BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

TECHNICAL CONFERENCE ON IMPLEMENTATION ISSUES UNDER THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978	)))))	**DOCKET NO. AD16-16-000**

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I'd like to thank the Commission for the opportunity to appear at the PURPA technical conference scheduled for June 29, 2016. These comments detail and align with the testimony I intend to present regarding the determination of avoided costs.

Renewable Resources and PURPA Projects

At the outset, it is important to understand some background on Idaho's renewable resources and our PURPA projects. Idaho is fortunate to have abundant and available renewable resources including: hydropower, geothermal, solar, wind, and even cogeneration resources. According to the U.S. Energy Information Administration, 82% of Idaho's net electric generation in 2014 came from renewable energy resources. In particular, hydroelectric power supplied 60% of net electricity generation in 2014 – the second largest share in the Nation after Washington State.

Idaho's three investor-owned utilities (Idaho Power, Avista, and PacifiCorp)[1] have approximately 135 PURPA projects under contract just in Idaho representing a nameplate capacity of more than 1,200 megawatts (MW) – all without a State renewable portfolio standard. In the first 25 years of PURPA, Idaho Power had accumulated less than 200 MW of PURPA

[1] Across their multi-state service areas, Idaho Power has 130 PURPA projects under contract representing more than 1,130 MW; PacifiCorp has about 167 PURPA projects representing more than 2,150 MW, with pending requests for more than 3,250 MW totaling nearly 5,400 MW; and Avista has 18 PURPA projects totaling 47 MW.

power and PacifiCorp had about 300 MW. Since 2007, the amount of PURPA generation for Idaho Power has increased nearly six-fold, and seven-fold for PacifiCorp. In 2010-2011, the Idaho PUC was asked to consider about 448 MW of PURPA wind generation that, if approved, would have obligated Idaho ratepayers to pay approximately $2.169 billion over a 20-year period. Most recently, in the three months from November 2014 to January 2015, the Idaho PUC approved 13 solar projects totaling more than 400 MW (some of which were later canceled).

Continue to Allow States to Adopt their Avoided Cost Methodology

Turning to our panel topics, the Federal Energy Regulatory Commission should continue to recognize that there are various methods for calculating avoided costs. States utilize an array of methodologies to calculate avoided cost and should retain the authority to select a methodology that best suits their situations. In Idaho, the eligibility thresholds for "standard" or published avoided cost rates for wind and solar qualifying facilities (QFs) projects are set at 100 kilowatts (kW) or less, and set at 10 average MW (aMW) for all other types of QF generation. 18 C.F.R. § 292.304(c). Our standard rates are based on a surrogate resource of a natural gas combined-cycle combustion turbine with natural gas fuel costs adjusted annually. Idaho's standard avoided cost rates reflect seasonal values of QF output and other factors (e.g., heavy/light load hours). Idaho QFs with standard or published avoided cost rates are eligible for 20-year contracts. However, most cogeneration (or combined heat and power) QFs elect to have much shorter contracts than 20 years so as not to "out live" their host plants. In other words, cogeneration QFs do not typically contract to sell power to our utilities for periods longer than 5-10 years. For example, PacifiCorp reports that its cogeneration or CPH contracts usually are renewed each year.

Larger QFs (solar and wind projects greater than 100 kW, and all other QFs with outputs greater than 10 aMW) in Idaho are required to individually negotiate their PURPA contracts using each utility's integrated resource plan (IRP) as a starting point for negotiations with the regulated utility (hence, IRP methodology). All three of Idaho's utilities have developed PURPA negotiating procedures that include benchmarks and time-lines approved by the Idaho PUC. Avoided cost rates for QF output are calculated with hourly prices for the duration of the PURPA contract and recognize the value of each QF facility to the utility. IRP-based avoided cost rates also recognize rate differences between heavy-load and light-load periods.

Reducing the Length of Large QF Contracts to Two Years

As mentioned above, Idaho QFs with design capacity above the standard or published rate eligibility caps have individually negotiated avoided cost rates. The QF and the utility use the IRP methodology to calculate the avoided cost rates based on the specific characteristics of the resource. At the option of each QF, pursuant to FERC regulations, the utility's avoided cost rates for energy and capacity are calculated either at the time of delivery or at the time the contractual obligation is incurred. The Idaho PUC recently reduced the contract length for large QFs. The decision was based upon several findings.

1. Falling Avoided Cost Rates. The Idaho PUC found that there was general agreement that avoided cost rates for large QF projects are declining and will continue to decline in the future. With long-term avoided cost rates in decline, allowing QFs to fix their avoided cost rates for long terms of up to 20 years results in avoided cost rates which exceed or "overestimate avoided cost rates in the future." The longer the contract term, the greater the disparity. In Idaho, the avoided cost rates for large, IRP-based QF projects have declined over time especially over the last several years when QFs have offered hundreds of MW of power for sale. In our

most recent PURPA docket, Idaho Power demonstrated that the average cost for PURPA power since 2001 has exceed the Mid-Columbia (Mid-C) Index Price and is projected to continue to exceed the Mid-C price through 2032. Likewise, PacifiCorp's levelized avoided cost rates for 15-year contract terms in Wyoming shows a decrease of approximately 50% from 2011 through 2015 (from approximately $60 per megawatt-hour to less than $30 per megawatt-hour). Fixed, long-term avoided cost rates will exceed actual avoided cost rates and are inconsistent with the public interest under Section 210 of PURPA. 16 U.S.C. § 824a-3(b). As the Commission has stated on several occasions, "the intention [of Congress] was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly encouraged alternatives" of PURPA. *Southern Cal. Edison, San Diego Gas & Elec.,* 71 FERC ¶ 61,269 at p. 62,080 (1995). Absent an ability to update avoided costs periodically inside of a long-term contract, shorter contract lengths are the only way to ensure that avoided costs paid to QFs do not unfairly harm ratepayers.

2. <u>Forecasting Avoided Costs for 20 Years Shifts Risk to Ratepayers</u>. Section 210(b) of PURPA mandated that the avoided cost rates shall be just and reasonable to the electric consumers of the utility and in the public interest. The Commission defined "avoided cost" to mean "the incremental costs to a utility [for] energy or capacity or both which but for the purchase from the qualifying facility . . . such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6). The Commission has indicated that the avoided cost price structure was to make "ratepayers indifferent" as to whether the utility was procuring resources itself or purchasing PURPA power.

When the Commission issued Order No. 69 in 1980, it recognized that avoided costs calculated when parties enter into a PURPA contract might result in future avoided costs during the term of the contract being greater than actual avoided costs at the time of delivery. 45 Fed.Reg. at 12,225-26; *City of Ketchikan*, 94 FERC ¶ 61,293, 2001 WL 275023 at *6. In such cases, the Commission observed that a utility "would subsidize the [QF] at the expense of the utility's other ratepayers." 45 Fed.Reg. at 12,224. However, the Commission rationalized that over the long run, these "overestimated" avoided costs would balance out against other "underestimated" avoided costs. *Id.* The Idaho PUC's experience does not support this supposition.

3. No Need for Additional Power. The Idaho PUC found that the three Idaho utilities do not need new generation. In fact, they each currently have a surplus of capacity for roughly the next decade. In addition, electric loads are no longer growing at the pace they once were and are generally flat.[2] This may be due to increased efficiency of electric appliances, energy conservation, demand-side management programs, and distributed generation combined with slower economic growth. Simply put, Idaho utilities have no need for more generation of any type to serve load, particularly intermittent generation. However, under PURPA's "must purchase" obligation, utilities and ultimately their ratepayers are still required to buy QF generation and at the same time pay the capital costs of existing generating facilities which are necessary to help balance the intermittent generation of PURPA resources. Consequently, the theory behind determination of an avoided cost rate is thwarted. The acquisition of PURPA resources is not transparent to a utility's ratepayers because as intermittent "must take" resources grow, the utility must continue to invest in base load resources to balance load and reliably serve customers. Ratepayers avoid fuel costs that would otherwise be spent, absent the QF resource, but ultimately costs for the ratepayer go up because intermittent resources cannot entirely replace the need for base load power. If investment in base load resources is required, not because the

[2] Energy NewsData, *Flat Electricity Sales in Pacific Northwest*, "Clearing Up" No. 1751 at 5 (June 3, 2016).

utility needs additional generation, but because it must balance intermittent “must take” QF energy, how are costs being avoided?

Another way to look at the oversupply of PURPA generation is to compare its proportion to utility loads. The growth in PURPA generation for PacifiCorp was enough in 2015 to supply more than 100% of PacifiCorp’s average Idaho retail load in 2014 and 275% of its minimum Idaho retail load in 2014. For Idaho Power, its peak load for 2014 was about 3,200 MW while its minimum load was approximately 1,070 MW.

4. Mitigation. The Idaho PUC found that the concern about reducing 20-year contracts to 2-year contracts was mitigated by several factors. First and foremost, as long as utilities “must purchase” power from QFs, PURPA facilities will have a mandatory purchaser. Second, a QF’s entitlement to payment for capacity is determined at the time of the new PURPA contract, not at every two-year interval. Third, Treasury grants and tax credits are still available to the QF. Fourth, longer term contracts are still available on a case-by-case basis. The flexibility to continue to make these modifications within the state that is being impact is paramount. Removing the discretion currently afforded to states would effectively discount any consideration of the impact to ratepayers, which is presently mandated by FERC regulations. Each state’s regulatory authority is in the best position to make well-reasoned decisions as long as those decisions are not contrary to PURPA or inconsistent with FERC regulations.

Avoided Cost Capacity Payments

The Idaho PUC believes that the avoided cost rates for capacity should only begin once the purchasing utility is no longer in a capacity-surplus situation. Requiring a utility to pay for capacity that it does not need is not just and reasonable to electric consumers of the utility nor in the public interest. Under Idaho’s avoided cost methodology, if a utility has a capacity surplus, then a first-time QF entering into its initial two-year IRP contract is not eligible to receive any payments for capacity. At such time as the purchasing utility becomes capacity deficient, then the QF is eligible to receive capacity payments from that point forward. In other words, once the PURPA power is incorporated into the purchasing utility's resource "stack" or mix, the QF preserves its entitlement to receive capacity payments. By including a capacity payment only when the utility becomes capacity deficient, utilities are paying rates that are a more accurate reflection of a true avoided cost for the QF power. This is consistent with FERC Order No. 69 and precedent. A capacity rate updated at the start of each two-year term is a truer reflection of the utility's avoided costs for capacity.

Curtailment

In Rule 304(f), the Commission provides that a utility may curtail its purchase of energy or capacity from a QF when, "due to operational circumstances, purchases from [QFs] will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself." 18 C.F.R. § 292.304(f)(1).

The Commission recently noted that the purpose behind 292.304(f) was to preserve contractual obligations incurred by the electric utility to purchase from a QF. *Idaho Wind Partners 1, LLC*, 140 FERC ¶ 61,219 at 13. The Commission has since held, "A utility may not curtail unilaterally where the QF electric energy is purchased . . . pursuant to a long-term obligation." *Id.* at 14, *citing Entergy*, 137 FERC ¶ 61,199 at p. 56.

As a state regulatory agency, the Idaho PUC is a partner in protecting reliability of the electric grid. From the Idaho PUC's perspective, the desire for renewable resources should never overshadow or outweigh reliability. Thus, the Idaho PUC believes reasonable regulations allowing for curtailment of QF generation should be promulgated.