the fact that costs cannot be avoided and should not be included in the determination of avoided costs.[94] The Joint QFs' proposal must fail for this reason alone.

Second, a number of the identified upgrades may not actually be needed, making them inappropriate to include in avoided cost pricing.[95] Under PURPA, utilities are not required to pay more than their avoided costs for QF purchases.[96] As Staff correctly points out,[97] FERC has interpreted this cap on avoided cost to prohibit payment for environmental costs unless they are "real costs that would be incurred by utilities;" that is, costs that will *actually* be avoided.[98] A

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[91] Joint QF Parties/100, Higgins/4-6, 10-14.
[92] *Id.* at 14.
[93] PAC/1100, Dickman/13.
[94] PAC/1100, Dickman/13. In fact, the Hayden 1 SCR has already been placed in service. Engineering, design, and procurement for the Hayden 2, Jim Bridger 3, and Jim Bridger 4 SCR projects are also underway. *Id.*
[95] PAC/1100, Dickman/14.
[96] 16 U.S.C. § 824a-3(b) ("No such rule prescribed under subsection (a) of this section shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy."); 18 C.F.R. § 292.304 (2015); Order No. 14-058 at 22 ("[We] conclude that any costs imposed on a utility that are above the utility's avoided costs must be assigned to the QF in order to comport with PURPA avoided cost principles.")
[97] *See* Staff/600, Andrus/19.
[98] *So. Cal. Edison*, 71 FERC ¶ 61,269 at 62,080 (1995).

number of the upgrade costs listed in PacifiCorp's IRP, however, may turn out to be unnecessary as environmental requirements are finalized.[99] These upgrades do not qualify as the type of costs appropriate for inclusion in avoided cost under PURPA and FERC precedent.

Finally, the proposal by the Joint QFs is inappropriate because it fails to account for the benefits lost to the utility if the environmental upgrades are, in fact, eliminated. Elimination of the identified environmental upgrades would significantly affect the Company's generation portfolio. Coal plants provide low-cost base load generation, as well as operating reserves and load following capability.[100] The Company's IRP takes these benefits and other trade-offs into account when evaluating whether investments in environmental upgrades are appropriate.[101] If the Company does not invest in an environmental upgrade that is required to comply with the Regional Haze Rule, the Company will no longer be able to operate the plant as a coal-fired generator.[102] Given the operational characteristics of a coal-fired plant and those of renewable QFs, it is impractical to replace an entire existing coal plant with many individual QFs.[103] Consequently, the proposal by the Joint QF Parties is simply inappropriate.

2. <u>The Sufficiency Period Should Not Be Extended Based On Challenges to IRP Assumptions About QF Contract Renewals; However, if Any Reassessment of the Sufficiency Period Is Required, that Reassessment Must Also Account for New QF Contracts</u>.

The Joint QFs suggest that PacifiCorp's IRP inappropriately assumes that 122 MW of QF contracts will be renewed upon the expiration of their term, and that an extension of the

[99] PAC/1100, Dickman/13-15. As Mr. Dickman notes, as requirements are finalized, and decisions on Regional Haze Rule-related investments are ripe, they will be included in an IRP for Commission review and acknowledgement. *Id.* at 14. Additionally, Mr. Higgins' own reply testimony recognizes the uncertain nature of EPA's 111(d) regulations where he states, "[the] precise implications of PacifiCorp's compliance with Section 111(d) are not known to me at this time…." Joint QF Parties/200, Higgins/4.
[100] PAC/1100, Dickman/15.
[101] *Id.*
[102] *Id.*
[103] As Mr. Dickman points out, using the 36.7 percent capacity contribution for a single axis tracking solar project (the highest of the wind and solar capacity contributions) listed in the 2015 IRP, replacing a 350 MW share of the capacity lost by eliminating Jim Bridger Unit 3 would require over 950 MW of new solar capacity from QFs. *Id.* This unrealistic result does not account for the lost dispatchability and lost energy from a base load generator.

sufficiency period is therefore warranted.[104] This assertion, however, is one-sided and inaccurate, and the Joint QFs' recommendation should be rejected.

Until the Company's 2015 IRP is finalized, reviewed, and 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.[105] Since the time the 2015 IRP inputs were finalized, the Company has executed additional contracts with QFs totaling more than 300 MW of additional nameplate capacity.[106] 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 needs.

3. <u>Potential Inaccuracies in IRP Assumptions Regarding Resource Sufficiency Do Not Warrant Imputation of Additional Capacity Payments; Inaccuracies Cut Both Ways.</u>

REC argues that using market prices during the sufficiency period fails to recognize that timing of new resources in PacifiCorp's IRP is likely to be inaccurate, warranting the imputation of additional capacity payments.[107] REC notes, for example, that the Company acquired the Chehalis generating plant in 2008 even when the IRP at the time did not include a new thermal resource until 2012.[108]

This is a one-sided example that provides no support for REC's proposal. Given the nature of forecasts and long-term planning processes, some assumptions ultimately turn out to be inaccurate. These inaccuracies may cause the Company's IRP resource portfolio to change, but

[104] *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.
[105] PAC/1100, Dickman/17.
[106] *Id.*
[107] Coalition/500, Lowe/7-8.
[108] *Id.*

those changes cut both ways.[109] For example, from April 2014 through August 2014, the Company's standard avoided costs were based on the 2011 IRP, which anticipated a new CCCT would be acquired in 2016.[110] In September 2012, the Company advised the Commission that it planned to cancel the then-pending RFP for the resource because its updated assessments indicated it no longer needed the CCCT in 2016.[111] Although the Company no longer needed the new resource, avoided costs had been set with a deficiency period beginning in 2016, and the Company executed contracts with 19 QFs totaling 161 MW of nameplate capacity that included inaccurate rates.[112]

4. If the Utility Is in a Resource Sufficient Position, Renewing QFs Should Not Receive a Capacity Payment.

REC argues that renewing QFs should be entitled to capacity payments as part of contract renewals, since they would have been receiving such payments during the last years of an existing contract.[113] PacifiCorp disagrees. A utility's avoided costs are not static; they must be updated to account for changes in market and system conditions. As avoided costs are updated and QFs seek new contracts, the most current avoided cost information should be applied to new contracts, consistent with the customer indifference standard. As Mr. Dickman notes, REC's proposal is simply an attempt to lock in capacity payments beyond the 20-year term currently allowed in Oregon.[114] Given that utilities are typically limited to contracting and hedging horizons of less than 36 months for energy contracts because of concerns about price risk, market liquidity, prudency, and other risk considerations, it would be harmful to customers to guarantee a never-ending capacity payment to a QF without accounting for the risk to utility customers.[115]

[109] PAC/1400, Dickman/4-5.
[110] *Id.*
[111] *Id.* at 5.
[112] *Id.*
[113] Coalition/400, Lowe/19-20; Coalition/500, Lowe/7-8.
[114] PAC/1100, Dickman/18-19.
[115] It is also a problematic case of cherry-picking. REC proposes to pay existing QFs capacity costs in perpetuity, while at the same time assuming those QFs do not exist when determining the timing of capacity payments for new QF projects.

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?

To ensure that customers pay no more than actual avoided cost prices, PacifiCorp urges the Commission to adopt the PDDRR Method[116] for the calculating non-standard avoided costs. The PDDRR Method is a differential revenue requirement approach that relies on information from PacifiCorp's IRP and measures the impact a specific QF has on PacifiCorp's revenue requirement.[117] PacifiCorp currently uses the PDDRR Method in Utah, Wyoming, and Idaho to calculate non-standard avoided costs.[118] Independently calculating the avoided cost of large QFs using the PDDRR Method is a more accurate approach for determining the value of the energy and capacity on PacifiCorp's system than the current method of making individual adjustments to the Proxy Method, because it directly measures the impact each specific QF has on PacifiCorp's power costs.[119] Increasing the accuracy of avoided costs is particularly important with respect to large QFs.

PacifiCorp, like the other utilities in this docket, believes that Oregon utilities should be allowed to employ different production cost models or tailor specific adjustments to match their unique cost structure.[120] The goal for calculating non-standard avoided costs should be to most accurately determine costs that can be avoided by each utility given the characteristics of an individual QF and the circumstances of each utility's system.

A. The PDDRR Method Represents a Significant Improvement over the Existing Proxy Method.

In Oregon, non-standard avoided costs are currently determined by starting with the Proxy Method—the same method used to set standard avoided costs—then modifying the results

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[116] PDDRR stands for "Partial Displacement Differential Revenue Requirement."
[117] PAC/800, Dickman/16. The PDDRR Method was also discussed in Phase I. *See* PacifiCorp Phase I Opening Testimony, PAC/100, Dickman/11-16 (Feb. 4, 2013).
[118] PAC/800, Dickman/16. A variation of the PDDRR is used in Idaho called the Highest Displaceable Incremental Cost Method, or the IRP method. *Id.*
[119] *Id.* at 16-17.
[120] PAC/800, Dickman/17.

using a limited set of discrete adjustments meant to mitigate the deficiencies of that method.[121] The list of authorized adjustments allowed under the current method was derived from the seven factors outlined in the Federal Energy Regulatory Commission's (FERC) PURPA regulations; specifically, 18 C.F.R. § 292.304(e)(2). Under federal law, these seven factors are to be taken into account to the extent practicable in setting avoided costs. The Commission's current method, however, takes into account only a subset of these factors, including dispatchability and reliability. Other factors are addressed as separate contract issues, and still others are not addressed at all.[122]

By contrast, the PDDRR Method takes into account all of the key avoided-cost factors identified by federal regulations.[123] Moreover, PacifiCorp's experience in other jurisdictions is that independently calculating the avoided cost of large QFs using the PDDRR Method is a more accurate approach for determining the value of the energy and capacity on the Company's system, taking into account the unique characteristics of each QF.[124] Staff supports the Company's use of the PDDRR Method for non-standard QFs, explaining that it is "likely to provide a more accurate quantification of the impact of a QF based on its specific

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[121] This method was originally adopted in Order No. 07-360. *See In re Staff's Investigation into Elec. Util. Purchases from Qualifying Facilities,* Docket No.UM 1129, Order No. 07-360 (Aug. 20, 2007). The list of authorized adjustments was derived from the seven factors outlined in 18 C.F.R. § 292.304(e)(2), which states that, when determining avoided cost, the following factors "shall, to the extent practicable, be taken into account:

i) The ability of the utility to dispatch the qualifying facility;
ii) The expected or demonstrated reliability of the qualifying facility;
iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirements, and sanctions for non-compliance;
iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;
v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;
vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and
vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities."

[122] *See* PAC/800, Dickman/20-21.

[123] 18 C.F.R. § 292.304(e)(2).

[124] PAC/800, Dickman 16-17.

characteristics" than the current method.[125] Staff believes the accuracy of the PDDRR Method justifies its higher level of complexity.[126]

1. The PDDRR Methodology.

Under the PDDRR Method, avoided costs consist of three main components: avoided capacity costs, avoided energy costs, and integration costs (where appropriate).[127] To determine avoided costs, the Company performs two simulations using GRID, the Company's production cost model, to determine the system energy value of a QF resource, taking into account the QF's specific operating characteristics and point of delivery on the Company's system.[128] As noted above, this method takes into account not only the Commission's currently authorized adjustment factors, but also the additional statutory factors identified by FERC under 18 C.F.R. § 282.304(e)(2).

The model accounts for factors such as the QF's location, delivery pattern, and capacity contribution.[129] In addition, the two issues left unaddressed by Order No. 07-360, the aggregate capacity of QFs on the Company's system, and smaller capacity increments and shorter lead times available from QFs, are easily accounted for with a modeled approach that recognizes all of the executed and proposed QFs expected to connect to PacifiCorp's system.[130] The PDDRR Method uses the best information available to PacifiCorp at the time the QF pricing is prepared, providing accurate avoided cost prices and thereby maintaining retail customer indifference.[131]

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[125] *See,* Staff/500, Andrus/34; *see also* Staff/100, Bless/8; Coalition/200, Schoenbeck/9 (from Phase I).
[126] *Id.*
[127] *See* PAC/800, Dickman/18-23.
[128] PAC/800, Dickman/18.
[129] PAC/800, Dickman/21.
[130] PAC/800, Dickman/21. A proposed QF contract is one that has begun the process required to enter into a PPA with the Company, but for which a signed contract has not yet been executed. *Id.* at 24. These QFs have either signed a long-term PPA with the Company or have requested avoided cost prices and are actively negotiating a long-term PPA, and will be contractually obligated to deliver power to the Company during future periods when the Company's resource planning indicates a major resource would be needed. *Id.* Mr. Dickman explains how the PDDRR accounts for QF energy and capacity at PAC/800, Dickman/18-23.
[131] PAC/800, Dickman/23.

2. Deficiencies in the Current Method.

The Commission's current model, which relies heavily on the Proxy Method, is inaccurate by comparison. The Proxy Method fails to account for a number of critical factors easily addressed by the PDDRR method, and also makes inaccurate assumptions about costs being incurred. For example, as Mr. Dickman explains, the Proxy Method assumes that PacifiCorp can always use the output of a given QF to avoid making market purchases (or to make additional market sales) during the resource sufficiency period, and is always able to save the variable cost of the IRP proxy resource during the resource deficiency period.[132] In reality, this is not the case.[133]

Recognizing the inaccuracies inherent in the Proxy Method, the Commission has noted its limitations. In Order No. 14-058, for example, the Commission acknowledged that, "the application of our current [standard rate] methodology may result in the utility and its customers offering prices in excess of actual avoided cost."[134] In that order, the Commission adopted incremental improvements to the Proxy Method itself, but did not address changes to the non-standard method that are needed to accurately calculate the avoided costs of large QFs.[135]

A more accurate method of calculating non-standard avoided costs is sorely needed, because the more accurate PDDRR method can have a significant impact on the Company's avoided costs when compared to the Proxy Method. Table 2 below compares the current standard avoided costs to the PDDRR method using the same vintage of inputs used in the standard rates:[136]

[132] PAC/800, Dickman/18-19.
[133] *Id.* at 19.
[134] Order No. 14-058 at 7.
[135] PAC/800, Dickman/19.
[136] *See* PAC/800, Dickman/19.

Table 2
15 Year (2016 - 2035) Nominal Levelized Price at 6.882% Discount Rate ($/MWh)

	PDDRR	Current Sch 37	
		Standard	Renewable
Wind 27.0% CF	$36.64	$40.91	$59.24
Solar 23.6% CF	$37.11	$46.88	$66.54
Thermal 85.0% CF	$43.68	$52.07	$70.40

B. The Commission Has Endorsed the Use of Differential GRID Runs Over Proxy Approaches Because of GRID's Improved Accuracy.

A Commission order adopting use of the PDDRR Method would be consistent with the Commission's prior decisions rejecting a proxy approach in other contexts in favor of differential GRID runs.[137] In PacifiCorp's annual transition adjustment mechanism (TAM) dockets, the Commission has endorsed the use of differential GRID runs because, despite their higher level of complexity, they better capture the actual costs incurred by the utility and its customers due to incremental changes to the Company's loads or resources.[138] PacifiCorp asks the Commission to reach the same conclusion regarding need for accuracy in the calculation of avoided costs. A differential modeling approach best accounts for the Company's actual, appropriate operational responses to system changes, yields the most accurate calculation of non-standard avoided costs, and best determines the costs that customers should pay large QFs under PURPA.[139]

The Commission's adoption of GRID modeling in the TAM context is relevant here. In the TAM context, GRID modeling is used to calculate the impact of loss of load when a customer leaves the Company's system under direct access. In the avoided cost context, by contrast, GRID modeling costs calculates the impact of adding a new QF resource to the Company's system. As Mr. Dickman explains, these two scenarios are two sides of the same

[137] PAC/800, Dickman/26-29 (citing *In re Investigation into Direct Access Issues for Indus. and Commercial Customers Under SB 1149*, Docket UM 1081, Order No. 04-516 at 10-11 (Sept. 14, 2004)).
[138] PAC/800, Dickman/28 (citing *In the Matter of PacifiCorp dba Pacific Power 2014 Transmission Adjustment Mechanism,* Docket No. UE 264, Order No. 13-387 (Oct. 28, 2013)).
[139] PAC/800, Dickman/27. While the PDDRR method and the existing Proxy Method can produce similar results, they can also be very different depending on the circumstances. *Compare* PAC/300, Dickman/13 to PAC/800, Dickman/19.

coin, and are both best modeled by a differential modeling approach.[140] Likewise, both situations involve analogous tradeoffs between simplicity (under a proxy approach) and accuracy (under a production cost model-based approach). In either context, GRID modeling best calculates the actual costs associated with a change in Company resources, whether due to addition of new generation or loss of load. As the Commission concluded in Docket UE 179, it is important to "value utility resources impacted by direct access based on actual, appropriate operational responses."[141] A GRID modeling approach best meets these goals, both in the TAM context and in the context of avoided costs.[142]

C. Objections to the PDDRR Method Are Misplaced.

REC and CREA object to the use of a model-based approach for calculating non-standard avoided costs. REC claims that using a model is too complex and subject to dispute,[143] while CREA argues that using a model is too costly and complex.[144] PacifiCorp believes these concerns are misplaced, particularly when weighed against the benefits of the model's accuracy. Balance between transparency and accuracy is an important consideration in avoided cost pricing. As noted above, Staff supports the Company's use of the PDDRR Method for non-standard QFs, despite its higher level of complexity, due to the accuracy it brings.[145]

With respect to transparency, the GRID model is neither new nor novel. 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. As

[140] PAC/800, Dickman/26-27.
[141] *In re Pacific Power & Light Request for a General Rate Increase,* Docket No. UE 179, Order No. 05-1050 (Sept. 28, 2005); Order No. 04-516 at 10.
[142] REC argues that the GRID model was designed to estimate power costs, not avoided costs. Coalition/500, Lowe/13. This appears to be based on a misunderstanding of the GRID model. The GRID model calculates net power costs by solving for the least-cost solution to balance the Company's system based on a set of resources, load, and operational constraints. The addition of QF generation in the model displaces the highest-cost purchases or generation or results in incremental market sales, and calculates the incremental increases or decreases in the Company's net power costs. For this reason, the GRID model is ideally suited for calculating the costs avoided with the addition of a QF.
[143] *Id.* at 9-14.
[144] CREA/500, Skeahan/17-18.
[145] *See, e.g.,* Staff/500, Andrus/34; *see also,* Staff/100, Bless/8; Coalition/200, Schoenbeck/9 (Phase I).

noted previously, it is used to calculate net power costs in PacifiCorp's annual Oregon TAM filings and it is used to produce avoided cost prices under the PDDRR Method for QF projects in Utah, Idaho, and Wyoming.[146] PacifiCorp has made the model available at no cost to developers and intervenors, and has agreed to provide assistance and training to those wishing to use it.[147] In short, the model has been widely available and has a proven track record for multiple uses across multiple jurisdictions.

D. Conclusion.

The Company believes that, particularly in the context of larger QFs, it is important to develop avoided cost prices that value resources based on "*actual, appropriate operational responses*." Given the widespread use and availability of the GRID model, the balance between transparency and accuracy weighs in favor of utilizing the PDDRR Method. While any model is only as good as its inputs, the GRID model reflects the unique characteristics of PacifiCorp's system and the actual costs that are avoided with each unique QF, and thus is a far more accurate method.[148]

Issue 8: When Is There a Legally Enforceable Obligation?

FERC has established that PURPA allows a QF to sell to a utility under two commercial scenarios: (1) under a contract (PPA); or (2) through a non-contractual, but binding, legally enforceable obligation (LEO).[149] The LEO is an important concept for a number of reasons. First, it acts to prevent the utility from avoiding purchases from a QF by refusing to sign a power purchase agreement with the QF.[150] Second, it acts as a threshold standard a QF must meet in order to qualify to sell to a utility (at a given avoided cost). Thus, the LEO acts to protect both

146 PAC/800, Dickman/16.
147 PAC/1100, Dickman/20.
148 PAC/800, Dickman/16-17.
149 *Grouse Creek Wind Park, LLC*, 142 FERC ¶ 61,187 at P 36 (2013) (*Grouse Creek*). A QF may also sell generation on an "as available" basis, a scenario not at issue here.
150 *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, 45 Fed. Reg. 12214, 12224, FERC Order No. 69 (Feb. 25, 1980).

the QF and the utility (and ultimately the utility customers that will bear the costs of avoided cost purchases from QFs).

As FERC has explained,

> [T]he phrase legally enforceable obligation is broader than simply a contract between an electric utility and a QF and . . . the phrase is used to prevent an electric utility from avoiding its PURPA obligations by refusing to sign a contract, or . . . delaying the signing of a contract, so that a later and lower avoided cost is applicable.[151]

In other words, the purpose of a LEO is *not* to allow a QF to lock in an avoided cost rate early, or to allow a QF to avoid providing mandated informational requirements, or to allow a QF to bypass timelines and procedures laid out by a state commission for establishing the right to a PPA, but rather to give a QF recourse when a utility actually refuses to sign a contract or needlessly delays doing so. As FERC emphasized, this option to sell via legally enforceable obligation was "specifically adopted to prevent utilities from circumventing the requirement of PURPA that utilities purchase energy and capacity from QFs."[152]

The question framed in Issue 8, "[w]hen is there a legally enforceable obligation," is somewhat misleading. PURPA does not define precisely when a LEO arises, nor does a LEO arise in a vacuum: it arises when a state commission says it does, so long as the state commission stays within the bounds of federal precedent. The question, then, should be when *does this Commission* believe a LEO should arise? Under PURPA's scheme of dual state and federal enforcement, the issue of when a LEO arises has been explicitly delegated to the Oregon PUC.[153] While FERC's rulings delineate the outer limits of a LEO, they do not usurp the state's broad discretion to define the specific point in time when a LEO arises. For that reason, reference to FERC precedent without more definition by the state leaves the issue unclear and ripe for dispute. By contrast, a state's specific definition of when a LEO arises gives QFs and utilities

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[151] *Cedar Creek Wind, LLC*, 137 FERC ¶ 61,006 at P 36 (2011) (*Cedar Creek*).
[152] *Id.* at P 32.
[153] *Power Res. Grp. v. Public Util. Comm'n. of Texas*, 422 F.3d 231, 238 (5th Cir. 2005); *West Penn Power Co.*, 71 FERC ¶61,153, 61,495 (1995) (same).

certainty on this issue, and provides the clarity needed to avoid unnecessary and protracted disagreement about QF and utility obligations.[154]

This Commission, more than many other state regulatory bodies, has established detailed processes and procedures required for a QF and a utility to negotiate a contract for the sale of QF energy and capacity. Recognizing those existing process and procedures, the Company recommends that the Commission set criteria for establishing a LEO using the reference point in the Company's approved tariffs: when a QF approves a final draft PPA under section B(5) on page 10 of the Company's Schedule 37—the point in time when a QF has provided all project information required by the PPA and accepted a final draft agreement.[155] This recommendation is framed in terms of the Company's approved negotiation procedures, which are extremely helpful for this purpose. This recommendation also identifies the steps negotiating parties are required to follow, identifies when a QF can use to those steps to obtain a LEO (framed in terms of the Company's already-approved tariffs), and provides an avenue for relief in the event a QF believes the Company is refusing to sign a contract or needlessly delaying the process set out by the Commission—precisely the circumstances in which FERC believes a LEO is necessary.

This recommendation represents a fair and common-sense approach that comports with Commission process and with FERC precedent, provides certainty for the parties involved, and ensures that both parties have completed and agreed on all components in the standard PPA. The process described in Schedule 37 sets out all the necessary information required for the Company to draft a contract for the QF.[156] Schedule 37 processes, timelines and standard contracts were vetted by parties and approved by the Commission. The requirement that a QF meet all project information requirements in the contract and accept a final draft agreement is a fair milestone for

[154] PAC/1000, Griswold/9-11.
[155] While this recommendation notes Schedule 37, recommendation is meant to be inclusive of Schedule 37 and Schedule 38 QF contracts.
[156] PAC/1300, Griswold/6.

both parties for establishing a LEO.[157] And, as the Company will discuss later, this milestone provides a clear definition of QF "commitment."

A. Commission Discretion.

The Commission has a great deal of discretion to determine precisely when a LEO arises. "It is up to the States, not [FERC], to determine the specific parameters of individual QF power purchase agreements, including the date at which a legally enforceable obligation is incurred under State law."[158] Although Congress sought to promote energy generation by QFs through PURPA, it did not intend to do so at the expense of the consumer. PURPA requires utilities to purchase power generated by QFs, but also mandates that the rates utilities pay for such power "shall be just and reasonable to the electric consumers of the electric utility and in the public interest."[159] Oregon's PURPA regulations contain a parallel provision.[160] Oregon's LEO rule should therefore respect the notion of a LEO established by PURPA, while at the same time ensuring that QFs are not permitted to lock in high avoided costs rates by gaming the system.

B. Legal Uncertainty Surrounding Oregon's Existing LEO Rule.

The uncertainty in Oregon regarding when a LEO arises is driven largely by the fact that Oregon's existing LEO rule is inconsistent with FERC precedent. The Oregon Commission's LEO rule is found at OAR 860-029-0010(29)(a)-(b), and provides that a LEO exists on the earlier of:

> (a) The date on which a binding, written obligation is entered into between a qualifying facility and a public utility to deliver energy, capacity, or energy and capacity; or
>
> (b) The date agreed to, in writing, by the qualifying facility and the electric utility as the date the obligation is incurred for the purposes of calculating the applicable rate.

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[157] In the event a dispute arises, the Company's Commission-approved tariffs provide for a dispute resolution process that allows the Commission to determine what appropriate avoided cost price that should apply—as well as any other disputed terms and conditions. *Id.*
[158] *Power Res. Grp.*, 422 F.3d at 238; *West Penn Power Co.*, 71 FERC ¶61,153, 61,495 (same).
[159] 16 U.S.C. §824a-3(b)(1).
[160] OAR 860-029-0040(1)(a) ("Rates for purchases by public utilities shall [be] just and reasonable to the public utility's customers and in the public interest….")

In other words, existing Oregon Commission rules, in combination with PacifiCorp's Commission-approved Oregon Schedule 37, state that a QF is not entitled to a particular avoided cost rate until both parties have executed a PPA or until the parties agree in writing to the date a LEO occurs.[161] In recent years, however, FERC has stated that PURPA precludes states from requiring an executed contract as a condition for obtaining a LEO.[162] The Oregon rule, while still on the books, crosses the boundary of when FERC believes it is appropriate for a state to define a LEO, and thus is currently legally infirm.

The fact that the Oregon LEO rule is in legal limbo has created uncertainty and conflict. Specifically, it creates issues when avoided costs are declining, and when the Commission issues major rulings on QF contract terms and eligibility criteria.[163] When avoided cost prices are rising, the majority of QFs will seek new PPAs or seek to renew existing PPAs after the price change has occurred (unless there is some other milestone they need to achieve such as incentive funding or a tax credit deadline).[164] When avoided cost prices are falling, by contrast, or when a Commission decision is pending that will affect the terms and conditions of QF contracts, the requests for QF PPAs and declarations of LEOs for QF projects become frenzied as developers try to lock in higher prices for long-term PPAs. The rush to establish a LEO before lower prices or new policies are in place inevitably leads to disputes about when a LEO is established.[165] Mr. Griswold's testimony describes in detail the influx of partially completed PPAs and LEO declarations that have wreaked havoc on the Company's operations in recent years.[166]

To avoid these unnecessary disputes, PacifiCorp asks the Commission to establish specific criteria a QF must satisfy in order to establish that it has "commit[ed] itself to sell all or part of its electric output to an electric utility," as required by FERC.[167] A bright-line test will

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[161] *See* OAR 860-029-0010; *International Paper Co. v. PacifiCorp, dba Pacific Power*, Docket No. UM 1449, Order No. 09-439 at 6 (Nov. 4, 2009).
[162] *Grouse Creek* at P 36; *Cedar Creek* at P 35; *Murphy Flat Power, LLC,* 141 FERC ¶ 61,145 at P 24 (2012); *Rainbow Ranch Wind, LLC,* 139 FERC ¶ 61,077 at P 23 (2012).
[163] PAC/1000, Griswold/7-8.
[164] *Id.* at 8.
[165] *Id.* at 8-11.
[166] *Id.*
[167] *Grouse Creek,* 142 FERC ¶61,187 at P 36.

provide certainty for developers and utilities alike, and will reduce the number of disputes around LEO formation.

C. QF Commitment.

Under FERC's existing LEO guidelines, one critical component in establishing a LEO is that a QF must unequivocally "commit" to sell its energy and capacity to a utility.[168] The question of what constitutes QF "commitment" sufficient to meet LEO requirements is an open question before this Commission, and has not been discussed in detail at FERC. Given that a LEO binds a regulated utility to long-term legal commitments with a QF, commitments that can come at customer expense, PacifiCorp believes it is both fair and important to require a QF to demonstrate its "commitment" to sell energy and capacity to a utility in a meaningful way before a LEO arises. As will be discussed, many states have deemed it fair and appropriate to ensure a QF meets its end of the bargain by taking various concrete, meaningful steps before a LEO arises, and PacifiCorp believes it is important for the Commission to do so, as well.

As noted previously, FERC's general policy is to defer to the states on the question of when a LEO arises.[169] Its recent orders make clear that state discretion is limited by the bounds of PURPA itself, but state regulatory bodies nevertheless retain wide discretion to establish requirements within those boundaries. 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

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[168] *Id.* at P 37. *See also, JD Wind 1, LLC,* 129 FERC ¶ 61,148, at P 25 (2009) ("[A] QF, by committing itself to sell to an electric utility, also commits the electric utility to buy from the QF; these commitments result either in contracts or in non-contractual, but binding, legally enforceable obligations.").
[169] *See West Penn Power Co.,* 71 FERC ¶ 61,153, 61,495.

interconnection in a reasonable manner consistent with its commercial delivery date.[170] Texas, for example, has a "90-day rule" that provides that a utility may be compelled to purchase power from a QF pursuant to a LEO only if the QF can deliver that power within 90 days.[171] Other states have required QFs to take very specific, concrete steps as a precondition to the formation of a LEO.

In light of FERC's recent LEO orders, and in the absence of clear Oregon Commission guidance, PacifiCorp suggests the following criteria should be critical for determining whether a LEO has been created:

- The QF has engaged in an extended course of discussions with PacifiCorp, demonstrating a level of commitment to sell its power.[172]
- 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.

Consistent with these points, the Company recommends that the Commission utilize, at least as pertaining to the Company, PacifiCorp's Schedule 37 (or Schedule 38 for non-standard QFs) as the framework for creation of a LEO. Schedule 37 contains a step-by-step process for negotiating a power purchase agreement, including deadlines by which the utility must respond to various inquiries and submission from the QF. The Company believes that it is reasonable to

[170] *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).
[171] *See* Tex PUC Subst. R. 25.242(f)(1)(B); *Power Resource Grp., Inc.,* 422 F.3d at 239 (upholding 90-day rule as consistent with PURPA).
[172] *See, e.g., Grouse Creek* at P 37.

establish that a LEO has arisen (and a QF has appropriately committed itself) when the QF approves the final draft power purchase agreement as contemplated in B(5) on page 10 of Schedule 37.

The Commission-approved Schedule 37 and Schedule 38 processes provide a useful roadmap for LEO creation, laying out a clear framework for defining specific QF (and utility) requirements.[173] The rule proposed by the Company would fall within the bounds of FERC precedent, comport with the notions of fairness and due process, and dovetail with existing QF and utility contracting requirements. It would also provide QFs with ample opportunity to seek a specific avoided cost. Oregon QFs with projects in the queue have advanced notice that the Company's avoided cost rates will be changing, and therefore adequate time to begin the negotiation process contemplated by the Company's tariffs. The timing of PacifiCorp's avoided cost filings are mandated by statute—PacifiCorp is required to update its avoided cost prices at least every two years.[174] And with Order No. 14-058 allowing certain avoided cost updates on May 1 of each year, QFs again have ample notice of potential avoided cost changes, and have the opportunity to seek PPAs in a timely manner. Put another way, there are no surprises around the timing of avoided cost pricing that justify the disorderly and creative efforts some developers have taken to secure extant avoided cost pricing.

D. <u>Dispute Resolution.</u>

Some may argue that if such a standard were adopted, the utility could frustrate the establishment of a LEO by dragging out negotiations or repeatedly demanding more information from the QF. This is simply not the case. Schedule 37 contains specific information the Company requires and timelines in which the Company must act. If the Company seeks information beyond the bounds of Schedule 37 or fails to act within the established timelines, the

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[173] For example, PacifiCorp's Oregon Schedule 37 procedures require a QF to provide specific details about its facility, information about interconnection, evidence of QF certification, proof of facility ownership, a motive force plan, and other specific information. PacifiCorp believes the timeframes in Schedule 37, which assure a level of back-and-forth negotiations, are also essential to demonstrate "commitment" under the Oregon Commission-approved PPA process. PacifiCorp believes the requirements in PacifiCorp's Commission-approved tariffs and contracts can already be interpreted to put such obligations on QFs before a LEO is created.
[174] ORS 758.525.

QF can seek relief from the Commission. Defining a LEO by reference to Schedule 37 will allow both the utility and the QF to know the rules of establishing a LEO from the beginning, and will create standards that the Commission can review and enforce if either the utility or the QF attempt to frustrate or manipulate the establishment of a LEO. In a similar vein, the standards and procedures in Schedule 38 could be used to establish when a LEO arises for non-standard qualifying facilities.

As Mr. Griswold explains, if a QF is not required to take specific actions and make specific showings before a LEO is created, it can place the utility in the position of potentially being required to accept and pay for energy from a QF that the utility knows little about. This can present commercial, safety and resource planning issues for the utility.[175] Equally important, the lack of clear guidelines would allow QF developers to obtain pricing based on outdated information, to the detriment of Oregon customers and in violation of the ratepayer indifference mandate of PURPA.[176]

It is hard to imagine the Commission, in other circumstances, finding a contract prudent if the utility entered into that contract without conducting reasonable due diligence. By adopting the criteria already contained in Schedule 37 and Schedule 38 the Company is able to ensure it has information to conduct the minimum due diligence necessary prior to entering into a commercial relationship with a QF, while at the same time insuring the Company will not avoid a power purchase agreement by refusing to execute such an agreement.

E. Other Proposals

PacifiCorp disagrees with REC's suggestion that a QF should be entitled to a LEO even if it fails to provide required information to the utility. Schedule 37 and the standard contracts approved by the Commission identify the necessary information required for the Company to draft a contract for the QF. The Schedule and the standard contract were vetted by parties and approved by the Commission, and meeting any and all project information requirements in the

[175] PAC/1000, Griswold/20.
[176] *Id.*

contract is critical to complete a binding agreement for both parties. It is a sign of QF commitment.[177] Moreover, as noted previously, the concept of a LEO is not intended to provide a QF with entitlement to a specific avoided cost rate; it is intended to provide a QF with an entitlement to a long-term sale when a utility drags its feet or refuses to enter into a contract. An incomplete contract usually leads to contract amendments, disputes, and sometimes leads to a QF cancelling a contract or the Company putting a QF contract in default because the contract was rushed through the preparation process.[178]

REC also proposes that a QF should be able to "lock in" certain avoided cost prices if there are disputes that cannot be resolved before an avoided cost update goes into effect. Its proposal would allow QFs 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 construct would encourage inefficient negotiations as QFs would have an incentive to find disputes in order to lock in stale prices. 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 determine the appropriate avoided cost price that should apply when it resolves the contractual dispute under the Schedule 37 or Schedule 38 dispute resolution process.

In addition, REC appears to recommend that an existing QF should be able to seek a new QF contract up to three years before their existing QF PPA expires. There are some inherent issues with that proposal. PacifiCorp believes it is more appropriate to require a QF complete a new PPA within a year of the existing PPA expiring. The Company's experience has shown that a one year planning horizon provides the QF with certainty on the avoided costs, adequate time to complete a new QF PPA, and adequate time to complete any modifications to the QF's interconnection.

In short, the Company's proposal strikes a fair balance between QF rights and protecting the customer interest by providing the QF with everything PURPA promises, while protecting

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[177] *See, e.g.,* PAC/1300, Griswold/6-7.
[178] *Id.*

customers from the unknown obligations that can be foisted upon the Company by a QF that has failed to comply with the provisions required by the Commission for a PPA. A LEO that is based upon the milestone of the QF approving the final draft PPA as contemplated in B(5) on page 10 of Schedule 37 satisfies the requirements of the tariffs approved by the Commission, demonstrates that the QF has provided all required contract inputs and exhibits and signed off on the final draft agreement, and commits the Company to the agreement for execution. The Company can then move forward to execute knowing the document is complete and will not require amending, thus protecting customers from future litigation and complaints due to contracts being executed that are inaccurate or incomplete.[179]

F. Conclusion

The Company recommends that the Commission set criteria for establishing a LEO using the milestone of the QF approving the final draft PPA as contemplated in B(5) on page 10 of Schedule 37.[180] It provides both the QF and the utility with certainty, and provides the QF with the benefits intended by PURPA.

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?

In Phase I of this proceeding, the Commission determined that QFs are responsible for any third-party transmission costs associated with moving the QF's output from a load pocket (*i.e.*, an area where there is insufficient load to absorb the QF's output) to another load area on the utility's system.[181] In this Phase II, the focus of the issue has now shifted to an examination of how to calculate and account for these costs.

In Section A below, PacifiCorp offers a brief overview on the roles of a utility's merchant function and transmission function as relevant to a utility's transmission obligations under

[179] As Mr. Griswold notes, the Company's Commission-approved Schedule 37 contracts are clear and well established, and the Company works with QFs to find mutually agreeable terms and conditions when necessary. *See, e.g.*, PAC/1300, Griswold/9-10.
[180] While the focus of PacifiCorp's testimony on Issue 8 is toward Schedule 37, the testimony is meant to be inclusive of Schedule 37 and Schedule 38 QF contracts.
[181] Order No. 14-058 at 22.

PURPA, as well as to PacifiCorp's specific positions on Issue 9. PacifiCorp then discusses in Section B its position on the importance of reflecting the costs and benefits of third-party transmission service on an individualized QF project basis, as either an adjustment to the QF's avoided cost price or as an adjustment to the QF's contractual billing terms, through an addendum to the PPA. The Company then reviews how it must make long-term, firm transmission arrangements to deliver QF power in order to remain compliant with its PURPA mandatory purchase obligation and FERC's precedent on the same, and discusses why the Commission should disregard any suggestions that PacifiCorp provide regularly-updated maps or tables with designated load pocket information.

A. The Roles of a Utility's Merchant and Transmission Functions, as Relevant to Utility Transmission Obligations under PURPA.

Several intervenors offer recommendations that, under federal law, are unworkable or illegal to implement. Such recommendations appear to rest on misunderstandings about certain fundamental elements of the roles of a utility's merchant function and transmission function, and the rules governing the dealings between those two functions. These elements are critical to a utility's transmission obligations under PURPA, as well as to understanding PacifiCorp's positions on Issue 9. To provide some context regarding its responses on this issue, PacifiCorp offers the following brief summary.

PURPA obligates a utility to interconnect with a QF, purchase and make firm arrangements to deliver a QF's power,[182] and keep customers indifferent to such QF purchases.[183] Different business units within a single utility handle different aspects of these

[182] *See, e.g.*, 18 C.F.R. § 292.303 (discussing a utility's obligation to interconnect with and purchase power from QFs); *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215 (2013) (finding a PURPA violation where a proposed PPA provision would have treated a QF as if it were a *non-firm* transmission customer, as discussed in more detail below).

[183] *See, e.g.*, 18 C.F.R. § 292.304 (a)(1)-(2) (stating that rates for QF purchases must "[b]e just and reasonable to the electric consumer of the electric utility and in the public interest; and [n]ot discriminate against qualifying cogeneration and small power production facilities. Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.").

PURPA obligations, and those business units must fulfill their obligations within the bounds of other rules and regulations governing the relevant processes.

With regard to the obligation to make firm transmission arrangements to deliver a QF's power, PacifiCorp's merchant function – *not the QF* – is the transmission customer responsible for delivering that energy to load.[184] In particular, PacifiCorp's merchant function (the transmission customer in this context) contracts with PacifiCorp's transmission function (the transmission provider) to make all QF service arrangements. Thus, all of FERC's open access rules governing the provision of transmission service apply to this transaction. As most relevant here, PacifiCorp's merchant function must request transmission from PacifiCorp's transmission function in accordance with the terms and conditions of PacifiCorp's OATT,[185] and FERC's Standards of Conduct (SOC) limit the types of information that can be shared between those two entities. [186]

Generally speaking, in order to make these arrangements, PacifiCorp's merchant function requests designation of a QF's PPA as a Network Resource (also referred to as "DNR" status) under its Network Integration Transmission Service Agreement (NITSA) with PacifiCorp's transmission function.[187] PacifiCorp's transmission function must study the DNR request using the OATT-mandated study processes, and then gives PacifiCorp's merchant function information about, among other things, whether there is sufficient capacity available to accommodate the DNR request.[188] This determination depends on a host of very dynamic factors that can affect

[184] *See, e.g.*, *Entergy Servs., Inc.*, 137 FERC ¶ 61,199 at P 52 (2011) (stating that, once QF energy is purchased, it is the utility's responsibility to deliver that energy to load).
[185] The OATT sets forth the FERC-approved rates, terms and conditions under which PacifiCorp's transmission function provides transmission service to transmission customers, affiliated and non-affiliated.
[186] The SOC includes three primary rules: (1) the "independent functioning rule," which requires transmission function and merchant function employees to operate independently of each other; (2) the "no-conduit rule," which prohibits passing transmission function information to marketing function employees; and (3) the "transparency rule," which imposes posting requirements to help detect any instances of undue preference due to the improper disclosure of transmission function information. *See generally Standards of Conduct for Transmission Providers*, Order No. 717, 125 FERC ¶ 61,064 (2008).
[187] *See, e.g.*, PAC/1600, Griswold/4-6. *See also*, OATT, Section 30, Network Resources (setting forth requirements related to customer designation of Network Resources).
[188] *See generally* OATT, Section 32, Additional Study Procedures for Network Integration Transmission Service Requests.

expected transmission conditions in the particular area of the system where the QF has sited its project and during the particular timeframe of the request.[189]

Importantly, the majority of the information PacifiCorp's transmission function uses to perform its assessment of transmission conditions is non-public transmission information.[190] This means the information is only available to the transmission provider and, pursuant to the strict requirements of the SOC, cannot be shared with any transmission customer, including a utility's merchant function transmission customer.[191] Thus, PacifiCorp's merchant function does not know, or have access to the information necessary to making definite determinations about whether a QF's power can be accommodated until PacifiCorp's transmission function performs the OATT-required studies.[192]

If PacifiCorp's transmission function determines that a DNR request cannot be accommodated – in full or in part[193] – it works with PacifiCorp's merchant function within the confines of the OATT rules to determine what is required to provide the service requested.[194] In some cases, such as in the case of a QF project siting in a load pocket, this may mean that PacifiCorp's transmission function requires PacifiCorp's merchant function to demonstrate that it

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[189] *See, e.g.*, PAC/1300, Griswold/13-14; OATT, Section 32, Additional Study Procedures for Network Integration Transmission Service Requests. Pacific Power's transmission function will also perform an assessment of certain transmission system conditions for purposes of the QF's interconnection request, but per FERC's rules, this is a distinct assessment performed separately from the transmission service request study. *See, e.g.*, PAC/1000, Griswold/23; PAC/1300, Griswold/14-15; *see, e.g., Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 (2004), *on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005). Indeed, in that context, the QF (rather than Pacific Power's merchant function) is the customer. *Id.*

[190] *See generally Standards of Conduct for Transmission Providers*, Order No. 717, 125 FERC ¶ 61,064 (2008).

[191] *Id.*

[192] *See, e.g.*, PAC/1300, Griswold/14-15; PAC/1600, Griswold/6.

[193] *See, e.g.*, PAC/1600, Griswold/6 (discussing how in some cases Pacific Power's merchant function may only need to acquire a portion of the nameplate capacity of the QF if a portion of that nameplate capacity can be absorbed by load in the load pocket).

[194] *See, e.g.*, OATT, Section 32, Additional Study Procedures for Network Integration Transmission Service Requests.

has made certain transmission arrangements on third-party transmission systems.[195] This is because a load pocket is typically a more isolated area of PacifiCorp's (non-contiguous) transmission system that is partially, or even entirely, reliant on third-party transmission.[196] Thus, if a QF sites in a load pocket and PacifiCorp's transmission function determines that it creates excess generation conditions, *i.e.*, times when there is insufficient load to absorb generation, PacifiCorp transmission may determine that QF power must be delivered to load elsewhere on PacifiCorp's system in order to maintain reliability and/or serve load.[197]

Securing a transmission arrangement with a FERC-jurisdictional transmission provider is a highly regulated process governed by strict federal rules, even before any PURPA requirements are factored in – federal rules that must be followed when a utility's merchant function is securing transmission arrangements for QF power delivery, as they are with *all* transmission customer service requests. These fundamental elements of the roles of PacifiCorp's different business functions and FERC's open access rules are relevant to PacifiCorp's positions on Issue 9, as will now be addressed in the following sections.

B. Third-Party Transmission Service Should Be Reflected on an Individualized QF Project Basis.

PacifiCorp believes the costs and benefits of third-party transmission service should be reflected on an individualized QF project basis, as either an adjustment to the QF's avoided cost price or as an adjustment to the QF's contractual billing terms, through an addendum to the PPA.

[195] *See, e.g.*, PAC/1600, Griswold/5-6. Again, depending on the circumstances, discussions regarding the potential need for third-party transmission arrangements to deliver the QF power may have occurred, at least on a preliminary basis, as part of the QF's interconnection studies. *See, e.g.*, PAC/1000, Griswold/28; PAC/1600, Griswold/9. However, in accordance with the OATT study process, this information may only be high level, with final determinations regarding definite excess generation amounts and any necessary third-party transmission arrangements only being available once Pacific Power's transmission function studies the DNR request from Pacific Power's merchant function. PAC/1300, Griswold/14-15.

[196] PAC/1000, Griswold/22; PAC/1300, Griswold/12-13.

[197] Excess generation can lead to minimum load conditions, which require Pacific Power to back down its own resources, move generation elsewhere or curtail. PAC/1000, Griswold/22-23 (describing excess generation and minimum load conditions); PAC/1300, Griswold/14 (emphasizing that Pacific Power's merchant function relies on Pacific Power's transmission function to make determinations about excess generation).

An individualized QF project approach appropriately accounts for the different operational circumstances that may (or may not) necessitate third-party transmission arrangements in order for PacifiCorp to accommodate a particular QF purchase.[198] As discussed above, PacifiCorp's transmission function will make a determination on this issue by following the OATT-mandated study process, which requires consideration of a multitude of dynamic factors relevant to the particular area in which the QF has sited its project and during the particular timeframe of the request. In some cases, PacifiCorp's transmission function may determine that a QF's power can be delivered using existing capacity on PacifiCorp's system and/or existing transmission rights on third-party systems. In other cases, such as in some load pockets, PacifiCorp's transmission function may determine that PacifiCorp's merchant function must make third-party transmission arrangements in order for some (or all) of a QF's power to be delivered.

In addition, if third-party transmission arrangements are deemed necessary, the particular details of those arrangements will also vary on a QF project-by-project basis[199] (*e.g.*, whether surplus conditions exist and/or vary over the course of the year,[200] how far and over what system(s) must the QF power move to reach load,[201] what third-party rights are needed and available to accomplish this delivery,[202] etc.). Consideration of such issues is highly likely to impact the particular QF's contract process schedule because of the additional analysis and coordination necessary between PacifiCorp's different business units and third-party transmission providers.[203] In short, each QF project will have unique characteristics that significantly impact the analysis of the need for and details of third-party transmission arrangements, and each QF's PPA should be individually adjusted for the particular costs

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198 PAC/1000, Griswold/21-22; PAC/1300, Griswold/13-14, 21.
199 PAC/1000, Griswold/22.
200 PAC/1000, Griswold/24; PAC/1300, Griswold/13.
201 *See, e.g.*, PAC/1300, Griswold/19 (discussing an example that required two wheels – one over PGE's system and one over BPA's system).
202 PAC/1300, Griswold/15 (noting that information regarding the availability of capacity on a third-party's system is not available until Pacific Power's merchant function submits a request under that third-party transmission provider's OATT).
203 PAC/1000, Griswold/23.

incurred accordingly.[204] Indeed, contrary to the suggestions of some intervenors, including third-party transmission costs in the calculation of standard avoided cost would necessarily create unwarranted subsidization within QF prices because of the significant impact of the location of the QF and the local transmission loads on the determination of whether and what type of third-party transmission arrangements are needed[205] – a determination that cannot be made without following the OATT-mandated process for each and every QF.

For similar reasons, the Commission should disregard suggestions by intervenors that PacifiCorp offer QFs a fixed avoided cost price reduction over the contract term. Again, the third-party arrangements that may be necessary to accommodate a QF will necessarily be individual to its circumstances, including the fact that the third-party transmission provider may change the rate at which it provides that service under its OATT.[206] Thus, charging a QF a fixed rate could lead to an inaccurate pass through of costs and fail to keep PacifiCorp's customers indifferent to the purchase of the QF's power.[207]

Intervenors also suggest that QFs should be refunded for revenues associated with PacifiCorp's ability to resell or redirect the third-party service. Practically speaking, however, this is highly unlikely to occur given the general lack of interest typically available for delivering power on the paths and in the direction required to accommodate the QFs.[208]

C. PacifiCorp Must Make Long-Term, Firm Transmission Arrangements to Deliver QF Power to Remain Compliant with PURPA.

Contrary to the suggestion of some intervenors, PacifiCorp must purchase long-term, firm transmission to the extent third-party transmission arrangements are needed. As discussed below, this type of transmission arrangement: (1) provides a dependable right to wheel surplus generation to load on PacifiCorp's larger system for the full term of a QF PPA; and (2) is

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[204] *Id.* Mr. Griswold also discusses an example of a specific QF project (Threemile Canyon Wind Farm 1, LLC) that demonstrates how transmission issues are necessarily individual to each QF. PAC/1000, Griswold/25-27.
[205] PAC/1000, Griswold/22.
[206] PAC/1300, Griswold 15-16.
[207] *Id.*
[208] PAC/1300, Griswold 16.

required in order for PacifiCorp to remain compliant with FERC PURPA precedent. For these same reasons, the Commission should reject any proposals requiring PacifiCorp to offer QFs different transmission options, whether different service types (*e.g.*, short-term and/or non-firm) or alternatives to transmission arrangements (*e.g.*, curtailment).

1. Long-Term Firm Transmission Provides a Dependable Right to Wheel Surplus Generation to Load for the Full Term of the QF PPA.

PacifiCorp must be able to depend on the transmission arrangements it makes to deliver the QF power during the full length of the PPA term and to reliably serve load.

With regard to term, while firm transmission can be purchased on a short-term basis (*i.e.*, a term of less than a year), FERC open access transmission policies require a transmission customer to make a minimum five-year commitment in order to obtain renewal or "rollover" rights to that transmission capacity after the initial service agreement expires.[209] This means PacifiCorp's transmission rights could be displaced during the term of a QF's PPA if another transmission customer requests a higher priority service and there is insufficient transmission capacity to accommodate both transmission customers.[210] Thus, PacifiCorp must purchase long-term firm transmission (if it is available) in order to ensure that firm third-party transmission service will remain available over the term of the QF's PPA.[211]

Transmission can also be purchased on a non-firm basis. However, such arrangements present an even higher risk of displacement by higher priority customers, including during the term of the contract (and not just upon rollover). This makes non-firm transmission service

[209] PAC/1000, Griswold/24-25; PAC/1300, Griswold/17. While certain references in Mr. Griswold's testimony were to BPA's rollover rights tariff provision, this five year minimum requirement stems from FERC's standard rollover rights policies applicable to all transmission providers. *See generally, Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (2007).
[210] PAC/1000, Griswold/24-25; PAC/1300, Griswold/17.
[211] *Id.* The dependable nature of such rights over the long-term also addresses concerns expressed by some intervenors that they might somehow "lose" their DNR status if new projects are added. Pacific Power must follow the OATT rules for studying new and/or renewed projects and making determinations about whether and when third-party transmission service is necessary for DNR status. However, generally speaking, an existing QF in a load pocket already has DNR status and is accounted for in minimum load conditions assessed by Pacific Power's transmission function when new QFs are added. PAC/1300, Griswold 20-21.

inappropriate for reliable load service generally,[212] as well as for transmission service that PacifiCorp can count on using to deliver the QF's power for the entire term of the PPA.

2. Long-Term Firm Transmission Arrangements Are Required by FERC PURPA Precedent.

In addition to concerns about the dependability of other types of transmission arrangements, PacifiCorp believes it must purchase firm transmission arrangements in order to remain compliant with FERC PURPA precedent.[213] For instance, in *Pioneer Wind Park I, LLC*,[214] FERC found a PURPA violation where a proposed PPA provision would have treated the QF as if it were a *non-firm*, secondary network service transmission customer that could be curtailed before any existing Network Resources that were designated (*i.e.*, received DNR status) before execution of the QF's PPA.[215] Requiring PacifiCorp to provide QFs with non-firm transmission arrangement alternatives would appear to be in direct conflict with this FERC precedent.

For similar reasons, PacifiCorp also has serious concerns regarding intervenor suggestions that it be required to use curtailment as an alternative to purchasing long-term, firm transmission service.[216] To that end, FERC has issued unequivocal precedent that strictly prohibits the curtailment of QF resources except under two very narrow circumstances: (1)

[212] PAC/1000, Griswold/24-25; PAC/1300, Griswold/17. Indeed, as noted above, Pacific Power's merchant function requests DNR status for a QF's PPA under its network transmission service agreement with Pacific Power's transmission function – an agreement designed to provide load service to customers.
[213] *See, e.g.*, PAC/1600, Griswold/4.
[214] *Pioneer Wind Park I. LLC,* 145 FERC ¶ 61,215 at 58.
[215] *Id.*
[216] PAC/1300, Griswold/18; PAC/1600, Griswold/7-8.

system emergencies and (2) extreme light loading conditions.[217] In addition, PacifiCorp is bound by the terms of its OATT that require, among other things, curtailment on a non-discriminatory and *pro rata* basis.[218] Thus, PacifiCorp requests the Commission disregard these "curtailment alternative" suggestions in light of these regulations and OATT requirements.

D. The Commission Should Disregard Suggestions that PacifiCorp Provide Maps with Designated Load Pockets and/or Other Information Regarding Available Transmission Capacity.

Finally, PacifiCorp believes the Commission should disregard any suggestions that PacifiCorp provide maps or tables with designated load pockets and/or other regularly-updated information regarding transmission capacity availability. As discussed above, such determinations depend on a host of very dynamic factors that can affect expected transmission conditions in the particular area of the system where the QF has sited its project during the particular timeframe of the request. This means any such maps would be administratively burdensome to constantly update, and would not remain accurate for very long in any event.[219] In addition, as also discussed above, the majority of this information is considered non-public transmission information under the SOC, which means it is only available to the transmission provider and cannot be shared with any party—including PacifiCorp's merchant function—unless /until OATT studies are performed.[220]

[217] *See* 18 C.F.R. §§ 292.307(b), 292.304(f). FERC has interpreted these circumstances very narrowly. Section 307(b) provides that "During any system emergency, an electric utility may discontinue: (1) Purchases from a qualifying facility if such purchases would contribute to such emergency… ." The regulations define "system emergency" as "a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property." 18 C.F.R. § 292.101(b)(4). Additionally, FERC has issued orders providing guidance on the application of the "light load" exception, with the crux of FERC's findings being that Section 304(f) was intended to permit curtailments under a single specific and limited circumstance only – for QFs selling on an as-available basis during unanticipated light loading periods when a utility operating only base load units would be forced to cut back output from those units in order to accommodate the unscheduled QF energy purchases, and then those base load units may not be able to later increase their output levels rapidly when system demand increased. *See, e.g., Entergy Servs., Inc.*, 137 FERC ¶ 61,199 at P 55 (2011)
[218] PAC/1600, Griswold/7-8. *See, e.g.*, OATT Section 33.
[219] PAC/1300, Griswold 14; PAC/1600, Griswold, 8-9.
[220] *See, e.g.*, PAC/1600, Griswold/9.

III. CONCLUSION

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

Respectfully submitted this 2nd day of September, 2015.

By: ______________________________

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