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FEDERAL ENERGY REGULATORY COMMISSION

Implementation Issues Under the Public	)	
Utility Regulatory Policies Act of 1978	)	Docket No. AD16-16-000

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Participating on Behalf of the Edison Electric Institute
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Panel 2

Good afternoon, I am Al Brogan, Corporate Counsel for NorthWestern Energy. I would like to thank the Commission for the opportunity to participate today and for providing a forum to discuss issues associated with the implementation of the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Prior to joining NorthWestern Energy, I was an attorney for the Montana Public Service Commission. I have been directly involved in PURPA and avoided cost matters for the past 15 years. NorthWestern Energy serves 359,000 electric customers in Montana and 62,800 in South Dakota. NorthWestern Energy is a member of the Southwest Power Pool (SPP) for our South Dakota service territory and operates in bi-lateral markets in the northwest for our Montana territory. In the two territories combined, NorthWestern Energy owns 1,291 MW of nameplate capacity generation, including 120 MW of wind and 442 MW of hydroelectric generation. NorthWestern Energy currently purchases capacity and energy from 28 Qualifying Facilities (QFs) with a nameplate capacity of 177 MW and has contracts with another 45 QFs with a nameplate capacity of 155 MW that are being built. All, but one of these QFs under construction, are solar.

I am here today on behalf of the Edison Electric Institute or EEI. EEI is the association of U.S. shareholder-owned electric companies. EEI's members comprise approximately 70% of the U.S. electric power industry, provide electricity for 220 million Americans, operate in all 50 states and the District of Columbia, and directly employ more than 500,000 workers. With more than $100 billion in annual capital expenditures, the electric power industry is responsible for one million jobs related to the delivery of power, including the construction of modified or new infrastructure. EEI members operate in all areas of the country and under different market structures.

In 1978, Congress passed PURPA in response to the oil crisis gripping the country at the time. The goal of PURPA was to promote increased energy conservation and efficiency in order to stem the use of oil and provide the U.S. with greater energy independence. To further this goal, Congress also sought to encourage growth in the renewable energy sector. Section 210 of PURPA therefore required all electric utilities (including government-owned utilities and electric cooperatives) to purchase all of the electric output from certain qualifying small power producers, known as QFs, at the utilities "avoided cost." Avoided cost prices were deemed to be fair to customers because they could not exceed the costs that utilities would have incurred to generate the power themselves or to purchase power from third parties. Prices for QFs were generally set administratively by state commissions because there was no other means to determine avoided cost. These QFs must generally, but not always, use renewable or waste materials as fuel and are limited in size to 80MW of installed capacity, except for cogeneration projects.

Today, however, a profound transformation is underway across the United States as the way energy is produced and used is changing due to changes in technology, policy and customer expectations. The electric power industry is transitioning to cleaner generation sources and leading the way on renewables and next generation nuclear power. Generation from renewable energy resources, such as wind and solar, has increased substantially since PURPA was enacted. According to the U.S. Energy Information Administration (EIA), in just the past ten years, the mix of sources used to generate electricity has changed dramatically—today we are adding significant amounts of natural gas, wind and solar as we steadily retire coal-based power plants. Coal's share of total net electricity generation dropped from 50 percent in 2005 to 34 percent in 2015.[1] Oil fired generation, the original driver of PURPA, has been reduced to just 1% of all U.S. electric generation in 2015 down from 16.5% in 1978.[2] At the same time, one-third of all

[1] EIA, https://www.eia.gov/tools/faqs/faq.cfm?id=427&t=3
[2] Id.

electricity generated in 2015, came from zero-emitting resources, including nuclear, wind, solar, hydropower and other renewables.

This transformation comes on the heels of another: the significant competition in the power sector. As a result of a series of actions at the state and federal level, there is more competition in the power sector than ever before. Today, two-thirds of the U.S. population is served by wholesale regional electricity markets run by regional transmission organizations (RTOs) or independent system operators (ISOs) (collectively, RTOs). The value of electric energy can now be objectively established by the operation of competitive day-ahead markets and real-time prices for hourly and sub-hourly demand. The existence of electricity markets allows for price discovery – that is, an accurate determination of what a utility would pay for electricity that it does not generate. Administratively set avoided cost prices based on models, assumptions, and forecasts are bound to deviate from the actual cost of energy that a utility would purchase in the market. Where transparent competitive markets with day ahead prices exist, there is no reason to adhere to second-best avoided cost pricing mechanisms. Each utility's avoided cost should be based on the price for the relevant product in wholesale markets. The price paid to QFs for energy deliveries should be based on the price that a utility would pay for energy in the energy market from which it meets its energy needs, and the price paid for capacity should be based on the market from which the utility would purchase the capacity that it needs. This reliance on actual markets provides for the most accurate price discovery of avoided cost and is therefore fair to both QFs and utility customers. Even in states without RTOs, power prices are based on the cost of providing electricity and are reviewed by FERC and state commissions to ensure that they are just, reasonable and not discriminatory. Additionally, in the areas outside of RTOs, transparent, competitive markets have developed. Many state regulators use systems that compare the cost of utility generated power to competitive alternatives to assure that rates are just and reasonable.

Given the significant evolution of the power industry both from a competitive and resource standpoint, I applaud FERC for holding this technical conference and taking a hard look at their PURPA regulations to ensure that they appropriately reflect this new paradigm. While my colleague and fellow EEI witness, Joel Schmidt of Alliant Energy will talk about a number of issues around PURPA that our industry has seen such as the gaming of both the QF megawatt thresholds and the one mile rule by increasingly sophisticated generation providers, I would like to talk specifically about the issue of avoided costs.

As you know, under PURPA, FERC is required to establish an "avoided cost" rate that utilities must pay to QFs for their power. Through regulation, FERC appropriately gave the state commissions flexibility in determining a utility's avoided cost, though given recent trends it is unclear how much flexibility the states believe they have. In theory, these "avoided cost" rates are not supposed to exceed the incremental cost to the electric utility of purchasing or producing alternative electric energy.

In practice, determining an appropriate avoided cost rate has been increasingly controversial since the inception of PURPA. The various methods that are utilized routinely fail to reflect dynamic market conditions and often force utilities to enter into long-term contracts at prices that are substantially above-market, the costs of which are then passed through to our customers. This problem is only exacerbated by the mandatory purchase obligation that requires utilities to purchase power from a QF even if the power is not needed. Accordingly, utilities with large amounts of QF power on their system often must curtail or even shut down less expensive, more economic generation or be in violation of PURPA. In certain parts of the country, including states such as Montana where NorthWestern Energy is located, the problem is reaching almost crisis proportions as the utilities end up curtailing less expensive wind generation in order to purchase higher cost QF power at sometimes 3 to 4 times the price.

In order to address these concerns, EEI proposes changes to 18 CFR §292.304(d) and §292.304(e) of the Commission's Regulations addressing rates for purchases. The PURPA statute, 16 USC 824-1-3(b), provides two simple directives for purchases of QF power by electric utilities: "the rates for such purchases – 1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and 2) shall not discriminate against qualifying cogenerators or qualifying small power producers." The Commission's regulations, however, are much more prescriptive and given the current evolution of the industry may no longer serve these simple goals.

One of the key concerns that utilities have with QF contracts under the Commission's implementation of PURPA is the disconnect between QF pricing and the actual avoided cost of energy. This disconnect occurs for a number of reasons, however, chief among them, and within the control of the Commission, is the requirement that QFs be permitted to elect a price for generation that is locked in, often for upwards of 20 years or more, at the time the contract was entered into. While these long term contracts have remained fixed, prices for clean power resources have declined significantly over the past ten years. In fact, according to a recent study published by Lazard, "over the last six years, wind and solar generation have even become increasingly cost-competitive with more conventional generation technologies."[3] Between 2009 and 2015, wind LCOE declined 61% between and solar PV LCOE declined 82%.[4] Given the proliferation of clean energy alternatives, the current construct creates example after example of above-market QF contracts that are foisted upon the electric consumers that the PURPA avoided cost structure was intended to protect, while less expensive clean energy alternatives are being curtailed. Quite simply, it is no longer clear that the intent of the act is being met.

In order to remedy this problem, EEI recommends a simple change to §292.304(d):

(2) To provide energy ~~or~~ **and** capacity pursuant to a legally enforceable obligation for the delivery of energy ~~or~~ **and** capacity over a specified term in which case **the energy rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery and** the **capacity** rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:

(i) The avoided **capacity** costs, **if any**, calculated at the time of delivery; or

(ii) The avoided **capacity** costs, **if any**, calculated at the time the obligation is incurred, **but not more than 12 months prior to the time of delivery**.

[3] Lazard, *Levelized Cost of Energy Analysis 9.0*, September 2015, p. 10. https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf
[4] Id.

First, the proposed change would provide for the energy component of QF pricing to be tied to the time of delivery. It will also allow QF contract prices to more accurately reflect the true avoided cost of purchasing that energy, while still allowing the QF to select whether it wishes to be compensated for capacity, *if capacity is needed*, at either the time of delivery or at the time the obligation is incurred, but not more than 12 months prior to delivery. This recommended change helps to protect utility customers from being locked in to above-market contracts as it better tracks and reflects technological advancements and the concomitant cost savings in the renewable energy industry, while continuing to provide the guaranteed revenue stream to support these resources that is envisioned in the act.

As discussed, a number of changes have occurred in the industry since the passage of PURPA, including various market constructs and the way that generators, especially non-firm generation resources such as wind and solar, are accounted for and priced. In order to appropriately reflect these current realities, EEI recommends the inclusion of three additional factors to §292.304(e) as follows:

(e) Factors affecting rates for purchases. In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:

(1) The data provided pursuant to §292.302(b), (c), or (d), including State review of any such data;

(2) The **demonstrable** availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the utility to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

(iii) The intermittency of the production of energy of the class of qualifying facility;

(iv) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(v) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(vi) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vii) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(viii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The **demonstrable** costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

(5) The costs of transmission system network upgrades necessary for the qualifying facility to interconnect to the utility or for the utility to acquire or provide network integration transmission service, including any costs initially funded by the qualifying facility which are refunded to the qualifying facility by the utility or transmission provider.

(6) Any performance penalties imposed by Regional Transmission Organizations or Independent System Operators.

First, it is important to explicitly recognize that a large majority of QF projects fall into the category of variable energy resources. In part due to Federal tax policy, QFs are not willing to allow utilities to decrementally dispatch their resource. As such, these resources present unique challenges, and often increased costs, when compared to firm zero and low carbon generation resources such as hydro, natural gas, or nuclear. In order to better reflect this reality, EEI recommends that the Commission specifically include the intermittency of the QF resource as a factor to be taken into account by the states in determining avoided cost. This would be similar, for example, to the way that many RTOs take this intermittency into account when determining the amount of capacity credit generating resources receive in their respective capacity constructs.

Second, as currently written, FERC's regulations do not clearly permit states to consider the costs of transmission system network upgrades or the costs of network integration transmission services in the QF contract. While FERC has recently stated in *In re Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215, n. 73 (Dec. 16, 2013), that the ability to account for transmission or distribution costs directly related to facilities necessary to permit interconnected operations in the avoided cost calculation is implicit in the regulations, our experience is that it is at best unclear in practice. As these costs have continued to increase over time and are appropriately borne by the generation resource requiring the upgrade, it is both reasonable and consistent with good ratemaking practice to explicitly permit the inclusion of these costs as a factor in determining the appropriate avoided cost rates for a specific QF contract.

Finally, as the rules and requirements associated with RTOs continue to evolve, it only makes sense to ensure that the Commission's regulations accurately reflect those rules and allow states to take into account the potential costs associated with participation in those markets in the calculation of avoided costs. One current omission when reviewing FERC's regulations appears to be the ability of the state commissions to consider or include in the avoided cost payment any performance penalties that are assessed by the RTOs. This is an important inclusion to ensure that the avoided cost calculations are appropriately reflecting the true costs to utilities, and by direct extension utility customers, of the QF power purchase agreements.

In conclusion, EEI recognizes that the calculations of avoided costs are done at the state commissions and we appreciate FERC providing a forum to discuss these issues as part of this technical conference. As I have discussed, there are a number of specific areas within FERC's regulations where we believe modifications could go a long way toward providing additional clarity and needed reform to the avoided cost picture so that it better reflects the current state of the industry. In addition to the specific changes that EEI has recommended, we would also encourage FERC to continue to look for opportunities to increase communication and dialogue with state commissions so they better understand the flexibility that FERC sees in its regulations around avoided cost issues. This could include further discussion and clarity around the options available to state commission to address the problems with the long term contracts that result in above market purchase, increased customer costs, and enable the continued use of old, inefficient facilities; a discussion or even reconfirmation of the state commission's ability to permit zero dollar capacity payments if capacity is not needed in the utilities service territory; and/or, the encouragement of the use of requests for proposal (RFPs) or more competitive bidding type processes to ensure that the avoided costs are truly reflected in the contract prices.

Thank you again for the opportunity to participate in this Conference. I look forward to our discussion.