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DECISIONS OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION CONCERNING UTILITY PURCHASES OF GEOTHERMAL POWER

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ABSTRACT

Pursuant to an order by the California Public Utilities Commission, California utilities have filed standard offers for purchase of as-available and firm electricity generated by small non-utility power producers. This paper summarizes recent rulemaking actions by the California Public Utilities Commission in establishing standards for these utility power purchases. Since 1979, the Commission has endorsed payment of full avoided costs to cogenerators and small power producers on the grounds that such a policy would maximize independent power production from diverse sources. The Commission believes that this production will benefit California ratepayers by increasing diversity of supply and developing in-state resources.

The purpose of this paper is to provide a status report on actions by the California Public Utilities Commission (CPUC) establishing standards governing the prices, terms, and conditions of electric utility purchases of electric power from small power producers, including geothermal facilities. In the oral presentation at the Annual Meeting, the author will review CPUC actions in the intervening months since preparation of this written text in May 1982.

In recent years, the CPUC has gone on record supporting the encouragement of small power production by non-utility business entities. The basis for this support has been the CPUC's conclusion that small power production allows a utility to diversify its resource plan, which increases the reliability of its system and minimizes the risk that results from excessive reliance on a single technology. Ratepayers do not have to pay the costs of unscheduled outages of non-utility small power facilities. Reduced dependence on oil and gas is yet another important advantage of opening up the electric generation business to non-utility developers.

For these reasons, California has for some time promoted small power production, in decisions by the Commission, starting in 1979, and in actions by the State Legislature.1/ In Decision 91109, issued on December 19, 1979, the PUC adopted "avoided cost" as the reasonable basis for payment by a utility to purchase power from cogeneration facilities. "Avoided cost" means the added cost the utility avoids by not having to produce an additional unit of electricity at its existing facilities or from a new powerplant. The price thus reflects the value of a producer's power to the utility system. The CPUC chose avoided cost because this payment would encourage full economic development of new cogeneration and small power resources.

On January 21, 1982, the CPUC issued Decision 82-01-103 concerning its Order Instituting Rulemaking No. 2 (OIR-2). The key action in the OIR-2 decision is the Commission's requirement that a utility purchase electricity from private non-utility suppliers at a rate equal to the utility's full avoided cost. The Commission established several different methods to be used in calculating these avoided costs, each of which is to be used by the utilities in the formulation of a so-called "standard offer" to be made to all small power producers. OIR-2 sets up standards to be used in determining how much of the utility's marginal costs are actually avoided under different kinds of contractual arrangements. It establishes requirements for allocation of costs for interconnection of the producers with the utility. The decision also states the Commission's willingness to review special nonstandard contracts between qualifying facilities and utilities that do not meet the terms of one of the standard offers.

The Commission's purpose in requiring certain "standard" offers is to enable most of the contractual arrangements between private producers and utilities to be executed without Commission review, in order to avoid governmental approval delays. The decision requires the development of four different standard offers designed to reflect variations in firmness of supply and to provide some flexibility in financial arrangements. The decision directs that each utility offer a choice of contract terms at the seller's option. These choices are intended to be economically equivalent over the life of the contract.

The first of the standard offers is the offer to buy electricity on an "as-available" basis, that is, electricity provided without a long-term contract and/or a commitment to meet certain performance standards. Such an offer might be appropriate for a wind facility or a cogenerator with widely fluctuating heat loads. Under this "as available" offer, a small power producer will receive an "as available" energy payment in ¢/kWh equal to the

sum of the utility's avoided fuel cost at the time of delivery, plus an "as-available" capacity payment based on a percentage of the utility's annual capacity shortage costs. Because the utility's fuel costs are higher during peak periods, payments to private producers will be greater accordingly. For example, electricity produced during summer afternoons is worth the most. In other words, payments will be "time differentiated": the value of the electricity delivered to the utility will vary with the time of day and season.

If a producer can agree to certain performance standards, that is, the producer can guarantee delivery of electricity a set number of hours and during specified periods of the day or year, he or she is eligible for the "firm capacity standard offer." Under this contract, the small power producer must meet certain standards relating to availability at system peak, including dispatchability, reliability, scheduling of outages, and availability during emergencies. In return for adherence to these more stringent performance standards, the firm capacity offer allows the producer to receive a payment in ¢/kWh equal to the utility's avoided fuel costs plus a capacity payment reflecting the annual capacity cost of a combustion turbine.

The third and fourth standard offers required by the decision are more innovative. One of these simply adds a provision that can be used in conjunction with either of the offers described previously; namely, it allows the utility and a small power producer to fix an energy payment in advance for a five-year contract period. This "long-term energy price offer" allows both the utility and the private producer the certainty of a known price, based on a forecast of the utility's marginal fuel costs.

The fourth standard offer is to be based on the utility's long-run marginal costs. The other three standard offers I have just described are essentially based on the marginal costs of running the utility's existing system or its short-run marginal costs. Since it has been suggested that the utility's long-run marginal costs, namely the cost of building and running new power plants, would be different from the current short-run avoided costs (where a peaking gas turbine is used as a proxy for a short-run shortage cost), we have ordered the utilities to develop a long-run cost methodology on which long-term contract prices may be based.

In addition to requiring the utilities to set fair prices for purchases of power, the OIR-2 decision establishes rules regarding several other issues that can affect the viability of small power production. These include rates for sales of electricity to private producers, allocation of interconnection costs, requirements for availability during emergencies, and utility curtailment of purchases.

For example, in order to allow a small power producer to reap the full benefits of avoided cost pricing, our decision allows the private producer to buy electricity for its own needs at the going average rate, while selling all of the power it produces to the utility at what may be a higher marginal cost rate. This practice is called simultaneous purchase and sale.

An issue that has been in dispute in the past between utilities and private power producers is the question of who should pay for interconnection costs. The OIR-2 decision resolves this dispute by stating that the small power producer is responsible only for those costs of interconnection that exceed the cost the utility would otherwise incur to connect the producer as an ordinary customer.

With regard to availability during system emergencies, the OIR-2 decision requires small power producers to be available during system emergencies only if they are receiving the more attractive firm capacity payment. Under the firm capacity offer, the private producer will be expected to operate at maximum capacity on notice to meet utility needs during peak-load periods and emergencies.

After the decision was issued in January, applications for rehearing of the decision were filed by three California utilities. Responses to the applications for rehearing were filed by a number of parties, including Natomas Company, Thermal Power Company, and Union Oil Company. On April 12, 1982, the Commission issued Decision 82-04-071 modifying its original decision and denying rehearing.

The three utilities each questioned the use of a gas turbine proxy as the basis for calculating short-term capacity costs which is used for the as-available capacity payment and the firm capacity payment. The Commission acknowledged that the gas turbine is "merely a proxy for shortage costs," and does not suggest that it is the "desired incremental capacity choice. However its use is consistent with an incremental fuel cost that will for some time be based on oil or gas."2/ The Commission stated that it would entertain revisions in the as-available capacity methodology in utilities' general rate cases. The decision also stated that "as utilities reduce their dependency on oil, and other fuels fix their marginal cost, this fact should be taken into account in the calculations."3/

Several parties challenged the authority of the Public Utilities Commission to issue and enforce its January decision. The day after the decision, the District of Columbia Circuit Court of Appeals announced its decision in American Electric Power et al. v. Federal Energy Regulatory Commission (FERC). The Court remanded to FERC two of the four aspects of FERC regulations under PURPA that were challenged by utility interests. The regulations in question deal with the rates that an electric utility must pay to qualified facilities under PURPA and the utility's obligation to connect these facilities to its grid. The Court found that FERC did not adequately consider whether

payment below avoided cost would sufficiently stimulate cogeneration and small power production at a lower cost to the ratepayers and found that PURPA did not supersede those provisions of the Federal Power Act which require an evidentiary proceeding prior to the authorization of an interconnection. Southern California Edison and San Diego Gas & Electric have argued that the Court action means that the full avoided cost rates and blanket authority for qualifying facilities to interconnect are no longer in effect. The FERC petitioned the Court of Appeals for reconsideration and was unsuccessful. As of May 1982, it was anticipated that FERC would appeal the decision to the Supreme Court. The California PUC considers, however, that it is empowered to implement the OIR-2 decision. In its April decision, the PUC stated that "irrespective of the status of litigation on the FERC rules, Sections 2801 through 2804 of the [California] Public Utilities Code establish a comprehensive scheme 'to encourage private energy producers to competitively develop independent sources of natural gas and electric energy.'"4/

The three utilities and other parties took exception to the portion of the OIR-2 decision establishing periods during which purchases from qualifying facilities are not required. Their arguments focused on the potential situation in which the spill of utility-owned hydroelectric and/or curtailment of utility-owned geothermal plants would be required to permit mandated purchases from qualifying facilities. The Commission, considering these arguments, recognized the need for refinement of the standard price offer to avoid waste during these circumstances. As established in the OIR-2 decision, a utility can refuse to purchase electricity from qualifying facilities during any period during which, due to operational circumstances, purchases from qualifying facilities will result in system costs greater than those which the utility would incur if it did not make such purchases, but instead generate an equivalent amount of energy itself. The Commission uses the term "negative" avoided costs to define such periods. The Commission cites an example as the case when a base load or large oil-fired intermediate load plant is shut down at night due to an excess of QF electricity, but then cannot be restarted and brought up to its rated output for the next day's peak-load, thus necessitating instead the startup of a plant with very high generating costs (a gas turbine peaker) or an expensive energy purchase of capacity. The Commission was concerned that in the case where hydro is spilled a significant waste may occur if qualifying facilities (some of which burn nonrenewable fuels) are paid average avoided costs while water is wasted. The Commission decided that it would not permit a utility to refuse to purchase from qualifying facilities but would allow it to offer "hydro savings" prices to QFs during periods of potential hydro spill conditions on its own system, upon notice to the QFs. This would be a situation in which, if the utility were to accept full QF power, the utility would have to spill its own hydro resources. The Commission also stated that, since hydro savings pricing would create uncertainty and administrative burdens for QFs, utilities must consider all feasible alternatives before paying this price.

The OIR-2 decision also considered the issue of nonstandard contracts, those not filed pursuant to the "standard offers" filed by the utilities. The decision provides for utilities to file for review of nonstandard contracts with the Commission for a period of two years after the effective date of the decision. On April 21, the Commission issued Decision 82-04-087, approving certain provisions of a power sales agreement between U.S. Windpower, Inc. and Pacific Gas & Electric Company.5/ This case represents the first review of a nonstandard offer since the issuance of OIR-2. Since the procedure in this case is a good example of the "nonstandard review process" contemplated in the OIR-2 decision, it is an important case for small power producers to be aware of whether or not they are involved in wind power generation specifically.

PG&E and U.S. Windpower negotiated a power sales agreement with nonstandard pricing provisions calling for levelized payments above avoided costs. The payments above avoided costs would be offset by expected discounts to avoided costs in later years of the project, as well as interest payments. Under the agreement, PG&E will purchase all energy delivered from U.S. Windpower's 300MW wind generation facilities located in the Altamont Pass area of eastern Alameda County for a period of 30 years. PG&E and U.S. Windpower used PG&E's standard offer for wind facilities over 100kW as the starting point for negotiations. PG&E will pay U.S. Windpower a fixed price of 9¢ for each kWh actually delivered. The difference between the fixed price of 9¢ and 97% of the standard offer price at the time energy is delivered will be entered in a "Payment Tracking Account." In the early phase of the project, the fixed price of 9¢ will exceed 97% of the standard offer price. Once 97% of the standard offer price exceeds the fixed price, the balance in the Payment Tracking Account will be reduced as energy is delivered to PG&E. In the second phase, after the retirement of the Tracking Account balance, PG&E would pay U.S. Windpower 95% of the standard offer price for energy delivered. In the succeeding phase, Windpower will be paid 90%. This project was the subject of rigorous staff scrutiny, and the PUC staff analysis indicated that the allocation of project risk to the ratepayers under the specific terms of the contract was more than compensated by expected ratepayer benefits derived from the facility. The amount of ratepayer risk that is involved is limited to prudent levels by the provisions of the contract. In summary, the Commission's decision states that the agreement appears to offer the ratepayers high potential rewards at little risk; the fixed price is only slightly above current avoided costs, and there are safeguards written into the contract should the project experience early failure.

California utilities have filed standard offers effective May 12, 1982, for the following: (1) as-available power; (2) firm power--long-term capacity prices based on a gas turbine; (3) simplified offers for qualifying facilities under 100kW; and (4) related tariffs. Standard offers

for 5-year forecasted energy prices and for energy and capacity prices based on long-run avoided costs have been filed in proposal form by three utilities. Hearings are scheduled to begin July 12, 1982 on the as-available, firm, and below 100kW offers to determine their compliance with the OIR-2 decision.

FOOTNOTES

1. State of California, 1980, Public Utilities Code, Ch. 7, Private Energy Producers, Sections 2801-2824.

2. California Public Utilities Commission, 1982, Decision 82-04-071, Order Modifying Decision (D.) 82-01-103 and Denying Rehearing and Stay Thereof, at 2.

3. Ibid, at 3.

4. Ibid.

5. California Public Utilities Commission, 1982, Decision 82-04-087, Opinion.