S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter, on the Commission's own motion, establishing the method and avoided cost calculation for **UPPER PENINSULA POWER COMPANY** to fully comply with the Public Utility Regulatory Policies Act of 1978, 16 USC 2601 *et seq*.	)	Case No. U-18094

At the September 28, 2017 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Sally A. Talberg, Chairman
Hon. Norman J. Saari, Commissioner
Hon. Rachael A. Eubanks, Commissioner

OPINION AND ORDER

History of Proceedings

The Commission opened this docket in an order issued on May 3, 2016 (May 3 order), and directed Upper Peninsula Power Company (UPPCo) to file proposed avoided cost calculation methods and costs in accordance with the requirements of the Public Utility Regulatory Policies Act of 1978, PL 95–617; 92 Stat 3117 (PURPA) and the May 3 order. In its filing, UPPCo was instructed to provide avoided cost calculations using: (1) the hybrid proxy plant method proposed in the PURPA Report;[1] (2) the transfer price method developed under 2008 PA 295 (Act 295); and

[1] In an order issued on October 27, 2015, in Case No. U-17973, the Commission opened an investigation into issues concerning PURPA avoided costs. After a series of meetings and a round of comments, the investigation culminated on April 8, 2016, when the Commission Staff (Staff) filed a final report (PURPA Report).

(3) another method, if any, that the company wished to propose. UPPCo was also directed to file a proposed Standard Offer tariff, including applicable design capacity.

On June 17, 2016, UPPCo filed an application requesting approval of its "Full Requirement Contract Methodology" for determining avoided costs. Administrative Law Judge Suzanne D. Sonneborn (ALJ) held a prehearing conference on July 21, 2016. At the prehearing conference, over UPPCo's objection, the ALJ granted permissive intervention to Environmental Law & Policy Center, Ecology Center, Solar Energy Industries Association, and Vote Solar (collectively, ELPC). The Staff also participated in the proceedings.

An evidentiary hearing was conducted on March 7, 2017. The parties filed briefs and reply briefs, and on July 5, 2017, the ALJ issued her Proposal for Decision (PFD). On August 18, 2017, UPPCo and ELPC filed exceptions to the PFD, and on September 1, 2017, these parties filed replies to exceptions. The record in this proceeding consists of 216 pages of transcript and 13 exhibits that were admitted into evidence.

<u>Background</u>

On March 17, 1981, the Commission issued an order in Case No. U-6798, to implement the provisions of Section 210 of PURPA (16 USC 824a–3), which require, among other things, that the Commission establish the avoided cost amounts that an electric utility is obligated to pay to certain qualifying facilities (QFs). As defined in PURPA, a QF is a small power production facility or cogeneration facility that has a right to be served by, and sell to, its host electric utility at the utility's avoided cost. Cogeneration QFs produce electric energy and steam or other forms of energy, which are used for industrial, commercial, or cooling purposes. There is no maximum size limitation for PURPA qualification for cogeneration facilities. Small power production facilities are defined as facilities that use biomass, waste, or renewable resources, including wind, solar, and water, to produce electric power, and which, together with other facilities at the same site, have a generating capacity equal to or less than 80 megawatts (MW). *See*, 18 CFR 292.101.

PURPA requires electric utilities to purchase the energy offered by QFs at rates that are "just and reasonable to the electric consumer of the electric utility and in the public interest" and that do not "discriminate against qualifying cogeneration and small power production facilities." 18 CFR 292.304(a)(1)-(2). However, electric utilities are not required "to pay more than the avoided costs for purchases." "Avoided costs" are defined as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 CFR 292.101(b)(6).

In its evaluation of avoided costs, the Commission is required, to the extent it can, to consider the following criteria, set forth in 18 CFR 292.304(e):

> (1) Data regarding the utility's cost structure and plans to add capacity;
> (2) The availability of capacity or energy from a qualifying facility during daily and seasonal peak periods, including:
> (i) The ability of the utility to dispatch the qualifying facility;
> (ii) The reliability of the QF;
> (iii) Contract terms;
> (iv) The extent to which scheduled outages of the qualifying facility can be coordinated with scheduled outages of the utility's facilities;
> (v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies;
> (vi) The individual and aggregate value of energy and capacity from QFs on the electric utility's system;
> (vii) The smaller capacity increments and the shorter lead times available with additions of capacity from QFs.
> (3) The relationship of the availability of energy or capacity from the QF to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use.
> (4) The 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.

Finally, Federal Energy Regulatory Commission (FERC) regulations require the establishment of Standard Offer rates for utility purchases from QFs with a design capacity of 100 kilowatts (kW) or less. The 100 kW size limit is a floor for Standard Offers; thus, uniform contracts and rates for QFs larger than 100 kW may be established.

By 1993, the Commission had issued over 20 orders approving PURPA contracts, with avoided costs calculated on the basis of a proxy coal-fired generating unit. In 2016, the Commission noted that it had been over two decades since avoided cost rates were developed and that, in light of the significant changes in the energy landscape and the imminent expiration of many of the original PURPA contracts, it was an opportune time to undertake a comprehensive reexamination of PURPA, with a focus on identifying appropriate, updated methods for establishing avoided costs.

<u>Discussion</u>

The ALJ provided a detailed review of the record and positions of the parties that will not be repeated here. *See*, PFD, pp. 12-40. The ALJ observed that there was no dispute that UPPCo's avoided costs and Standard Offer should be reviewed and, if necessary, updated every two years; new PURPA contracts should be filed for Commission approval on an *ex parte* basis; and UPPCo's Standard Offer should be revised to reflect a credit for avoided line losses for projects connected at different voltage levels along with a technical correction. The parties did not agree on the methods for calculating avoided capacity and energy costs, and various matters concerning the Standard Offer. These issues are addressed *ad seriatim.*

1. Planning Horizon and Avoided Capacity and Energy Costs

UPPCo asserted that because of its small size, it is unlikely to build generation, but instead it would rely on purchasing capacity and energy. Accordingly, UPPCo recommended that its avoided costs be based on market costs for energy and capacity, rather than the avoided cost to build new generation. In addition, UPPCo pointed out that because it has a contract for capacity through May 31, 2020, it should not be required to pay a QF for capacity until that contract expires. UPPCo also claimed that its avoided energy cost should be based on locational marginal price (LMP) at the time the energy is delivered. After May 2020, UPPCo maintained that its avoided capacity cost should continue to be based on the market cost for capacity because this is a method that the FERC recognizes as reasonable and because it is more reflective of actual avoided costs for a small utility like UPPCo. For energy avoided cost after May 2020, UPPCo again advocated that the company pay a price equivalent to LMP at the time the energy is delivered. UPPCo did not propose a planning horizon of more than one year.

As it has in other PURPA avoided cost proceedings, the Staff contended that the use of a natural gas combustion turbine (NGCT) unit as a proxy for the cost of capacity was appropriate because this type of unit could be built quickly, at a relatively low cost, and an NGCT can be cycled on and off as needed. The Staff noted that the avoided cost of a proxy NGCT better represents the value of a long-term contract for capacity, compared to the price derived from the Midcontinent Independent System Operator, Inc., (MISO) annual planning reserve auction (PRA). The Staff's proposal also recognizes effective load carrying capability (ELCC) on-peak for intermittent resources. Finally, the Staff recommended that if UPPCo forecasts a need for capacity at any time over the next 10 years, the company should be required to pay a QF for capacity as well as energy.

For energy, the Staff proposed that a QF select one of three options: (1) LMP at the time of delivery; (2) the utility's LMP forecast over the contract period; or (3) payment based on the forecasted variable cost of a natural gas combined cycle (NGCC) unit as determined by the model used to calculate transfer prices pursuant to Act 295 for the period of the contract. The Staff noted that to obtain lower-cost energy, a utility would be more likely to build an NGCC than an NGCT; thus, the use of an NGCC unit as a proxy for avoided energy cost was appropriate. In addition, the Staff recommended that energy payments to a QF include a fixed investment cost attributable to energy (ICE) in addition to the LMP, LMP forecast, or the NGCC cost forecast. The Staff maintained that, in order to realize lower energy prices, additional capital costs to build an NGCC are incurred above the cost to build an NGCT. Thus, an ICE adder is appropriate to recognize this difference.

ELPC agreed that the Staff's hybrid proxy method was the most reasonable method for calculating avoided capacity and energy costs. However, in light of the fact that UPPCo has contracted for capacity until May 31, 2020, ELPC recommended that avoided capacity cost be set at UPPCo's contract rates until the contract expires. In addition to the contract rate for capacity, ELPC recommended that avoided capacity cost include all other potential avoided costs. Although ELPC agreed with the Staff's 10-year planning horizon, it nevertheless recommended that the planning period not commence until May 31, 2020.

After May 2020, ELPC recommended that the Commission implement the Staff's avoided cost method with certain modifications including: (1) recognition of UPPCo's obligations to supply renewable energy under the amendments to Act 295; (2) accounting for avoided transmission and distribution costs; (3) basing avoided cost on the ELCC of the proxy unit and not nameplate capacity; and (4) avoided compliance costs for carbon regulation to the extent that the utility is incurring these costs.

The ALJ found that no party disputed the fact that UPPCo has a contract for capacity until May 31, 2020, and accordingly, she agreed with ELPC, and UPPCo in part, that until the company's current contract expires, QFs should be paid for capacity at the contract rate in effect at the time the PURPA contract is entered into.[2] After May 31, 2020, UPPCo's avoided capacity cost should be established on the basis of the cost of an NGCT, albeit an 85 MW unit which, as UPPCo suggested, was a more appropriate size.

The ALJ also agreed with ELPC that the appropriate planning horizon, which should begin in 2020, should be set at 10 years. Thus, if any capacity requirement is forecast in the succeeding 10 years, UPPCo should pay avoided cost for capacity based on the avoided NGCT unit. Lastly, the ALJ agreed with the Staff and ELPC that for energy avoided cost, the Staff's three proposed options, including an ICE adder, were most reasonable.

UPPCo takes exception, arguing that the Commission should not adopt the same avoided cost method for UPPCo as it has for Consumers Energy Company (Consumers) and DTE Electric Company (DTE Electric) in other PURPA proceedings. UPPCo reasserts that the company should not be required to pay for any capacity until its current contract ends, and requiring the company to pay for unneeded capacity could result in increased power supply costs for UPPCo's customers. With respect to energy, the company again contends that it is unjust and unreasonable to use the same method to determine avoided energy cost for UPPCo as was approved for Consumers and DTE Electric. Like capacity, UPPCo states that it intends to purchase energy from the market and does not foresee building generation. UPPCo also takes exception to the use of a 10-year planning horizon, arguing that PURPA does not require the use of any particular planning period.

The Commission agrees with the ALJ and finds that until May 31, 2020, avoided capacity cost should be set at UPPCo's capacity contract price at the time that the PURPA contract is entered

[2] UPPCo's current capacity contract provides for a price of $25,000 per megawatt-year (MW-year) for 2017-2018; $30,000 per MW-year for 2018-2019; and $36,000 per MW-year for 2019-2020.

into, with an adjustment for ELCC applied to the QF. However, although the ALJ recommended that the Staff's NGCT combustion turbine should be the basis for avoided capacity cost after May 2020, the Commission finds that the appropriate method for determining avoided capacity cost to be implemented after May 31, 2020, should be addressed in UPPCo's next PURPA review. The Commission agrees that, given UPPCo's unique circumstances, circumstances that are very different from Consumers and DTE Electric (Michigan's two largest utilities), the Staff's proposed hybrid proxy method may not truly reflect UPPCo's avoided costs.

The Commission rejects UPPCo's claim that requiring the company to compensate a QF for capacity now would be unjust. The Commission observes that although the company has a contract for capacity now, UPPCo's own presentation shows that its costs under the contract will escalate from $25,000/MW-year in 2017-2018 to $36,000/MW-year in 2019-2020. Thus, entering into PURPA contracts with QFs in the near term may provide an opportunity for long-term capacity contracts at what may be quite favorable prices. Moreover, as the Commission has repeatedly found, the addition of incremental capacity through small PURPA contracts has significant ratepayer value not only for larger utilities, but also for small ones like UPPCo that must rely on an uncertain market for the future acquisition of capacity. Accordingly, the Commission finds that using UPPCo's current contract prices for capacity, adjusted by the ELCC for the specific generator, are a reasonable proxy for avoided capacity cost until May 31, 2020. However, because UPPCo's contract might end before the company's next biennial review is completed, the Commission directs UPPCo to file its next PURPA review application by February 1, 2019. At that time, as noted above, the Commission will review alternative methods for establishing avoided capacity cost for UPPCo specifically.

The Commission also agrees with the Staff, ELPC, and the ALJ that a 10-year planning horizon, beginning in 2020, is most appropriate for determining capacity requirements. As discussed above, there is value in adding incremental QF capacity now and deferring (or even eliminating) the need to acquire capacity in the future, whether through building new generation or through purchased power. And, as the Commission has determined in other PURPA proceedings, if UPPCo forecasts that no capacity is needed during the entire 10-year planning horizon, then UPPCo shall make a filing so indicating, and the avoided cost for capacity shall be reset to the MISO PRA.

For the avoided cost of energy, like capacity, the Commission does not envision that UPPCo, given its small size, will build any generation in the foreseeable future. Thus, the Commission finds that energy cost based on the avoided cost of an NGCC is inappropriate in this particular circumstance. The Commission therefore determines that a QF may opt for energy cost based either on LMP at the time the energy is delivered or based on the company's forecasted LMP. And because the Commission is not adopting a proxy plant for either capacity or energy, the application of an ICE adder is unnecessary. Like the calculation of avoided capacity cost, the appropriate calculation of avoided energy cost should also be reexamined in the company's next PURPA review. The Commission notes, however, that the LMP prices in the record, specifically those contained in Exhibit S-5, are only forecasted for 10 years. The Commission therefore finds that the record should be reopened for the limited purpose of receiving evidence on the forecast of LMP, at an appropriate node, for 20 years.

To that end, the parties shall file proposed LMP forecasts by October 16, 2017. Parties shall file responses by October 25, 2017. A hearing shall be conducted by the ALJ at 9:00 a.m. on November 9, 2017, and the ALJ shall set a briefing schedule so that the record and briefs in the reopened case are submitted to the Commission by December 1, 2017.

The Commission further finds that avoided costs established in this proceeding should only apply to new and renewed contracts, and that existing contracts, if any, should not be altered as a result of the determinations in this order. The Commission also finds that existing QFs with expiring contracts, if any, should have their contracts renewed at the full avoided cost rate, whether or not the company forecasts a capacity shortfall over the planning horizon, because the capacity and energy supplied by these QFs is already taken into account in the company's determinations about future capacity additions.

The Commission finds that these conclusions best represent the proper approach to determining the appropriate avoided energy and capacity costs for UPPCo.

2. Standard Offer Tariff

The Standard Offer is a tariffed rate paid to QFs through a standard contract with the utility. PURPA regulations require electric utilities to establish standard rates for purchases from QFs with capacity of 100 kW or less, but the regulations also give state commissions the authority to apply the Standard Offer to larger projects. 18 CFR 292.304(c)(1) and (2). The availability of a standard tariff reduces transaction costs for individual projects, thus reducing barriers to entry, especially for developers of smaller QFs. The disputed issues include the method and inputs to the Standard Offer rate, planning horizon for capacity additions by QFs, design capacity for the Standard Offer, and contract length.

For the Standard Offer, UPPCo again used its full requirement contract approach for both avoided capacity and energy costs, with a continuation of the current design capacity of 100 kW. UPPCo indicated that it took no position on contract length, provided the Commission adopts the company's avoided costs. The Staff again recommended the hybrid proxy method for setting avoided capacity and energy rates and proposed a design capacity of 1 to 5 MW, depending on the amount of capacity UPPCo requires during the planning horizon. The Staff also proposed that under the Standard Offer, a QF could opt for a contract length of five, 10 or 15 years. In addition, the Staff recommended that QFs under the Standard Offer receive credit for line loss savings and that renewable energy credits (RECs) should be transferred to UPPCo as part of the Standard Offer.

ELPC agreed generally with the Staff's method for calculating avoided cost for Standard Offer contracts. ELPC also recommended that the Standard Offer be made available to QFs of up to 5 MW, contending that larger QFs also benefit when transactions costs are reduced through the use of standardized contracts. ELPC also recommended that contracts be extended to at least 20 years.

The ALJ found that the Staff's recommendations should largely be adopted, except she determined that the Standard Offer contract length should be established at a minimum of 15 years. The ALJ found persuasive the claim that longer contracts would provide greater certainty to QFs by allowing better access to investment and financing. The ALJ agreed with the Staff that the design capacity for the Standard Offer should be established at 1 MW, with the proviso that this cap should be revisited in the next PURPA review. The ALJ noted UPPCo's concern that the higher cap could lead to increased interconnection costs, but found that this concern is speculative at this point.

UPPCo takes exception, arguing that the ALJ's recommendation of a 1 MW cap on the Standard Offer was decided on the basis that the Commission has previously approved a cap of this size for another, much larger utility. The company reiterates its concerns that a one-size-fits-all approach is unreasonable for a small utility like UPPCo, and further contends that it was not speculation that larger projects could involve higher costs for interconnection unless the QF pays for interconnection. UPPCo also objected to the recommended Standard Offer contract length of at least 15 years. UPPCo states that if the company's recommended avoided costs are not adopted, then it should not be expected to enter into long-term, enforceable agreements with QFs as recommended by the PFD.

In response, ELPC points out that, contrary to UPPCo's claims about the failure to take into account the company's unique circumstances, the ALJ recommended a smaller size cap and shorter contract length than the Commission has set in other proceedings. ELPC also points out that UPPCo ignores the provisions of 18 CFR 292.306, which requires QFs to pay the costs of interconnection.

ELPC also takes exception to the PFD, noting that while it agreed with ALJ's recommendation to expand the size cap, it still recommends that the cap be set at 2 MW, the same as the cap for Consumers and DTE Electric.

The Commission generally agrees with the ALJ's reasoning and conclusions and adopts the PFD on most issues concerning the Standard Offer tariff.   However the Commission finds that the methods for setting avoided capacity and energy costs, outlined above, should also apply to the Standard Offer. In addition, QFs should be permitted to opt for a contract term of five, 10, 15, or 20 years. The Commission finds that the longer contract length provides certainty for both the utility and the QF and that the size of the utility is not relevant to determining the appropriate contract length under the Standard Offer.

The Commission rejects UPPCo's proposal to limit the Standard Offer to the minimum 100 kW required under PURPA, noting that transaction costs can be substantial, even for some larger projects, thus leading to a situation where QFs are discouraged. Given UPPCo's size and limited need for capacity, a 1 MW cap is reasonable for now and should be evaluated in the company's next PURPA review along with other avoided cost issues. Although UPPCo raises the specter of high interconnection costs associated with larger projects, the company fails to recognize, as ELPC pointed out, interconnection costs are the responsibility of the QF, not the utility.

As the Commission discussed above, this case is remanded for the taking of additional evidence on the appropriate LMP forecast. As part of that reopened proceeding, parties shall present updated Standard Offer tariffs, which should include forecasted LMP energy rates for five, 10, 15, and 20 years and line losses by voltage level.[3]

3. Other Avoided Costs and Benefits

Other potential avoided costs and benefits associated with QF power include reduced transmission costs and line losses, reduced air emissions and environmental compliance costs, and the hedging value resulting from the use of QFs. ELPC recommended that the Commission establish a process for quantifying other avoided costs including undertaking an updated value-of-solar (VOS) study. UPPCo disagreed, observing that these costs are unique to each QF and should not be included in the Standard Offer.

The ALJ found that there was insufficient evidence in the record to address these additional avoided costs. She recommended that the Commission adopt the Staff's proposal in the PURPA report that these additional avoided costs be addressed on a case-by-case basis. With respect to ELPC's recommendation to undertake a VOS analysis, the ALJ observed that the Commission recently rejected the same proposal on grounds that it may be duplicative of other proceedings addressing distributed generation (DG).

[3] In light of the Commission's determination to reevaluate the appropriate method for determining UPPCo's avoided capacity cost in its next PURPA review, the Commission declines to adopt ELPC's recommendation to incorporate pre- and post- May 31, 2020 capacity values into the Standard Offer.

ELPC takes exception, arguing that its proposed VOS study is much more limited in scope than what is being addressed in the DG proceeding. According to ELPC, its proposal is focused on calculating avoided costs of solar DG solely for PURPA implementation.

The Commission agrees that there is insufficient information in this record to quantify other avoided costs and that parties may negotiate these terms.[4] The Commission further directs that interested parties shall include analyses of these costs in the next PURPA review proceeding. Finally, the Commission is not persuaded that ELPC's recommendation that a VOS analysis be undertaken is necessary in light of the DG efforts already underway, which already have a significant focus on solar energy.

THEREFORE, IT IS ORDERED that:

A. On or before October 16, 2017, the parties to this proceeding may file proposed locational marginal price forecasts for the Upper Peninsula Power Company as directed by this order. The parties shall at the same time file a proposed Standard Offer tariff that conforms to the findings in this order.

B. Parties to this proceeding may file responses to the initial filings by October 28, 2017.

C. A hearing shall be conducted by Administrative Law Judge Suzanne D. Sonneborn at 9:00 a.m. on November 9, 2017. At the hearing, the Administrative Law Judge shall set a briefing schedule so that the Commission can begin reading the record by December 1, 2017.

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[4] As acknowledged by the ALJ, the parties agreed that line loss information by voltage level should be incorporated into the Standard Offer.

The Commission reserves jurisdiction and may issue further orders as necessary.

MICHIGAN PUBLIC SERVICE COMMISSION

Sally A. Talberg, Chairman

Norman J. Saari, Commissioner

Rachael A. Eubanks, Commissioner

By its action of September 28, 2017.

Kavita Kale, Executive Secretary

P R O O F   O F   S E R V I C E

STATE OF MICHIGAN)

Case No. U-18094

County of Ingham)

Angela McGuire being duly sworn, deposes and says that on September 28, 2017 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Angela McGuire

Angela McGuire

Subscribed and sworn to before me
this 28th day of September 2017

Carol M Casale

Carol M. Casale
Notary Public, Saginaw County, Michigan
Acting in Eaton County
My Commission Expires: December 13, 2020

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