ORDER NO. 07-407

ENTERED 09/19/07

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1129

In the Matter of	)	
	)	
PUBLIC UTILITY COMMISSION OF OREGON	)	ERRATA ORDER
	)	
Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities.	)	

DISPOSITION: FILING DATE ADOPTED;
APPENDIX A CORRECTED

By Order No. 07-360 the Commission adopted guidelines for utility contract negotiations with large Qualifying Facilities and decided several other issues remaining from the first phase of the proceeding. From contacts with parties we have been made aware of several errors in the decision. In this order we correct those errors.

In Order No. 07-360 no date was set for utility tariff filings in compliance with the order. Herein, we adopt a date of 45 days from the date of this order.

The adopted guidelines are set forth in Appendix A, attached hereto. Guideline No. 12 inadvertently was misnumbered. In this order we clarify that the second Guideline No. 11 is intended to be Guideline No. 12 (referenced on page 25 of the body of the decision).

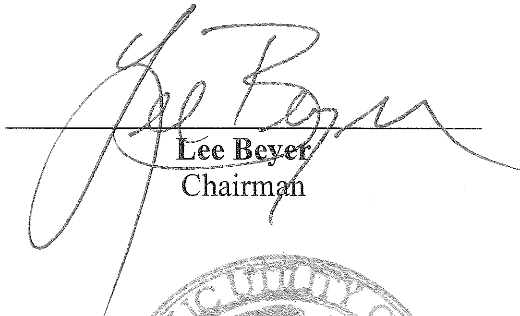
ORDER

IT IS ORDERED that:

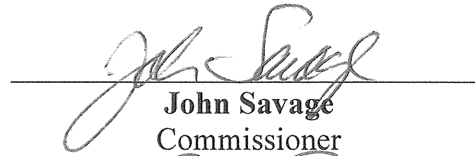
1. Within forty-five days of the effective date of this order, each electric utility shall file by application, and serve upon all parties to this proceeding, modified tariffs that incorporate the decisions adopted in this order.

2. The second Guideline enumerated No. 11 is renumbered No. 12.

Made, entered, and effective SEP 19 2007.



Lee Beyer
Chairman



John Savage
Commissioner

Ray Baum
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

APPENDIX A

Adopted Guidelines for Negotiation of Power Purchase Agreements for QFs[1] 10 MW or Larger

1. The utility should not impose terms and conditions beyond what is standard practice. The Edison Electric Institute master agreement is a useful starting point in negotiating QF agreements.

2. Utility tariffs should specify the following procedures for contract negotiations:

   a. The utility will provide an indicative pricing proposal for a QF that plans to provide firm energy or capacity and chooses avoided cost rates calculated at the time of the obligation. The utility will provide an indicative pricing proposal within 30 days of receipt of the information the utility requires from the QF. The proposal may include other terms and conditions, tailored to the individual characteristics of the proposed project. The avoided cost rates in the indicative pricing proposal will be based on the following:

      i. For Portland General Electric (PGE) and PacifiCorp, the yearly avoided costs approved for the 20-year period for standard contracts should serve as the starting point for negotiations. The prices may be modified to address specific enumerated factors approved by the Oregon Commission. The utility will provide to the QF a description of the methodology for each adjustment to standard avoided costs and how each adjustment was made.

      ii. For Idaho Power, the starting point for negotiations are the avoided costs calculated under the modeling methodology approved by the Idaho Public Utilities Commission for QFs over 10 MW, as refined by the Oregon Commission to incorporate stochastic analyses of electric and natural gas prices, loads, hydro and unplanned outages.

   b. The prospective QF may request in writing that the utility prepare a draft power purchase agreement to serve as the basis for negotiations. The utility may require additional information from the QF necessary to prepare a draft agreement.

   c. Within 30 days of receiving the required information, the utility will provide a draft power purchase agreement containing a comprehensive set of proposed terms and conditions.

   d. The QF must submit in writing a statement of its intention to begin negotiations with the utility and may include written comments and proposals. The utility is not obligated to begin negotiations until it receives written notification from the QF.

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[1] We use the term "QF" to mean the contracting party or the facility itself.

The utility will not unreasonably delay negotiations and will respond in good faith to all proposals by the QF.

e. When the parties have agreed, the utility will prepare a final version of the contract within 15 business days. A contract is not final and binding until signed by both parties.

f. At any time after 60 days from the date the QF has provided its written notification pursuant to paragraph d., the party may file a complaint with the Oregon Commission asking the Commission to adjudicate any unresolved contract terms and conditions.

3. QFs have the unilateral right to select a contract length of up to 20 years for a PURPA contract. The contract length selected by the QF may impact other contractual issues including, but not limited to, the avoided cost determination with respect to that QF.

4. The utility should consider the QF to be providing firm energy or capacity if the contract requires delivery of a specified amount of energy or capacity over a specified term and includes sanctions for non-compliance under a legally enforceable obligation. A utility shall not determine that a QF provides no capacity value simply because the utility did not select it through a competitive bidding process. For a QF providing firm energy or capacity:

   a. The utility and the QF should negotiate the time periods when the QF may schedule outages and the advance notification requirement for such outages, using provisions in the utility's partial requirements tariffs as guidance.

   b. The QF should be required to make best efforts to meet its capacity obligations during utility system emergencies.

   c. The utility and the QF should negotiate security, default, damage and termination provisions that keep the utility and its ratepayers whole in the event the QF fails to meet obligations under the contract.

   d. Delay of commercial operation should not be a cause of termination if the utility determines at the time of contract execution that it will be resource-sufficient as of the QF on-line date specified in the contract; however, damages may be appropriate.

   e. Lack of natural motive force for testing to prove commercial operation should not be a cause of termination.

   f. The utility should include a provision in the contract that states a utility may require a QF terminated due to its default and wishing to resume selling to the utility be subject to the terms of the original contract until its end date.

5. An "as available" obligation for delivery of energy, including deliveries in excess of nameplate rating or the amount committed in the QF contract, should be treated as a non-firm commitment. Non-firm commitments should not be subject to minimum delivery requirements, default damages for construction delay or under-delivery, default damages for the QF choosing to terminate the contract early, or default security for these purposes.

6. For QFs unable to establish creditworthiness, the utility must at a minimum allow the QF to choose either a letter of credit or cash escrow for providing default security. When determining security requirements, the utility should take into account the risk associated with the QF based on such factors as its size and type of supply commitments. Default security methodologies specified in PGE's and PacifiCorp's standard QF contracts are a useful starting point for negotiations with large QFs.

7. When QF rates are based on avoided costs calculated at the time of delivery, the utility should use day-ahead on- and off-peak market index prices at the appropriate market hub(s).

   a. For QFs providing firm energy or capacity that choose this option, avoided cost rates should be based on day-ahead market index prices for firm purchases.

   b. For QFs providing energy on an "as available" basis, avoided cost rates should be based on day-ahead market index prices for non-firm purchases.

8. The utility should not make adjustments to standard avoided cost rates other than those approved by the Oregon Commission and consistent with these guidelines.

9. The utility should make adjustments to avoided costs for reliability on an expected forward-looking basis. The utility should design QF rates to provide an incentive for the QF to achieve the contracted level and timing of energy deliveries.

10. The utility should make adjustments to avoided costs for dispatchability on a probabilistic, forward-looking basis.

11. If avoided cost rates for a QF are calculated at the time of the obligation and the utility's avoided resource is a fossil fuel plant, the utility should adjust avoided cost rates for the resource deficiency period to take into account avoided fossil fuel price risk.

12. Avoided cost rates for wind QFs should be adjusted for integration cost estimates based on studies conducted for the utility's system, unless the QF contracts for integration services with a third party.

    a. The utility should use the most recent integration cost data available, consistent with its evaluation of competitively bid and self-build wind resources.

    b. The portion of integration costs attributable to reserves costs should be based on the difference in such costs between the wind QF and the utility proxy plant.

    c. The utility should base first-year integration costs on the actual level of wind resources in the control area, plus the proposed QF. Integration costs for years two through five of the contract should be based on the expected level of wind resources in the control area each year, including the new resources the utility expects to add. Integration costs should be fixed at the year-five level, adjusted for inflation, for the remainder of the life of the wind projects in the control area.

    d. The utilities are prohibited from using a long-range planning target for wind resources as the basis for integration costs. However, if a utility is subject to near-term targets under a mandatory Renewable Portfolio Standard, the utility may base its integration costs on the level of renewable resources it must acquire over the next 10 years.

    e. In determining integration costs, the utility should make reasonable estimates regarding the portion of renewable resources to be acquired that will be intermittent resources.

13. The utility should adjust avoided cost rates for QF line losses relative to the utility proxy plant based on a proximity-based approach.

14. The utility should evaluate whether there are potential savings due to transmission and distribution system upgrades that can be avoided or deferred as a result of the QF's location relative to the utility proxy plant and adjust avoided cost rates accordingly.

15. The utility should not adjust avoided cost rates for any distribution or transmission system upgrades needed to accept QF power. Such costs should be separately charged as part of the interconnection process.

16. A utility should not adjust avoided cost rates based on its determination of the additional cost it might incur for any debt imputation by a credit rating agency.

17. Regarding Surplus Sale and Simultaneous Purchase and Sale:

    (1) QFs may either contract with the purchasing utility for a "surplus sale" or for a "simultaneous purchase and sale" provided, however, that the QF's selection of

either such contractual arrangement shall not be inconsistent with any retail tariff provision of the purchasing utility then in effect or any agreement between the QF and the purchasing utility;

(2) The two sale/purchase arrangements described in paragraph (1) will be available to QFs regardless of whether they qualify for standard contracts and rates or non-standard contracts and rates, however the "simultaneous purchase and sale" is not available to QFs not directly connected to the purchasing utility's electrical system;

(3) The negotiation parameters and guidelines should be the same for both sale/purchase arrangements described in paragraph (1); and

(4) The avoided cost calculations by the utilities do not require adjustment solely as a result of the selection of one of the sale/purchase arrangements described in paragraph (1), rather than the other.