BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

IN THE MATTER THE PUBLIC UTILITY COMMISSION OF OREGON Investigation Into Qualifying Facility Contracting and Pricing	CASE NO. UM 1610 REDACTED POST-HEARING LEGAL BRIEF OF THE COMMUNITY RENEWABLE ENERGY ASSOCIATION

I. INTRODUCTION

The Community Renewable Energy Association ("CREA") hereby respectfully submits this post-hearing legal brief to the Public Utility Commission of Oregon ("OPUC"). CREA again respectfully requests that the OPUC implement the Public Utility Regulatory Policies Act of 1978 ("PURPA") in a manner consistent with CREA's recommendations. The evidence adduced at the hearing further underscores the need to closely scrutinize the utilities' calculation of their avoided cost rates, and to not adopt proposals that would leave small community-based qualifying facilities ("QF") to individually negotiate pricing and contract terms with electric utilities. The OPUC should maintain the basic framework that it developed in docket UM 1129 to encourage development of small-scale community-based renewable generation from projects under 10 megawatts ("MW") in capacity.

II. LEGAL BACKGROUND

Section 210 of PURPA "seeks to *encourage* the development of cogeneration and small power production facilities." *FERC v. Mississippi*, 456 U.S. 742, 750 (1982) (emphasis added); 16 U.S.C. § 824a-3(a). Congress found this to be necessary because "traditional electricity utilities were reluctant to purchase power from, and to sell power to, the nontraditional facilities." *Mississippi*, 456 U.S. at 750. Congress further determined these facilities need to be *encouraged* because "cogenerators and small power producers are different from electric utilities*, not being guaranteed a rate of return on their activities generally* or on the activities vis-a-vis the sale of power to the utility *and whose risk in proceeding forward in the cogeneration or small power production enterprise is not guaranteed to be recoverable*." *Amer. Paper Institute, Inc. v. Amer. Elect. Power Serv. Corp.,* 461 U.S. 402, 414 (1983) (internal quotation omitted) (emphasis added). The law directs the Federal Energy Regulatory Commission ("FERC") to establish regulations to implement the requirement that electric utilities must purchase power from QFs. 16 U.S.C. § 824a-3(a)(1). In turn, PURPA requires state regulatory authorities to implement FERC's regulations. 16 U.S.C. § 824a-3(f).

Oregon law itself declares that it is "the policy of the State of Oregon to . . . [i]ncrease the marketability of electric energy produced by qualifying facilities located throughout the state for the benefit of Oregon's citizens" and to "[c]reate a settled and uniform institutional climate for qualifying facilities in Oregon." ORS 758.515(3). More recently, Oregon enacted its renewable portfolio standard ("RPS"), which requires utilities to obtain a certain percentage of their load requirements with specified "renewable energy sources." ORS 469A.005-300. The RPS further provides, "The Legislative Assembly finds that community-based renewable energy projects . . . are an essential element of Oregon's energy future." ORS 469A.210. The RPS therefore "declares that it is the goal of the State of Oregon that by 2025 at least eight percent of Oregon's retail electrical load comes from small-scale renewable energy projects with a generating capacity of 20 megawatts or less." *Id.* The law even mandates that all executive department agencies, including the OPUC, "***shall***" establish policies and procedures promoting the [eight percent] goal declared in this section." *Id.* (emphasis added).

III. ARGUMENT

A. <u>THE UTILITIES' ARGUMENTS OVERLOOK THAT FEDERAL AND STATE LAW REQUIRE THE ENCOURAGEMENT OF QF DEVELOPMENT.</u>

The OPUC has implemented a robust QF framework upon which the OPUC should build, and not scale back, in this proceeding. The law instructs the OPUC to implement PURPA in a manner that requires Oregon utilities to purchase QF output at the purchasing utility's *full* avoided costs. *See Amer. Paper Institute, Inc.,* 461 U.S. at 417-18; *see also Small Power Prod. and Cogeneration Facilities; Regulations Implementing Sec. 210 of the Pub. Util. Reg. Pol. Act of 1978*, Order No. 69, 45 Fed. Reg. 12,214, 12,222-12,223 (Feb. 25, 1980) (directly rejecting proposals to provide less than the *full* avoided cost).

The utilities appear to misunderstand PURPA's mandates. Idaho Power submits that the OPUC should not "focus on encouraging the development of renewable resources." Idaho Power/400, Stokes/6. And PGE focuses on the requirement in Oregon law that QF rates be "just and reasonable . . . and in the public interest." *See PGE Prehearing Brief* at 3 (quoting ORS 785.515(2)(b)). PGE fails to mention, however, that this provision of Oregon law is virtually identical to language contained in PURPA itself, *see* 16 U.S.C. § 824a-3(c)(1), and the U.S. Supreme Court has already unanimously held that FERC's full avoided cost rule satisfies this public interest requirement. *See Amer. Paper Inst., Inc.*, 461 U.S. at 417-18. The Court reasoned that "the words 'public interest' in a regulatory statute . . . take meaning from the purposes of the regulatory legislation," and "[t]he basic purpose of § 210 of PURPA was to increase the utilization of cogeneration and small power production facilities and to reduce reliance on fossil fuels." *Id.* at 17; *see Ind. Energy Producers Ass'n, Inc. v. Cal. Pub. Util. Commn.*, 36 F.3d 848, 854-55 (9th Cir. 1994) (holding that federal law preempted state commission rule that provided certain QFs with rate set at 80% or less of full avoided costs). To be in the public interest, PURPA rates must compensate QFs for the value of the full avoided costs.

Moreover, the requirement in Oregon's RPS to promote community-scale projects should not be ignored in this proceeding. *See* ORS 469A.210. At the time of docket UM 1129 and Order No. 05-584 implementing the bulk of the OPUC's current policies for small QFs, the Oregon legislature had not yet enacted Section 469A.210. *See* 2007 Or. Laws Ch. 301, § 24 (effective June 6, 2007); Amended by 2010 Or. Laws Ch.68, § 1 (effective March 18, 2010). To date, the OPUC has implemented no formal policies specifically addressing this provision of the RPS. "When asked in discovery, none of the utilities in this docket were able to explain any specific policies they have in place to meet this goal." CREA/100, Hilderbrand/6. The provision has been ignored.

Although 2025 is several years from now, the law specifically requires development of policies at this time. Reaching eight percent of load with projects under 20 MW cannot be achieve in a short time frame. For example, "To reach the 8% goal, PGE would need 200 aMW of projects sized under 20 MW." CREA/100, Hilderbrand/6. This would require would require "20 separate 10-MW projects with an unrealistically high capacity factor of 100%" or "approximately 600 MW of wind projects, which would be 60 different 10-MW projects." *Id.* PURPA is the only viable option for projects under 20 MW to sell renewable output to an Oregon electric utility. *See* CREA/100, Hilderbrand/7. These numbers would be unachievable if the eligibility cap is lowered to 3 MW, or less. This evidence cannot be ignored in favor of scaling back the OPUC's PURPA policies. Instead, the OPUC should build upon the existing policies, and address the issues that have arisen on the fringe of the OPUC's implementation in a manner that will limit disputes and further *encourage* QF development.

B. ISSUE 1. AVOIDED COST PRICE CALCULATIONS

ISSUE 1. A. WHAT IS THE MOST APPROPRIATE METHODOLOGY FOR CALCULATING AVOIDED COST PRICES?

Issue 1.A.i. Should the Commission retain the current method based on the cost of the next avoidable resource identified in the company's current IRP, allow an "IRP" method-based on computerized grid modeling, or allow some other method?

The OPUC should retain the general framework established in docket UM 1129. No compelling evidence exists to depart from those policies on this issue, as explained below.

a. The OPUC Should Retain the Current Method and Not Move to Computer Modeling for Any Avoided Cost Rates.

The OPUC should retain the current method for calculating standard rates based upon the avoided energy and capacity costs for the next avoidable resource in the IRP. CREA/200, Reading/2-9. The OPUC should reject proposals to adopt a computerized grid modeling methodology for calculating standard (for projects under 10 MW) or non-standard (for projects over 10 MW) avoided cost rates. In the words of the OPUC's Staff, "model-based approaches are not transparent to the QF developers and their lenders[,]" and "the results remain only as accurate as the forecasts and other inputs." Staff/100, Bless/9. It is especially important not to adopt a model based approach for small QFs under 10 MW because they will lack the resources to negotiate complex modeling and inputs with a utility. *See* CREA/100, Hilderbrand/11-12.

b. The OPUC Should Not Adopt Idaho Power's Single Run Methodology for Any Purpose.

Even if the OPUC adopts a modeling method for non-standard rates, the OPUC should reject Idaho Power's "single run" methodology. CREA/200, Reading/4-7. This methodology pretends that, unlike utility-owned plants, QF output cannot support off-system sales and thereby "ignores the full value QFs contribute." CREA/200, Reading/5. Thus QFs ineligible for standard rates "would not only need to negotiate rates with the utility, but they would also be guaranteed a rate that does not pay the full avoided costs." CREA/200, Reading/7; *see also* Staff/200, Bless/12 (agreeing with CREA on this point).

Idaho Power claims that PURPA's avoided cost definition does not "provide for the value associated with off-system sales of QF generation." *Idaho Power Prehearing Brief* at 9. This argument misunderstands the avoided cost rule. "Avoided costs mean the incremental cost to an electric utility of electrical energy or capacity or both which, *but for the purchase from the qualifying facility* or qualifying facilities, such utility would generate itself or purchase." 18 C.F.R. § 292.101(6) (emphasis added). FERC directly endorsed the double-run methodology that Idaho Power now argues is inconsistent with FERC's avoided cost rule. *See* Order No. 69, 45 Fed. Reg. at 12,216. A utility cannot calculate the total costs associated with a change in its resource portfolio without considering the impact of the new resource on the utility's off-system sales. *See* CREA/200, Reading/4-7. This is particularly true for Idaho Power because it relies heavily on off-system sales. *See id.* at 5. The single-run methodology will under-compensate any QF subjected to it, and it should not be adopted.

Issue 1.A.ii. Should the methodology be the same for all three electric utilities operating in Oregon?

CREA supports using the same methodology for all three Oregon utilities. This would allow for simplicity and ease of review. But if Idaho Power is permitted to use its Idaho PUC rules for consistency, those rules should only apply to Idaho Power. CREA/200, Reading/9.

ISSUE 1. B. SHOULD QFS HAVE THE OPTION TO ELECT AVOIDED COST PRICES THAT ARE LEVELIZED OR PARTIALLY LEVELIZED?

The OPUC should provide QFs the option to elect levelized pricing. *See* CREA/200, Reading/9-12; CREA/400, Hilderbrand/1-4. Unlike when this issue was raised but not addressed in 2005, sufficiency periods proposed at this time would extend up to six years in length and include prices that are at times *zero* or *even negative*. CREA/400, Hilderbrand/2. Because lenders require QFs to meet strict debt coverage ratios even in the early years of a project, these proposed sufficiency periods "will most likely stop any small community QF projects in Oregon – unless there is the option for levelized pricing." CREA/400, Hilderbrand/4. FERC specifically recognized this potential problem when it first promulgated its avoided cost rules, and specifically endorsed the use of levelized pricing "to match more closely the schedule of debt service of the facility." Order No. 69, 45 Fed. Reg. at 12,224. "During periods with a lengthy surplus period, levelization would allow QFs to build smaller increments of capacity on the system during that surplus period while leaving ratepayers indifferent over the life of the contract." CREA/200, Reading/12.

Levelized pricing is a critical issue. It presents the OPUC with the opportunity to build upon the policies implemented in docket UM 1129. In the years since levelization was last raised in Order No. 05-584, the Oregon legislature has enacted legislation that requires the OPUC to establish policies designed to achieve the eight percent goal for community-scale projects under 20 MW. *See* ORS 469A.210. The un-rebutted evidence establishes that the currently proposed sufficiency periods will prevent development of QFs under 20 MW. The OPUC should implement levelized pricing to address this problem.

ISSUE 1. C. SHOULD QFS SEEKING RENEWAL OF A STANDARD CONTRACT DURING A UTILITY'S SUFFICIENCY PERIOD BE GIVEN AN OPTION TO RECEIVE AN AVOIDED COST PRICE FOR ENERGY DELIVERED DURING THE SUFFICIENCY PERIOD THAT IS DIFFERENT THAN THE MARKET PRICE?

The OPUC should allow QFs renewing a contract to receive the full deficiency period rates in a follow-on contract. CREA/200, Reading/13. "An existing QF's capacity would have already been included in the utility's load and resource balance and could not be considered surplus power." *Id.* (quoting the Idaho PUC). Even Idaho Power implicitly agrees with the merit of this proposal by supporting its use for Idaho Power, despite not supporting several other Idaho PUC policies. Idaho Power/400, Stokes/24; *see also* CREA/200, Reading/12.

ISSUE 1. D. SHOULD THE COMMISSION ELIMINATE UNUSED PRICING OPTIONS?

CREA supports removal of the schedules for the gas market and banded gas market indexed options, so long as these options are available by request. CREA/200, Reading/13-14.

C. <u>ISSUE 2. RENEWABLE AVOIDED COST PRICE CALCULATION</u>

ISSUE 2. A. SHOULD THERE BE DIFFERENT AVOIDED COST PRICES FOR DIFFERENT RENEWABLE GENERATION SOURCES? (FOR EXAMPLE DIFFERENT AVOIDED COST PRICES FOR INTERMITTENT VS. BASE LOAD RENEWABLES; DIFFERENT AVOIDED COST PRICES FOR DIFFERENT TECHNOLOGIES, SUCH AS SOLAR, WIND, GEOTHERMAL, HYDRO, AND BIOMASS.)

The renewable avoided cost rates should be adjusted upwards during the deficiency period to compensate those renewable QFs who allow the utility to partially or fully avoid the costs of integrating renewable power from the avoided large utility wind plant. CREA/300, Svendsen/3-7. PacifiCorp's proposal to not to make an upward adjustment would be an illegal failure to compensate renewable QFs for the full avoided costs. *See* CREA/302. An upward adjustment should apply to baseload QFs, solar QFs, and even wind QFs that are too small to impose significant integration costs or that contract with a third party or a transmission provider to integrate their output prior to delivery to the utility. CREA/300, Svendsen/5-7.

ISSUE 2. B. HOW SHOULD ENVIRONMENTAL ATTRIBUTES BE DEFINED FOR PURPOSES OF PURPA TRANSACTIONS?

The definition should specify that the renewable QF conveys RECs necessary for compliance with Oregon's RPS during the deficiency period, but retains any remaining environmental attributes such as greenhouse gas offsets. CREA/300, Svendsen/7-11. At all other times, QF contracts should specify that the QF retains all environmental attributes. *Id.* PGE and PacifiCorp do not dispute this approach. *See* PAC/400, Griswold/2; PGE/300, Macfarlane-Morton/2; *PGE Prehearing Brief* at 6 n.1.

ISSUE 2. C. SHOULD THE COMMISSION AMEND OAR 860-022-0075, WHICH SPECIFIES THAT THE NON-ENERGY ATTRIBUTES OF ENERGY GENERATED BY THE QF REMAIN WITH THE QF UNLESS DIFFERENT TREATMENT IS SPECIFIED BY CONTRACT?

The OPUC should not amend the regulation. Renewable QF contracts can require the renewable QF to convey RECs to the utility, and QFs choosing to sell at the non-renewable rates should continue to retain all environmental attributes. CREA/300, Svendsen/11-12. PGE and PacifiCorp agree. *See* PAC/400, Griswold/2; PGE/300, Macfarlane-Morton/2. Idaho Power is the only party to recommend otherwise, and there is no logical or legal basis for its proposal to assign RECs to the utility while paying the QF a non-renewable rate.

a. Idaho Power Identifies No Logical Reason to Change the OPUC's Policy.

For non-renewable rates, the OPUC already concluded QFs retain the RECs because "rates based on avoided costs do not include compensation for any social and environmental benefits that may be associated with a particular facility's generation of electricity." *In Re Rulemaking to Adopt and Amend Rules Related to Ownership of the Non-energy Attributes of Renewable Energy (Green Tags), Energy Service Supplier Certification Requirements, and Use of Terms "Electric Utility" and "Electric Company,"* Oregon PUC Case No. AR 495, Order No. 05-1229, at 8 (2005). The OPUC was correct. FERC recently declared a state commission "cannot, consistent with PURPA, assign ownership of the RECs to the Utilities on the grounds that the avoided cost rates in their PURPA PPAs compensate the QFs for RECs in addition to energy and capacity." *See Morgantown Energy Assoc.*, 140 FERC ¶ 61,223, at P 24 (2012), *deny'g recon.*[1] Idaho Power has not demonstrated that the facts have changed since the OPUC established its perfectly logical and legal policy on REC ownership.

b. Idaho Power's Alternative REC Proposal Lacks Evidentiary Support.

In an apparent concession that its initial proposal was misguided, Idaho Power now proposes that a QF eligible for standard rates may retain its RECs, but to sell under non-standard rates a QF must assign 50 percent of their RECs to the utilities. *See Idaho Power's Prehearing Brief* at 2, 10. This recommendation lacks any logical or evidentiary support. There is no material distinction between the calculation of Idaho Power's standard and non-standard rates that would justify a difference in REC ownership. Both rates are currently calculated utilizing the proxy method. Neither rate provides QFs with compensation for the costs of compliance with Oregon's RPS like the OPUC's renewable avoided cost rates.

Moreover, there is no basis for distinction between standard and non-standard rates even if Idaho Power's single-run modeling methodology were adopted for non-standard rates because the rate would not be calculated on the assumption that 50 percent of the avoided generation would provide Idaho Power with RECs. As Idaho Power explains, its single-run proposal attempts to model the cost of the next incremental unit of hourly generation. *See Idaho Power's Prehearing Brief* at 8 n.31. This includes generation already in its resource stack, such as

[1] The *Morgantown Energy Assoc.* decision addressed a different situation from where the avoided cost rate is based upon the costs of a renewable resource, such as in the OPUC's renewable avoided cost rate. CREA agrees that the QF choosing the renewable rates should convey the RECs to the utility during the deficiency period. This is consistent with FERC's determination that a state utility commission may create a separate avoided cost rate for QFs enabling a utility to avoid costs associated with a resource procurement requirement, such as Oregon's RPS. *Calif. Pub. Util. Commn.*, 133 FERC ¶ 61,059 (2010), *order grant'g clarif. and dismissing reh'g*, *rehearing denied* by134 FERC ¶ 61,044 (2011).

Company-owned thermal resources, incremental costs associated with longer-term market purchases, and the incremental costs of market purchases. *Id.* Idaho Power does not assert that 50 percent (or indeed any percent) of these resources provide Idaho Power with RECs. The avoided costs of backing down a coal or gas plant do not compensate QFs for RECs, and Idaho Power has failed to identify any long-term contract conveying it RECs that factors into this analysis. Because there is no evidence that non-standard rates compensate QFs for anything other than energy and capacity, Idaho Power's proposal lacks merit.

c. Approving Idaho Power's REC Proposal Would Result in an Illegal Taking.

Assigning 50 percent of a QF's RECs to Idaho Power while only compensating the QF for energy and capacity would amount to an unconstitutional taking. *See* Oregon Const., Art. I, § 18; U.S. Const. Amend. V, Cl. 4. Idaho Power's apparent purpose for obtaining 50 percent of the non-standard QFs' RECs free of charge is to reduce the costs of compliance with any future RPS by obtaining RECs for free. But the purpose of the Takings Clause is to prohibit the "Government from forcing some people alone to bear public burdens which, in all fairness and justice, should be borne by the public as a whole." *Armstrong v. U.S.,* 364 U.S. 40, 49 (1960).

RECs are a compensable property interest because the Takings Clause "is addressed to every sort of interest the citizen may possess." *U.S. v. Gen. Motors Corp.*, 323 U.S. 373, 378 (1945); *see also Ruckelshaus v. Monsanto Co.,* 467 U.S. 986, 1003-04 (1984) (intangible trade secret property); *Members of the Peanut Quota Holders Ass'n v. U.S.*, 421 F. 3d 1323, 1332 (Fed. Cir. 2005) (government issued peanut quotas). And as FERC has determined, a state commission "cannot, consistent with PURPA, assign ownership of the RECs to the Utilities on the grounds that the avoided cost rates in their PURPA PPAs compensate the QFs for RECs in addition to energy and capacity." *Morgantown Energy Assoc.*, 140 FERC ¶ 61,223, at P 24. It therefore follows that, if the OPUC were to adopt and enforce Idaho Power's proposal, the OPUC would cause a physical taking of 50 percent of the QF's RECs by assigning them to Idaho Power for *no compensation*. The Takings Clause prohibits this without just compensation. *See Loretto v. Teleprompter Manhattan CATV Corp.*, 458 U.S. 419, 438-39 (1982); *Kimball Laundry Co. v. U.S.,* 338 U.S.1, 12-13 (1949).

Idaho Power may point to a string of cases from Connecticut as support for its proposal. *See Wheelabrator Lisbon, Inc. v. Connecticut Dept. of Pub. Util. Control*, 531 F.3d 183 (2nd Cir. 2008). These cases are off-point. In these cases, the waste-to-energy QF at issue entered into a PURPA PPA in 1991. *Id.* at 186. "In 2002, the specific credits at issue . . . became marketable by the creation of a market for such credits pursuant to the laws of several states, including Connecticut." *Id.* Based on construction of the 1991 contract, the Connecticut Supreme Court concluded that the 1991 contract assigned REC ownership to the utility, and therefore the state commission's decision did not constitute a taking in violation of the state constitution. *Wheelabrator Lisbon, Inc. v. Dept. of Pub. Util. Control,* 931 A.2d 159, 176-77 (Conn. 2007). The federal district court likewise rejected a challenge under the Takings Clause on the ground that the Connecticut RECs "were created after the parties entered into the [contract]." *Wheelabrator Lisbon, Inc. v. Connecticut Dept. of Pub. Util. Control*, 526 F.Supp.2d 295, 307 (D. Conn. 2006).[2]

In stark contrast, Oregon law states that RECs belong to the QF if the QF is selling pursuant to a contract that pre-dates Oregon's RPS. *See* ORS 758.552. And with regard to new

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2 The Second Circuit did not address the takings issue. *Wheelabrator Lisbon, Inc.*, 531 F.3d 183. *See also City of New Martinsville v. Pub. Serv. Commn. of W. Va.*, 729 S.E.2d 188, 197 n.13 (W.Va. 2012) (concluding no taking occurred in determination of ownership of RECs in contract pre-dating creation of RECs).

QF contracts, there is no dispute that RECs exist today, and that Idaho Power's non-standard rates *do not compensate QFs for RECs*. FERC has stated, "while a state may decide that a sale of power at wholesale automatically transfers the ownership of the state-created RECs, that requirement must find its authority in state law, not PURPA." *Morgantown Energy Assoc.*, 140 FERC ¶ 61,223 at P 24 (emphasis added). Oregon's RPS does not proclaim that a sale of RPS compliant electricity at wholesale automatically transfers ownership of Oregon RECs. In fact, existing Oregon law and regulation states just the opposite with regard to QF sales. Requiring QFs to gift 50 percent of the RECs to utilities as a precondition to exercise their right to sell QF energy and capacity at the full avoided cost rates is therefore a taking.

In short, in the eleventh hour of this proceeding, Idaho Power has asked the OPUC to simply adopt the Idaho PUC's reasoning. That would be a mistake. The OPUC has its own independent PURPA duties and should not simply adopt another state's illegal policy on RECs.

D. ISSUE 3. SCHEDULE FOR AVOIDED COST PRICE UPDATES

ISSUE 3. A. SHOULD THE COMMISSION REVISE THE CURRENT SCHEDULE OF UPDATES AT LEAST EVERY TWO YEARS AND WITHIN 30 DAYS OF EACH IRP ACKNOWLEDGEMENT?

Generally speaking, the utilities control the filing of any price updates, and the OPUC should therefore ensure that whatever schedule is adopted is fair and predictable to create a "settled and uniform climate" for QFs. *See* ORS 758.515(3); CREA/100, Hilderbrand/7-11. CREA supports proposals to supplement the full updates occurring after IRP acknowledgement with an annual update limited to gas prices, market prices, new loads and contracts in excess of four years, *and* the status of production tax credit. CREA/400, Hilderbrand/4; Staff/200, Bless/23; One Energy/200, Eddie/5. This is fair and predictable.

ISSUE 3. B. SHOULD THE COMMISSION SPECIFY CRITERIA TO DETERMINE

WHETHER AND WHEN MID-CYCLE UPDATES ARE APPROPRIATE?

The OPUC should specify transparent criteria of a year from the last update or a set date each year to provide predictability. *See* CREA/400, Hilderbrand/4; Staff/200, Bless/23.

ISSUE 3. C. SHOULD THE COMMISSION SPECIFY WHAT FACTORS CAN BE UPDATED IN MID-CYCLE? (SUCH AS FACTORS INCLUDING BUT NOT LIMITED TO GAS PRICE OR STATUS OF PRODUCTION TAX CREDIT.)

The OPUC should not implement mid-cycle updates beyond the annual updates proposed in Issue 3.A. PacifiCorp asks the OPUC to allow it to conduct mid-cycle updates in addition to annual updates. *See PacifiCorp's Prehearing Brief* at 7. This proposal cuts against Oregon law's directive that the OPUC create a "settled and uniform institutional climate for qualifying facilities in Oregon." ORS 758.515(3). The sufficiency and deficiency periods already create a large opportunity for utility gaming to ensure that rates remain lower than true avoided costs, and mid-cycle updates allow for further gaming and more disputes between unexpected rate changes. The OPUC should only allow a single annual update outside of the two-year cycle.

ISSUE 3. D. TO WHAT EXTENT (IF ANY) CAN DATA FROM IRPS THAT ARE IN LATE STAGES OF REVIEW AND WHOSE ACKNOWLEDGEMENT IS PENDING BE FACTORED INTO THE CALCULATION OF AVOIDED COST PRICES?

CREA agrees with Staff that the OPUC should only allow for use of acknowledged IRPs or *acknowledged* IRP updates. *See* Staff/200, Bless/23.

ISSUE 3. E. ARE THERE CIRCUMSTANCES UNDER WHICH THE RENEWABLE PORTFOLIO IMPLEMENTATION PLAN SHOULD BE USED IN LIEU OF THE ACKNOWLEDGED IRP FOR PURPOSES OF DETERMINING RENEWABLE RESOURCE SUFFICIENCY?

CREA has no specific position on this issue.

E. <u>ISSUE 4. PRICE ADJUSTMENT FOR SPECIFIC QF CHARACTERISTICS</u>

ISSUE 4. A. SHOULD THE COSTS ASSOCIATED WITH INTEGRATION OF INTERMITTENT RESOURCES (BOTH AVOIDED AND INCURRED) BE INCLUDED

IN THE CALCULATION OF AVOIDED COST PRICES OR OTHERWISE BE ACCOUNTED FOR IN THE STANDARD CONTRACT? IF SO, WHAT IS THE APPROPRIATE METHODOLOGY?

The OPUC should not accept the utilities' one-sided proposal to reduce the standard avoided cost rates to account for wind integration. Additionally, the OPUC should apply any wind integration charge *only in conjunction* with other policies that require inclusion of benefits provided by small QFs in the rates, and should ensure such a charge is implemented in a manner that complies with legal requirements and avoids potential disputes.

a. The OPUC Would Be Well Within Its Discretion to Maintain Its Existing Policy.

In docket UM 1129, the OPUC reached a logical conclusion that it would require calculation of standard rates in the aggregate, and overlook certain project-specific costs and benefits that may exist. *See, e.g., In Re Staff's Investigation Related to Electric Utility Purchases from Qualifying Facilities*, OPUC Docket No. UM 1129, Order No. 05-584, 38-39 (2005). The record in this proceeding does not compel the OPUC to abandon this policy for small QFs (under 10 MW). PacifiCorp itself argues "QF-specific or resource-specific adjustment to standard avoided costs, which undermine the purposes and advantages of standard rates, should generally be avoided." *PacifiCorp's Prehearing Brief* at 3. Apparently, the utilities only endorse "resource-specific" adjustments if doing so results in a lower rate. Their approach is unfair.

Additionally, the utilities have not demonstrated that small QFs impose the same integration costs as a large utility wind plant. *See* CREA/200, Reading/14-17. At least one Northwest utility that has studied the issue has concluded that smaller, dispersed projects impose lower wind integration costs on a utility. CREA/200, Reading/16. The utilities are unable to provide a study concluding to the contrary. Apparently they have not studied the issue. In sum, small QFs are not compensated for many project-specific benefits under the existing framework or under the framework proposed by the utilities. For these reasons, the OPUC would be well within its discretion to reject implementation of a wind integration charge for small QFs.

b. The OPUC Should Not Implement Wind Integration for Standard Rates Without Also Ensuring Standard Rates Account for Aggregate Benefits.

In the alternative, if the OPUC implements an integration charge for small QFs, the OPUC can only ensure that small QFs are compensated at the *full* avoided costs by implementing upward adjustments to the standard rates to fully account for many benefits small QFs provide (discussed below in Issues 4. C.). As noted above, the problem with the proposal to isolate and apply wind integration charges to small QFs is that it cuts against the conscious decision in docket UM 1129 to calculate rates in the aggregate and overlook granular individual costs *as well as benefits* of small QFs. *See, e.g., In Re Staff's Investigation Related to Electric Utility Purchases from Qualifying Facilities*, Order No. 05-584 at 38-39. The OPUC's standard rates fail to account for many characteristics that would *increase* avoided cost rates for small projects. *See, e.g.,* CREA/200, Reading/14-16, 23-28; CREA/300, Svendsen/14-17; One Energy/200, Eddie/1-2. Without implementing adjustments for these aggregate benefits, the utilities' one-way adjustment would arbitrarily decrease the avoided cost rates below any reasonable estimate of the full avoided costs.

c. A Wind Integration Charge Should Not Apply to Solar QFs.

Any integration charge should not apply to solar QFs. RNP/100, Lindsay/8-9. The record contains no credible evidence that supports using wind integration as a proxy for solar integration. And the utilities have conducted no solar integration studies. The utilities' current levels of solar penetration are far too low to support the conclusion that solar QFs will impose integration costs. *See, e.g.,* RNP/100, Lindsay/9. The only evidence in the record of a solar integration study utilizing actual solar data indicates that the solar integration cost is 18 percent of a wind integration cost. *See id.* (discussing Bonneville Power Administration's solar integration study). Reducing the avoided cost rates with a hypothetical and over-inflated solar integration cost would violate PURPA's full avoided cost rule.

d. Any Wind Integration Charge Must be Properly Reviewed.

If the OPUC adopts a wind integration charge for standard rates, the OPUC will need to ensure that the wind integration reduction is accurately calculated. Oregon law requires that the integration charge, along with all other components of avoided cost rates, "shall be reviewed and approved by the Commission." ORS 758.525(1). The record indicates, however, that the utilities have become accustomed to evading a meaningful review of their integration charges. RNP/100, Lindsay/10-17. For example, Idaho Power claims its "wind integration study provides a robust evidentiary support for Idaho Power's proposed wind integration charge." *Idaho Power's Prehearing Brief* at 11. But the record reflects "major methodological flaws" with Idaho Power's wind study, RNP/100, Lindsay/14-15, and even demonstrates that third-party input was an afterthought. *See* CREA/501 (containing input from the third-party technical review panel after completion of the wind study and even after the initiation of this proceeding). Allowing the utility to unilaterally calculate the rate in an Integrated Resource Plan ("IRP") or elsewhere without meaningful review does not meet the requirements of ORS 758.525(1).

e. Any Wind Integration Charge Should Be Properly Implemented.

There are also several implementation issues that should be properly addressed with regard to any wind integration charges that may apply to standard rates. First, any wind integration charge should be reduced for partially or fully integrated QF wind deliveries. This would appropriately provide small wind QFs with the opportunity to secure balancing services (or even storage services) from third parties in a more cost effective manner than the utilities may estimate in wind studies. *See* CREA/200, Reading/16-17; CREA/300, Svendsen/5.

However, CREA strongly urges the OPUC not to adopt a policy that any QF *must* secure wind balancing services from its balancing authority area ("BAA") to be entitled to a PURPA contract, as Staff initially proposed. Staff/100, Bless/27. This would violate PURPA because a utility may not require QFs delivering "non-firm" wind output to "firm" their output as a precondition to receive a contract containing fixed, long-term rates. *See Exelon Wind 1, LLC v. Smitherman*, Case No. A-09-CA-917-SS, 2012 Westlaw 4465607 at ** 8, 10-12 (W.D. Tex. Sept. 25, 2012), *appeal pending*. The OPUC should not violate PURPA in this manner.

Additionally, a requirement to separately secure balancing services in order to sell under PURPA may even defeat a QF's federal right to sell power altogether because the QF cannot always secure such services from a third party. CREA/400, Hilderbrand/6-7. This would be particularly so if the QF were directly connected to the purchasing utility. Under that circumstance, the QF may need to separately secure balancing services from the purchasing utility's transmission function, even though the QF has no direct relationship with the purchasing utility's transmission function. *See id.* There would inevitably be disputes between the QF and the purchasing utility over this new step in the process. In fact, the QF's attempt to require the purchasing utility to provide balancing services through its transmission function is the crux of the dispute in the ongoing *PaTu Wind Farm, LLC v. Portland General Electric Co.* complaint proceeding in docket UM 1566, albeit in the context of an off-system QF sale. Staff's proposal would make this same dispute likely in the context of QFs directly interconnected to the purchasing utility, which is the vast majority of intermittent QFs. *See* PAC/300, Dickman/29 (noting that PacifiCorp purchases from no off-system wind QFs). In the words of PacifiCorp's witness, "I see no advantage to the added complexity." PAC/300, Dickman/29.

Although Staff appears to have modified its initial proposal, Staff's revised proposal is still problematic because it appears to adjust avoided cost rates downward even if the wind QF purchases integration services from a third party and thus delivers a balanced product. Staff/200, Bless/14; Staff/201, Bless/2. It also focuses on charges the BAA would assess to the off-system QF in calculating the avoided cost rates. Staff/201, Bless/2. This is the wrong approach because the charges by a transmission provider or BAA to a QF are irrelevant to the purchasing utility's avoided costs. The relevant costs under PURPA are the costs avoided by the purchasing utility – here, the costs avoided by the QF's delivery of a balanced product.

The best implementation approach already exists. If wind integration will apply to standard contracts, the OPUC should use the approach adopted in UM 1129 for large QFs. CREA/400, Hilderbrand/7. Large QFs have the option of using the purchasing utility's estimated wind integration costs as a fixed reduction to the avoided cost rates, *or* agreeing in the contract to secure such services from a third party and receiving no reduction to the avoided cost rates. *In Re Staff's Investigation Related to Electric Utility Purchases from Qualifying Facilities*, OPUC Docket No. UM 1129, Order No. 07-360, 24-25 (2007). This flexible principle could apply to the variety of potential delivery and balancing options.

f. The OPUC Should Determine that Changes to Pricing Policy Apply Only Prospectively to Future QF Contracts.

Finally, PURPA prohibits implementation of any integration charge for any small QF with an existing legally enforceable obligation. 16 U.S.C. § 824a-3(e). "Congress did not intend to impose traditional ratemaking concepts on sales by qualifying facilities to utilities." *Amer. Paper Institute, Inc.*, 461 U.S. at 414. Thus the rates in a QF's long-term PPA are not subject to later revision for changed circumstances – such as increased wind integration costs. *See Or. Trail Elec. Consumers Co-op, Inc. v. Co-Gen Co.*, 7 P.3d 594, 604-06 (Or. App. 2000). PURPA prohibits a state commission or a utility from unilaterally adjusting the rates in a fixed price QF contract, or otherwise adjusting the compensation paid to the QF under the contract. *See Idaho Wind Partners 1, LLC*, 140 FERC ¶ 61,219, at PP 40-41 & n.42 (2012).

ISSUE 4. B. SHOULD THE COSTS OR BENEFITS ASSOCIATED WITH THIRD PARTY TRANSMISSION BE INCLUDED IN THE CALCULATION OF AVOIDED COST PRICES OR OTHERWISE ACCOUNTED FOR IN THE STANDARD CONTRACT?

This issue presents two distinct issues. First, if the proxy resource is an off-system resource, the avoided cost rates should be adjusted upwards to account for the avoided third-party transmission costs. Second, the OPUC should resolve the issue of how to treat third-party transmission costs incurred to move output from one part of PacifiCorp's system to another part of its system (the "load pocket" issue) by rejecting PacifiCorp's proposed Advice No. 11-011.

a. If the Avoided Resource Is Off-System, the Avoided Cost Rates Must Include the Full Avoided Costs for Third-Party Transmission.

A state commission may include the costs of avoided transmission in calculation of the avoided cost rates. *Calif. Pub. Util. Commn.*, 133 FERC ¶ 61,059, P 31 (2010). PURPA requires QFs to pay for third-party transmission costs to deliver their output to the purchasing utility's system. *See* 18 C.F.R. § 292.303(d). When the utility purchases from a QF, therefore, the utility avoids any transmission costs associated with delivery from its avoided generation resource to its system. For PGE and PacifiCorp, the avoided cost rate calculation should include an avoided third-party transmission cost adder because these utilities commonly build resources off-system. CREA/200, Reading/19-20; CREA/300, Svendsen/12-15. That PGE already includes third-party transmission as a component of its avoided costs underscores this point.

PacifiCorp's claim that its resources will always directly connect to its system overlooks that PacifiCorp has multiple gas-fired and wind-powered non-QF resources that require PacifiCorp to pay for third-party transmission just to get the output to PacifiCorp's system. *See* Tr. at 66, 90-91. Although PacifiCorp also has on-system resources, the OPUC should not take PacifiCorp's representations at face value in calculating avoided cost rates. PacifiCorp should identify a location for its proxy resources and explain how that location affects third-party transmission costs and other factors, further discussed in Issue 4C below.

Additionally, as with other components of the avoided cost rates, ORS 758.525(1) requires the OPUC to thoroughly review the utility's calculation of its avoided third-party transmission costs. PGE's estimate is unrealistically low. CREA/300, Svendsen/14-15. The OPUC should require both PGE and PacifiCorp to include reasonable assumptions.

b. The OPUC Should Reject PacifiCorp's "Load Pocket" Proposal.

Distinct from the costs to get QF or non-QF output to the utility's system, this issue addresses how to account for the costs of third-party transmission necessary to move power from the initial point of delivery on PacifiCorp's system to PacifiCorp's load. Because of the disparate nature of PacifiCorp's multi-state system, PacifiCorp relies on third-party transmission to move power around its various "load pockets." *See* CREA/200, Reading/17-20; CREA/202. PacifiCorp's proposal to assign these costs to QFs would violate PURPA and lead to disputes.

i. PacifiCorp's proposal would violate PURPA by failing to compensate QFs for the full avoided costs.

PURPA requires that costs incurred at the avoided resource should be included in the avoided cost rates if they are a cost for which the QF would be responsible under a PURPA contract. PacifiCorp's proposal turns this principle on its head by attempting to assign costs to a

QF without accounting for those actual avoided costs in the calculation of the avoided cost rates.

PacifiCorp is incorrect to claim that its avoided resources would not use third-party transmission to move power from the initial point of delivery to PacifiCorp's loads. PacifiCorp evasively stated in discovery that PacifiCorp's three gas-fired plants with a direct interconnection to PacifiCorp do not use third-party transmission under "system normal operating conditions." Tr. at 66:8 – 67:20; CREA/202, Reading/1-2.[3] Although PacifiCorp's witness testified not to know what "normal operating conditions" means, Tr. at 67:12, the record reflects that even directly connected gas-fired plants on PacifiCorp's system require third-party transmission during certain times. PacifiCorp admitted the "costs of third party transmission services were included in the three referenced gas plants resource evaluations." Tr. at 72:21 - 73:10; CREA/503 at 6.

Yet PacifiCorp's avoided cost rate ignores this cost and includes "simply the cost to interconnect and doesn't include the cost past the point of interconnection." Tr. at 58:20-22; CREA/503 at 4. Furthermore, PacifiCorp's witness testified that QFs would be assigned the full costs of firm, third-party transmission even if that transmission would not be needed during "normal operating conditions" but only for perhaps as little as 15 hours per year. Tr. at 63:20 - 64:11. Thus PacifiCorp would require QFs to pay for third-party transmission associated with "load pockets," but ignore that cost in the avoided cost rate calculation. PacifiCorp's proposal therefore violates FERC's avoided cost rule. If PacifiCorp assigns to small QFs the cost of third-party transmission associated with "load pockets," it is an avoided cost that PacifiCorp must

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[3] PacifiCorp's only other two gas-fired plants actually use third-party transmission just to get any output to PacifiCorp's system, as noted above. Thus each of PacifiCorp's five gas-fired plants impose some amount of third-party transmission costs on PacifiCorp's customers.

include in the calculation of all standard avoided cost rates.[4]

The easiest solution, however, is to reaffirm the OPUC's existing policy on this point. In docket UM 1129, the OPUC implicitly assumed that the costs associated with load pockets are a project specific detail that balances out in the aggregate for standard rates. The record in this case confirms that failure to account for load pocket transmission costs as a cost adder in the standard avoided cost calculation balances out with the limited circumstances where a small QF imposes an essentially de minimis amount of third-party transmission costs on PacifiCorp. *See* Tr. at 94:8 - 95:9 (describing the "very small" proportional cost imposed by Three Mile Canyon). PacifiCorp itself claims that the circumstances where QFs will impose this cost are "very, very limited situations." Tr. at 107:20-21. The OPUC's current policy is therefore the best solution to the issue, particularly in light of the other shortcomings with PacifiCorp's proposal.

ii. PacifiCorp's proposal would violate PURPA by depriving all Oregon QFs of the right to lock in an avoided cost rate that is fixed throughout the term of the contract.

PURPA provides QFs with the right lock in long-term fixed avoided cost rates calculated at the time of the obligation. *See* 18 C.F.R. § 292.304(b)(5), (d)(2). FERC explained that the benefit of fixed rates is to provide "certainty with regard to return on investment." Order No. 69, 45 Fed. Reg. at 12,224. PacifiCorp's proposal violates this principle because, to be entitled to a PURPA contract with PacifiCorp, the QF would need to agree to be responsible for the ongoing and unfixed third-party point-to-point transmission costs. Tr. at 82:22 - 83:13; CREA/505 at 13. PacifiCorp's witness testified not to know if Bonneville Power Administration's ("BPA") transmission rates can change. Tr. at 83:21 - 84:13. But in reality transmission providers can

[4] This third-party cost component associated with load pockets would be in addition to any third-party transmission cost adders necessary to account for costs to deliver generation to the initial point of delivery on PacifiCorp's system.

implement significant transmission rate increases at any time. *See* 77 Fed. Reg. 66,966 (Nov. 8, 2012) (announcing BPA's ongoing transmission rate case).[5] PacifiCorp would assign this unfixed transmission cost to QFs. This violates QFs' rights to fixed rates.

Moreover, PacifiCorp's proposal repeals the right to certainty with regard to return on investment for every single Oregon small QF – not just those few QFs that would ultimately cause a need for third-party transmission. PacifiCorp's proposed tariff gives PacifiCorp the option of commencing the investigation into whether third-party transmission is necessary at the "*later of*" execution of the contract or the time the QF provides the necessary information to commence the investigation. Tr. at 75:23 – 78:24; CREA/505 at 4. The QF would have no right to ascertain if its project will be responsible for unfixed transmission costs prior to the time of contract execution. The standard rates are not fixed under this proposal. This would undermine the ability to finance PURPA contracts and repeal the availability of fixed-price standard rates.

iii. PacifiCorp's proposal would violate PURPA by requiring a QF to waive FERC's standards of conduct to exercise its PURPA rights.

PacifiCorp's proposal also frustrates the purpose of FERC's functional separation rules. To promote open access to interstate transmission, FERC adopted standards of conduct for transmission providers. *See Open Access Same–Time Information System and Standards of Conduct,* Order No. 889, FERC Stats. & Regs. ¶ 31,035, 61 Fed.Reg. 21,737 (1996), *on reh'g,* Order No. 889–A, FERC Stats. & Regs. ¶ 31,049, 62 Fed.Reg. 12,484 (1997), *on reh'g,* Order No. 889–B, 81 FERC ¶ 61,253 (1997); *see also* 18 C.F.R. § 358.5(b)(1), § 358.6. FERC intended its standard of conduct rules to limit the ability of utilities to abuse their vertical

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[5] In fact, FERC approved an increase in PacifiCorp's transmission rates on the same day as the hearing in this matter where PacifiCorp's witness testified that he did not know if transmission rates can increase. *See PacifiCorp*, 143 FERC ¶ 61,162 (May 23, 2013).

monopoly power to prevent their competitors from accessing electricity markets.

Yet PacifiCorp's witness admitted that the proposed tariff would require each Oregon QF to waive FERC's functional separation rules in order to have PacifiCorp conduct the "load pocket" study. Tr. at 82:5-20. Such a waiver is only necessary because PacifiCorp's proposed tariff requires the QF to pay for transmission studies and services on PacifiCorp's and third-parties' systems, but is designed to provide the QF with no right of direct contact with any transmission function personnel. *See* CREA/505 at 4-5. Instead, PacifiCorp's merchant function QF contract administrators submit and negotiate all transmission requests, studies, and contracts. The utility's QF contract administrator should not be a "go-between" for the QF and the provider of transmission services for which the QF will pay. And the OPUC should not condition the right to sell under PURPA on the QF's agreement to waive the protections of FERC's functional separation rules. This is a fatal design flaw in PacifiCorp's tariff.

iv. PacifiCorp's proposal would violate PURPA by assigning transmission costs beyond the point of delivery to the QF.

PURPA does not allow PacifiCorp to assign third-party transmission costs beyond the point of delivery to the QF. Staff and PacifiCorp misunderstand 18 C.F.R. § 292.303(d), which requires QFs to pay for third-party transmission costs up to the purchasing utility's system. This provision directly addresses the third-party transmission costs for which a QF is responsible, and it does not include third-party transmission costs beyond the point of delivery. Simply put, FERC's rules provide no basis for assigning such costs to QFs, particularly in this case where the avoided cost rates do not account for similar costs at the avoided resource.

v. PacifiCorp's proposed standard contract would result in disputes with any unsuspecting QFs who sign it.

Even if PacifiCorp's proposal complied with the threshold legal requirements (which it does not), the proposed tariff is so one-sided in PacifiCorp's favor that it will inevitably lead to disputes over unfair treatment and should be rejected as bad QF policy. For example, after the QF signs the standard contract and subsequently learns from PacifiCorp of the "load pocket" problem, the tariff imposes no obligation on PacifiCorp to negotiate a reasonable alternative solution to purchasing expensive third-party transmission through PacifiCorp. *See* CREA/505 at 5. Numerous other alternatives could exist, including limited curtailment rights or a less expensive form of transmission than firm point-to-point transmission. But the proposed standard contract purports to eliminate PacifiCorp's duty to "attempt to negotiate a mutually agreeable alternative solution." CREA/505 at 13. This appears to be an attempt to repeal the covenant of good faith and fair dealing that exists in every contract in Oregon. *See Morrow v. Red Shield Ins. Co.,* 159 P.3d 384, 388-89 (Or. App. 2007). Unsuspecting QFs will not expect such onerous terms in a Commission-approved agreement, and this will undoubtedly lead to disputes.

PacifiCorp's entire approach is unfair. PacifiCorp's witness testified that, although Company-owned gas-fired resources use third-party transmission, these Company-owned resources provide PacifiCorp the option of "backing down that resource instead of purchasing transmission." Tr. at 108:17-25. This rationalization only further highlights the bias against QFs. PacifiCorp could avoid purchasing transmission for QFs also if it would only agree to negotiate for curtailment rights instead of offering acquisition of firm transmission as the only solution in its tariff. The OPUC should not accept this illegal and unfair proposal.

ISSUE 4. C. HOW SHOULD THE SEVEN FACTORS OF 18 CFR § 292.304(E)(2) BE TAKEN INTO ACCOUNT?

The OPUC should implement FERC's seven factors in the aggregate for standard rates. Additionally, the OPUC should ensure that utilities properly account for all of the benefits of small QFs in the standard rates, particularly if the OPUC moves towards a wind integration charge with increasing granularity.

a. The Standard Rates Should Be Calculated in the Aggregate.

FERC's regulation allows for consideration of these factors in the aggregate and to the extent practicable. *See* 18 C.F.R. § 292.304(e)(2)(vi). For standard rates, the OPUC should apply the seven factors in the aggregate and should include reasonable adders for all components of the applicable avoided resource and deferral of "lumpy" utility investments. CREA/200, Reading/20-28; CREA/300, Svendsen/15-17. Utility complaints that Oregon QFs are not "dispatchable" are wholly unfounded because the Oregon avoided cost rates *do not pay QFs to be dispatchable*. *See* CREA/200, Reading/22. Furthermore, the utilities are *not* including proper assumptions for avoided transmission, avoided gas transportation and storage, avoided costs associated with deferring large utility investments, or avoided line losses for very small QFs (under 3 MW). CREA/200, Reading/17-20, 23-28; CREA/300, Svendsen/14-18; ODOE/400, Carver/6. These are avoided costs of QF generation that should be included in the rates.

b. PacifiCorp's Undervaluation of Its Renewable Avoided Costs Highlights the Need to Require Oregon Utilities to Fully Account for All Aggregate Avoided Costs in Standard Rates.

PacifiCorp's proposed renewable avoided cost rate severely under-values the avoided costs and demonstrates the need to fully scrutinize a utility's calculation of its avoided costs. PacifiCorp chose to site the hypothetical plant in Wyoming where capacity factors are high, but then proceeded to ignore the major costs specific to a Wyoming wind farm.

The first major flaw with the rate is that it ignores the taxes applicable to a Wyoming wind farm. PacifiCorp openly admitted that the rate failed to take into account Wyoming's five percent sales tax for wind farms and the $1 per MWh excise tax. Tr. at 50:21 - 53:17; One

Energy/411. PacifiCorp provided no substantive explanation for these significant errors that serve to under-value the aggregate costs that renewable QFs would allow PacifiCorp to avoid.

An even larger error is that PacifiCorp failed to account for well-documented transmission costs. *See* Tr. at 24:17 - 25:3 (admitting there were no "incremental transmission costs beyond the point of interconnection that were directly attributed to this proxy"); Tr. at 37:6-20; CREA/302, Svendsen/1. The OPUC's policy for small QFs is to require the QF to pay for all interconnection and transmission costs to the utility's system, and even transmission upgrades on the purchasing utility's system to get the output to the utility's load. *See* OAR 860-0082-0035(4); *see also* Tr. at 23:8-19.[6] Thus, despite PacifiCorp's position, any incremental transmission costs at the avoided wind farm in Wyoming must be included in the avoided cost rates just as interconnection costs are.

The OPUC should not accept PacifiCorp's position that it can build a large wind farm in its Aeolus wind bubble in Wyoming without incurring incremental transmission costs. PacifiCorp's own documents refute its claim by demonstrating that "the transmission infrastructure needs required to deliver the resource to adjacent network load bubbles is considered as part of [request for proposal] RFP evaluation." Tr. at 31:5-17;[7] CREA/503 at 10. According to PacifiCorp's witness, the purpose of considering transmission costs in an RFP is to "identify costs that would be required as a result of adding that generating resource at a particular location." Tr. at 31:24 - 32:3. PacifiCorp even estimated the transmission costs at the same

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6 This is distinct from the costs associated with third-party transmission between load pockets, which as noted above should not be the responsibility of any QFs because no provision of state or federal law directly assigns those costs to QFs, and they are not included in avoided cost rates.

7 Although PacifiCorp's witness speculated at the hearing that these costs in the RFP documents may have been interconnection costs, Tr. at 33:6-8, the RFP documents show that at some locations these costs were as high as $798 million and quite clearly listed necessary transmission upgrades. *See* CREA/503 at 43.

Aeolus bubble mentioned above in its 2009 and 2011 All Source RFPs, and assumed a 400 MW resource interconnecting at Aeolus would cost $160 million to $173 million in incremental transmission upgrades. *See* CREA/503 at 25, 43. Consequently, PacifiCorp assigned those costs to non-QF bidders attempting to compete against PacifiCorp's utility-owned proposals sited at other locations, such as PacifiCorp's Lakeside location, where transmission costs were lower. Tr. at 34:21-22. This evidence fully refutes PacifiCorp's position that incremental transmission costs are zero to deliver output from a large wind farm in Aeolus. *See* CREA/302, Svendsen/1.

Moreover, even when PacifiCorp included transmission costs in the IRP, PacifiCorp's numbers grossly understate the cost. In the IRP that generated the renewable wind proxy in Aeolus, PacifiCorp estimated it would cost BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL million in transmission costs to deliver 1500 MW of Aeolus wind to load. Conf. Tr. at 42:21- 43:21; Conf. One Energy/402. This is far less than the $173 million PacifiCorp assigned the much smaller 400 MW gas-fired resource at the same location in PacifiCorp's RFP. *See* CREA/503 at 25, 43. And even worse yet, PacifiCorp did not even include the underestimate from the IRP in its avoided cost calculation, where it included no incremental transmission costs. PacifiCorp's $173 million omission is very significant because the all-in costs in PacifiCorp's wind proxy were only approximately $400 million. Tr. at 52 (containing approximation); Conf. Tr. at 40:21-22 (containing exact figure).

PacifiCorp's wind proxy plant is a fiction that severely underestimates the avoided costs. The OPUC should see through the policy it began in Order No. 11-505 to allow for the addition of small increments of community-scale renewable generation to PacifiCorp's system in Oregon by fully accounting for *all* of the aggregate avoided costs in the renewable rates. And this example again highlights the need to fully scrutinize each utility's proposed avoided cost rates.

c. **Staff's Proposal to Differentiate Rates Based on Capacity Would Fail to Account for the Full Avoided Costs if Implemented as Proposed and Without Taking into Account Aggregate QF Benefits.**

The OPUC Staff has proposed to differentiate the capacity component of rates for small QFs. CREA opposes this proposal because of the complexity it inserts into calculation of standard rates. CREA/400, Hilderbrand/6; CREA/200, Reading/4. If the OPUC adopts this proposal, the OPUC should use the Effective Load Carrying Capability ("ELCC") method to ensure the avoided cost rates fully account for QF capacity. ODOE/100, Carver/7-8. Finally, as with other project-specific decrements to the rate, implementation of a capacity component to small QFs will result in under-compensation to small QFs if the OPUC does not also fully account for the avoided costs small projects provide in the aggregate, as described above.

F. ISSUE 5. ELIGIBILITY ISSUES

ISSUE 5. A. SHOULD THE COMMISSION CHANGE THE 10 MW CAP FOR THE STANDARD CONTRACT?

The OPUC should not lower the eligibility cap. CREA/100, Hilderbrand/11-13; CREA/200, Reading/28-30. The OPUC's 10-MW cap is entirely consistent with federal law and with the mandates that the OPUC "[i]ncrease the marketability of" QF energy and "[c]reate a settled and uniform institutional climate" for QFs. ORS 758.515(3). Lowering the cap would undermine QF development in Oregon. *See* ODOE/500, Elliott/3 (noting that several QFs under 10 MW funded by ODOE have unequivocally stated that they would not have built their QFs without standard contracts). Furthermore, the OPUC would fail to be implementing policies to ensure that Oregon meets eight percent of its electricity needs from small projects under 20 MW if it were to lower the cap. *See* CREA/100, Hilderbrand/5-7.

ISSUE 5. B. WHAT SHOULD BE THE CRITERIA TO DETERMINE WHETHER A QF IS A "SINGLE QF" FOR PURPOSES OF ELIGIBILITY FOR THE STANDARD

CONTRACT?

The OPUC should reject proposals to eliminate the passive investor exception in the Partial Stipulation because passive investors are an important component of community renewable energy projects. *See* CREA/100, Hilderbrand/13-16; *see also* PacifiCorp/202 (containing the Partial Stipulation). Idaho Power itself admits that the OPUC's five-mile separation rule largely mitigates the risk of widespread disaggregation. Idaho Power/200, Stokes/62 n.54. If the OPUC is concerned, any existing loophole could be closed by utilizing the Internal Revenue Service's ("IRS") definition of "passive investor." *See* CREA/400, Hilderbrand/9. Under IRS rules, a passive investor may not "materially participate" by way of involvement in the operations of the activity that is regular, continuous, and substantial. 26 U.S.C. § 469(c), (h)(1). Inserting this language into the Partial Stipulation would prevent a single entity from owning and operating more than one small QF within five miles of another, while still preserving the ability of more than one community-scale project to use the same passive investor. CREA reiterates that it remains willing to work with other parties to draft appropriate language, and it does not appear that the positions are that far apart.

ISSUE 5. C. SHOULD THE RESOURCE TECHNOLOGY AFFECT THE SIZE OF THE CAP FOR THE STANDARD CONTRACT CAP OR THE CRITERIA FOR DETERMINING WHETHER A QF IS A "SINGLE QF"?

Resource technology should not affect the size or criteria for the cap for the reasons stated above in Issue 5. B.

ISSUE 5. D. CAN A QF RECEIVE OREGON'S RENEWABLE AVOIDED COST PRICE IF THE QF OWNER WILL SELL THE RECS IN ANOTHER STATE?

A renewable QF should retain the right to dispose of its RECs in another state during the sufficiency period. CREA/100, Hilderbrand/17; PGE/400, Macfarlane-Morton/4.

G. ISSUE 6. CONTRACTING ISSUES

ISSUE 6. B. WHEN IS THERE A LEGALLY ENFORCEABLE OBLIGATION?

The OPUC should adopt a rule whereby QFs create a legally enforceable obligation ("LEO") by negotiating to a point of disagreement and then requesting that a utility file a disputed contract unexecuted with the OPUC for resolution. *See* CREA/100, Hilderbrand/18-19. This is the FERC policy for interconnection agreements that appropriately recognizes the parties may reach an impasse, and allows for preservation of the queue position by filing the utility's proposed agreement unexecuted for resolution of disputed issues. *Standardization of Generator Interconnection Agreements and Proc.*, Order No. 2003,104 FERC ¶ 61,103, P 240 (2003). By requesting that the contract be filed unexecuted, the QF would agree to be bound by the terms ultimately deemed reasonable by the OPUC, and thereby create a LEO.

The OPUC's existing administrative rule is illegal because it requires the utility's written agreement to create a LEO. *See* OAR 860-029-0010(29). FERC has emphasized that "the phrase legally enforceable obligation is broader than simply a contract between an electric utility and a QF and that 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." *Cedar Creek Wind, LLC*, 137 FERC ¶ 61,006, at P 36 (2011); *see also Grouse Creek Wind Park, LLC*, 142 FERC ¶ 61,187, at P 40 (2013). "[I]f the electric utility refuses to sign a contract, the QF may seek state regulatory authority assistance to enforce the PURPA-imposed obligation on the electric utility to purchase from the QF, and a noncontractual, but still legally enforceable, obligation will be created pursuant to the state's implementation of PURPA." *JD Wind 1, LLC*, 129 FERC ¶ 61,148, at P 25 (2009).

Although PacifiCorp's witness testified that CREA's proposed use of an unexecuted filing rule "lacks merit," PAC/400, Griswold/23:13, the same witness testified at the hearing that he is not even familiar with FERC's unexecuted filing policy. Tr. at 86:6-22. He also testified prior to the hearing that the OPUC's existing dispute resolution process is adequate, but evidence at the hearing proved that the dispute resolution process is not available for small QFs. Tr. at 86:23 – 89:1; CREA/506 at 2. Even if it were available, there is nothing in the dispute resolution process that entitles a QF to create a LEO prior to having the disputed terms resolved, which is the entire point of the unexecuted filing process. Instead, PacifiCorp proposes a process where a LEO could not be formed until "both parties agree to execution of the document" because the QF must agree to all terms in the contract drafted by PacifiCorp. Tr. at 85:9-10. This proposal has no meaningful distinction from the rules FERC found illegal. It precludes a QF from forming a LEO without agreeing to the utility's terms. In contrast, when a dispute arises, an unexecuted filing requirement allows the QF to create a LEO binding itself to terms to be set by the OPUC.

Finally, the OPUC should reject PGE's proposed rule that QFs be online within one year of forming a LEO because this would require many, or even most, QFs to commence construction prior to financing. CREA/100, Hilderbrand/19-20; CREA/200, Reading/31-35. This proposal, if adopted, would discourage QF development – especially for small projects.

ISSUE 6. E. HOW SHOULD CONTRACTS ADDRESS MECHANICAL AVAILABILITY?

Although CREA agrees with Three Mile Canyon that a MAG is unnecessary in this context, CREA urges the OPUC to adopt PacifiCorp's MAG for all three utilities if the MAG is retained. *See* CREA/100, Hilderbrand/20-29. PacifiCorp's proposed 90 percent availability requirement is far more reasonable for a small project than PGE's proposal to maintain its 95 percent level. *See id.* at 20-24. PGE's continued reliance on its ability to acheive high availability factors at its very large Biglow wind farm is without merit because availability becomes a significant problem later in a plant's life and is much riskier for small projects. *Id*.

Additionally, the OPUC should take steps to correct the MAG in PaTu Wind Farm, LLC ("PaTu") PPA, which is the only PPA executed with PGE's existing MAG. This MAG is commercially unreasonable and even purports to allow PGE to evade its mandatory purchase obligation by terminating PaTu's PPA for failure to achieve the onerous MAG in any single year. CREA/100, Hilderbrand/22-29. ODOE has even indicated that termination provisions will preclude it from financing QFs, ODOE/200, Elliott/6, and PGE itself proposes to move to a liquidated damages remedy unless the shortfall is severe or repeated. PGE/300, Macfarlane-Morton/23. The OPUC should direct PGE to renegotiate the PaTu MAG, or at least inform PGE that it would not be penalized in a rate recovery proceeding for agreeing to a more reasonable requirement for PaTu.

ISSUE 6. I. WHAT IS THE APPROPRIATE CONTRACT TERM? WHAT IS THE APPROPRIATE DURATION FOR THE FIXED PRICE PORTION OF THE CONTRACT?

The OPUC should not reduce the fixed-rate term to less than fifteen years, particularly since sufficiency periods can be up to six years in length. CREA/400, Hilderbrand/2-3. Instead, the OPUC should extend the fixed-rate term to twenty years or longer, especially for very small QFs. CREA/100, Hilderbrand/30; CREA/200, Reading/35-36; OneEnergy/200, Eddie/21-23 (concluding 25-year fixed rate may be necessary for financing of solar projects under 3 MW).

IV. CONCLUSION

The OPUC should build upon the policies developed in docket UM 1129 to begin to establish policies promoting Oregon's goal of serving eight percent of utility load with community renewable energy projects under 20 MW. For this and the other reasons explained above, CREA respectfully requests that the OPUC adopt the policies recommended herein.

RESPECTFULLY SUBMITTED this 17th day of June 2013.

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 17th day of June, 2013, a true and correct copy of the within and foregoing **POST-HEARING REPLY BRIEF OF THE COMMUNITY RENEWABLE ENERGY ASSOCIATION** was served as shown to:

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