ORDER NO. 05-584

ENTERED 05/13/05

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1129

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

TABLE OF CONTENTS

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

DISPOSITION: PURPA POLICIES ADOPTED

I. SUMMARY

In this order, we evaluate specific policies and procedures to determine whether Commission goals relating to the Public Utility Regulatory Policies Act (PURPA)[1] could be more effectively implemented and achieved. A basic purpose of PURPA is to provide a market for the electricity produced by small power producers and cogenerators. This Commission's goal has been to encourage the economically efficient development of these qualifying facilities (QFs), while protecting ratepayers by ensuring that utilities pay rates equal to that which they would have incurred in lieu of purchasing QF power.[2]

Our decisions in this proceeding are consistent with this goal, and apply primarily to standard contract rates, terms and conditions for QF power. These decisions include the following:

<u>Eligibility for and Term of Standard Contracts</u>

- Establishing a 10 MW standard contract eligibility threshold.
- Adopting the manufacturer's nameplate capacity for a QF project as the measure of eligibility for standard contracts.
- Establishing a maximum standard contract term of twenty years. Allowing a QF to select fixed pricing for the first fifteen years of

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[1] The United States Congress passed PURPA in 1978, as codifed in the United States Codes (USC) at *16 U.S.C. § 824a-3*.
[2] *See* Order No. 81-319 at 3.

the standard contract, but requiring the selection of a market pricing option for the last five years.

Calculation of Avoided Costs

- Requiring PacifiCorp and Portland General Electric (PGE) to use the historical methodology to calculate avoided costs rates when either utility is in a resource deficient position.

- Requiring PacifiCorp and PGE to use monthly on- and off-peak forward market prices, as of the utility's avoided cost filing, to calculate avoided costs when either utility is in a resource sufficient position.

- Allowing Idaho Power to use the surrogate avoided resource (SAR) methodology to calculate avoided rates, regardless of the utility's resource position.

- Requiring payment of full avoided costs pursuant to the appropriate methodology for all energy, whether intermittent or firm, that is delivered by a QF under a standard contract to a utility up to the nameplate rating of the project.

- Requiring payment for energy only for all energy delivered over the nameplate rating for a QF under standard contract.

Pricing

- Requiring utilities to offer three pricing options for standard QF contracts: (1) the Fixed Price Method; (2) the Deadband Method; and (3) the Gas Market Method. Requiring PGE to also offer its proposed Mid-C Index Rate Option.

Security, Construction Credit, Insurance and Indemnity Requirements

- Requiring all QFs to establish creditworthiness by making a set of representations and warranties that the QF has good credit, including that it is current on existing debt obligations and has not been a debtor in a bankruptcy proceeding within the preceding two years.

- If a QF cannot establish creditworthiness, requiring the QF to provide a reasonable amount of default security, as determined by the utility—but subject to Commission review—by one of the following means selected by a QF: senior lien, step-in rights, a cash escrow or a line of credit.

- In the event a QF defaults and the market prices of energy to replace the contracted for energy exceed the contract price, requiring that future payments to the QF after the default period ends must be commensurately reduced over a reasonable period of time to recoup costs incurred.

- Requiring that, if a utility is in a resource deficient position at the time a QF contract is signed and the QF project is not operational by the date specified in the contract, and market energy prices to replace the contracted for energy exceed the contract price, future payments to the QF after the default period ends must be commensurately reduced over a reasonable period of time to recoup costs incurred.

- Requiring the incorporation of a mutual indemnity clause in contracts.

- Requiring all QFs with a design capacity above 200 kW to carry a reasonable amount of general liability insurance.

Repeal of PURPA

- Concluding that QF contracts do not terminate upon repeal of PURPA, unless termination of QF contracts is mandated by federal or state law.

We find that the evidence presented in this proceeding was largely inadequate to develop specific guidance regarding non-standard contracts, except on issues that were identified at the start of this proceeding as applying to non-standard contracts. We affirm, however, that it is our intent and goal to facilitate the development of QFs of all sizes. Consequently, in this order, we identify several issues pertaining to non-standard contracts that require further development in a second phase of this docket. These issues are in addition to issues that had been identified at the start of this proceeding as being properly addressed in a second phase, as well as issues applying to standard contracts that we also identify herein as appropriate for further development in a second phase.

The issues identified for the second phase include:

- Development of negotiation parameters and guidelines for non-standard QF contracts.

- In the event of the inability of a QF to establish creditworthiness, determination of an appropriate amount of default security to be required.
- Further exploration of how the calculation of avoided cost should reflect the nature and quality of QF energy.
- Further exploration of a Mechanical Availability Guarantee (MAG).
- Further exploration of market pricing options and alternatives to using nameplate capacity to determine the size of a QF project for standard contract eligibility purposes.
- Cap on amount of default losses that can be recouped, pursuant to future QF contract payment reductions.
- Liability insurance for QFs with a design capacity at or under 200 kW.
- Negotiation parameters and guidelines for "simultaneous sale and purchase" QF contract.
- Negotiating "net output sales" for non-standard contracts.
- Further exploration of Staff's role in the informal dispute resolution of QF contract disputes.

II. INTRODUCTION

A. PROCEDURAL BACKGROUND

On January 20, 2004, the Commission opened an investigation related to electric utility purchases from qualifying facilities (QFs). We opened the investigation due to concerns raised by industrial and rural developers and operators of QF projects about the availability of standard rates and the terms and conditions of contracts for purchases of electricity from QF projects.

On February 11, 2004, an initial prehearing conference was held and a partial procedural schedule was established. Pacific Power & Light, dba PacifiCorp (PacifiCorp), Portland General Electric Company (PGE) and Idaho Power Company (Idaho Power) (collectively "the electric utilities") filed Informational Filings to provide foundational information about the current state of their respective tariffs and contracts relating to qualifying facilities. A workshop to discuss the filings followed on March 23, 2004. On June 18, 2004, a second prehearing conference was held and a full procedural schedule was established. In addition, parties agreed to address six issues in the first phase of this investigation.[3] Other issues that had been identified by the Commission Staff (Staff) for potential consideration were left to be taken up in a subsequent phase of the proceeding or in a separate proceeding.[4]

On August 3, 2004, Staff and several Intervenors filed testimony. Intervenors fall into three general categories—the electric utilities, current and potential cogenerators and small power producers, and consumer representatives and public agencies concerned with state energy policies—and include the following entities: Ascentergy Corporation; Central Oregon Irrigation District; Columbia Energy Partners; the Fair Rate Coalition (FRC); J. R. Simplot Company (Simplot); Idaho Power; the Industrial Customers of Northwest Utilities (ICNU); Middlefork Irrigation District; PacifiCorp; PGE; the Oregon Department of Energy (ODOE); the Sherman County Court

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[3] Parties addressed the following issues in this proceeding: (1) Contract length and price structure: What is the appropriate contract length which is consistent with the Federal PURPA law standards and which will balance the interests of the QF developers and the utility's customers? Current practice is a five-year term. What is the appropriate pricing structure (e.g., prices that vary by year, prices that are levelized over the contract term) and should the Commission specify that structure? Current practice varies by utility, size of customer, and date of agreement; (2) Size threshold for standard rates: What size facilities should be eligible for standard purchase rates and a standard power purchase agreement which is consistent with the Federal PURPA law standards and which will balance the interests of the QF developers and the utility's customers. The current threshold is one MW; (3) Utility tariff content: What prices, terms and conditions should be included in utility tariffs? How should the Commission ensure that all terms and conditions it approves in the avoided cost filings are publicly available? Current practice is to include only basic pricing, terms and conditions in the tariff for small qualifying facilities (1 MW or less). The other avoided cost information approved by the Commission is contained in the utility's filing; (4) Avoided cost calculation methods: What is the appropriate method for calculating avoided costs? Current practice is to use (a) the variable costs of operating existing generating facilities until projected supply deficits occur and (b) when new resources are needed, their estimated capacity and energy costs; (5) Applicability of Oregon PURPA administrative rules: Since federal PURPA still applies to all electric companies and the Commission is responsible for its implementation, what is the practical effect of the ORS 757.612 exemption for PGE and Pacific? The administrative rules need further review to differentiate the rules that implement federal PURPA from the rules that were specific to Oregon PURPA law; (6) Dispute mediation: What should be the Commission and staff roles in mediating or litigating PURPA-related disputes? Current practice is described above.

[4] Potential issues identified by Staff that were deferred until a subsequent phase or separate proceeding include the following: (1) Alternative forms of regulation: Do utilities have a financial incentive to discourage the development of qualifying facilities due to reduced sales? If so, should the Commission use other types of regulation (e.g., decoupling) to mitigate the disincentives; (2) Filing cycle for avoided cost studies and related tariffs: Currently the companies file avoided cost studies about every two years following IRP acknowledgement and they update standard purchase rates and contract terms accordingly. In addition, OAR 860-029-0080(4) requires electric utilities contracting to buy non-firm power from a qualifying facility to submit quarterly filings of avoided energy costs. PGE is the only Oregon investor-owned utility with such a contract. Even though the rule no longer applies to PGE, the company files, and staff reviews, quarterly avoided cost filings. Staff recommends consideration of this issue in the context of the Commission's review of Least-Cost Planning (Docket No. UM 1056); (3) Net metering: Net metering allows customers, in essence, to run their meter backwards and receive credit on the electric bill when their generation exceeds their use. Currently, eligibility is limited to customers with a generating capacity of 25 kW or less from certain types of resources. In the future, the Commission may want to consider raising this threshold; (4) Interconnection procedures and agreements: Staff is monitoring federal proceedings related to these issues. At a later date, staff plans to ask the Commission to open a proceeding to establish state interconnection standards; (5) Standby rates: The Commission addressed PGE's standby tariffs in Docket No. UE 158.

(Sherman County); Symbiotics, LLC; and Weyerhaeuser Corporation. On September 17, 2004, the electric utilities filed rebuttal testimony. Supplemental rebuttal testimony was submitted on September 30, 2004. On October 14, 2004, Staff and Intervenors filed surrebuttal testimony. A hearing was conducted on October 27, 2004, and October 28, 2004. The parties filed opening briefs on December 23, 2004, and reply briefs on January 27, 2005. On February 7, 2005, oral argument was held.

B. HISTORICAL BACKGROUND

Sections 201 and 210 of PURPA encourage resource competition and the development of cogeneration and renewable energy technologies by non-utility power producers called "qualifying facilities" or "QFs."[5] PURPA requires the Federal Energy Regulatory Commission (FERC) to prescribe and periodically revise rules that "require electric utilities to offer to . . . purchase electric energy from [QFs]."[6] PURPA further specifies that the rates paid by utilities for electric energy purchased from QFs may not exceed "the incremental cost to the electric utility of alternative electric energy."[7] PURPA defines incremental costs as "the cost to the electric utility of the electric energy which, but for the purchases from such [QF], such utility would generate or purchase from another source."[8] PURPA also requires electric utilities to purchase power from QFs at rates that are just and reasonable to the utility's customers and in the public interest and that do not discriminate against QFs, but that are not more than avoided costs.[9]

FERC complied with its PURPA obligation by promulgating Title 18, Part 292 in the Code of Federal Regulations (CFR).[10] In so doing, FERC stated that "a basic purpose of section 210 of PURPA is to provide a market for the electricity generated by small power producers and cogenerators."[11] Regulations adopted by FERC seek to create this market by requiring utilities to purchase electricity from QFs at the utility's "full avoided costs" and to adopt non-discriminatory interconnection and back-up power policies and pricing. FERC's full avoided cost rule was unanimously upheld by the Supreme Court in 1983.[12]

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[5] A "qualifying facility" refers to a cogeneration facility or a small power production facility. OAR 860-029-0010(22). *See also* OAR 860-029-0010(25). PURPA defined two types of qualifying facilities: (1) a cogeneration facility that produces electric energy and steam or forms of useful energy (such as heat) that can be used for industrial, commercial, heating or cooling purposes. Cogenerators may be any size, so long as plant thermal output is at least five percent of total energy output. If fueled by oil or gas, the plant must meet certain efficiency criteria; and (2) A small power production facility that produces electric energy using biomass, waste or renewable resources as the primary energy source. Such facilities must have a nameplate capacity of 80 MW or less. In addition, at least three-fourths of the plant's energy must be derived from renewable resources or waste products.

[6] 16 U.S.C. § 824a-3(a).

[7] 16 U.S.C. § 824a-3(b).

[8] 16 U.S.C. § 824a-3(d).

[9] *Id*. § 824a-3(b)(1) and (2).

[10] 18 CFR §292.101 et seq.

[11] Federal Register, Vol. 45, No. 38, (February 25, 1980) (hereinafter, "Federal Register"), p. 12221.

[12] *Federal Energy Regulatory Commission v. American Electric Power Service Corporation*, 76 L. Ed. 2d 22, 34 (May 16, 1983).

PURPA also requires states to implement the promulgated FERC rules for investor-owned electric utilities.[13] Indeed, PURPA and FERC regulations delegate calculation of appropriate QF contract rates to individual state agencies. Oregon passed parallel state legislation (ORS 756.516 and ORS 758.500, et seq.). The Commission[14] first began developing rules implementing the federal and state requirements in 1980.[15]

In August of 1980, the Commission initiated rulemaking proceedings, Docket No. R 58, to establish QF policies. Order No. 80-568 solicited public input on identified issues and directed each electric utility to submit draft tariffs and other written materials details proposals for contracting with QFs. On May 6, 1981, the Commission entered Order No. 81-319 setting forth general policies and proposed rules for contracting with QFs. The intent of the order was:

> to provide maximum economic incentives for development of qualifying facilities while insuring that the costs of such development do not adversely impact utility ratepayers who ultimately pay these costs. The Commissioner will generally attempt to maintain this balance by requiring purchases of power from qualifying facilities at the purchasing utilities incremental generation and/or purchasing cost, thereby costing the ratepayers no more than the cost of the utility's own generation or wholesale purchases.[16]

The order established policies including: (1) rates for QF purchases would be at avoided costs; (2) standard rates would be available for QFs with a design capacity of 100 kW or less; (3) non-firm energy would be valued at the time of delivery; (4) firm energy would be valued, at the option of the QF, at the time a legal obligation is incurred to purchase the energy or at the time of delivery; (5) levelized payments would be allowed; (6) non-performance penalties were disallowed; (7) utilities could maintain a 10 percent reserve or require performance bonds as protection against non-performance; and (8) interconnection costs could be spread over a reasonable length of time, with one-half the contract term being deemed as reasonable.

On October 29, 1981, the Commission entered Order No. 81-755 adopting rules for contracting with QFs. The rules set forth factors to be considered in establishing avoided costs and required utilities to file avoided cost data on an annual and quarterly basis, subject to Commission review. QF rates were subject to a standard of review that required the rates to be just and reasonable to ratepayers and in the public interest.

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[13] *Id*.

[14] At the time, there was only one Commissioner and the agency was typically referred to as "the Commissioner." For ease and clarity in this order, however, the term, "the Commission" will be used, even when referencing actions taken by the Commissioner, except in quotes from prior orders.

[15] *See* OAR 860-029-0001 et seq, (2004). Pursuant to ORS 757.612(4), OAR 860-029-0001 exempts public utilities that satisfy the public purpose obligations set forth under ORS 757.612 from the Oregon PURPA laws.

[16] Order No. 81-319 at 3.

On September 12, 1984, the Commission entered Order No. 84-720 which modified certain QF contracting policies, including as follows: (1) required utilities to use a 35-year time period to project avoided costs rather than the 20-year statutory minimum; (2) required inclusion of a capacity payment in avoided cost calculations; (3) required seasonally differentiated short-term avoided energy costs; and (4) required standard contracts for QFs under 100 kW to be based on a projected 20-year contract life.

Less than two weeks later, the Commission entered Order No. 84-742, which addressed several significant policy issues regarding QF contracts. One issue was declining avoided cost rates resulting from an energy surplus in the region and consequent concerns that QF development would be hindered. A particular concern existed for QFs with a nameplate rating of 100 kW or less that typically did not have fixed-price agreements but rates that fluctuated with avoided costs. The Commission rejected a proposal to implement rates in excess of avoided costs. In rejecting this request, the Commission noted:

> Higher rates would make more projects feasible. However, the Commissioner has another goal to consider. That goal is to obtain service for ratepayers at reasonable rates. With upward pressure on utility rates coming from a variety of sources, the Commissioner is reluctant to impose higher costs on ratepayers.
>
> The Commissioner believes that the best balance between the two goals is to set rates equal to avoided costs. In periods of surplus, such as now, fewer projects are needed. When deficits are projected, avoided costs will rise and opportunities for profitable facility development will expand. Therefore, as a general policy, the Commissioner endorses adherence to avoided costs as the best pricing method.[17]

Instead, the Commission approved QFs with a nameplate rating of 100 kW or less having the option to enter into a long-term contract based on avoided costs in effect at the time the QF signed its original power delivery agreement or a short-term (five year) contract at the standard rate in effect the preceding year, escalated at four percent a year.

In Order No. 84-742, the Commission also addressed the issue of inequity in bargaining power between small QFs and utilities. Rather than adopting a proposal to establish the terms of QF contracts in a rulemaking, the Commission encouraged greater use of the Commission's dispute resolution services as, "the most effective way to equalize bargaining power."[18] A party could also file a petition with the Commission

[17] Order No. 84-742 at 3.
[18] *Id*. at 5.

requesting establishment of the terms of a QF contract. In Order No. 84-742, the Commission also addressed utility recovery of QF contract costs, stating:

> Since utilities are required by law to make purchases, and the Commissioner reviews the contracts, the chances of legitimate expenditures being disallowed are very small. The public interest will be better served by retaining the ability to examine the legitimacy of all utility expenditures. The Commissioner believes that the risk of non-recovery is a very small one that should be borne by the utility.[19]

In January 1985, the Commission entered Order No. 85-010, which addressed the issue of levelization. Partial levelization of the fixed cost (*i.e.*, capital costs) of the capacity portion of avoided costs was approved as a continuing policy. In the order, the Commission rejected levelization of variable costs and fixed operation and maintenance costs. The Commission approved a proposal by Staff to begin levelized payments in the year the utility was scheduled to begin development of a new resource. Prior to that year, QFs would receive nonlevelized payments. The Commission rejected a recommendation that QFs be allowed to "lock in" avoided costs during negotiations on other aspects of a contract. The Commission also indicated that a rule would be developed to address the Commission's role in dispute resolution.

Orders issued in 1986 and 1987 broadened, then narrowed, the Commission's dispute resolution role. Order No. 86-488 set forth rules establishing an informal assistance role, at the request of either a QF developer or an electric utility, for Staff to play in resolving disputes arising during contract negotiation. Order No. 87-1154 cancelled these rules and that role, however. Although a docket was opened to continue investigation into cogeneration, no order was ever entered in the proceeding. Instead, the Commission made a report to the Legislature.

In the 1988 report to the Oregon Legislature, the Commission stated its policy regarding PURPA implementation:

> It is the policy of the Oregon Public Utility Commission that federal and state laws and regulations will be carried out in a manner that encourages the economically efficient development of qualifying facilities in Oregon. It is the goal of the Commission to ensure desired qualifying facility development through stable and predictable actions by the Commission, accurate price signals, and full information to developers and the public regarding power sales requirements.[20]

[19] *Id*.

[20] Order No. 91-1605, entered on November 26, 1991, in Docket No. AR 246, implemented the change.

In addition to discussing the Commission's general policies, the report addressed numerous specific policy matters, including the methodology to determine avoided costs and issues regarding the QF contracting process. The report made several recommendations, including the following: (1) a proxy plant should not be used to determine avoided costs; (2) standard contracts for QFs sized at 1 megawatt (MW) or less warranted further investigation; (3) Staff should not participate in informal dispute resolution in order to preserve objectivity in ratemaking proceedings; and (4) QF contracts should not be pre-approved for cost recovery.

In Order No. 91-1383, entered in a docket primarily addressing competitive bidding policies, the Commission addressed issues affecting QFs in both PURPA and competitive bidding contracts. In the order, the Commission indicated that, due to the transaction costs in negotiating a QF contract, the capacity size limit to be eligible for standard rates should be raised from 100 kilowatts of nameplate capacity to 1000 kW or less. The order specified that a rulemaking would be opened to change the capacity limitation.[21] With regard to the length of contracts, the Commission indicated, "[t]he length of the contract a utility and a winning project sponsor agree to should result from their negotiations rather than from a Commission fiat."[22] The Commission then adopted the following three criteria for evaluating the prudency of contracts with terms of 20 years or more: (1) Whether there is a high probability that the resource will be operable well beyond 20 years; (2) Whether the developer could obtain financing for the resource for contract lengths of less than 20 years; and (3) Whether the resource's physical and cost characteristics make contract terms of more than 20 years advantageous to all parties.

Five years later, however, as the energy industry was undergoing tremendous change and evolving towards more competitive markets, the Commission limited the terms of QF contracts to five years. On October 30, 1996, PGE filed Advice No. 96-21, which proposed five-year term limits on QF contracts. In support of the term limit, PGE represented that the majority of long term power purchase contracts being negotiated in the energy market at the time were for periods of three to five years and that a QF contract longer than five years posed significant risk to PGE and its ratepayers. Staff supported the proposal, noting "[g]iven the continued movement toward a competitive marketplace for electricity and the prevalence of wholesale transactions for terms of five years or less," it is difficult to justify long-term QF contracts.[23] At the December 17, 1996 Public Meeting, the Commission adopted PGE's filing, thereby establishing a five-year contract length standard beginning in 1997.

C. SCOPE AND FRAMEWORK OF THIS ORDER

Before turning to the parties' arguments, we must clarify the scope and framework of this Order. As discussed above, we opened this proceeding to generally

[21] Order No. 91-1383 at 15.
[22] *Id*. at 16.
[23] Staff Report for December 17, 1996 Public Meeting, at 4.

investigate issues related to energy purchases from QFs by electric utilities. When the investigation was opened, Staff identified a number of general issues to be discussed. Ultimately, six of these general issues were designated to be taken up in this proceeding.[24]

Parties devoted significant attention in this proceeding to discussion of general PURPA requirements and the responsibilities of states to implement PURPA. We do not view the purpose of this docket to be a review of the Commission's general PURPA goals and policies, however. As discussed above, this Commission has consistently interpreted its PURPA mandate to be the adoption of policies and rules that promote QF development, using among other tactics, accurate price signals and full information to developers, while ensuring that utilities pay no more than avoided costs.

We view the purpose of this investigation to be an evaluation of specific rules and policies to determine whether the general PURPA goals that this Commission has long articulated could be more effectively implemented and achieved. This purpose is consistent with the scope of the proceeding agreed to by the parties. Staff requested that this investigation be opened in order to address the lack of recent QF development and recommended that we address six specific issues in the initial phase of this proceeding. Parties eventually agreed to this scope.

We reject PacifiCorp's arguments that the proceeding's scope is restricted solely to the review and revision of standard contract terms and conditions and does not encompass issues associated with the negotiation of non-standard contracts. We agree with Staff that the proceeding's scope is not limited to standard contracts, at least with regard to five of the six issues addressed.[25] Unfortunately, however, the parties presented little evidence regarding parameters and negotiating guidelines for non-standard contract terms and conditions. Although much of the evidence introduced in this proceeding could have potentially been used to support arguments for adopting more detailed negotiation guidelines and parameters for non-standard contracts, as Weyerhaeuser argues, the evidence was neither framed nor addressed in this manner. Consequently, as we later discuss in more detail, we conclude that the record in this proceeding does not support the adoption of detailed negotiation guidelines and parameters for non-standard contracts at this time.

Nonetheless, our intent with regard to implementation of PURPA remains the same as first articulated in 1981. We seek to provide maximum incentives for the development of QFs of *all* sizes, while ensuring that ratepayers remain indifferent to QF power by having utilities pay no more than their avoided costs. We are persuaded that significant barriers exist to the negotiation of non-standard contracts and that the detailed negotiation parameters and guidelines, as well as other measures, may overcome these barriers. Consequently, we deem it appropriate to address parameters and guidelines for the negotiation of non-standard contracts in a second phase of this proceeding.

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[24] *See supra* note 3.

[25] Issue number two, which addresses eligibility for standard contracts, was necessarily focused on standard contracts, although resolution of the issue has ramifications for non-standard contracts.

In keeping with how issues were framed and the nature of evidence introduced in this proceeding, the bulk of policy decisions made in this order exclusively apply to standard contracts. Certain issues, however, have consequences for the negotiation of non-standard contracts. For example, decisions regarding the calculation of avoided costs will have ramifications for the negotiation of non-standard contracts since these avoided costs are the starting point for negotiations of such contracts. Other issues were general in nature from the start. For example, dispute resolution procedures and the applicability of PURPA administrative rules are issues that have general applicability to all QF contracts and negotiations. A number of sub-issues were also identified in this proceeding having general consequences for both standard and non-standard QF contracts alike.

To be clear about the applicability of our decisions to standard contracts versus non-standard contracts, we indicate, where warranted, how such decisions affect negotiation of non-standard contracts. We also identify when it is appropriate to take an issue up, as it relates to either standard or non-standard contracts, or both, in a second phase of this proceeding.

III. STANDARD CONTRACT TERMS AND CONDITIONS

The term, “standard contract,” has been widely used by parties since passage of the federal PURPA law. The term is used to describe a standard set of rates, terms and conditions that govern a utility’s purchase of electrical power from QFs at avoided cost. Standard contracts are made available to a defined class of QFs that are deemed eligible under federal or state law to receive standard rates.

Parties raised a range of issues regarding standard contracts in this proceeding, including calculation of avoided costs, standard contract pricing and the appropriate length of a standard contract. A particularly contentious issue in this proceeding concerned eligibility to receive a standard contract. We address each issue and sub-issue raised during this proceeding, making policy decisions on many of the issues, and deferring or dismissing other issues as appropriate.

A. SIZE ELIGIBILITY TO RECEIVE STANDARD CONTRACTS

1. Overview

Most parties propose continuing to divide QFs into two categories: QFs that are eligible to sell power pursuant to a standard contract, and QFs that are not eligible for a standard contract. Standard contracts have pre-established rates, terms and conditions that an eligible QF can elect without any negotiation with the purchasing utility. If a QF is not eligible for a standard contract, a utility is still obligated to purchase a QF’s net output at the utility’s avoided cost, but the QF must negotiate the rates, terms and conditions of a power purchase contract with the purchasing utility.

The primary disagreement among the parties is the appropriate size threshold that should divide the two categories. The current threshold is 1 MW. Thus, QFs sized at or under 1 MW in size are eligible to obtain standard contract terms and conditions, while QFs over 1 MW are required to negotiate individual contracts with electric utilities.

2. Parties' Positions

All parties propose that the current eligibility threshold be increased, but significantly disagree as to the extent of the increase. The proposals range from a modest increase of 1 MW (applicable to all QF technologies other than wind) to elimination of the capacity ceiling for standard contract eligibility such that *all* QFs would be eligible for a standard contract.

All three electric utilities recommend a modest increase in the eligibility threshold. PacifiCorp and Idaho Power propose that the threshold be increased to 3 MW. PGE recommends that the standard contract ceiling capacity be increased to 5 MW for wind QFs, but only 2 MW for all other QF technologies. All three electric utilities caution against raising the threshold too high, as standard rates may overcompensate and subsidize QFs due to avoided cost calculations not being customized for particular projects. Idaho Power estimates the difference between levelized standard pricing based on the SAR methodology and alternatively calculated avoided costs to be as much as $0.01 per kWh. Idaho Power and PacifiCorp both observe that such a differential may result in a significant subsidy should it be applied to sizeable QF projects.

The utilities further comment that the primary rationale for offering standard rates to smaller QFs is to overcome prohibitive transaction costs that a very small QF must incur to negotiate a power contract.[26] They take the position that the threshold should be set no higher than essential to overcome market barriers associated with transaction costs. Although challenged by Staff, PacifiCorp initially justified the 3 MW threshold as representing the division between QF interconnection at transmission facilities, rather than a utility's distribution system. PacifiCorp also observes that a 3 MW QF project requires approximately $3 million in capital costs to construct, and argues that no evidence has been presented that a developer of a project of this magnitude or greater cannot afford the transaction costs that must be incurred to negotiate a non-

[26] PURPA regulations mandate that standard rates made available to QFs up to 100 kW only. 18 CFR § 292.304(c)(1). FERC stated in the order implementing PURPA:

> The Commission is aware that the supply characteristics of a particular facility may vary in value from the average rates set forth in the utility's standard rates required by this paragraph. If the Commission were to require individualized rates, however, the transaction costs associated with administration of the program would likely render the program uneconomic for this size of qualifying facility. As a result, the Commission will require that standard tariffs be implemented for facilities 100 kW or less." Order No. 69, Small Power Production and Cogeneration Facilities, FERC Regulation Preambles 1977-1981 ¶ 30,128, 45 12,214 (Feb. 25, 1980, 45 Fed. Reg. 24, 126 (Apr. 9, 1980).

standard contract with avoided cost rates that fairly reflect the characteristics of the project. PGE also observes that some parties may intend to engage in negotiations regardless of the availability of standard contract rates, terms and conditions and that a standard contract would be a fallback position in such negotiations. PGE asserts that concerns raised by parties advocating a significant increase in the eligibility threshold would be better addressed by improving transparency in the transaction process between utilities and QFs.

The utilities raise particular concerns regarding the ability of intermittent resources, such as wind and solar QFs, to receive standard rates. Idaho Power asserts that standard rates, to the extent they are based on the costs of an optimized generating resource that produces firm energy, overcompensate and subsidize intermittent QFs that produce non-firm energy. On the other hand, PGE proposes to recognize the low expected energy output per MW of installed capacity for wind resources by differentiating for eligibility purposes between wind QF resources and other QF resources. PGE would raise the eligibility threshold for wind resources to 5 MW.

Staff and ODOE recommend an increase in the capacity ceiling from 1 MW to 10 MW. Staff concludes that 10 MW was the appropriate threshold after conducting a thorough study of the recent history of QF development in Oregon, an evaluation of current utility power purchasing practices, and a review of pending QF projects identified by the State Energy Loan Program (SELP). Staff argues that an increase in the eligibility threshold is warranted in order to recognize that transaction costs and *other* market barriers, such as the lack of transparency for negotiated QF contract rates, terms and conditions, prevent successful negotiation of a power purchase contract for QFs that are at or under 10 MW. Staff also argues that the 10 MW threshold recognizes the inability of smaller QFs to participate in other market opportunities to sell power, including utility solicitations. ODOE bases its 10 MW eligibility threshold on past experience with the development of local wind projects, its coordination of Oregon's Renewable Action Plan, and as manager of SELP. ODOE represents that at 10 MW, negotiation costs become a relatively small fraction of total $10 million investment costs.

ICNU, Sherman County, Simplot and Weyerhaeuser all recommend significant increases in the capacity ceiling. Weyerhaeuser recommends a 100 MW threshold, while ICNU, Sherman County and Simplot initially proposed elimination of the capacity ceiling. Ultimately, ICNU recommends a 40 MW threshold for non-wind resources, while Sherman County and Simplot indicate that a 25 MW threshold would be acceptable. Although acknowledging the argument that larger QFs should have the resources and ability to negotiate avoided cost rates and contract terms and conditions with a utility, all four parties argue that QFs of all sizes are hindered by utility advantages, particularly superior knowledge of facts regarding utility systems and energy needs. Based on the experience of the state of Idaho, Weyerhaeuser observes that a standard contract threshold effectively acts as a cap on the size of QF that operates in the state, as few, if any, non-standard contracts above the threshold ever get negotiated. Indeed, ICNU argues that the eligibility threshold for standard contracts should be significantly raised for the purpose of ensuring that utilities cannot continue thwarting power purchases from larger QFs. ICNU also asserts that no party has rebutted evidence that larger QFs have no more leverage in negotiating with utilities than small QFs, are often unable to sell electricity in the wholesale market or participate in utility RFPs, and experience unique problems in QF contract negotiations.

PacifiCorp dismisses what it calls the "black box" argument of the larger QFs, stating that the allegations that utilities exploit asymmetries in information and bargaining power when negotiating with QFs are unproven. PacifiCorp suggests that the proper manner to address concerns about an uneven playing field is to ensure greater transparency and efficiency in the negotiation process, not to expand eligibility for standard contract terms and conditions.

Idaho Power also comments that setting the capacity threshold as high as 100 MW would compromise utility resource planning. Idaho Power adds that a competitive bidding process for resources would be undermined if standard rates were available to 100 MW QFs. Moreover, the limit would be problematic if applied to Idaho Power, as the company's total load in Oregon is 108 average megawatts (aMW).

In lieu of raising the eligibility threshold to 100 MW, Weyerhaeuser recommends that the Commission provide detailed guidance about the proper scope and nature of rates, terms and conditions for non-standard contracts. Weyerhaeuser asserts that more detailed guidance would provide larger QFs with a stronger negotiation position, as well as a baseline against which to compare offered terms and conditions. Weyerhaeuser represents that evidence presented in the case, although initially introduced as support for parties' positions on appropriate standard contract terms, provides a record for the Commission to adopt more detailed guidelines for non-standard contract negotiations. Weyerhaeuser observes that Staff agrees that Commission approval of certain policies, including contract duration, calculation of avoided costs and the pricing based on gas indexing, for standard contracts should apply to non-standard contracts. Weyerhaeuser urges the Commission to use the record in this proceed to adopt a broader array of guidelines for non-standard contracts. In briefing, Weyerhaeuser sets forth proposed guidelines that it argues are supported by the record.

In briefing, ICNU also recommends that the Commission provide more specific requirements regarding negotiation of non-standard contract terms and conditions. In particular, ICNU calls for additional guidance about how Oregon's avoided cost calculation should be modified for non-standard contracts to address factors identified by FERC, such as dispatch, reliability, scheduling outages and line losses.[27] Without such guidance, ICNU argues that the standard contract eligibility threshold could practically function as a cap on the size of QF projects developed. ICNU acknowledges that the record was insufficient, however, to determine a full panoply of guidelines and urges the Commission to take up the issues in subsequent proceedings.

3. Resolution

[27] *See* 18 C.F.R. § 292.304(e).

We continue to adhere to the policy, as articulated in Order No. 91-1605, that standard contract rates, terms and conditions are intended to be used as a means to remove transaction costs associated with QF contract negotiation, when such costs act as a market barrier to QF development.[28] Standard contracts are designed to eliminate negotiations and to thereby remove transaction costs. In implementing PURPA, FERC recognized that some QF projects would be too small and have projected revenues too minimal to justify investing the upfront costs necessary to engage an attorney on an hourly basis to negotiate a QF power purchase contract. Classifying these costs as "transaction costs," FERC determined that it was appropriate to eliminate transaction costs for a defined class of very small QFs.[29] Consequently, FERC mandated that QF projects sized at 100 kW or smaller would be eligible for standard contracts.[30] FERC discerned, however, that experience might demonstrate that this threshold was insufficient and delegated authority to state commissions to increase it.[31] As individual states have gained greater familiarity with QF projects, many states have increased the minimal threshold. This Commission has done so in the past and is asked to do so again in this proceeding.

The evidence in this proceeding shows that market barriers other than transaction costs pose obstacles to a QF's negotiation of a power purchase contract. In addition to transaction costs, which in economics and related disciplines are traditionally considered to encompass only those costs that are incurred to make an economic exchange, parties identified other market barriers such as asymmetric information and an unlevel playing field that obstruct the negotiation of non-standard QF contracts. Just like transaction costs, these market barriers can render certain QF projects uneconomic to get off the ground if an individual contract must be negotiated. We conclude that it is appropriate and in keeping with the general PURPA policies of this Commission and FERC to increase the eligibility threshold for standard contracts in order to overcome economic impediments created by these market barriers.

At the same time, however, we recognize a need to balance our interest in reducing these market barriers with our goal of ensuring that a utility pays a QF no more than its avoided costs for the purchase of energy. With standard contracts, project characteristics that cause the utility's cost savings to differ from its actual avoided costs are ignored. No party presented evidence in this docket that the special characteristics of larger projects do not need to be considered in order to achieve rates that reflect actual avoided costs. Furthermore, the risk customers face because avoided costs in the future may be different from the prices paid under a standard contract (through the Fixed-Price Method, for example) is greater for a large QF than a small one.

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[28] Order No. 91-1605, at page 2 states: ". . . [T]he transaction costs associated with negotiating a QF/utility power purchase agreement could be prohibitive for small QFs and effectively eliminate them from the marketplace. The standard rate is intended to address this concern by minimizing the transaction costs of negotiating a power purchase agreement."
[29] *See supra* note 42.
[30] 18 C.F.R. § 292.304(c).
[31] 18 C.F.R. §292.304(c)(2).

We deem the recommendation of Staff and ODOE to raise the standard contract eligibility threshold to 10 MW to be reasonable.[32] We rely, in particular, on the facts that Staff's proposed threshold of 10 MW took into account the extent to which market barriers prevented successful negotiation of a contract and that ODOE, which has significant experience with the development of QF projects, indicated that 10 MW represented a point at which the costs of negotiation become a reasonable fraction of total investment costs.

We are persuaded that QFs greater in size than 10 MW face market barriers, such as asymmetric information and an unlevel playing field, that impede negotiation of a viable QF power purchase contract with electric utilities. We agree with PacifiCorp and PGE, however, and conclude that such market barriers will be best overcome for those QFs by improved negotiation parameters and guidelines and greater transparency in the negotiation process.

Although some of the evidence presented in this case could potentially support adoption of specific QF contract negotiation parameters and guidelines, as requested by Weyerhaeuser, the parties did not address the evidence from this standpoint. Even the evidence presented by Weyerhaeuser was initially introduced for the purpose of supporting appropriate standard contract terms and conditions that would be available to QFs as large as 100 MW. We conclude that the evidence in this proceeding did not receive the analysis and examination that would be needed to support the adoption of negotiation guidelines for non-standard contracts. Consequently, we direct parties to take up the issue of negotiation guidelines and parameters for non-standard contracts in the second phase of this proceeding. Although Staff identified certain issues, such as contract duration, that could potentially be resolved with regard to both standard and non-standard contracts, we conclude that it is preferable to address the full scope of non-standard rates, terms and conditions on a collective basis. Consequently, we decline to adopt rates, terms and conditions, or associated parameters or guidelines, for non-standard contracts, except to the extent that we do so explicitly.

B. STANDARD CONTRACT LENGTH

1. Parties' Positions

All parties proposed a significant increase in the term of standard contracts. Proposals to increase the maximum standard term from five years ranged up to thirty years and beyond for some QF technologies. Most parties advocate increasing the maximum standard term from five to either fifteen or twenty years. Parties preferring a fifteen year term for standard contracts raise concerns that standard rates will not track avoided costs over too long of a term. They caution that the risks are great, pointing to past history when high QF rates were locked in for terms up to thirty-five years. Parties that favor an increase to twenty years, however, express concern that financing for many QF projects requires the longer term.

[32] Having raised the eligibility threshold to 10 MW, we decline to distinguish between wind and non-wind QF resources by instituting a higher eligibility threshold for wind resources.

PacifiCorp, PGE, Idaho Power[33] and Staff each propose that the maximum standard contract term be fifteen years, with QFs having the discretion to request any term up to the maximum. The consensus of these parties is that the maximum standard contract term should be no longer than necessary to facilitate QF financing. All indicate that a term of fifteen years represents an appropriate balance between attracting QF financing and limiting the risks that accompany long range power price forecasting.

A primary basis for Staff's recommendation for a 15-year maximum term are past representations by the ODOE that fifteen years is a sufficient financing period for some QF projects, and that certain QF project developers have requested 15-year loans in the recent past. Staff particularly relies on a letter sent in December 2003 from the loan program manager for ODOE's SELP to the Commission that indicates 15 years was a usual term for QF contracts.[34] Staff is reluctant to support a contract term longer than 15 years due to the likelihood that fixed avoided cost rates would diverge over time from actual avoided costs. Moreover, Staff recognizes that utilities must enter into must-take QF contracts without the full evaluation of cost and risk that would be associated with other power resources. PacifiCorp and PGE concur. While PGE observes that it is inappropriate to compare terms for QF contracts with terms for other utility resources due to the discretion and safeguards associated with those resources, all three parties note that 15 years is within the range of other utility resources.

ODOE recommends a maximum term of 20 years, noting that such time frame generally represents the middle point of typical terms for other utility resources. ODOE disagrees with Staff's claim that a term of fifteen years is sufficient to attract financing. ODOE indicates that since 1980, ODOE's loan program has financed twenty-one QF projects. Of those, sixteen projects have been financed for periods of twenty to twenty-five years, three for shorter terms, and two for longer. ODOE asserts that "twenty years should allow for adequate financing of the majority of QF projects our program has reviewed,"[35] and notes that some QF projects will be economically feasible only with a twenty-year term. Sherman County, Simplot Company and Weyerhaeuser concur that the maximum standard contract term should be twenty years. Weyerhaeuser adds that the Commission should provide that existing standard contracts may be renewed for ten years.

Two parties argue that the maximum term for standard contract term should be, in many cases, much longer than twenty years. FRC does not specify what the

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[33] Observing that the Idaho Commission has authorized twenty year QF contracts in Idaho, Idaho Power notes that 20-year terms in Oregon would provide administrative ease for the Company. Idaho Power further observes, however, that the QF contracts have protections that may not be authorized in Oregon. Consequently, Idaho Power requests that it be allowed to implement some of the same provisions authorized by the Idaho Commission in Oregon should a maximum standard contract term of 20 years be adopted in Oregon.

[34] The letter stated: "As a lender, it is important to have a power purchase contract that equals the loan term, usually fifteen years." Staff 200 at 6; *See* Staff 202 at 1.

[35] ODOE 3 at 2.

initial term of a QF contract should be, other than to say it should be as long as reasonably possible. FRC does, however, seek an evergreen provision that would effectively extend a QF contract over the entire economic life of a QF project. An evergreen provision would allow a QF, at its sole discretion, to continually renew a QF contract, presumably as long as the QF was able to economically operate under the contract. ICNU, on the other hand, asserts that QF contracts should extend, from the start, through the economic life of a facility. For example, a hydro QF project would be eligible to receive a standard contract for a term of up to fifty years, while a biomass QF would be eligible to receive a standard contract with a term between ten and fifteen years. ICNU asserts that financing is difficult and more expensive to obtain when contract lives are less than economic lives, and that matching QF contract life with economic life treats QF projects on par with how other utility resources are addressed.

2. Resolution

We conclude that establishing an appropriate maximum term for standard contracts requires us to balance two goals. A primary goal in this proceeding is to accurately price QF power. We also seek, however, to ensure that QF projects that are deemed eligible to receive standard contracts have viable opportunities to enter into a standard contract. To achieve this latter goal, it is necessary to ensure that the terms of the standard contract facilitate appropriate financing for a QF project. Consequently, we agree with Staff and other parties that our fundamental objective is to establish a maximum standard contract term that enables eligible QFs to obtain adequate financing, but limits the possible divergence of standard contract rates from actual avoided costs.

In adopting this objective, we implicitly reject the position advocated by FRC and ICNU that the life of a QF contract should extend, at the discretion of the QF developer, over the entire economic life of the project. We observe that neither FRC nor ICNU presented evidence indicating that the economic viability of a QF project requires financing that is equal to the economic life of the QF facility. Although ICNU represented that such financing would put QFs on par with utility resources, ICNU did not assert that such financing was *required* for the viability of QF projects. Although a QF project may have an economic operating life of up to 50 years, it is probable that the project may be initially financed over a period far less than its economic life.

We conclude that the contract term length minimally necessary to ensure that most QF projects can be financed should be the maximum term for standard contracts. The evidence presented in this proceeding is inconclusive, however, about whether that length of term is 15 or 20 years. No party was definitive regarding a recommendation. For example, although PacifiCorp consistently recommended that 15 years be established as the maximum standard contract, PacifiCorp did so with some ambiguity, stating: “[a] contract term of 15 years *should be* adequate to address the financiability concerns raised in this proceeding.”[36]

[36] PacifiCorp Opening Brief at 4; PacifiCorp 100 at 5 (emphasis added).

No party, other than ODOE which finances QF projects through SELP, presented testimony about the appropriate term for QF contracts from entities that are likely to finance the projects. Although Staff presented evidence that ODOE has represented in the recent past that 15 years is an appropriate term, ODOE itself argued in this proceeding that 20 years is minimally adequate.

Given its role as a facilitator and financier of QF projects, we find ODOE's testimony to be the most persuasive in this proceeding. Consequently, we adopt ODOE's recommendation that the maximum term of a standard contract be raised to 20 years. In so doing, however, we acknowledge that 20 years is a significant amount of time over which to forecast avoided costs. Indeed, divergence between forecasted and actual avoided costs must be expected over a period of 20 years. Given our desire to calculate avoided costs as accurately as possible, and the testimony of several parties that avoided costs should not be fixed beyond 15 years, we are persuaded that standard contract prices should be fixed for only the first 15 years of the 20-year term. Tariffs and standard contract terms should provide that, in the event a QF opts for a standard contract with a 20-year term, the QF must take one of the market pricing options that we address later in this order for the final five years of the contract.[37]

C. CALCULATION OF STANDARD AVOIDED COSTS

1. Overview

FERC defines a utility's full avoided costs 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."[38] Thus, the goal of calculating avoided costs is to accurately estimate the costs a utility would incur to obtain an amount of power that it purchases from a QF, either by the utility's self-generation or by purchase from a third party. Each utility serving customers in the state of Oregon currently utilizes an individualized methodology to calculate avoided costs.

QFs with design capacities larger than the relevant standard contract threshold are still entitled to sell power to a utility at avoided costs, but receive avoided cost rates that are individually negotiated with a utility to reflect specific characteristics of the project and its interconnection with the utility. Negotiations typically start with the standard avoided costs, however.[39] Consequently, in setting standard avoided costs, we

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[37] *See discussion*, page 34.
[38] 18 C.F.R. § 292.101(b)(6).
[39] 18 C.F.R. § 292.304(e). Non-standard avoided cost rates deviate from standard avoided costs in order to reflect the following considerations set forth by FERC:

(1) The utility's system cost data;
(2) The availability of capacity or energy from a QF 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 terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

acknowledge that we are also setting a starting point for negotiation of rates for non-standard contracts.

2. Parties' Positions

Calculation of each electric utility's standard avoided costs begins with the utility filing an integrated resource plan (IRP) for a 20-year planning horizon, as required every two years. Within thirty days of the Commission's acknowledgement of an IRP, the utility makes an avoided cost filing based on its IRP, but updated as appropriate.[40] Consistent with IRP filings, utilities calculate avoided costs for a period of 20 to 25 years.

Each utility represents that its current avoided cost methodology has been designed to capture the avoided costs actually realized by the electric utility when it purchases power from a QF. For example, PGE considers it appropriate to use expected wholesale power market prices to determine avoided costs for its system due to PGE's significant market purchases. PGE observes that paying market prices to QFs equates to PGE purchasing power on the market, which is consistent with its current operations.

PGE further explains that, as of its 2001 avoided cost filing, PGE bases avoided costs on projections of the wholesale market price of energy delivered to PGE's system. The 2001 filing listed expected market prices for a period of 20 years, as calculated by PGE's Multiple Area and Network Energy Transaction (MONET) model. Initially, in years 2001 and 2002, PGE based avoided costs on a published electricity index of forward trading prices for the Pacific Northwest. Since 2003, PGE bases avoided costs on a published index indicative of natural gas prices in the Northwest and a correlation factor that reflects the relationship between electricity and gas prices. PGE represents that as fixed costs of new resources added over time are fully reflected in long-term market prices, separate fixed capacity and energy components are not appropriate. PGE also indicates that capacity contracts are no longer available in the marketplace at economic prices. PGE separates QF power deliveries into firm and non-firm categories. Assuming firm power prescheduled and delivered flat across each hour, as well as a strong correlation to gas prices, avoided costs paid to a QF are based on an indexed

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(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;
(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;
(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and
(vii) 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 QF 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 costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a QF, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

[40] *See* OAR 860-029-0080(3).

expected market price. Standard contract rates are based on the average of expected market prices for a year, broken down by season and on- and off-peak. Non-standard contracts are customized for the characteristics of the QF project. PGE challenges the appropriateness of paying capacity fees for non-firm energy for which there is no delivery commitment.

PGE's current avoided calculation represents a break with tradition. Historically, when in a period of resource surplus or sufficiency, Oregon electric utilities have calculated avoided costs based only on the variable costs of operating existing generating facilities. In periods of resource deficiency, the calculation of avoided costs has historically included both the variable and fixed costs of avoided resources. Recent utility resource plans identify a natural gas-fired combined cycle combustion turbine (CCCT) as a proxy plant for calculating costs that can be avoided when QF power replaces new utility resources. The theory that underlies separate calculations for periods of resource sufficiency and deficiency is that a utility is actively planning to acquire, and therefore can actually avoid acquiring new resources, only when the utility is in a resource deficient position.

PacifiCorp's current avoided costs methodology is founded on the historical approach. PacifiCorp explains that its avoided costs are based until 2006, while PacifiCorp is in a resource sufficient position, on the marginal production cost of existing units. Beginning in 2007, PacifiCorp anticipates needing new resources to provide summer and winter capacity as well as additional energy to meet its resource requirements, and therefore bases its long term avoided costs on CCCT costs.

To calculate avoided costs, PacifiCorp begins with the load and resource balances developed in conjunction with its 2003 IRP planning process. During periods of resource sufficiency, PacifiCorp calculates avoided energy costs based on the displacement of purchased power and existing thermal resources, as modeled by the company's GRID model, with data input that includes the 2003 IRP monthly load and resource data. To calculate the short-run avoided costs, PacifiCorp compares the difference between two production cost studies, with one study assuming a 50 aMW increase in system resources, at zero running cost, to serve as a proxy for QF generation. During periods of resource insufficiency, PacifiCorp determines avoided costs based on the fixed and variable costs of a CCCT as a proxy for the planned resource that could be avoided or deferred. Since CCCTs are built as base load units that provide both capacity and energy, it is appropriate to split the fixed costs of this unit into capacity and energy components. To determine the portion of fixed costs allocated to capacity, PacifiCorp uses the fixed cost of a single-cycle combustion turbine (SCCT), which is usually acquired as a capacity resource, to define the portion of the fixed cost of the CCCT that is assigned to capacity. Fixed costs for a CCCT in excess of SCCT costs are assigned to energy and are added to the variable production (fuel) cost of the CCCT to determine the total avoided energy costs. The fuel cost of the CCCT, based on gas price forecasts, defines the variable energy costs. Avoided energy costs can be differentiated between on-peak and off-peak periods. To make this calculation, PacifiCorp assumes that all capacity costs are incurred to meet on-peak load requirements.

As explained in Idaho Power's informational filing, Idaho Power also breaks with the historical approach and uses the surrogate avoided resource (SAR) methodology to calculate avoided costs for Oregon. Idaho Power uses input and cost variables that are associated with a surrogate CCCT, as approved by the Idaho Public Utilities Commission.[41] Idaho Power prepares an annual forecast of on-peak and off-peak avoided costs for the surrogate CCCT that have been adjusted for seasonal differentiation and use a gas price forecast derived from the Draft Fuel Price Forecasts for the Fifth Northwest Conservation and Electric Power Plan that was issued by the Northwest Power Planning Council on April 25, 2002. Prices for generation during off-peak hours reflect the variable costs of the surrogate CCCT, while prices for generation during peak times reflect capitalized costs plus variable costs. If a QF cannot commit to provide firm power, power will be purchased from that QF at a price that reflects only the value of the energy.

When PGE and PacifiCorp are in a resource-deficit position, Staff recommends that these utilities use the historical methodology to calculate avoided costs. Staff disagrees with the premise that a utility need not pay a QF for capacity during a resource surplus period, however. Staff maintains that QF capacity during a resource surplus period has value to the utility, as the utility can sell capacity into market or use the additional capacity to improve reliability. ODOE agrees, stating:

> Planning reserve margins for capacity resources are a target to maintain an adequate but not a perfect level of reliability. It is always useful to have increased reliability from having more capacity resources.[42]

Staff and ODOE also identify advantages to incremental capacity added by QFs, rather than lumpy capacity being added by new utility plant. When the utility is in a resource-surplus position, Staff asserts that capacity should be valued, using one of two methodologies that would establish a "market-based" value for avoided capacity costs.

One methodology would value avoided costs at the sum of the variable cost of operating existing generating facilities, plus the price of capacity in the wholesale market. Staff recommends that this methodology, when employed in standard contracts, be combined with levelization of the avoided capacity costs. Although ODOE would prefer use of the SAR methodology to calculate avoided costs at all times, if market pricing is used to value avoided cost, ODOE argues that separate market prices for capacity should be included in the calculation. ODOE represents that capacity is routinely sold among utilities in Western and Northwestern regions and can be valued on a market basis. Although Staff generally opposes levelization, Staff contends that levelization of avoided capacity payments when a utility is resource sufficient is appropriate, as compensation for a QF's assistance in meeting future demand growth and as a means to encourage QF development.

[41] IPUC Order 29124.
[42] ODOE 1 at 4, lines 9-11.

The utilities oppose any levelization of payments. Observing that levelization front-loads payments, the utilities warn that levelization of payments increases ratepayers' risks. Indeed, PGE and Idaho Power characterize levelization as a loan that imposes the risk of default on ratepayers. Should the Commission adopt levelization in any form, the utilities argue that greater security requirements will be necessary.

The second methodology would value avoided costs at monthly on- and off-peak forward market power prices as of a utility's avoided cost filing, thereby embedding the market value of capacity in the avoided cost rate. Staff ultimately prefers the adoption of this market-based methodology, as does PacifiCorp and ODOE. ODOE notes that forward firm energy markets at the Mid-Columbia hub are more liquid and standardized than markets for capacity contracts.

Staff would apply either market methodology to both intermittent and firm resources. Staff asserts that intermittent resources are, on average, available during peak hours and should, therefore, receive capacity credit. Staff recommends against always reducing avoided cost payments to energy-only payments when a QF delivers less energy than expected.[43]

Staff also recommends imposing a mechanical availability guarantee (MAG) in each standard contract. The MAG would be based on the QF's capability to produce power based on the project's capacity factor, with consideration for factors that reduce capability, including scheduled maintenance, system emergencies or a force majeure event. If they do no meet the availability threshold, utilities would be able to reduce QF payments to energy-only rates, subtracting the capacity component until the QF demonstrates that it has corrected production problems. PGE criticizes Staff's proposed MAG as guaranteeing little. ODOE, on the other hand, is concerned that the MAG could unduly penalize a QF for operational unavailability that is beyond its control. As an example, ODOE points out that maintenance delays could be extended by a third party vendor. ODOE also argues that, should the MAG result in the reduction of capacity payments, the reduction should be implemented as a reduction in future payments and that QFs should be allowed to demonstrate the reinstitution of mechanical availability within 30 days.

With regard to Idaho Power, Staff recognizes the administrative efficiency advantages of having consistency between the company's avoided cost calculations in its Oregon and Idaho jurisdictions. Consequently, Staff recommends that Idaho Power be authorized to use the SAR methodology in Oregon, regardless of whether Idaho Power is in a resource surplus or deficit position, with only one modification: Idaho Power should be required to file avoided costs for on- and off-peak hours. Staff recommends that all other requirements adopted by the Commission in this docket apply to Idaho Power. PacifiCorp does not oppose authorization of a different avoided costs calculation for Idaho Power.

In order to facilitate implementation of its pricing recommendations, Staff proposes one additional requirement for avoided costs calculations. Staff recommends that utilities develop avoided costs for both a fixed set of prices and an indexed set of prices. As will be further discussed, the fixed avoided costs would be used, for pricing purposes, as a basis for Staff's fixed pricing option while the indexed avoided costs would be used as a basis for rates developed pursuant to Staff's Deadband and Gas Market methods.

For varying reasons, ODOE, Sherman County and Simplot recommend that the Commission not differentiate with regard to the calculation of avoided costs when a utility is in a resource deficient position versus a resource sufficient position, and urge the Commission to adopt the SAR methodology, as approved by the Idaho Commission, to calculate avoided costs at all times. Sherman County and Simplot oppose calculating different avoided costs depending on whether a utility is in a resource surplus or deficit position based on administrative burden and concerns that utility planning processes minimize resource deficits. They observe that the need to determine a utility's resource position requires resolution of issues such as IRP assumptions relative to load growth projections and water year averages. Sherman County and J. R. Simplot primarily recommend that the Commission adopt the SAR approach for administrative ease. Similarly, ODOE argues that it is difficult to distinguish between when a utility is resource deficient as opposed to sufficient. Moreover, ODOE objects to the current calculation of avoided costs when a utility is in a resource deficit position. ODOE's objection is based on the volatility and uncertainty about market prices and concerns about proper valuation of capacity. ODOE favors SAR's valuation of avoided costs in all years at the full cost of a CCCT.

ICNU recommends that avoided costs be based on utility-specific resources or a proxy CCCT as a surrogate resource. Similarly, Weyerhaeuser objects to avoided costs reflecting only variable costs until the first year a utility is in a supply deficit position. Weyerhaeuser argues that avoided costs should reflect the full costs of an avoidable resource, generally agreed to be represented by a CCCT. Weyerhaeuser also supports the incremental capacity additions of QFs. Weyerhaeuser would make an exception, however, if a utility could demonstrate that it is in a resource surplus position that is likely to last more than five years.

Staff and the utilities object to the global application of the SAR methodology on several grounds. PGE deems the SAR methodology to be an artificial construct that doesn't adequately capture avoided costs for individual utilities. Another complaint, as articulated by Staff and PacifiCorp, is that SAR fails to differentiate avoided costs by season or time of day. Unlike the historical volumetric pricing model used by PacifiCorp, the SAR methodology would spread capacity benefits across all hours and would not differentiate between seasons or peak and off-peak hours, thereby removing incentives for QFs to deliver power when it is most needed. PacifiCorp states that utilities receive a capacity benefit from QF deliveries during peak hours and that volumetric pricing aligns the payment of capacity benefits with periods when surplus capacity has the greatest reliability benefits. PacifiCorp also argues that SAR's elimination of any differentiation between a utility's resource surplus and deficit position results in ratepayers paying too much, because utilities back down less expensive resources due to surplus QF capacity. Staff agrees, but notes that capacity always has some value.

3. Resolution

A primary dispute among the parties with regard to the calculation of avoided costs centers on the question of whether the calculation should be differentiated in order to reflect a utility's resource position. If we conclude that the calculation should be differentiated, parties debate what the scope and nature of that differentiation should be.

Parties arguing that there should be no differentiation uniformly recommend that we adopt the SAR methodology as a singular approach to calculating standard avoided cost rates, regardless of a utility's resource status. These parties introduced little evidence, however, that the SAR methodology is a substantively better approach than the historical methodology to calculate avoided costs when a utility is in a resource deficient position.

We are reluctant to abandon this Commission's long history of differentiating the calculation of avoided costs for a utility in a resource deficit position from a utility in a surplus position. The historical differentiation is based on recognition that a utility's avoided costs differ depending on the resource position of the utility. In a period of resource deficiency, the historical calculation of avoided costs has included both the variable and fixed costs of a planned resource in order to reflect the actual deferral or avoidance of that resource. In a period of resource sufficiency, however, the historical calculation of avoided costs has included only the variable costs of operating an existing resource, reflecting the inability of a resource sufficient utility to defer or avoid a resource when QF generation is committed.

We remain convinced that the accurate calculation of avoided costs requires differentiation when a utility is in a resource sufficient position versus a resource deficient position. As it is one of our primary goals to ensure that avoided costs are calculated accurately, we are not persuaded that the procedural administrative efficiency benefits of using the SAR methodology in all situations outweigh the substantive benefits of using different calculations depending on a utility's resource position. Consequently, we decline to adopt the SAR methodology as a singular approach to calculating standard avoided cost rates.

We find that administrative efficiency interests do, however, justify authorizing Idaho Power to continue using the SAR methodology to calculate avoided costs regardless of its resource position. In recognition of the fact that Idaho Power exclusively uses the SAR methodology in its Idaho service territory, where it serves far more customers than its Oregon service territory, we find that the administrative burdens to Idaho Power of developing and applying new avoided cost methodologies in Oregon outweigh the potential benefits and justify allowing Idaho Power to continue to use the SAR methodology. Consequently, we direct Idaho Power to continue using the SAR methodology to uniformly calculate avoided rates in Oregon.[44] We adopt Staff's proposed modification to this practice, however; Idaho Power should file avoided costs for on-peak and off-peak hours.

As for PacifiCorp or PGE, we adopt Staff's recommendation that these utilities apply the methodology historically used in Oregon to calculate avoided cost rates when either is resource deficient. Pursuant to this methodology, avoided cost rates for PacifiCorp and PGE, when either utility is in a resource deficient position, will reflect the variable and fixed costs of a natural gas-fired CCCT. In the second phase of this proceeding, parties may address whether the new resource used to determine avoided costs in the deficit period should instead be identified in the utility's IRP (which may select something other than a natural gas-fired CCCT).

Consequently, we direct PGE to discontinue using the market-based methodology it most recently employed to calculate avoided costs. In doing so, we find the substantive concern raised by ODOE regarding the use of market prices to have merit. The calculation of avoided costs when a utility is in a resource deficient position should reflect longer term resource decisions that are subject to deferral or avoidance due to QF power purchases. Although a utility may acquire market resources as demand gradually builds, at some point the increase in demand warrants the utility making plans to build or acquire long-term generation resources. At that point, calculation of avoided costs should reflect the potential deferral or avoidance of such generation resources. In Docket No. LC 33, we recently addressed PGE's long-term resource plans, which include development of a new electric generation resource.[45] Based on these long-term resource plans, we deem it appropriate for PGE to calculate avoided costs based on the historical approach.

Having determined that calculation of avoided costs will be differentiated to reflect a utility's resource position, we next address the more fundamental dispute among the parties regarding the scope and nature of such differentiation. We conclude that the basis for differentiation should not be whether capacity is valued *at all*, but *how* it is valued. When in a period of resource sufficiency, PGE and PacifiCorp have historically calculated avoided costs based only on the variable costs of operating existing generating resources. Staff and several other parties, however, challenged the lack of capacity payments to QFs when a utility is in a resource sufficient position, arguing that QF capacity has at least some value to utilities at all times and that this value should be compensated for.

When a utility is in a resource sufficient position, we adopt Staff's recommendation that QF capacity be valued based on the market. Although valuation of QF capacity based on the market price of capacity itself has significant appeal, we are concerned about inconsistent evidence regarding the viability of the market for capacity.

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[44] As we note throughout this order, this is the only exception we make for Idaho Power. All other resolutions of issues in this order shall apply to all electric utilities operating in Oregon, including Idaho Power.

[45] *See* Order Nos. 04-375 and 04-376.

Consequently, of the two market-based valuation methodologies proposed by Staff, we adopt the methodology that values avoided costs when a utility is in a resource sufficient position at monthly on- and off-peak forward market prices as of the utility's avoided cost filing.[46] We agree with Staff that this approach embeds the value of incremental QF capacity in the total market-based avoided cost rate. We find this valuation mechanism to be appropriate given the likelihood that a utility will address probable gaps between increasing demand and actual resources, in the absence of incremental QF capacity, with purchases of energy and capacity on the market. Indeed, we find PGE's recent history of buying significant resources on the market prior to a commitment to build new utility plant to be illustrative. To the extent that a party can provide evidence regarding the market pricing of capacity, however, we remain open to reconsideration of this decision in the next phase of this proceeding.

Although we find that firm energy provides the most reliable capacity benefits, we are persuaded by Staff's argument regarding the average availability of intermittent resources. Consequently, we conclude that intermittent and firm resources should be valued equally,[47] and direct utilities to pay full avoided costs pursuant to the appropriate methodology for all energy delivered under a QF standard contract, but only up to the nameplate rating of the facility. As electric utilities cannot expect and, therefore, would not rely on deliveries of excess energy in any manner, we conclude that energy delivered in excess of the nameplate rating does not provide capacity benefits that warrant payment of full avoided costs. Because we conclude that utilities have a legal obligation to take all energy provided by a QF, we direct the utilities to accept delivery of excess energy, but to compensate QFs for only the energy itself and not capacity. In such situations, utilities should use the methodology that has historically been used when utilities are in a resource deficient position.

Given our position that a QF's commitment of firm energy is preferable to non-firm deliveries, we are intrigued by Staff's proposed MAG. We find, however, that the evidence introduced regarding the MAG is too limited to make any determinations about its viability and suitability. For example, although Staff indicated that a QF's MAG would be based on the QF's capacity factor, adjusted for consideration of factors that reduce this capacity, including maintenance, system emergencies or a force majeure, there was little discussion among the parties about how these adjustments would be applied in standard contracts. Without further development of such details we conclude that the MAG would likely lead to contractual disputes which would undermine the purpose of standard contracts. Consequently, we decline to require a MAG.

Finally we note that in our view, issues relating to the scope, nature and quality of QF energy, and the effects of these factors on the calculation of avoided costs, were inadequately developed factually by the parties. A second phase of this investigation is anticipated. We envision an ongoing process to improve opportunities

[46] As we do not adopt Staff's proposed methodology that would separately value capacity and pay levelized rates, we need not address the issue of levelization in this Order.

[47] Parties may present evidence on the value of intermittent power vis-à-vis firm power in the second phase of this proceeding.

for QF power at realistic avoided cost rates. Consequently, we encourage parties to further refine such issues and to raise them for reconsideration, as appropriate, in the second phase of this proceeding.

D. FREQUENCY OF SETTING AVOIDED COSTS RATES

1. Parties' Positions

Three parties commented on how often avoided cost rates should be filed with the Commission and reviewed and approved. PacifiCorp recommends that electric utilities be allowed to update avoided costs more frequently than every two years in order to reflect new resources being added to a utility's system. Both Staff and ODOE support maintaining the current filing schedule which requires each utility to make an avoided cost filing every two years coincident with the IRP process. Staff objects to PacifiCorp's proposal, calling it "unbalanced" as it would allow a utility to update avoided costs when a change in circumstances causes the utility to be in a resource sufficient position, but would fail to direct a utility to update avoided costs when a change in circumstances causes the utility to be in a deficit resource position.

2. Resolution

We affirm the continued use of a two-year filing cycle for avoided cost rates. We acknowledge, however, that circumstances can significantly change within a short period of time to render avoided costs outdated. As it is our overriding goal to accurately assess avoided costs on an ongoing basis, we deem it appropriate to introduce some flexibility into the process that is used to establish avoided cost rates.

Understanding that circumstances may change to make existing avoided cost rates either too low or too high, we recognize that other parties besides the utility may wish to address avoided cost rates on an unscheduled basis. Consequently, we will exercise our discretion, when appropriate, to direct a utility to make an avoided cost filing between scheduled filings. The Commission may institute a supplementary proceeding to review a utility's avoided costs on its own motion or at the request of any party. We encourage parties to notify the Commission when it may be appropriate to review avoided cost rates between filing deadlines.

We also note that this issue intersects with the filing cycle issues identified by Staff for future consideration.[48] Consequently, we expect that the issue may receive further attention in the future.

[48] *See supra* note 4.

E. ADDER ON AVOIDED COSTS

1. Parties' Positions

FRC represents a class of very small QFs with installed capacities that are less than 500 kilowatts. FRC argues that the class of QFs under 3 MW (or alternatively, under 1 MW) should be paid an "adder" of .5 to 1.5 mills to recognize the reliance of this class of QFs on a reasonable rate at the time that QF projects were initially developed, or to compensate this class of QFs for the additional costs that utilities and ratepayers avoid through the benefits conferred by small QF generation. FRC indicates that these benefits include civic and community advantages, geographical diversity and aesthetics.

FRC offers a recent case decided by the Vermont Public Service Board (Vermont Commission) as support for its position.[49] FRC represents that the Vermont Commission approved an avoided cost adder to compensate for the time lag in utility payments to QFs and argues that this authorization is analogous to the adder requested by FRC.

Staff and PGE both oppose the proposed adder. PGE asserts that the adder would be compensation in excess of avoided costs, while Staff points out that any environmental benefits are already rewarded due to the QF's retention of renewable certificates, also known as green tags, than can be traded or sold on the market.

2. Resolution

Pursuant to section 210(b) of PURPA, the rate paid to QFs cannot exceed the incremental cost to the utility of alternative electric energy. Consequently, in setting avoided cost rates, only costs which would actually be incurred by a utility in lieu of purchasing QF power may be compensated for by rates that are based on avoided costs. The authority of states to prescribe rates for sales by QFs that exceed avoided costs is clear: states are preempted from doing so by section 210(b) of PURPA.[50] With regard to environmental costs, FERC has specifically held:

> Under section 210(b) of PURPA, 'no rule . . . shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.' Thus, in setting avoided cost rates, a state may only account for costs which actually would be incurred by utilities. A state may, through state action, influence what costs are incurred by the utility. Thus, accounting for

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[49] *In Re 14 Vermont Electric Utilities*, Docket No. 6270, Vt. P.S.B, 212 PUR 4th 405, 2001 WL 1359779 (2001) (pagination not available).

[50] *See Connecticut Light and Power Company*, 70 FERC 61,012 (January 11, 1995), reconsideration denied, 71 FERC 61,035 (Connecticut statute requiring purchase of QF energy at retail rate preempted by section 210 of PURPA insofar as the statute requires rates that would exceed avoided cost); *Midwest Power Systems, Inc.*, 78 FERC 61,067 (January 29, 1997) (Rates prescribed by Iowa Utilities Board for wind-generated QF power preempted by PURPA to the extent they are in excess of avoided costs)

> environmental costs may be part of a state's approach to encouraging renewable generation. For example, a state may impose a tax or other charge on all generation produced by a particular fuel, and thus increase the costs which would be incurred by utilities in building and operating plants that use fuel. Conversely, a state may also subsidize certain types of generation, for instance wind, or other renewables, through, e.g., tax credits.
>
> A state, however, may not set avoided cost rates . . . by imposing environmental adders or subtractors that are not based on real costs that would be incurred by utilities. Such practices would result in rates which exceed the incremental cost to the electric utility and are prohibited by PURPA.[51]

Although FRC identifies several benefits of small QF generation, FRC fails to identify how those benefits actually result in costs that a utility incurs in the absence of purchasing power from small QFs. Without such evidence, we must conclude that an adder on standard avoided cost rates would represent costs in excess of avoided costs which PURPA prohibits us from approving.

In addition, we find FRC's reliance on the cited Vermont case to be misplaced. Because the case was decided on the grounds that the fee at issue was not an avoided cost adder, it is inapposite to FRC's specific request that the Commission authorize an adder for QFs under 3 MW. In that case, Vermont utilities sought to eliminate or minimize "payment lag adders" in existing contracts with QFs.[52] The QFs responded that doing so would deprive them of the time value of avoided cost payments, which would effectively reduce their avoided cost rates.[53] According to the utilities, however, the payment lag adders were not required by PURPA or regulation by FERC and were, therefore, independent of the calculation of avoided costs such that reducing the adders would not change avoided cost rates.[54] The Vermont Commission agreed that the payment lag adders were not part of avoided cost rates, representing instead separate compensation in the agreements to account for the time value of money paid under those agreements, and concluded that PURPA did not preempt the relief requested by the utilities.[55]

For these reasons, we reject FRC's proposal for an adder to avoided costs for QFs sized at or less than either 3 MW or 1 MW.

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[51] *Southern California Edison Company, San Diego Gas & Electric Company*, 71 FERC 61,269 (June 2, 1995).
[52] *In Re 14 Vermont Electric Utilities* (pagination not available).
[53] *Id*.
[54] *Id*.
[55] *Id*.

F. PRICING

1. Parties' Positions

Determining what methodology to use to calculate avoided costs is one step of a two-step process to establish the price that utilities will pay for electric power supplied by QFs under standard contracts. A second step involves applying the avoided cost methodology within a pricing structure to compute standard rates. Currently, a volumetric pricing structure is employed by all three of the electric utilities.

Staff recommends implementing more pricing options than currently exist for standard contracts. In addition to a Fixed Price Method, Staff proposes two variable pricing options which are respectively identified as: (1) the Deadband Method; and (2) the Gas Market Method. Both options would alter how QF payments are calculated.

The Fixed Price Method would pay prices, established at the time the contract is executed, over the contract's entire term. Under this option, a utility would pay fixed rates that are based on a single set of forecasted natural gas prices in the utility's last approved avoided-cost filing. The Fixed Price Method would remit a total avoided energy cost, calculated as the cost of energy plus capitalized energy costs at a certain capacity factor based on a natural gas price forecast, with prices modified to account for shrinkage and transportation costs.

The Deadband and Gas Market Methods would base the fuel price component of QF rates on monthly natural gas price indexes. The Deadband Method would bound the rates that a QF receives within a floor and ceiling based on 90 percent and 110 percent of the natural gas price forecast that is included in the avoided-cost filing in place at the time of the contract execution—*i.e.*, the same natural gas price forecast used to set fixed rates. The Gas Market Method uses a monthly indexed price with no forecast to set avoided cost rates. Staff contends these two pricing options allow QF prices to reflect ongoing market conditions, rather than tying prices to a long-term natural gas forecast that is subject to inaccuracy. Staff opines that hydro and wind QFs would likely prefer the Deadband Method, while natural gas-fired cogeneration QFs would choose the Gas Market Method.

Under either of these market methods, the total avoided energy cost of the traditional avoided cost payment would be replaced by two index components, the actual natural gas price used (AGPU) and a factor for non-index costs (NIC), such as shrinkage, transportation and capitalized energy costs that are not accounted for by an index. The off-peak price of energy would equal the sum of AGPU and NIC. To calculate the on-peak price of energy, the off-peak price would be added to avoided capacity costs allocated to on-peak hours.

The AGPU would be calculated differently under Staff's two proposed market methods. The Deadband Method would require calculation of the fuel index price, which requires the appropriate forecast natural gas price contained in the utility's then approved avoided cost filing being multiplied by the assumed heat rate of the applicable CCCT, as well as calculation of floor and ceiling prices based on 90 percent and 110 percent of this forecast natural gas price. The weighted monthly average index price of natural gas at Sumas would then be compared against the deadband values and, if over or under, the floor or ceiling would be used as the AGPU. Under the Gas Market Method, AGPU would equal the monthly indexed gas price, multiplied by the heat rate of the applicable CCCT.

Staff proposes to differentiate the availability of the options based on QF size. QFs under two megawatts in size would be allowed to select either the Fixed Price option or the Gas Market Method. QFs that are greater than two megawatts but under the maximum threshold for standard contract eligibility would select between the Deadband and the Gas Market Methods. QFs ineligible for standard contracts due to their size would be required to negotiate a custom pricing structure.

Staff argues that the proposed market methods accommodate differences among QFs with different fuel types regarding financing needs, market access, and levels of risk aversion. Moreover, Staff asserts, the proposed market methods better reflect the actual market price for electricity, thereby ensuring more accurate avoided cost payments and insulating ratepayers from harm of paying too much for power. Indeed, Staff acknowledges the probability that market prices will deviate from forecasted prices over time and advises against allowing QFs larger than two megawatts to select the Fixed Pricing Option.

PGE also proposes that QFs have three pricing options. PGE agrees that a fixed price option is appropriate. PGE also agrees an option that indexes the variable cost component of avoided costs to a natural gas index is appropriate. However, PGE proposes that an annual natural gas index be used rather than a monthly index. Staff counters that a monthly index better reflects variations in natural gas prices throughout the year, giving QFs more accurate price signals and capturing avoided costs better.

PGE does not support Staff's Deadband Method, observing that this option would provide a QF with a fixed price stream while subjecting either the QF or ratepayers to risk should the prices swing significantly above the ceiling or below the floor. Instead, PGE proposes an alternative market pricing option that would offer a daily indexed rate based on the Dow Jones Mid-Columbia electricity price index (Mid-C index). As PGE generally buys energy on the market, PGE asserts that it is appropriate to have PGE's avoided costs set by the market. PGE also notes that the Mid-C index has the advantage of varying by season and on- and off-peak. For these reasons, PGE argues the Mid-C index option would be a "viable and highly transparent pricing mechanism" that sends appropriate price signals to QFs and allows QFs to participate in wholesale market opportunities. Staff supports PGE's proposed Mid-C index rate option as a pricing methodology to be offered by PGE, but not PacifiCorp since PacifiCorp may purchase power on hubs other than the Mid-C. Staff encourages PacifiCorp to develop a market-based pricing option, however.

PacifiCorp advocates continuation of existing volumetric pricing, but does not oppose Staff's market methods. PacifiCorp points out, however, that in the interest of fairness and administrative ease, it would be appropriate to allow QFs of all sizes to select among the same set of pricing options. PacifiCorp also contends that each utility should select which natural gas index to use, based on that utility's system characteristics. PacifiCorp states that Opal is the appropriate index for it to use, as most of its gas resources that are not constrained are located in the Desert Southwest.

Idaho Power indicates that it could apply Staff's market pricing structures to the SAR methodology and, therefore, does not oppose Staff's proposal. Idaho Power raises concerns with PGE's proposed Mid-C pricing structure, however, noting the difficulty in implementing an hourly index price option.

ODOE expresses concerns that the Deadband Method may hinder a QF's ability to obtain adequate project financing because lenders will evaluate projected revenues of the proposed facility based on floor prices. Should the Commission adopt the Deadband Method, ODOE suggests that the Commission also adopt a twenty-year maximum term for standard contracts to offset any financing disadvantage caused by the Deadband Method.

Weyerhaeuser agrees that two pricing options, a fixed price option and a natural gas indexed price, should be implemented, but argued both options should be available to QFs of all sizes. Weyerhaeuser also cautioned against Staff's proposed Deadband Method. Calling the proposed floor and ceiling artificial, Weyerhaeuser advises that they would create additional risks either for QFs or for ratepayers, depending on market activity. Weyerhaeuser argues that caps and floors on natural gas indices are not needed because utilities can obtain the same by hedging against gas market swings.

ICNU indicates that as an overriding principle, QF pricing structures should provide predictability and allow a potential developer or investor to easily evaluate the economic feasibility of a project. ICNU also asserts that pricing options should be universally available to QFs.

2. Resolution

We conclude that the adoption of more pricing options for QF standard contracts is consistent with our goal, in this proceeding, to more accurately value avoided costs. Recognizing that a QF is in the best position to select a pricing option that best suits its operations, and agreeing with PacifiCorp and ICNU that fairness and administrative ease call for all eligible QFs to have the same set of pricing options, we do not adopt Staff's proposed limitations on the availability of certain pricing options. Instead, we adopt four pricing options for PGE and three pricing options for PacifiCorp and Idaho Power, with no qualifications regarding the ability of an eligible QF to choose among these options.

All three electric utilities shall offer the same three pricing options, as follows: (1) the Fixed Price Method; (2) the Deadband Method; and (3) the Gas Market Method. We adopt each of these methodologies, as defined by Staff. We delegate implementation decisions to each utility but direct each utility to work with Staff, as appropriate, to develop implementation tariffs and standard contract rates, terms and conditions. For example, each utility may designate the natural gas index to be used to implement the Deadband Method. Although PacifiCorp indicates that it set forth an implementation plan for each of Staff's proposed pricing methodologies and asks us for approval of this plan, it is not clear that other parties had a full and adequate opportunity to respond in full. Consequently, we decline to approve PacifiCorp's implementation plan at this time. The tariffs and standard contract forms of all three electric utilities should provide information about implementation of the adopted pricing methodologies. We will evaluate each utility's implementation of the pricing methodology in the proper forum.

For PGE, we also adopt its proposed Mid-C Index Rate Option. Neither PacifiCorp nor Idaho Power proposed a market indexed pricing option and we do not direct either to implement one at this time. Idaho Power raised concerns about whether its effort to develop an indexed pricing option would be too great to be warranted, and we acknowledge that the effort required to develop an indexed pricing option for Idaho Power may be vastly greater than potential benefits to QFs in Idaho Power's service territory that would be likely to select an indexed pricing option. Consequently, we leave it to Idaho Power's discretion whether or not to pursue development of an indexed pricing option. We direct PacifiCorp, however, to work with Staff to evaluate whether it would be appropriate to develop an indexed pricing option and encourage either Staff or PacifiCorp to offer an indexed pricing option for PacifiCorp in the second phase of this proceeding.

Only the Deadband Method was the subject of any concern or criticism by the parties. ODOE's concerns about effects on financing are overcome, however, by our decision to allow all QFs eligible for standard contracts to choose any of the options. A QF project that is concerned that the Deadband Method may hinder financing options is free to select a different pricing methodology. Although we acknowledge the risk posed by the Deadband Method of price swings above and below the methodology's ceiling and floor, we deem it important to make a market pricing option available to QFs that provides a sufficient revenue stream to attract financing. The Gas Market Method and PGE's fully indexed pricing option will provide useful counter examples for comparison purposes. We advise parties that it may be appropriate to further consider market pricing options in the second phase of this proceeding.

G. FORECASTING NATURAL GAS PRICES

1. Parties' Positions

With regard to implementation of its proposed pricing structure, Staff recommends that each utility specify in its avoided cost filing the hub, or combination of hubs, used to forecast natural gas market prices. Staff also recommends that each utility specify the published natural gas prices index that it will use to determine QF rates under the Deadband and Gas Market Methods.

ODOE disagrees, asserting that natural gas forecasts should be consistent among the utilities. ODOE is concerned that utilities have an incentive to underestimate natural gas forecasts in order to reduce avoided cost rates. Moreover, ODOE contends that evidence did not show that wholesale natural gas prices for the various Northwest hubs would vary among utilities, with the exception of small differences for transportation costs. For the purpose of setting avoided costs, ODOE claims that the only substantive difference in natural gas costs among Oregon utilities should be the mix of hubs used, and the weighting of each hub. ODOE recommends adopting methods to ensure consistency among utility price forecasts, including preparation by Staff of twenty-year natural gas price forecasts for the three local hubs to be reviewed in a contested case proceeding every two years. Sherman County and Simplot concur that a single, transparent forecast prepared by a neutral third party should be used.

Staff counters that consistency between a utility's calculation of avoided costs and its actual resource decisions is more important than consistency among the utilities' price forecasts. Staff observes that utilities have different views on future natural gas prices and that a utility's particular view influences that utility's resource planning decisions. Staff concludes, therefore, that "the principle of 'consistency' is best advanced by continuing to review avoided costs using the utility's view of prices because those prices are consistent with the utility's actual resource decisions."[56]

ODOE also expresses a concern that the current avoided cost filing process does not provide parties with a sufficient opportunity to review and challenge utilities' gas price forecasts. Staff disagrees, explaining that a utility files its avoided costs as a proposed tariff, giving ODOE or any party an opportunity to request a suspension of the tariff with full process available to investigate the reasonableness of the filing.

ODOE also takes issue with PacifiCorp's exclusive use of the Opal gas price index to calculate avoided costs. ODOE argues that it is inappropriate for PacifiCorp to match its western control area load resource balance with eastern control area gas prices, particularly since PacifiCorp is likely to site its next power plant in the eastern control area.

2. Resolution

We decline to require the use of a single natural gas forecast to set avoided costs rates. As Staff notes, utilities have differing views on future natural gas prices and, consequently, there could be legitimate variations among utility forecasts. Moreover, the continued review of avoided costs based on each utility's view of prices is consistent with each utility's actual resource decisions.

We do not share ODOE's concern about the inability to review and challenge a utility's gas price forecast. Avoided cost filings are subject to suspension and the same investigatory process that any tariff filing may undergo. Natural gas forecasts that utilities use in avoided cost filings are, therefore, also subject to investigation and full review. We encourage ODOE and other interested parties to seek suspension of an

[56] Staff 700 at 2-3.

avoided cost filing when necessary to address concerns about natural gas forecasts, or any other aspect of a utility's filing. Indeed, an issue that would be appropriate to raise in an avoided cost proceeding is PacifiCorp's exclusive use of the Opal index to forecast natural gas prices. In any future examination, Staff or another party may introduce an independent natural gas forecast for comparison.

H. COSTS INCURRED DUE TO NATURAL GAS PRICE VOLATILITY

1. Parties' Positions

PacifiCorp represents that the proposed indexed pricing options will place greater risks on electric utilities. Because customer rates are established in general rate cases based on normalized conditions, PacifiCorp explains that utilities bear the risk between rate cases for any deviation between projected and actual costs. PacifiCorp argues that indexed pricing guarantees that costs will deviate from projected costs, thereby significantly increasing utilities' risk should a considerable volume of QF generation be indexed to gas.

PacifiCorp recommends that utilities' risk be mitigated and proposes that a mechanism, such as deferred accounting or a power cost adjustment (PCA), be implemented to allow utilities to recover costs associated with natural gas volatility. PacifiCorp also asserts that electric utilities should be able to recover any hedging costs that are prudently incurred in connection with indexed QF power purchase costs.

Staff counters that utilities recover fuel costs for utility-owned generation based on expected future gas prices, yet pay for fuel based on actual market prices. Staff observes that recovery risk for indexed rates should, therefore, be no different than recovery of utility-owned generation costs. Staff also points out that utilities have the ability to hedge against natural gas volatility. Staff indicates that it would be appropriate to consider recovery of a utility's prudently incurred hedging costs in a general rate case, so long as both the associated benefits and costs are reflected in test year revenue requirements.

ICNU opposes the use of deferred accounting or a PCA mechanism for recovery of costs associated with utilities' exposure to natural gas volatility due to indexed pricing. ICNU asserts that deferral of costs should be approved only under extraordinary circumstances and that institution of a PCA is justified only if a utility is actually facing and incurring costs associated with market volatility. ICNU opines that PacifiCorp has failed to demonstrate such conditions. ICNU also observes that the use of either mechanism should only be considered in conjunction with evaluation of a utility's cost of capital, and contemplation of whether a utility's authorized cost of capital should be lowered to reflect a reduction in the amount of risk the utility faces. Finally, ICNU asserts that it is outside the scope of this docket to address the use of deferred accounting or a PCA to recover natural gas volatility costs that utilities may incur due to indexed pricing. ICNU and Weyerhaeuser support utilities' use of hedging tools to address natural gas volatility and do not object to the recovery of hedging costs.

2. Resolution

We are not persuaded that it is appropriate to handle cost recovery for indexed QF payments differently than cost recovery for other energy resources. Staff's analogy to cost recovery for utility generation is an appropriate one and informs our decision. We also conclude that PacifiCorp has failed to adequately distinguish the risks associated with recovery of indexed QF payments.

To the extent that utilities desire to generally address risk mitigation methods, we advise utilities to raise such issues in dockets better suited to this discussion. For example, a proposed PCA mechanism would be best addressed as part of a general rate case proceeding. We also remind parties that a decision in Docket No. UM 1147 regarding our deferred accounting policies is currently pending and will eventually govern all applications for deferred accounting.

Hedging tools are financial instruments that can be used to reduce the risk of price volatility in certain markets. We have previously addressed the use of hedging tools to address volatility in natural gas markets in Order No. 99-272. The use of hedging instruments to mitigate risks associated with contracts that pay QFs indexed prices and the recovery of hedging costs incurred by utilities to mitigate QF contract risks were appropriately raised as issues in this proceeding. We find that such issues should be fully considered, but we do not find that a record has been sufficiently developed to allow us to do so in this order. Consequently, we direct parties to raise the issues again in the appropriate dockets, such as a general rate case or a proceeding that addresses PGE's resource valuation mechanism.

I. PRICING ADJUSTMENTS FOR STANDARD CONTRACTS

1. Parties' Positions

Perhaps in anticipation that standard rates may be made available to QFs with design capacities larger than the threshold limits that they proposed, PacifiCorp and PGE recommend that the Commission allow some standard contract pricing flexibility for certain project-specific characteristics. PacifiCorp notes that Staff agrees that parties to a standard contract may negotiate term variations. PacifiCorp recommends, however, that utilities be allowed to impose certain pricing adjustments in order to address issues that might include integration costs, debt imputation, or commercial and operational costs associated with intermittent QF resources.

Staff counters that the characteristics of a specific QF may impose costs greater or lesser than costs captured by the standard contract rate, but notes that on balance, the standard contract rate is deemed to provide a fair rate to QFs eligible to receive it. Staff observes that the ability of utilities to impose pricing adjustments would undermine the transparency, simplicity, timeliness and economy of a standard contracting process.

2. Resolution

In this order, we establish standard contract rates, terms and conditions that incorporate sufficient flexibility to address QF project-specific characteristics that we have deemed it appropriate to address. For example, the pricing structure we have adopted allows certain QFs to select a pricing option suitable to fuel and risk characteristics of the facility. As another example, QF pricing provides differentiation on a seasonal, as well as peak and off-peak basis. We believe further flexibility in negotiating the terms of a standard contract would fundamentally undermine the purposes and advantages of standard contracts and, therefore, deny the request by PacifiCorp and PGE for additional pricing flexibility.

Standard contracts are designed to minimize the need for parties to engage in contract negotiations. Consequently, any flexibility in the terms and conditions of a standard contract should be specifically delineated and bounded. To the extent that a party anticipated the need for flexibility with regard to a particular standard contract term or condition, the specific issue should have been raised and examined in this proceeding. It is inappropriate to request that standard contracts be subject to potential negotiation to address project-specific characteristics. In any case, we note that certain issues, such as integration costs, will likely be taken up during the second phase of this investigation when interconnection procedures and agreements will be addressed.

J. DETERMINING ELIGIBILITY TO RECEIVE A STANDARD CONTRACT

1. Parties' Positions

To be eligible to receive a standard contract, a QF must be sized at or under the 10 MW threshold we have established herein. Parties raised an issue in this proceeding regarding how the threshold is defined with regard to measuring QF eligibility. Staff recommends basing QF eligibility for standard contracts on the manufacturer's nameplate capacity for a particular facility. Staff maintains that nameplate capacity provides a clear standard that is not subject to manipulation. Staff also argues that, over the course of a year, a QF's average output will align with its nameplate rating. ICNU concurs with Staff's position, asserting that QFs may operationally fluctuate over the course of a year, but on average produce energy below the nameplate capacity.

Idaho Power contends the issue is more complicated and recommends that an alternative approach. Idaho Power also disagrees with Staff, asserting that nameplate capacity is subject to manipulation. Idaho Power initially recommended a metered energy test be applied on an hourly basis. Under this methodology, standard contract rates, terms and conditions would not apply to metered energy delivered in any month that exceeded 10,000 kWh per hour. Idaho Power ultimately recommends adoption of the monthly metered energy standard instituted by the Idaho Commission, which established a two-part test to determine QF eligibility for standard contracts.[57] A QF developer must initially provide evidence that, under normal or average design conditions, a QF project will not generate more than the threshold amount on a monthly average basis. Energy delivered is then metered on a monthly basis, and standard contract rates are not paid for any energy delivered in excess of the monthly threshold. PacifiCorp supports adoption of either an hourly or monthly metered energy test with a cap on standard contract payments, combined with requiring a QF developer to represent that a particular project does not exceed the threshold.

During cross examination of Staff's witnesses, Weyerhaeuser raised another question, asking whether a QF with a nameplate capacity greater than the size threshold for standard contract eligibility could agree to sell an amount of power equal to, or lower than, the threshold in order to qualify for standard contract terms. Staff argues no. Asserting that standard contracts are offered as a means to overcome transactional barriers experienced by QFs deemed to be disadvantaged, Staff reasons that QFs larger than the threshold size are capable of negotiating a contract and should not be eligible in any way for standard contract terms.

2. Resolution

Design capacity was established as the criterion for standard contract eligibility in Order No. 81-319. We deem the evidence introduced in this proceeding insufficient to justify imposing a different standard at this time.

Design capacity, as defined by the manufacturer's nameplate capacity for a QF project, will continue to be the measure of eligibility for standard contracts. In order to be eligible to receive standard contract terms and conditions, a QF must have a manufacturer's nameplate capacity at or under 10 MW. If a QF's nameplate capacity is greater than 10 MW, the QF is ineligible to receive a standard contract and cannot agree to operate at a lower threshold level in order to qualify for a standard contract.

As we have emphasized in this Order, the purpose of standard contracts is to eliminate negotiations for QF projects for which they would be economically prohibitive. We have determined that QF projects larger in size than 10 MW have the financial resources to engage in QF purchase contract negotiations despite the hurdles posed by market barriers that they face. Consequently, we do not discern any justification for permitting a QF with a nameplate capacity larger than 10 MW to reduce operations to 10 MW or less in order to receive standard contract terms and conditions.

Although significant evidence may have been presented to the Idaho Commission that conclusively established the inappropriateness of using the manufacturer's nameplate capacity, the bulk of any such evidence was not presented in this proceeding. We cannot make a decision based upon evidence that did not receive full examination and vetting in this docket. To the extent parties wish to introduce

[57] IPUC Order No. 29632, in Case No. IPC-E-04-8/IPC-E-04-10.

additional evidence on this issue, they are invited to do so in the second phase of this proceeding.

K. STANDARD CONTRACT FORM

1. Parties' Positions

Two parties recommend that we adopt model standard contracts created or approved by an independent organization or another state public utility commission. FRC recommends that the Commission adopt a model standard contract endorsed by the National Association of Regulatory Utility Commissioners (NARUC), while Weyerhaeuser suggests that the Edison Electric Institute (EEI) Master Agreement or standard contract forms approved by the California Public Utilities Commission be used to draft default standards for non-rate terms and conditions.[58]

Staff and three other parties recommend that each utility draft its own standard contract within the framework that we adopt in this order. PacifiCorp indicates that it currently has three separate standard contract forms: one form addresses projects up to 100 kW, another addresses projects up to 1 MW and a third addresses projects over 1 MW. Although the terms of the three contracts are similar, selected terms vary to address particular characteristics of projects of a certain size. PacifiCorp states that additional contract forms may be necessary should the Commission adopt pricing options and recommends that the Commission allow flexibility in the form and number of standard contracts. Observing that it is consistency across the utilities on essential contract terms that matters, not variations on non-essential terms, Sherman County and Simplot agree with PacifiCorp that each utility should draft compliant standard contract forms. Staff recommends that each utility file standard contract forms with the Commission for approval, and advises that approved forms should be made publicly available in the same manner as tariffs.

2. Resolution

For reasons presented by Sherman County, Simplot, and PacifiCorp, we decline to adopt a model standard contract form and agree that each utility should draft its own standard contract rates, terms and conditions. We therefore direct the electric utilities to draft and file one or more standard contract forms as necessary to comply with our decisions in this order. Standard contract forms should accompany revised tariffs. We direct utilities to file standard contract forms with revised tariffs within sixty days of this order. We expect each standard contract form to contain terms and conditions that are consistent with the resolution of issues in this order or past orders, as appropriate. It is not necessary, however, that particular terms be identically worded across all standard contract forms, so long as the meaning of each term is consistent with the present or past decisions. We expect that terms that are not specifically discussed in this order or past orders will vary among the utilities. Staff will review each standard contract form and work with each utility to ensure the compliance of submitted standard contract forms.

[58] Weyerhaeuser submitted a California Standard Offer No. 1 QF Contract as Exhibit 102.

Filed standard contract forms will be subject to the same suspension and approval process as tariffs.

L. SECURITY, CONSTRUCTION CREDIT, INSURANCE AND INDEMNITY REQUIREMENTS

1. Overview

The parties engaged in significant discussion regarding what terms should be included in standard contracts to address a variety of recognized contractual risks. Recognized risks include the timely construction of a QF project and its online availability by the start of scheduled power deliveries, the failure of a QF to provide promised power due to operational interruption, and third-party liabilities arising from a QF accident or failure. Although interconnected in many ways, each risk must be separately addressed.

2. Default Terms

a. Overview

Under a standard contract, a QF agrees to provide a certain amount of power to a utility in exchange for payment of avoided cost rates. After the QF project is operational, there are a number of reasons why a QF might not deliver the promised amount of power, including weather-related reductions in resource availability, operating problems which may be extended due to vendor repair problems, mismanagement, or bankruptcy. Parties debate whether it is necessary to include terms and conditions in standard contracts that delineate what constitutes a default and provide for compensation to the utility in the event that costs are incurred to replace the QF power.

Standard contracts currently require QFs to demonstrate creditworthiness, or to make a specified amount of funding available to the utility party as “default security.” The default security would typically be in the form of a letter of credit or a cash escrow that could be used as reimbursement in the event the QF defaults after it begins operation. Only PacifiCorp provided detailed information about current security requirements in standard contracts.

To demonstrate creditworthiness to PacifiCorp, a QF with a design capacity up 99 kW in size must make a series of representations and warranties, including that it is current on debt repayment and has not been a debtor in a bankruptcy proceeding. A QF that is sized between 100 kW and 999 kW must provide evidence of operating history for five years, or meet a financial test and have no material change in financial condition in the past two years. A QF with a design capacity greater than 1,000 kW must meet a published credit rating test.

Sample standard contract forms filed as part of the utilities’ informational filings in this proceeding did not specify the amount of required default security that is typically required. PacifiCorp states that its credit and security requirements are currently being further developed, but represents that a 4.95 MW project would be required to submit default security in an amount that would cover PacifiCorp's replacement power costs for twelve months. Default security would have a floor amount equal to three months of average monthly output times an average purchase price, or three months of average monthly payments by PacifiCorp. PacifiCorp also imposes annual and lifetime caps and adjusts default security requirements on an annual basis. If a QF provides non-firm power on an as-delivered basis and does not receive capacity payments, PacifiCorp does not require default security.

b. Parties' Positions

In the absence of other documentation, Staff considers the default security term of a generic power purchase agreement form, which accompanied a request for proposals by PacifiCorp for renewable resources, to be representative of the amount of default security that may be required by a utility of QF projects that have a design capacity of 1 MW or more. The power purchase agreement specified an amount equal to the positive difference between the contract purchase price and the result of 110 percent of forward power prices at the appropriate market hub for the next 18 months, multiplied by the estimated monthly outputs under the contract. Staff notes that Idaho Power indicated it would likely use the amount of energy expected to be provided under the contract for two years multiplied by the price per MWh that is specified for the first contract year.

Staff is concerned about this level of default security requirements, and questions whether a small QF will be able to obtain and make available the level of security required, particularly in the form of a letter of credit. As a result, Staff is ultimately concerned that utilities' default security requirements will hamper QF development. Rather than require a letter of credit or escrow deposit, Staff recommends that standard contracts specify that, in the event of default, should market prices exceed the QF contract price during the default period, future payments that are resumed after the end of the default period would be commensurately reduced over a reasonable time period.

In the event that levelized rates are authorized for QFs, Staff recognizes the need for default security requirements beyond a contractual term that would reduce future payments. Staff acknowledges that levelized payments would subject the utility and its ratepayers to overpaying the QF in the early years of the contract should the QF breach the contract in later years. Should a QF receive levelized payments, Staff recommends that the utility allow the QF to select one of the following default security measures: credit rating requirements; a senior lien on the facility; step-in rights; a cash escrow; or a letter of contract. Staff also takes the position that default should not be triggered by weather-related conditions for QF projects that use natural motive force for generation.

ODOE indicates that as risks arising from potential QF default are small, default security is not warranted. Any benefits that might be provided by default security in standard contracts would be outweighed by the barriers to QF development imposed by the requirements. ODOE agrees, however, that default security is warranted if payments are levelized. ODOE acknowledges that, over the course of a contract with levelized payments, there will be a certain period during which the QF will be paid in excess of the fixed year-to-year contract price. ODOE asserts that the associated risks can be quantified by comparing revenue streams under a levelized and non-levelized contract. ODOE states that it is appropriate to require default security in the amount of the difference between the two revenue streams. The amount of security required could be calculated at the inception of the contract on a year-by-year basis. ODOE recommends that the total amount of security required be limited, however, to "around 2% of the capital cost of the project."[59] ODOE further qualifies that it might be appropriate to scale this cap based on the type of QF technology. ODOE suggests that QFs be able to choose between a non-levelized rate with no default security requirements and a level rate with a known level of default security required. A letter of credit should not be required as they are typically too difficult and expensive for a smaller QF to obtain.

PacifiCorp asserts that to ensure the indifference of ratepayers between QF power and other sources of electric power, the risks of QF development and operation need to be considered. Consequently, PacifiCorp argues that it is appropriate to require that a QF demonstrate creditworthiness, or alternatively to provide credit assurance in the amount of the anticipated replacement cost of QF power. Replacement cost is measured as the difference between the contract price and the expected market price.

For QFs smaller than 3 MW, however, PacifiCorp is willing to modify its existing requirements. PacifiCorp would allow a QF that is 3 MW or less to establish creditworthiness by making a set of representations and warranties that would include an affirmative statement that the QF is current on its financial obligations and that it has not been a debtor in a bankruptcy proceeding within the past two years. PacifiCorp will not require default security from any QF that is sized at 3 MW or less. In the event of default, to the extent PacifiCorp incurs replacement costs greater than the contract price, PacifiCorp will recoup the difference from future payments. PacifiCorp suggests implementation of a reasonable cap on the amount that can be recouped from future payments, however.

c. Resolution

Pursuant to the rates, terms and conditions that we adopt in this order, standard contracts for the purchase of electric power from QFs will be long term, must-take contracts with significant revenue impacts. Contracts of this scope and nature, regardless of their subject matter, typically impose some level of security requirements on one or more of the parties. Although ODOE represents that risks arising from potential default by a QF are likely small, ODOE does not quantify the risk. Indeed, no party provides any empirical evidence of the risks associated with QF default.

[59] ODOE 3 at 6.

In the absence of such evidence, we conclude that it would not be prudent to subject utilities and, in turn, their ratepayers, to an unknown level of unsecured risk. We agree, however, that the risk may be relatively low and that an unreasonably high level of security may create a major impediment to the development of QF projects. Consequently, the question is not whether to require *any* default security, but rather what level of default security requirements should be required?

We are persuaded that all QFs should be required to establish creditworthiness by making a set of representations and warranties that the QF has good credit, including that it is current on existing debt obligations and has not been a debtor in a bankruptcy proceeding within the preceding two years. Requiring a party to a contract to enter the contract with good credit is a reasonable and prudent requirement.

Although PacifiCorp recommends that QFs with a design capacity of 3 MW or less be required to establish creditworthiness by making a set of representations and warranties that the QF has good credit, PacifiCorp did not indicate any recourse if the QF could not, in good faith, make such representations and warranties. We conclude, however, that in the event that a QF cannot demonstrate creditworthiness, the QF should be required, regardless of its size, to provide some default security. In the absence of an applicable proposal, we adopt Staff's proposal that requires a QF unable to satisfy credit rating requirements to provide a reasonable amount of default security by one of the following means, selected at the QF's discretion: senior lien, step-in rights, a cash escrow or a line of credit. As parties did not address the proper amount of default security, we decline to impose any requirements at this time and leave this determination to the discretion of each utility, subject to Commission review of the standard contract provision implementing the amount. We direct parties to further address the appropriate amount of default security in the event that a QF cannot demonstrate creditworthiness in the second phase of this proceeding.

Should a QF demonstrate creditworthiness, we conclude that some provision for default security in the event that it is needed is appropriate. In balancing the goals of facilitating QF contracts while sufficiently protecting ratepayers, we recognize that the primary aim is to ensure that ratepayers remain indifferent to the source of power that serves them. Although default security provided in the form of a letter of credit or escrow deposit provides immediate recovery of costs incurred due to a QF's default, we are persuaded that terms providing for future recovery over the course of a long term contract are reasonable. Consequently, we adopt Staff's recommendation that standard contracts include a clause providing that, in the event that a QF defaults and the market prices to replace the contracted for energy exceed the contract price, future payments after the default period ends shall be commensurately reduced over a reasonable period of time to recoup the costs incurred by the utilities. Although PacifiCorp proposed a reasonable cap on the amount that can be recouped, PacifiCorp provided no further detail. As no evidence was presented regarding the appropriate size of such a cap, nor any evidence about alternate provisions, we decline to impose any requirements. Instead, we encourage PacifiCorp to raise this issue in the second phase of this proceeding.

3. Construction Credit

a. Overview

A standard contract for a QF project under development will typically specify an operational date for the QF. On that date, the parties anticipate the QF will begin power deliveries for which it will be compensated. Construction delays may interfere with the timely completion and start-up of a QF project. Parties debate whether construction delays may result in compensable harm to the utility and its ratepayers should the anticipated QF power need to be replaced with higher priced power.

Standard contracts typically require QFs to provide "project development security" in the form of a letter of credit or a deposit in escrow for a specified amount. The intent is to provide funds that the utility party can draw upon should a construction delay occur that postpones the commercial operation of the QF.

b. Parties' Positions

Again, Staff considers the project development security term of a generic power purchase agreement form, which accompanied a request for proposals by PacifiCorp for renewable resources, to be representative of the amount of project security likely to be required of QF projects over 1 MW. The power purchase agreement specifies an amount equal to the result of the amount of energy expected to be provided under the contract for a period of two years, multiplied by the price per MWh that is specified for the first contract year.

Rather than requiring a QF to provide a letter of credit or an escrow deposit during construction, Staff recommends that utilities require a QF to provide a construction or performance bond. Staff indicates that a bond required by a financing company would suffice. Staff asserts that such a bond will provide about the same protection to the utility as a letter of credit or escrow deposit would, but at a more affordable cost.

ODOE represents that it is standard financing practice to require a performance and payment bond during construction to insure funding to complete the project. Such bonds do not require completion of the project by the anticipated date, however, and do not provide funds to third parties that may rely on the project beginning operation. Nevertheless, ODOE recommends against allowing utilities to require an additional performance bond.

PacifiCorp indicates that it would consider allowing performance bonds to be used to provide project development security if they are shown to provide the same safeguards as traditional forms of security.

c. Resolution

As an agency experienced with financing of QF projects, ODOE persuades us that financing companies require appropriate security to ensure that a QF project is fully developed. Consequently, we conclude that the issue before us is not what level of security is needed should a contracted QF project never be operational. Rather, the issue we must consider is what security is needed should a contracted QF project be delayed in coming on line?

This situation is effectively no different than a default situation. In both situations, the utility may need to replace the contracted for energy at market prices that may exceed the contract price. The only difference with regard to construction default or delay will be that replacement will occur not far in advance of the date of contract implementation.

At the time the contract is signed, we would expect parties to be aware of whether the contracting utility is in a resource deficient or sufficient position. We observe that if a utility is in a resource sufficient position, the contracted-for energy will likely not need to be immediately replaced. Consequently, we do not discern any reason to require additional security requirements in such a situation. If the utility is in a resource deficient position, however, it is more likely that the utility will need to replace the contracted for energy. Such a situation should be able to be addressed, however, with the same security requirements imposed in a general default situation. Although Staff proposes the use of a performance bond to address construction delays, evidence was inconclusive as to the availability and effectiveness of such instruments to address costs to third parties. We find that it would be more appropriate, in the event of construction default or delay, to impose the same default security requirements that we have already authorized in the event of default or delay after a QF facility is operational.[60] We direct the electric utilities to draft construction default provisions that are consistent with these default security provisions.

4. Indemnity and Liability Insurance Requirements

a. Overview

QF standard contracts usually require all QFs, regardless of size, to indemnify utilities and to carry various types of liability insurance in varying amounts. They also may require the QF to name the utility as an additional insured on the QF's policies. A primary purpose of these insurance requirements, in conjunction with an indemnity clause, is to pay for litigation and judgment costs arising out of any lawsuit that is instituted against a QF based on its operations.

[60] *See discussion*, page 45.

b. Parties' Positions

FRC members testified that utilities' insurance requirements are new—relative to existing standard contracts signed many years ago—and act as a significant impediment to development of small QF projects because insurance is difficult and expensive to obtain and maintain.[61] For example, testimony by Mr. Steve Sanders, the proprietor and operator of Minikahda Hydropower Co. LLC, indicated that the insurer for his construction business is unable to provide a one million dollar liability policy for his QF operations for less than $10,000 a year. Ms. Toni Roush, proprietor and operator of Roush Hydro, testified that although she was aware of one insurance carrier that would underwrite an affordable insurance policy for QFs, most insurance providers did not have sufficient familiarity with the risks associated with small QF operation to offer an affordable policy. Other FRC members characterized insurance simply as an unknown cost.

In response to past complaints from QFs that the insurance requirements are onerous and unfair, Staff recommends that standard contracts not impose any insurance requirements on QFs. Although Staff supports the inclusion of indemnity clauses in standard contracts and considers it prudent for QFs to carry liability insurance, Staff takes the position that the QF, not the utility, should determine the type and level of insurance to be carried. Staff is concerned that the insurance terms required by utilities impose greater cost than is necessary to obtain satisfactory insurance. Moreover, given no past record of any event that required a QF to rely on insurance, Staff perceives the risk to be low that insurance of the type and level currently required by utilities would be necessary. Consequently, Staff contends that the potential harm to ratepayers caused by a QF carrying inadequate insurance is too small to justify imposing insurance requirements deemed sufficient by the utilities.

Staff also observes that insurance is often not mandated for other types of contracts between utilities and small energy providers. For example, NARUC has recently published a model interconnection agreement that does not contain mandatory insurance requirements, and Staff states that eighteen states do not mandate insurance coverage for QFs interconnecting with utilities.[62] Staff also notes that the Oregon net metering law prohibits utilities from imposing insurance requirements.[63] Staff would support inclusion of language in QF standard contracts that is similar to that contained in the net metering statute.

PacifiCorp asserts that indemnity clauses and insurance coverage are complementary and should be mutually included in QF contracts. PacifiCorp states that absent insurance coverage, QFs may lack the financial resources to satisfy indemnity obligations which subjects ratepayers to inappropriate risk. Observing that the risks of

[61] FRC members indicate that utilities did not require insurance when they originally entered into QF contracts. Upon renewal of these contracts, however, utilities are seeking to impose insurance requirements.
[62] Staff 100 at 10-11, citing the Interstate Renewable Energy Council's ("IREC") "Interconnection Regulations for Non-Net-Metered Distribution Generation" (June 2004).
[63] *See* ORS 757.300(4)(a)-(c).

interconnection between a utility and a QF include fire, electrical surges and electrocution, PacifiCorp argues that the level of risk exposure is not commensurate with QF size and that the potentially smaller financial resources of small QFs render them less likely to be able to fulfill indemnity clauses without the aid of insurance. Indeed, PacifiCorp observes that if a small QF cannot afford liability insurance, it will not be able to afford litigation and judgment costs arising from a lawsuit. Nevertheless, PacifiCorp opines that should the Commission exempt QFs from carrying insurance, the exemption should only apply to very small QFs with capacities at 100 kW or under, and the Commission should specify that utilities may recover costs arising out of lawsuits directed against uninsured QFs.

To the extent QFs are required to carry insurance, PacifiCorp argues that utilities should mandate the level of insurance required in order to assure consistency among QFs. PacifiCorp indicates that it is willing to work with QFs to obtain satisfactory insurance options. PacifiCorp also observes that insurance requirements imposed on QFs are not discriminatory, as PacifiCorp requires liability insurance to be carried by all vendors with which it contracts. Moreover, PacifiCorp notes that Oregon typically requires vendors with which it contracts to carry sufficient insurance.

PacifiCorp considers the NARUC model interconnection agreement to be inadequate. In any case, PacifiCorp observes that the NARUC model is not pertinent to QF power purchase contracts. Moreover, PacifiCorp points out that the model agreement may be outdated based on November 2004 filings in a FERC docket addressing the standardization of small generator interconnection procedures. In that proceeding, PacifiCorp represents, NARUC and other parties submitted a consensus proposal that requires insurance for small interconnected generators.[64]

PacifiCorp also takes issue with Staff’s assertion that eighteen states prevent utilities from requiring QFs to carry insurance. In the first place, PacifiCorp argues that Staff’s assertion is based on a document that pertains to interconnection agreements, not QF power purchase contracts. Second, PacifiCorp contends that the document at issue actually only discusses eighteen states that have conclusively resolved the issue of insurance, with seven of those states requiring some form of insurance. PacifiCorp asserts that it reviewed a different IREC publication that indicates most utilities require liability insurance to be carried by interconnecting distributed generation facilities. Similarly, PacifiCorp points out that Oregon’s net metering statute applies to net metering projects that are 25 kW or less in size and that the statutory language would provide little security against third-party lawsuits against utilities for QF conduct.

Idaho Power urges the Commission to allow utilities to require that QFs carry proper liability insurance as the Idaho Commission has done. The Idaho Commission has considered appropriate liability insurance requirements twice, concluding both times that QFs should carry insurance.[65] Idaho Power states that in

[64] Reply Brief of PacifiCorp at 10, citing “Second Interim Report of Coalition of Parties Seeking Consensus on Small Generator Interconnection Issues,” Docket No. RM-02-12-000 (Nov. 22, 2004).
[65] Idaho Power 100 at 12-13, referring to Case No. U-1006-292 and Case No. IPC-E-03-16.

2003, the Idaho Commission concluded that Idaho Power's business insurance requirements, including the requirement that all QFs, regardless of size, carry general liability insurance, should be maintained with only minor changes. Idaho Power notes that 71 QFs have obtained liability insurance in Idaho, including numerous QFs smaller than 100 kW that carry the required one million dollars in insurance coverage. PGE points to experience in Idaho as evidence that insurance requirements do not impede QF development. Both Idaho Power and PGE maintain that ratepayers should not be forced to bear *any* risk for accidents or negligence resulting from QF operation and that insurance is an appropriate means to protect them. Should the Commission decline to grant utilities the authority to mandate insurance requirements, Idaho Power requests that any costs that arise out of QF litigation be strictly allocated to Oregon ratepayers. Staff opposes the allocation of a singular category of costs to one jurisdiction.

c. Resolution

Standard contracts typically include mutual indemnity clauses and no party contests the appropriateness of such terms. We affirm the appropriateness of including indemnity clauses in standard contracts. No party requested that we specify the wording of such clauses, and we discern no need to do so. We direct utilities to individually draft standard contract indemnity clauses.

We conclude that the issues of indemnity provisions and liability insurance requirements[66] are inextricably linked, as they share the common and complementary purpose of minimizing risks associated with the interconnection of a utility and QF. Indeed, we understand a primary role of general liability insurance to be to provide the resources necessary to fulfill promises that are made in an indemnity clause.

Most parties weighing in on the subject of liability insurance, including Staff, agree that it is prudent for all QFs to carry liability insurance. Nevertheless, the parties' discussion regarding appropriate liability insurance requirements focused primarily on the question of whether standard contracts should require QFs to carry *any* insurance, rather than on the alternate question, if insurance coverage is required, what kind, and how much, should be specified. With regard to the question of whether all QFs should be required to carry liability insurance, the parties' underlying concern seems to be, not whether it is necessary or prudent for QFs to carry some amount of liability insurance—again, most if not all parties agree that it is—but whether it is feasible, in terms of availability and cost, for certain QF projects to obtain and carry sufficient liability insurance.

We find it unfortunate that no party presented testimony from, or based on, the representations of an insurer. Idaho Power testified that all 71 QFs that have

[66] Although parties did not explicitly list the types of insurance at issue in this proceeding, we consider the discussion to be limited to property and general liability insurance that covers risks associated with interconnection of a utility and QF. We consider other types of insurance, such as workers' compensation, employer's liability and automobile insurance to be beyond the scope and purpose of insurance at issue in this proceeding.

entered into standard contracts in Idaho, regardless of the size of the QF, have obtained the required liability insurance. We have limited evidence about the scope of insurance requirements in standard contracts in Idaho, however, and we do not have any evidence about whether any QF in Idaho did not enter into a standard contract due to the level of required insurance. Consequently, we deem Idaho Power's testimony about the wide-spread availability of insurance to be of limited value. We also find the testimony about insurance requirements in standard contracts or interconnection agreements to be inconclusive. Moreover, we do not have any testimony from QFs larger than the very small QFs represented by FRC about their experiences obtaining liability insurance. Additionally, although some utilities expressed a willingness to work with QFs having difficulty obtaining liability insurance, we do not have any testimony from the utilities about the availability and cost of such insurance. Consequently, we only have the uncontested testimony of FRC members who testified that liability insurance is either not available, or is prohibitively difficult or expensive to obtain, for very small QFs operating in Oregon.

We must conclude, therefore, that it is inappropriate to require QFs that have a design capacity of 200 kW or less to be required to obtain general liability insurance. Nevertheless, we are not persuaded that the absence of past incidents requiring QFs to rely on liability insurance indicates that insurance will not be needed in the future and we reiterate our position that it is prudent for *every* QF to carry liability insurance. Consequently, we encourage QFs with a design capacity of 200 kW or less to pursue liability insurance on their own. We also encourage the electric utilities to work, in the coming months, with QFs that have a design capacity of 200 kW or less to determine whether reasonably priced general liability insurance is available. If the utilities find that such insurance is available, parties may raise the issue again in the second phase of this proceeding.

We direct the utilities to require all other QFs that sign standard contracts to obtain prudent amounts of general liability insurance. As parties did not raise the issue, we do not address the scope of general liability insurance considered prudent. Should this issue be of concern to any party, we encourage that party to raise it in the second phase of this proceeding.

We recognize that making an exception to general liability insurance requirements for QFs with a design capacity of 200 kW or less exposes utilities to some risk. No party presented any evidence, however, regarding the potential scope of such risk. In the absence of such evidence, we conclude that the risk is likely small and decline to make any conclusions, for Idaho Power or any other electric utility, about the need to pre-approve recovery of costs stemming from QF uninsured liability. Parties may further raise this issue, however, in the second phase of this proceeding.

IV. ISSUES OF GENERAL APPLICABILITY TO STANDARD AND NEGOTIATED QF CONTRACTS

A. SIMULTANEOUS PURCHASE AND SALE OPTION

1. Parties' Positions

One form of QF power is thermally-balanced combined heat and power (CHP) installations. Manufacturing facilities with installed CHP can supply energy for on-site manufacturing processes and under an existing QF contract—whether standard or custom—sell any excess power that is not needed to power the site, to a utility at the utility's avoided cost. Weyerhaeuser argues that CHP QFs should have more than one option for selling cogeneration power and requests the ability to sell the entire output from a CHP installation, less internal auxiliary use, to a utility at its avoided costs, with the host manufacturing facility's onsite load being fully served by the utility pursuant to a standard tariff. Weyerhaeuser labels this arrangement a "simultaneous purchase and sale option" and represents that FERC has approved it.[67]

Weyerhaeuser acknowledges that there should be some limitations on the ability of a CHP QF to elect to sell its entire generational output (net internal auxiliary use). Weyerhaeuser suggests that utilities may impose reasonable limitations on the frequency with which a QF is allowed to transfer between a simultaneous purchase and sale and the sale of surplus power only. Weyerhaeuser also recommends that CHP QFs be prohibited from switching between the two options more than one time a year. Moreover, Weyerhaeuser declares that a QF electing a simultaneous purchase and sale option must abide by the terms of service of the utility's sales tariff, and be required to pay for any additional metering needed to facilitate the simultaneous purchase and sale option.

PacifiCorp interprets Weyerhaeuser's proposal as a request to be able to alternate once a year between Schedule 47 (the full requirements tariff) and Schedule 36 (the partial requirements tariff), and raises practical and policy concerns with such an arrangement. From a practical standpoint, PacifiCorp represents that tariff rules would need to be modified to implement Weyerhaeuser's proposal, as current tariff rules require a customer to stay on either tariff for a period of five years before switching to another tariff. PacifiCorp also expresses concern that allowing QFs to alternate between options may be inappropriate from a policy perspective:

> The effect of Weyerhaeuser's proposal is to allow it to game (to the detriment of ratepayers) the difference between the Company's retail rates and the QF avoided cost rates. Basically, Weyerhaeuser wants firm prices

[67] Weyerhaeuser 100 at 12, citing *Connecticut Valley Electric Company, Inc. v. Federal Energy Regulatory Commission*, 208 F.3d 1037, 1040 (D.C. Cir. 2000), affirming *Connecticut Valley Electric Company, Inc. v. Wheelabrator Claremont Company, L.P. and Related Actions*, 82 FERC 61,116 (1998) and 83 FERC 61,136 (1998) (order denying rehearing).

> for generation that it will only put to the company when it is least valuable *and* a tariff entitlement to move its load on and off the grid without paying demand charges that reflect the cost to the Company of that optionality. Such proposal is inconsistent with the principle of ratepayer neutrality and should be rejected.[68]

Weyerhaeuser responds that its proposal should be accommodated according to existing tariff rules. Weyerhaeuser also argues ratepayers are indifferent to when QF power is sold to and purchased by a utility, as the power is sold at avoided cost.

2. Resolution

FERC precedent firmly establishes that a QF may sell no more than "net output" under PURPA.[69] "Net output" of a QF facility is defined by FERC as a facility's "send out after subtraction of the power used to operate auxiliary equipment in the facility necessary for power generation (such as pumps, blowers, fuel preparation machinery, exciters) and for other essential electricity uses in the facility from the gross generator output."[70] FERC has reaffirmed this limitation on several occasions and has refused to allow exceptions.[71]

Pursuant to FERC precedent, a QF may already sell the full net output of its facility, as opposed to surplus power only, to a utility. QFs are free to negotiate a net output sale that is consistent with FERC standards and with existing utility tariffs and rules. Standard contracts, on the other hand, currently provide only for a "surplus sale." Weyerhaeuser raises the question of whether standard contracts should also contemplate a "net output sale."

There was no discussion, however, from the parties about whether the avoided cost calculation requires modification to accurately reflect a "net output sale." As such, we do not believe there is sufficient evidence to warrant imposing a requirement that standard contracts offer a "simultaneous purchase and sale option." We observe, however, that many, if not most or all, CHP projects will be larger than the threshold we have designated for standard contracts. Consequently, most CHP QFs that desire a "simultaneous sale and purchase" arrangement will be required to negotiate a non-standard contract with a utility. We acknowledge that there may be hurdles to negotiating a "simultaneous sale and purchase" QF contract and encourage parties to

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[68] PPL 100 at 29.
[69] *See Occidental Geothermal, Inc.*, 17 F.E.R.C. ¶ 61,231 (1981); *Power Developers, Inc*., 32 F.E.R.C. ¶ 61,101 (1985); and *Penntech Papers, Inc*., 48 F.E.R.C. ¶ 61,120 (1989).
[70] *Occidental Geothermal, Inc.*, 17 F.E.R.C. ¶ 61, 444 (1981).
[71] *See Turner Falls Limited Partnership,* 53 F.E.R.C. ¶ 61,075 (1990) (denied request to waive "net output" standard for determining electric power production capacity of a QF); *Conn. Valley Electric Cooperative v. Wheelabrator Claremont Co. L.P., Carolina Power & Light Co. v. Stone Container Corp., and Niagra Mohawk Power Corp. v. Penntech Paper, Inc.*, 82 F.E.R.C. ¶ 61,116 (1998) (reiterated that a QF may not sell in excess of its net output); *Conn. Valley Electric Cooperative v. Wheelabrator Claremont Co. L.P., Carolina Power & Light Co. v. Stone Container Corp., and Niagra Mohawk Power Corp. v. Penntech Paper, Inc.*, 83 F.E.R.C. ¶ 61,136 (1998) (denies rehearing)

raise the issue of how to better facilitate "net output sales" in the second phase of this proceeding.

B. DISPUTE RESOLUTION

1. Overview

Pursuant to ORS 756.500, any person may file a formal complaint regarding the negotiation or enforcement of a QF contract. Unless a formal complaint is filed, the Commission does not intervene in negotiations or disputes between parties, other than to provide general information as requested. The Commission does not currently offer informal dispute resolution mechanisms.

2. Parties' Positions

Staff and two parties, PacifiCorp and PGE, comment on the proper role of the Commission in resolving disputes about QF contracts. All recommend that the Commission retain its current policy. Staff advises that the existing policy reduces real and perceived opportunities for Staff to be viewed as unobjective should a formal complaint be filed.

Although most parties did not directly address this issue, several parties comment that greater oversight of the non-standard contract negotiation process is needed. For example, as previously discussed, both Weyerhaeuser and ICNU call for greater guidelines regarding negotiation of non-standard QF contracts. PGE also suggests that concerns about negotiation of non-standard contracts could be addressed by improving the process and increasing its transparency.

3. Resolution

We have already concluded that certain market barriers impede the negotiation of non-standard contracts and have directed parties to develop, in a second phase of this proceeding, negotiation parameters and guidelines that would overcome these market barriers and facilitate negotiations. We understand, however, that even with better parameters and guidelines, disputes may arise during negotiation of a non-standard contract. We also understand that formal dispute mechanisms are not timely during contract negotiations. Consequently, we find that it is appropriate to reconsider whether Staff should have a role in the resolution of informal disputes.

As we explained in the Historical Background section of this order, the role of Staff in resolving QF disputes has varied over time. Staff currently does not participate in the informal resolution of QF contract disputes, due to concerns that such efforts would adversely affect Staff's objectivity, or the perception of Staff's objectivity, in formal disputes or rate cases.[72] We encourage parties to determine, in the second

[72] *See* "Report to the Sixty-Fifth Legislative Assembly and Energy Policy Review Committee," (November 1, 1988), p. 19.

phase of this proceeding, whether there is a role for Staff to play in the informal resolution of QF contract negotiation disputes that will not compromise Staff's objectivity in formal proceedings.

C. APPROVAL OF INDIVIDUAL QF CONTRACTS

1. Parties' Positions

Both PacifiCorp and Idaho Power argue that utilities should receive up-front assurances from the Commission that costs undertaken in a QF power purchase contract will be fully recovered and not subject to any disallowance. Both utilities contend that QF power purchase contracts are unique among other power purchase contracts. Idaho Power points to the fixed nature of standard contracts, while PacifiCorp observes that utilities do not make decisions regarding the location, timing, and cost effectiveness of QF power as they do for contracts for other resources. Consequently, PacifiCorp and Idaho Power argue that QF power costs should not be subject to prudency disallowances and should automatically be included in rates.

Although PacifiCorp acknowledges that there is no history of disallowance of QF power costs in any state in which the company provides service, PacifiCorp maintains that the potential for disallowance is a significant concern, particularly since QF power purchase costs may be more than other energy purchase costs. Indeed, PacifiCorp opines that prevalent perceptions that utilities are reluctant to contract with QFs may be due to utilities' efforts to mitigate exposure to regulatory disallowance. PacifiCorp also notes concerns that, as a multi-state utility, some portion of its costs for Oregon QF purchases may be disallowed in other jurisdictions. Idaho Power and PacifiCorp recommend that each QF power purchase contract be filed with the Commission and approved on an individual basis. Idaho Power indicates that this has been the practice of the Idaho Commission for the past twenty years. ICNU, Sherman County and Simplot all support pre-filing of QF power purchase contracts and pre-approval of associated costs, although ICNU notes that the Commission should continue to exercise oversight over the administration of QF contracts.

Staff disagrees that QF power purchase contracts should be pre-filed or pre-approved. Staff argues that the basic regulatory compact allows utilities to recover all prudently incurred costs, including payments to QFs, and that no greater assurances are needed. Staff observes that the Commission does not individually review other power purchase contracts and asserts that the utilities have failed to demonstrate why QF contracts should be treated differently. Staff notes that there is no history of past disallowances to cause concern and maintains that the Commission should retain the discretion to review utility actions in connection with a QF power purchase contract. Moreover, Staff contends that the Commission's approval of each QF contract would add unnecessary delay to the QF power purchase contracting process which developers cannot afford. PacifiCorp counters that the Commission could dispense with individual QF contract review and make a general finding in this order that QF power purchases executed pursuant to approved tariffs and a standard contract form are per se reasonable for ratemaking purposes.

2. Resolution

While we agree with parties that QF power purchase contracts are unique among other power purchase contracts, we conclude that the unique characteristics of QF contracts already provide utilities with sufficient assurances, pursuant to the traditional regulatory compact that governs cost recovery, and that costs incurred under the contracts will be recovered. For example, in this Order, we have directed utilities to file QF power purchase standard contract forms. Those forms will be pre-approved for compliance with all standards set forth in this Order or still applicable prior orders. Although pre-approval of the standard contract form is not pre-approval of a utility's recovery of costs that are incurred under a particular standard contract, utilities are assured, to the extent a standard contract is entered into with a QF, that we have pre-approved the rates, terms and conditions of the agreement with the QF. With regard to non-standard contracts, utilities have the obligation to negotiate and administer non-standard power purchase contracts with QFs that comply with federal and state mandates. The good faith fulfillment of this obligation is the best means for a utility to mitigate the risk of prudency disallowances associated with QF contracts. Indeed, we find utilities' lack of discretion regarding issues such as the location, timing, and cost effectiveness of QF power contracts favors the likelihood of a QF contract being deemed prudent. We determine that it is unnecessary and inappropriate to treat cost recovery of costs incurred under QF contracts any differently than cost recovery is handled for all other power purchase contracts.

We do so because we agree with ICNU that we should maintain our ability to oversee the administration of QF contracts. We disagree with ICNU, however, that we would be able to effectively oversee the administration of QF contracts should a contract be pre-approved with regard to general prudency and cost recovery issues, in addition to the approval of its rates, terms, and conditions, if it is a standard contract. Due to the finality of our decisions, such pre-approval would foreclose future opportunities to address administration of the contract. We also are not convinced that we have the legal authority to bind future Commissions on ratemaking treatment of long-term contracts.

D. REPEAL OF PURPA

1. Parties' Positions

PacifiCorp requests that the Commission address the issue of recovery of QF contract costs in the event that PURPA is repealed by the United States Congress. Although PacifiCorp expects to be able to continue recovering costs associated with then existing QF contracts should PURPA be repealed, PacifiCorp desires the authority to terminate QF contracts in the event that cost recovery will not be available.

Staff objects, arguing that a QF should be able to rely on the full term of a power purchase contract. Staff recommends that the Commission clarify that, absent contrary direction by federal or state law, the repeal of PURPA would not terminate then existing QF contracts. ODOE, Weyerhaeuser and ICNU agree, observing that a PURPA termination clause would have a chilling effect on QF financing.

2. Resolution

We agree that existing QF contracts should not terminate upon the repeal of PURPA, but should continue in effect with utilities able to recover contract costs under normal regulatory principles and procedures. We cannot, however, predict the provisions of future legislation, although the repeal of PURPA on a retroactive basis might be legally barred. We direct utilities to insert a clause in any QF contract that specifies that QF contracts do not terminate upon the repeal of PURPA, unless such termination is mandated by federal or state law. We believe this provision provides all the protection that is available under the law, but should not have any adverse effect on financing as it imposes no additional risk on QFs.

E. ADMINISTRATIVE RULES REVISIONS

1. Overview

The federal PURPA statute[73] and related FERC regulations[74] are applicable to, and the Commission is responsible for implementing the same, for all three electric utilities operating in the state of Oregon. Pursuant to electric industry restructuring and Senate Bill 1149, PacifiCorp and PGE have been exempted from the Oregon PURPA[75] pursuant to ORS 757.613(4). With this exemption, the Commission's PURPA regulations at Division 29 of the Oregon Administrative Rules[76] were also amended to not apply to the state's electric utilities.

2. Parties' Positions

Asserting that it was inappropriate to exempt the state's electric utilities from the Commission's PURPA regulations because they implement both Federal and Oregon PURPA law, Staff recommends that the Commission open a rulemaking to consider whether, and how, to modify Division 29 of the Oregon Administrative Rules. Staff states that the rulemaking would address the consistency of the rules with federal PURPA law, and to clarify which rules, if any, apply to electric utilities given the provisions of ORS 757.612(4).[77] Staff initially proposed that a temporary rulemaking be opened for these purposes in order to address the issues expediently and to prevent potential financial harm to QFs. In response to several parties' opposition to a temporary rulemaking, however, Staff ultimately recommends that the scope and nature of the rulemaking be determined at the start of the new proceeding.

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[73] *See supra* note 2.
[74] *See supra* note 10.
[75] ORS 758.505 through 758.555.
[76] *See supra* note 11.
[77] After the passage of Senate Bill 1149 (SB 1149), OAR 860-029-0001 was modified to provide that rules in the division did not apply to public utilities that satisfy their public purpose obligations under ORS 757.612.

PacifiCorp and PGE agree that it is appropriate to open a rulemaking that addresses the Commission regulations implementing federal PURPA law, but disagree that it is necessary to implement temporary rules. PacifiCorp states that Staff has not demonstrated how QFs may be financially harmed without temporary rules. Both PacifiCorp and PGE call for a deliberate review of Commission regulations.

3. Resolution

We concur with all parties commenting on this issue that it is appropriate to open a rulemaking to update our PURPA-related regulations. We do not find, however, that a case was made for the implementation of temporary rules. A rulemaking will be opened at a later date to revise our PURPA-related regulations on a permanent basis.

F. TARIFF CONTENT

1. Parties' Positions

The Commission's current rules require utilities to set forth standard contract rates and terms in tariffs that are filed with the Commission.[78] Staff proposes that this rule be retained, but advises that utilities be required to augment the information that is currently provided, in addition to filing standard contract forms. Staff recommends that tariffs specify approved 20-year avoided costs and set forth detailed information about avoided cost pricing. Staff also recommends that tariffs should state that standard avoided costs are the starting point for negotiation of non-standard contracts and set forth the FERC-mandated factors that may result in adjustment of these rates. To the extent the Commission adopts Staff's recommendations on several issues in this proceeding, Staff recommends that the tariffs specify policy decisions. For example, Staff suggests that tariffs include a statement that the rates paid under a standard contract are established upon execution of the contract and continue during the term of the contract, as well as a statement that QF contracts do not terminate in the event of the repeal of federal PURPA laws.

PacifiCorp agrees that tariffs should be supplemented to conform to the Commission's Order in this docket, in addition to standard contract forms being filed with the Commission. PacifiCorp does not oppose Staff's recommendation that tariffs set forth full avoided cost pricing information. PacifiCorp also recommends that tariffs contain information about the process for entering into a QF power purchase contract.

PGE disagrees, taking the position that current tariff filings are sufficient and opining that tariffs should be minimalist in nature. PGE argues that tariffs should contain only key information, including specification of avoided costs, pricing options and interconnection requirements. PGE observes that detailed information is better made

[78] *See* OAR 860-029-0040(4)(a).

available upon request or electronically at a utility's website. Staff counters that the Commission's rules favor making all relevant information available through tariffs.[79]

2. Resolution

The goal of tariffs is to provide sufficient information about the terms, rates and conditions of utility service to an inquiring third party. We have already determined that information provided in tariffs will be supplemented with filed standard contract forms that contain full information about the terms, rates and conditions governing the sale and transfer of electrical energy between a utility and a QF project with a design capacity at or under 10 MW. We conclude, therefore, that the pertinent tariffs should provide information that will not be provided in the standard contract forms. Our objective is to ensure that the combination of tariffs and standard contract forms will provide a potential QF developer with readily accessible information that facilitates a decision by the QF developer about whether to contact a utility for further information.

We expect tariffs to contain information including the following: (1) full details about the process to enter into a standard contract or a negotiated contract, including instructions to contact a utility for further information; (2) specification of avoided costs including how they are calculated; (3) details about how non-standard contracts are negotiated, including a statement that the starting point for negotiation of price is standard avoided costs and that standard avoided costs may be modified to address specific factors mandated by federal and state law; (4) delineation of these factors; and (5) general information about pricing options.

ORDER

IT IS ORDERED that:

1. Within sixty days of the effective date of this order, each electric utility shall file by application, and serve upon all parties to this proceeding, one or more standard contract forms that set forth standard rates, terms and conditions that are consistent with the policy decisions made in this order.

2. The standard contract form shall become effective 30 days after the date of filing, unless otherwise suspended by the Commission. Prior to effectiveness, the standard contract forms shall be considered initial offers.

3. A QF or electric utility which signs an initial offer may not modify such offer until the term of the resulting contract expires. Any later modifications to a standard contract form will be prospective only and will not alter the terms of the initial offer.

[79] *See, e.g.*, OAR 860-022-0010.

4. Each electric utility shall also file, with its standard contract forms, revised tariffs that implement the resolutions made in this order.

5. Tariffs shall become effective 30 days after the date of filing, unless otherwise suspended by the Commission.

6. A subsequent phase of this proceeding will be opened to address issues previously identified by the parties, as well as those identified in this order.

7. Rate recovery of hedging costs to mitigate indexed QF rates may be addressed in appropriate future dockets, such as a utility's general rate case.

8. A rulemaking will be opened at a later date to revise, on a permanent basis, the Commission's PURPA regulations at Division 29 of the Oregon Administrative Rules.

Made, entered, and effective MAY 1 3 2005.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

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 to a court pursuant to applicable law.