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December 12, 2011

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Oregon Public Utility Commission
550 Capitol Street NE, Ste 215
Salem, OR 97301-2551

Attn: Filing Center

RE: UE 235 (Phase 1) – PacifiCorp's Reply Brief

PacifiCorp d/b/a Pacific Power ("PacifiCorp or the Company") encloses for filing its Reply Brief in the above-referenced docket.

Please contact Joelle Steward, Regulatory Manager, at (503) 813-5542 for questions on this matter.

Sincerely,

Andrea L. Kelly
Vice President, Regulation

Enclosure

cc: Service List – UE 235

CERTIFICATE OF SERVICE

I hereby certify that on this 12th of December, 2011, I caused to be served, via email and/or overnight delivery, a true and correct copy of the foregoing document on the following named person(s) at his or her last-known address(es) indicated below.

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BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 235

IN THE MATTER OF PUBLIC UTILITY COMMISSION OF OREGON, Investigation into Avoided Cost Purchases from Qualifying Facilities – Schedule 37	**PACIFICORP'S REPLY BRIEF (PHASE ONE)**

PacifiCorp, dba Pacific Power (or "Company"), respectfully submits this Reply Brief to the Public Utility Commission of Oregon ("Commission") in reply to the Response Briefs of the Staff of the Commission ("Staff"), Renewable Northwest Project ("RNP") and the Community Renewable Energy Association ("CREA").

I. INTRODUCTION

Phase One of this docket presents the predicate legal and policy issue raised by PacifiCorp's proposed revisions to Schedule 37, which is whether the Public Utility Regulatory Policies Act of 1978 ("PURPA") is violated by requiring PacifiCorp to both pay Qualifying Facility ("QF") Schedule 37 prices for generation and bear the cost of third-party transmission charges to move the QF's generation from the point of delivery to PacifiCorp load. While this issue is straightforward, CREA in particular has added unnecessary complexity by introducing extraneous issues and disputed or immaterial facts.

Refocusing Phase One to its proper scope demonstrates that PacifiCorp's modified Schedule 37 requiring QFs to pay third-party transmission charges is reasonable because it: (1) ensures compliance with PURPA; (2) does not change the avoided cost methodology adopted in Docket UM 1129; (3) is consistent with Commission policy, which already assigns certain costs, *e.g.*, interconnection costs, directly to QFs on a case-by-case basis; (4) proposes to pass-on only verifiable and transparent third-party costs incurred pursuant to publicly available transmission tariffs or rate schedules; (5) is applicable only to that subset of Schedule 37 QFs in load constrained areas requiring third-party transmission to serve load; (6) treats third-party transmission costs and savings symmetrically; and (7) is specific to and sends the right price signals for PacifiCorp's unique transmission system topology in Oregon.

II. QUESTIONS PRESENTED AND SHORT ANSWERS

A. The Parties' Responses to the Legal Questions Presented Demonstrate the Limited Areas of Controversy in this Case.

a. Question 1: Is PURPA violated if PacifiCorp is required to pay Schedule 37 prices and PacifiCorp must also pay for third-party transmission to move QF output from the point of delivery to PacifiCorp load?

This is the fundamental question presented by PacifiCorp's proposed revisions to Schedule 37. Staff and PacifiCorp agree that if the Company is required to incur costs above its avoided cost as a result of having to acquire third-party transmission, then PURPA is violated.

Incorrectly combining an analysis of PacifiCorp's network transmission service and third-party transmission, CREA and RNP argue that there is no PURPA violation because PacifiCorp has not demonstrated a systematic overpayment to QFs based on an analysis of all transmission costs associated with Schedule 37 QFs. This is the wrong standard. Neither Federal Energy Regulatory Commission ("FERC") nor Oregon Commission precedent require a system-wide review of all QF transmission costs and benefits as a prerequisite to the direct assignment of discrete interconnection costs or third-party transmission costs or benefits. Instead, the cases demonstrate that in this context, "systematic" means material and recurring and "aggregate" refers to the combined group of QFs for whom PacifiCorp must acquire third-party transmission.

Applying the correct standard, it is clear that there is a systematic overpayment in the aggregate to Schedule 37 QFs who cause but do not now pay incremental third-party transmission costs.

b. Question 2: Is PURPA violated if PacifiCorp is required to pay Schedule 37 prices and PacifiCorp must also pay for third-party transmission to move QF output from the point of delivery to PacifiCorp load; and the cost to purchase third-party transmission service to move QF output to PacifiCorp load is not, in aggregate, offset by savings in third-party transmission service costs created by other Schedule 37 QFs?

Question 3: Is PURPA violated if PacifiCorp is required to pay Schedule 37 prices and PacifiCorp must also pay for third-party transmission to move QF output from the point of delivery to PacifiCorp load; and the cost to purchase third-party transmission service to move QF output to PacifiCorp load is, in aggregate, offset by savings in third-party transmission service costs created by other Schedule 37 QFs?

These questions are complementary subparts of Question 1. Logically, if the answer to Question 3 is "no," as agreed by PacifiCorp, Staff, and CREA, then the answer to Question 2 must be "yes." CREA, however, answered Question 2, "not necessarily." CREA can justify that conclusion only by assuming additional facts related to PacifiCorp's network transmission, not *third-party transmission expenses*, which are the subject of this docket.

CREA's assumption fundamentally changes Question 2 and impermissibly seeks to broaden the scope of this docket. Relying only on the facts assumed in the question, *i.e.*, that "the cost to purchase third-party transmission service to move QF output to PacifiCorp load is not, in the aggregate, offset by savings in third-party transmission service costs created by other Schedule 37 QFs," CREA's answer to Question 2 must be "yes" to be consistent with its answer to Question 3. Otherwise CREA is left to argue that PURPA is not violated when Schedule 37 QFs impose costs on PacifiCorp over and above the Schedule 37 avoided cost rate, a proposition that is on its face legally unsupportable.

III. MATERIAL FACTS

PacifiCorp requests that its revised Schedule 37 be approved based upon the resolution of the legal and policy issues presented in this Phase of the docket. The Commission can then review, as needed, QF-specific third-party transmission costs and benefits on a case-by-case basis.

In its Opening Brief, the Company provided a set of proposed facts as background for the Commission, not anticipating CREA's unwillingness to stipulate to any of the basic facts proposed by PacifiCorp. PacifiCorp likewise did not anticipate that CREA would propose an alternative set of facts which are for the most part either inaccurate or immaterial. Given the lack of stipulated material facts, the Company recommends that the Commission defer fact-finding, as necessary, to Phase Two of this docket.

Much of CREA's argument relies on the unproven assertion that Schedule 37 QFs as a group produce transmission savings for PacifiCorp. As explained below, PacifiCorp does not agree that a netting of schedule-wide transmission costs and benefits is required for approval of the Company's proposed tariff change, which applies to only a small subset of Schedule 37 QFs and involves only third-party transmission. However, if the Commission believes it needs a factual record to determine "whether the cost to purchase third-party transmission service to move QF output to Pacific Power load is not, in aggregate, offset by savings in third-party transmission service costs created by other Schedule 37 Qualifying Facilities," this issue has been specifically reserved for Phase Two of this case.

For the record, PacifiCorp's specific response to each Material Fact set forth by CREA is included in its attachment, Appendix A.

IV. DISCUSSION

A. PURPA is Violated if PacifiCorp is Required to Pay Third-Party Transmission Costs In Addition to Full Avoided Cost Prices for QF Output.

1. There is General Agreement on the Applicable Legal Framework.

There appears to be little disagreement among the parties that payments to QFs under PURPA must be just and reasonable, non-discriminatory, and not in excess of the utility's avoided cost.[1] The underlying policy behind the PURPA avoided cost methodology is to ensure that utility customers remain indifferent to the purchase of QF output.[2] This Commission has noted that Congress enacted PURPA "to encourage the economically efficient development of QFs, *while protecting ratepayers by ensuring that utilities incur costs no greater than they would have incurred in lieu of purchasing QF power*."[3]

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[1] 16 U.S.C. § 824a-3(b), (d); *American Paper Institute, Inc. v. American Electric Power Service Corp.*, 461 US 402, 413 (1983) (PURPA "sets full avoided cost as the maximum rate that the Commission may prescribe"); accord, *Independent Energy Producers Association v. California Public Utilities Commission*, 36 F.3d 848, 850 (9th Cir. 1994); *see also Connecticut Light and Power Company*, 70 FERC ¶ 61,012, 61,029 (1995) (state imposed rates for purchase of QF output which exceed the purchasing utility's avoided cost violate PURPA and FERC regulations).

[2] *So. Cal. Ed. Co.*, 71 F.E.R.C. ¶ 61,269, 62,080 (1995).

[3] *In the Matter of Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Docket UM 1129, Order No. 07-360 at 1 (Aug. 20, 2007) (emphasis added); *see also* Order No. 05-584 at 11 ("We seek to provide maximum incentives for the development of QFs of *all* sizes, while ensuring that ratepayers remain indifferent to QF power by having utilities pay no more than their avoided costs.").

To ensure customer indifference, PURPA itself and the Commission's rules implementing PURPA rely upon but-for causation when determining the avoided cost rate and accompanying charges, such as interconnection costs.[4] This requires that costs that would not otherwise be incurred *but for* the purchase of the QFs energy and capacity must be recovered from the QF. Otherwise the utility's customers are subsidizing the QF, which is strictly prohibited by PURPA.[5]

Applying this rationale, the Idaho Public Utilities Commission ("IPUC") approved a downward adjustment in a negotiated QF contract because transmission costs and constraints made the generation output less valuable to PacifiCorp than the hypothetical surrogate avoided resource. Such an adjustment was proper under 18 C.F.R. § 292.304(e)(i), which directs consideration of dispatchability when setting avoided cost rates.[6] Other commissions, including the Oregon Commission, have specifically allowed consideration of transmission savings associated with the location of the QF. In another application of these principles, FERC requires off-system QFs to arrange and pay for third-party transmission expenses to wheel the QF's output to the utility purchasing the power under PURPA.[7]

PacifiCorp's Schedule 37 represents the Commission's determination of its full avoided cost for small QFs, *i.e.*, QFs with capacity less than 10 MW. If PacifiCorp's customers are required to pay for third-party transmission expenses to wheel the QF's

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[4] 16 U.S.C. § 824a-3(b), (d); OAR 860-029-0010(1); OAR 860-029-0060.

[5] *See Independent Energy Producers Association v. California Public Utilities Comm'n*, 36 F.3d 848, 858 (9th Cir. 1994) ("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] *Rosebud v. Idaho Public Utilities Commission*, 128 Idaho 609, 917 P.2d 766 (1996).

[7] 18 C.F.R. § 292.303(d).

output to PacifiCorp's load in addition to Schedule 37 prices, then customers would be subsidizing the QF. This violates PURPA. It also assumes, irrationally, that but for the QF purchase, PacifiCorp would intentionally acquire or build new generation in a location where PacifiCorp would have to bear third-party transmission costs to export power out of the constrained area into the PacifiCorp system.

2. PacifiCorp has Identified "Systematic" Overpayment to QFs.

CREA argues that PacifiCorp can only demonstrate a violation of PURPA if it can identify "systematic overpayments to QFs resulting from the Company incurring third-party transmission expenses to wheel QF output out of load pockets."[8] While CREA relies on *Edison II*[9] to support its contention that PacifiCorp failed to demonstrate systematic overpayment, that case supports PacifiCorp's position. In *Edison II*, the California Court of Appeals upheld a California Public Utilities Commission ("CPUC") decision rejecting a challenge to the CPUC's avoided cost methodology because the avoided costs exceeded the spot market price only sporadically.[10] The CPUC concluded that PURPA was not violated because the methodology did not produce systematic (i.e., recurring) prices in excess of avoided costs.

Here the third-party transmission costs PacifiCorp is incurring on behalf of QFs in load-constrained areas are ongoing, material costs that systematically result in this subset of Schedule 37 QFs receiving more than full avoided cost for their output (both individually and in the aggregate). This is precisely the type of the systematic, recurring cost that the CPUC implied would constitute a violation of PURPA.

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[8] Opening Brief of CREA at 19.

[9] *So. Cal. Ed. Co. v. Pub. Util. Comm'n of Calf.*, 128 Cal.App.4th 1, 11 (2005).

[10] *So. Cal. Ed. Co. v. Pub. Util. Comm'n of Calf.*, 128 Cal.App.4th 1, 11 (2005).

CREA is also critical of PacifiCorp for "providing no evidence" to support its claim of systematic overpayment to QFs in load-constrained areas.[11] Because the overpayment involves the discrete and readily identifiable issue of third-party transmission, PacifiCorp submits that this is primarily an issue of law and policy, not fact. If the Commission needs additional evidence, however, the Company will provide it in Phase Two or in future cases involving the application of Schedule 37, as modified, to specific QFs.

3. FERC Has Never Required a Determination of Overall Transmission Costs or Savings Based on All QFs in Order to Allow QF-Specific Transmission-related Charges or Credits.

RNP argues that PURPA is violated only when the overall transmission costs incurred by PacifiCorp are systematically higher than the transmission costs avoided as determined by considering all Schedule 37 QFs, not just those delivering to load pockets.[12] CREA makes a similar argument.[13]

As support for this proposition, both RNP and CREA cite to FERC's October 21, 2010, order in *California Public Utility Commission v. So. Cal. Ed.*[14] Nowhere does that order direct commissions to consider "all system QFs" when determining whether PURPA requires the imposition of a transmission-related charge or credit to a particular QF. On the contrary, FERC held that a QF may receive a location "bonus" if it builds in a transmission constrained area (*i.e.*, a location which would require upgrades in order to import power) so long as "the CPUC bases the avoided cost 'adder' or 'bonus' on an

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[11] Opening Brief of CREA at 20.

[12] RNP Response Brief at 1.

[13] Opening Brief of CREA at 20.

[14] *Calif. Pub. Util. Comm'n v. So. Cal. Ed. Co. et al*, 133 FERC ¶ 61,059 at ¶ 31 (Oct. 21, 2010).

actual determination of the expected costs of upgrades to the distribution or transmission system that the QFs will permit the purchasing utility to avoid."[15]

Importantly, FERC did not find that a location "bonus" required an initial examination of system-wide, aggregate QF-related transmission costs and savings. Rather, FERC focused its analysis on the costs avoided in the particular transmission constrained area where the QF chooses to construct its project. By definition, a location bonus is QF-specific, considering the area the QF in question seeks to locate and the specific upgrades that the QF may allow the utility to avoid.

In FERC's Order 69, which first adopted its PURPA regulations, FERC similarly noted that compensation for changes in line losses caused by a QF's locational relationship to load should be determined on a case-by-case basis.[16] Notably absent from FERC's analysis is a requirement that the utility must first assess its system-wide line losses for all QFs before analyzing on a case-by-case basis the line loss changes associated with a specific QF.

While CREA argues that a PURPA violation can occur only if the "costs [PacifiCorp] has identified outweigh the system-wide, aggregate benefits of Schedule 37 QFs",[17] there is nothing in FERC's regulations that requires transmission cost or benefit analysis to occur in the aggregate. There is only one factor in the regulation, 18 C.F.R. § 292.304(3)(2)(vi), that references the aggregate impact of QFs. All other factors speak to the individual characteristics of the specific QF. For example, factors include the dispatchability of the QF, the reliability of the QF, the contract terms, and the

[15] *Calif. Pub. Util. Comm'n v. So. Cal. Ed. Co. et al*, 133 FERC ¶ 61,059 at ¶ 31 (Oct. 21, 2010).

[16] FERC Order No. 69, 45 Fed. Reg. 12,214, 12,227 (Feb. 25, 1980).

[17] Opening Brief of CREA at 20.

coordination of scheduled outages for utility facilities with the QF's scheduled outages. None of these factors can be determined in the aggregate.[18]

Importantly, the factor that is most applicable here because it relates directly to transmission costs or savings says nothing about requiring aggregate analysis. 18 C.F.R. § 292.304(e)(4) allows the consideration of costs or savings resulting from variations in line losses from those that would occur in the absence of the QF. This provision is necessarily tied to the specific QF because the location of the QF determines its line loss. Locationally dependent factors by definition cannot be determined on an aggregate, system-wide basis because they are unique to each QF. That is precisely why the Company proposed charging individual QFs for third-party transmission, instead of socializing them to other QFs through the avoided cost calculation or asking customers to continue to subsidize these costs.

4. The Oregon Commission Has Never Required a Determination of Overall Transmission Costs or Savings Based on All QFs in Order to Allow QF-Specific Transmission-related Charges or Credits.

The Oregon Commission has long recognized that transmission costs or savings resulting from a PURPA transaction should be evaluated and quantified on a case-specific basis. In an order pre-dating Docket UM 1129, the Commission discussed the inclusion of transmission losses and costs in the avoided cost rate.[19] At that time Portland General Electric Company ("PGE") was the only utility in Oregon that included transmission losses in the avoided cost rate. Citing OAR 860-029-0040(5)(d), which

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[18] FERC's 18 C.F.R. § 292.304(e) factors govern both negotiated and standard contracts. 18 C.F.R. § 292.304(3)(i) states that standard rates for purchase "shall be consistent with paragraphs (a) *and (e)* of this section."

[19] *Re Investigation of Avoided Costs*, Docket UM 21, Order No. 84-720, 62 P.U.R.4th 397, 410 (Sept. 12, 1984).

calls for the inclusion, to the extent practicable, of lines losses in the avoided cost calculation, Staff argued that the avoided cost rate for all utilities should include a component for changes in line losses. The Commission noted: "Because the utility's line losses may be increased or decreased as a result of QF purchases, line loss estimates will be more accurate when adjusted on an individual basis."[20] Thus, the Commission ordered utilities to adjust the avoided cost rate on a "contract-by-contract basis" based on the "individual QF's situation."[21]

The Commission continued this approach for large QFs in Docket UM 1129. Guideline 14 from the Commission's Guidelines for Negotiation of Power Purchase Agreements for QFs 10MW or Larger requires consideration and an adjustment to avoided costs for "potential savings due to transmission and distribution system upgrades that can be avoided or deferred as a result of the QF's location relative to the utility proxy plant."[22] Guideline 15 requires that distribution or transmission upgrades needed to accept QF power be "separately charged as a part of the interconnection process." [23]

5. Third-Party Transmission Costs and Benefits are Not Assessed as Part of the Avoided Cost Calculation for QFs Less Than 10 MW

CREA's brief includes several contradictory assertions regarding whether and to what extent transmission costs and benefits are now included in the Schedule 37 avoided cost rate. On page 5 of its brief CREA states that "CREA does not agree that Schedule 37 rates reflect PacifiCorp's full avoided cost rates." CREA then argued that Schedule

[20] *Id.*

[21] *Id.*

[22] *In the Matter of Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Docket UM 1129, Order No. 07-360 at Appendix A at 4 (Aug. 20, 2007).

[23] *Id.*

37 rates take into account the net costs of third-party transmission during excess generation events because "Schedule 37 rates can be read to take such events into account without reducing rates."[24] Later, CREA asserts that Schedule 37 QFs are not compensated for "*any* avoided transmission costs."[25]

To be clear, Schedule 37 rates *do not* take into account third-party transmission costs or savings resulting from QF transactions. Indeed, this is precisely why the Company maintains that PURPA is violated when it is required to pass along to customers (not the QFs) the third-party transmission expenses required to wheel QF output from the point of interconnection to PacifiCorp's load. Any location-specific costs incurred because of third-party transmission that are directly attributable to the QF projects are therefore above full avoided cost and in violation of PURPA.

B. PacifiCorp's Proposed Tariff Changes Are Consistent with UM 1129.

CREA argues that if the Commission allows PacifiCorp to charge QFs for the third-party transmission service to transmit the QF's output to PacifiCorp load, it will undermine the Commission's decision in Docket UM 1129.[26] In Order No. 05-584 the Commission made clear that standard contracts, such as PacifiCorp's Schedule 37 contract, "are intended to be used as a means to remove transaction costs associated with QF contract negotiations, when such costs act as a market barrier to QF development."[27]

In an earlier PURPA docket, the Commission made a similar statement: "The standard rate is intended to address [the concern that prohibitive transaction costs may

[24] Opening Brief of CREA at 5-6.

[25] Opening Brief of CREA at 16 (emphasis added).

[26] Opening Brief of CREA at 14-16.

[27] Order No. 05-584 at 16.

effectively eliminate QFs from the market] by minimizing transaction costs of negotiating a power purchase agreement."

PacifiCorp's proposal would not materially increase the transactional costs associated with the negotiation of a Schedule 37 contract because PacifiCorp is not requesting modification of the Schedule 37 avoided cost rate or any material standard contract provisions. PacifiCorp's proposal is consistent with the Commission's current approach to small QFs, which contemplates some individualized negotiation, as long as it is "specifically delineated and bounded."[28]

C. PacifiCorp's Proposal is Consistent with the Treatment of Related QF Costs.

The Company's proposal is also consistent with how the Oregon Commission and FERC account for costs other than the purchase prices of energy and capacity, such as interconnection costs and transmission costs where the QF is interconnected to a utility other than the purchasing utility.

Under the Oregon rules developed in Dockets UM 1401 and AR 521, both large and small QFs are required to pay for all interconnection costs reasonably incurred by the utility.[29] These are costs incurred directly by the interconnecting utility and are recovered outside of the avoided cost rate. The Commission requires QFs to pay for these costs to prevent customer subsidization of QFs and ensure that customers remain indifferent to QF purchases.[30]

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[28] Order No. 05-584 at 39.

[29] See discussion in PacifiCorp's Opening Brief at 18-20

[30] *See Investigation into Interconnection of PURPA Qualifying Facilities With Nameplate Capacity Larger than* 20 MW, Docket UM 1401, Order No. 10-132 at 3 (Apr. 7, 2010) (absent "quantifiable system-wide benefits" large QFs pay for all interconnection costs); OAR 860-029-0060 (small QFs pay all interconnection costs).

Under FERC regulations, a QF located on the transmission or distribution system of one utility (Utility A) but seeking to require that Utility B purchase its energy under PURPA, must pay the third-party transmission cost.[31]

As Staff agrees, the rationale underlying these policies supports PacifiCorp's proposed modifications to Schedule 37.[32]

D. The Third Party Transmission Expenses Charged to QFs are Transparent and Verifiable.

PacifiCorp's proposed tariff modifications seek to directly assign the net costs of third-party transmission expenses only. These transmission costs are, by and large,[33] incurred pursuant to publicly available transmission rate schedules and tariffs developed in transparent processes and applied in a non-discriminatory manner.[34]

The importance of this fact is implicit in CREA's argument that it would welcome the engagement of a "neutral third party to devise a formula calculating the precise transmission costs and benefits of incremental QF additions at each potential delivery point in Oregon."[35] While CREA's proposal is beyond the scope of this docket, it concedes the value of neutral third party involvement, such as that implicated in

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[31] Specifically, 18 C.F.R. § 292.303(d) provides that "[t]he rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to §292.304(e)(4) *and shall not include any charges for transmission.*"

[32] Opening Brief of Staff at 7.

[33] Instances where third-party transmission costs are not incurred pursuant to publicly available Open Access Transmission Tariffs (OATT) include bilateral transmission agreements that are considered "grandfathered" or pre-OATT. Except under rare circumstances, these agreements are FERC-jurisdictional and are filed with FERC by the transmission provider.

[34] The relevant portions of the BPA, PGE and Idaho Power transmission agreements and tariffs are Attachments A-D to the Company's Opening Brief.

[35] Opening Brief of CREA at 22.

acquiring (or avoiding) third-party transmission under the current open access regulatory paradigm.

E. PacifiCorp's Proposed Tariff Changes Are Narrowly Tailored and Will Be Applied Symmetrically.

PacifiCorp's proposed tariff modifications are narrowly tailored to apply to only those QFs in load constrained locations for whom third-party transmission must be acquired. CREA's brief acknowledges that PacifiCorp's proposal applies to only "a small handful of QFs that require the purchase of third-party transmission."[36] While PacifiCorp's proposed tariff change is necessary to fairly allocate significant incremental transmission expense, it will not impact the majority of Schedule 37 QFs.

PacifiCorp's proposal is equitable because the Company proposes not only to charge QFs for costs incurred, but also to credit savings to QFs when they allow PacifiCorp to save third-party transmission expenses. PacifiCorp has made this symmetrical approach, to which Staff fully agrees,[37] explicit in the revised version of Schedule 37 attached to this Reply Brief as Appendix B.

F. PacifiCorp's Proposal Is Specific to PacifiCorp and Sends the Right Price Signals for the Company's Uniquely Configured Oregon Service Territory.

In Order No. 05-584, the Commission noted that it has "consistently interpreted its PURPA mandate to be the adoption of policies and rules that promote QF development, using among other tactics, *accurate price signals and full information to developers*, while ensuring that utilities pay no more than avoided costs."[38] PacifiCorp's proposal supports this policy because it will make clear to QFs up front that they will be

[36] Opening Brief of CREA at 22.

[37] Opening Brief of Staff at 7.

[38] Order No. 05-584 at 11 (emphasis added).

responsible for third-party transmission expenses incurred by PacifiCorp to wheel the QF's output to load. PacifiCorp's transmission system topology in Oregon is fragmented and frequently interconnected by third-party transmission systems. PacifiCorp's proposal is designed to constructively address and respond to transmission issues specific to PacifiCorp's unique transmission system topology.

G. CREA's Remaining Arguments Go Beyond the Scope of this Docket.

The parties developed the issues to be addressed in this docket, which are reflected in ALJ Kirkpatrick's October 5 Ruling and addressed in PacifiCorp's Opening and Reply Briefs. The issues for this phase of the docket are purely legal/policy and focus on PacifiCorp's narrowly tailored request to directly charge to QFs *third-party transmission costs* incurred because of the QF's location in a load pocket. CREA, however, has briefed a very different set of issues, arguing that Schedule 37 either takes into account transmission expenses or, in violation of PURPA, does not, and that PacifiCorp's request should be denied because PURPA requires the avoided cost rate to include *all* transmission costs, not just third-party transmission costs.[39]

The majority of CREA's arguments go beyond the issues presented in this docket and seek to reopen Docket UM 1129. The scope of this docket is limited to third-party transmission costs and the issues presented to the ALJ (and agreed to by CREA) do not reach the question of whether the avoided cost rate should include a component for avoided transmission costs. If the Commission determines a need to modify its standard avoided cost calculation for QFs less than 10 MW to address transmission costs, it should

[39] Opening Brief of CREA at 12-14.

do so in a generic docket with appropriate fact-finding, not in this PacifiCorp-specific docket.

V. CONCLUSION

PacifiCorp respectfully requests that the Commission approve its proposed revisions to Schedule 37. Doing so will ensure that PacifiCorp's customers remain economically indifferent to QF transactions, as required by PURPA, while also treating small QFs in a fair and equitable manner.

Dated this 12th day of December 2011.

Respectfully Submitted,

Mary Wiencke

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Appendix A

PacifiCorp's Response to CREA's Additional Material Facts

PacifiCorp's response to the accuracy of CREA's Material Facts is set forth below. PacifiCorp does not agree that all of CREA's Material Facts are, in fact, material. In addition, many of CREA's Material Facts are actually statements of law or policy, not fact. PacifiCorp therefore reserves its right to object to all of CREA's Material Facts on these grounds.

CREA's Additional Material Facts

1. The Commission approved methodology for standard Schedule 37 fixed rates requires calculation based on the alternative cost for PacifiCorp to acquire energy from market resources during a resource sufficiency period, and the marginal fixed and variable costs for a natural gas fired combined cycle combustion turbine ("CCCT") plant during a resource deficiency period.

PacifiCorp's Response: Agree.

2. In PacifiCorp's 2011 Integrated Resource Plan ("IRP"), PacifiCorp uses a transmission topology consisting of 19 bubbles (geographical areas) in its eastern control area and 15 bubbles in its western control area designed to best describe major load and generation centers, regional transmission congestion impacts, import/export availability, and external market dynamics. Firm transmission paths link the bubbles.

PacifiCorp's Response: PacifiCorp's 2011 IRP speaks for itself, and PacifiCorp does not necessarily agree with CREA's characterization of this document.

3. PacifiCorp states that its loads are growing.

PacifiCorp's Response: Mr. Duvall's testimony in UE 227 speaks for itself and PacifiCorp does not necessarily agree with CREA's characterization of these documents.

4. PacifiCorp's 2011 IRP states that it is currently using market purchases as one means to meet its growing load needs. PacifiCorp engages in market electricity purchases from multiple market hubs throughout the western United States, including Mid-Columbia, Palo Verde, Four Corners, California-Oregon Border, Mead, Mona, the California market (Cal ISO), and the Nevada-Oregon Border. The third party transmission costs to move power from these hubs to load are included in Oregon customers' rates.

PacifiCorp's Response: PacifiCorp's IRP speaks for itself and PacifiCorp does not necessarily agree with CREA's characterization of this document. PacifiCorp specifically denies the last sentence because its third-party transmission costs are not always reflected in Oregon rates.

5. PacifiCorp currently plans to build several additional transmission lines connecting the west control area (including Oregon) and other parts of its territory to meet its loads, expand regional resource needs, and access market resources. PacifiCorp's IRP includes a map demonstrating PacifiCorp's extensive expansions planned for its own transmission network, and includes as "Action Items" steps necessary to build six major transmission lines to link its generation resources and load sinks.

PacifiCorp's Response: PacifiCorp's 2011 IRP speaks for itself, and PacifiCorp does not necessarily agree with CREA's characterization of this document.

6. PacifiCorp also must use third party transmission to connect its load and generation centers. PacifiCorp's 2010 Federal Energy Regulatory Commission ("FERC") Form No. 1 shows that PacifiCorp's 2010 total transmission expense was equivalent to an additional 10 percent cost over and above PacifiCorp's 2010 total power production expense (including Company-generated power and purchased power). It also showed that approximately 70 percent of PacifiCorp's transmission expense was for third-party transmission, and that approximately 50 percent of PacifiCorp's transmission expense was for BPA transmission. Thus, 2010 BPA transmission expenses amounted to an added expense equivalent to approximately 5 percent of PacifiCorp's total power production expense.

PacifiCorp's Response: PacifiCorp's FERC Form 1 speaks for itself, and PacifiCorp does not necessarily agree with CREA's characterization of this document.

7. PacifiCorp will incur transmission costs to transmit incremental additions of generation to serve growing loads. In PacifiCorp's most-recent power cost update case, PacifiCorp testified that in 2011 and 2012 it will need to acquire "new transmission contracts to wheeling power [sic] to serve the Company's load obligations."

PacifiCorp's Response: Mr. Duvall's testimony in UE 227 speaks for itself and PacifiCorp does not necessarily agree with CREA's characterization of these documents.

8. PacifiCorp has several natural gas plants, including nine in Utah and two in Washington, but only two located in Oregon. PacifiCorp's two gas plants located in Oregon are the Hermiston plants.

PacifiCorp's Response: PacifiCorp's 2011 IRP speaks for itself, and PacifiCorp does not necessarily agree with CREA's characterization of this document.

9. None of PacifiCorp's gas plants are located in an Oregon load center. Even the Hermiston plants rely on transmission to serve at least two different load centers, and PacifiCorp is currently planning to construct a new transmission line to provide more transmission from the Hermiston plants to one load center. PacifiCorp's 2010 FERC Form No. 1 even states that PacifiCorp purchases transmission from the Hermiston Generating Company.

PacifiCorp's Response: PacifiCorp's FERC Form 1 speaks for itself, and PacifiCorp does not necessarily agree with CREA's characterization of this document.

10. PacifiCorp's Schedule 37 resource sufficiency period avoided cost rates, based on a market resource, do not include adders to the avoided cost rate to account for avoided transmission costs to bring the electricity to load.

PacifiCorp's Response: PacifiCorp agrees that no transmission costs or credits are included in Schedule 37.

11. PacifiCorp's Schedule 37 resource deficiency period avoided cost rates, based on the gas plant costs, do not include adders to the avoided cost rate to account for avoided transmission costs to bring the electricity to load.

PacifiCorp's Response: PacifiCorp agrees that no transmission costs or credits are included in Schedule 37.

12. The Commission determined that QFs provide the utility with capacity and should be compensated for that capacity even in resource sufficient periods.

PacifiCorp's Response: Order No. 05-584 speaks for itself and PacifiCorp does not necessarily agree with CREA's characterization of this document.

13. In the aggregate, QFs defer the need for market purchases and long-term generation resources. PacifiCorp includes firm QF power purchase agreements ("PPAs") in its load and resource balance for purposes of determining its capacity needs in the future.

PacifiCorp's Response: PacifiCorp's 2011 IRP speaks for itself, and PacifiCorp does not necessarily agree with CREA's characterization of this document. In addition, PacifiCorp objects to the first sentence as conclusory and unsupported.

14. Schedule 37 QF capacity, in the aggregate, provides PacifiCorp with capacity that defers the need to acquire market resources and associated transmission rights over transmission owned by third parties, or upgrades to PacifiCorp's transmission system.

PacifiCorp's Response: PacifiCorp objects to this statements as conclusory and unsupported.

15. Schedule 37 QF capacity, in the aggregate, provides PacifiCorp with capacity that defers the need to acquire new generation resources, including gas plants, and associated transmission rights over transmission owned by third parties, or upgrades to PacifiCorp's transmission system.

PacifiCorp's Response: PacifiCorp objects to this statements as conclusory and unsupported.

16. Commission rules require Schedule 37 QFs to pay all costs for interconnection and associated local distribution and network upgrades to PacifiCorp's system necessitated by their project, and do not include cost-sharing provisions.

PacifiCorp's Response: Order No. 09-196 speaks for itself and PacifiCorp does not necessarily agree with CREA's characterization of this document. In addition, PacifiCorp specifically objects to the word "network" in the statement, which should instead refer to "system."

17. PacifiCorp and/or its ratepayers pay the costs of interconnection and local distribution upgrades, as well as any third-party transmission or upgrades to PacifiCorp's transmission system, needed for utility owned generation facilities, such as a new CCCT gas plant.

PacifiCorp's Response: PacifiCorp objects to this statement as an inaccurate overgeneralization.

18. Commission rules allow for non-Schedule 37 QFs, exceeding 20 MW in size, to obtain a refund for network transmission upgrades to PacifiCorp's system if the QF can prove the upgrade will provide system-wide benefits.

PacifiCorp's Response: Order No. 10-132 speaks for itself and PacifiCorp does not necessarily agree with CREA's characterization of this document.

19. Under PacifiCorp's OATT, non-PURPA independent developers interconnecting to PacifiCorp's system may receive a refund for transmission upgrades to PacifiCorp's system required for their interconnection and delivery. PacifiCorp and its ratepayers pay these refunds.

PacifiCorp's Response: PacifiCorp objects to this statement as an inaccurate overgeneralization.

[Legislative]

B. Procedures (continued)

5 After reviewing the final draft power purchase agreement, the owner may either prepare another set of written comments and proposals or approve the final draft power purchase agreement. If the owner prepares written comments and proposals the Company will respond in 15 business days to those comments and proposals.

6. When both parties are in full agreement as to all terms and conditions of the draft power purchase agreement, the Company will prepare and forward to the owner within 15 business days, a final executable version of the agreement. Following the Company's execution a completely executed copy will be returned to the owner. Prices and other terms and conditions in the power purchase agreement will not be final and binding until the power purchase agreement has been executed by both parties and will be subject to modification after execution as provided in paragraph 7, below.

7. The prices and other terms and conditions in an executed power purchase agreement with a QF over 100 kW will be contingent upon PacifiCorp Transmission approving designation of the QF as a Network Resource under PacifiCorp Transmission's FERC Electric Tariff Volume No. 11 Pro Forma Open Access Transmission Tariff and as further provided in this paragraph 7.

(a) PacifiCorp Commercial and Trading will submit to PacifiCorp Transmission a request for Network Resource designation of the QF within five business days of the later of (i) execution of the power purchase agreement by both parties or (ii) the QF owner providing the Company with QF information necessary to submit a request.

(b) If in designating a QF as a Network Resource, PacifiCorp Transmission identifies a need for additional transmission service (other than the Network Integration Transmission Service for which the QF is designated a Network Resource) in order for the Company to use the QF's net output to serve the Company's network load, then the owner will have 15 business days from the date of the Network Resource designation to agree to pay to PacifiCorp ~~all costs incurred~~the amount owed to any third-party transmission provider for such additional transmission for the duration of the power purchase agreement. Such amount will be net of any third-party transmission savings that offset third-party transmission costs associated with delivery of the QU's output to PacifiCorp's load. If available, such additional transmission will be acquired by the Company in the form of long-term firm point-to-point service in the capacity identified in the Network Resource status designation rounded up to the nearest whole megawatt.

(continued)

~~(c) If the owner does not agree within the 15-business-day period to pay for such additional transmission, or if such additional transmission is not timely available in the form of long-term firm~~~~**II. Process for Negotiating Interconnection Agreements**~~

~~[NOTE: Section II applies only to QFs connecting directly to PacifiCorp's electrical system. An off-system QF should contact its local utility or transmission provider to determine the interconnection requirements and wheeling arrangement necessary to move the power to PacifiCorp's system.]~~

~~In addition to negotiating a power purchase agreement, QFs intending to make sales to the Company are also required to enter into an interconnection agreement that governs the physical interconnection of the project to the Company's transmission or distribution system. The Company's obligation to make purchases from a QF is conditioned upon the QF completing all necessary interconnection arrangements. It is recommended that the owner initiate its request for interconnection 18 months ahead of the anticipated in-service date to help ensure that necessary interconnection arrangements proceed in a timely manner on a parallel track with negotiation of the power purchase agreement.~~

(continued)

[Clean]

B. Procedures (continued)

5 After reviewing the final draft power purchase agreement, the owner may either prepare another set of written comments and proposals or approve the final draft power purchase agreement. If the owner prepares written comments and proposals the Company will respond in 15 business days to those comments and proposals.

6. When both parties are in full agreement as to all terms and conditions of the draft power purchase agreement, the Company will prepare and forward to the owner within 15 business days, a final executable version of the agreement. Following the Company's execution a completely executed copy will be returned to the owner. Prices and other terms and conditions in the power purchase agreement will not be final and binding until the power purchase agreement has been executed by both parties and will be subject to modification after execution as provided in paragraph 7, below.

7. The prices and other terms and conditions in an executed power purchase agreement with a QF over 100 kW will be contingent upon PacifiCorp Transmission approving designation of the QF as a Network Resource under PacifiCorp Transmission's FERC Electric Tariff Volume No. 11 Pro Forma Open Access Transmission Tariff and as further provided in this paragraph 7.

(a) PacifiCorp Commercial and Trading will submit to PacifiCorp Transmission a request for Network Resource designation of the QF within five business days of the later of (i) execution of the power purchase agreement by both parties or (ii) the QF owner providing the Company with QF information necessary to submit a request.

(b) If in designating a QF as a Network Resource, PacifiCorp Transmission identifies a need for additional transmission service (other than the Network Integration Transmission Service for which the QF is designated a Network Resource) in order for the Company to use the QF's net output to serve the Company's network load, then the owner will have 15 business days from the date of the Network Resource designation to agree to pay to PacifiCorp the amount owed to any third-party transmission provider for such additional transmission for the duration of the power purchase agreement. Such amount will be net of any third-party transmission savings that offset third-party transmission costs associated with delivery of the QU's output to PacifiCorp's load. If available, such additional transmission will be acquired by the Company in the form of long-term firm point-to-point service in the capacity identified in the Network Resource status designation rounded up to the nearest whole megawatt.

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