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Via Electronic Filing and U.S. Mail

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
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SALEM OR 97308-2148

RE: **Docket No. UM 1129 Phase II** - In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities.

Enclosed for filing in the above-captioned docket is the Public Utility Commission Staff's Direct Testimony. This document is being filed by electronic mail with the PUC Filing Center.

/s/ Kay Barnes

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PUBLIC UTILITY COMMISSION OF OREGON

UM 1129 - PHASE II

STAFF DIRECT TESTIMONY OF

LISA SCHWARTZ
STEVE W. CHRISS
THOMAS D. MORGAN
MICHAEL DOUGHERTY

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

February 27, 2006

CASE: UM 1129 – Phase II
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1800

Direct Testimony

February 27, 2006

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Lisa Schwartz. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. HAVE YOU FILED TESTIMONY PREVIOUSLY IN THIS CASE?

A. Yes. I filed Staff/200, Staff/600, Staff/1000, Staff/1500 and related exhibits. My qualifications are listed in Staff/201.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My testimony addresses issues related to Qualifying Facilities (QFs) larger than 10 megawatts (MW), including contract length, avoided cost adjustment factors, negotiating simultaneous sale and purchase contracts, negotiating net output sales contracts, and contract negotiation procedures, schedules and information requirements. In addition, as directed by the Commission, I further explore issues related to Mechanical Availability Guarantees, definition of nameplate capacity for determining eligibility for standard contracts and rates, and dispute resolution. Finally, I address integration costs, the role of competitive bidding in setting avoided cost pricing for the largest QFs, and the effects of the Energy Policy Act (EPAct) of 2005.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Staff Exhibit 1801, responses to Staff data requests, consisting of three pages. I also prepared Staff Exhibit 1802, a one-page summary of integration cost estimates from a survey by Lawrence Berkeley National Laboratory.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

CONTRACT LENGTH FOR QFS LARGER THAN 10 MW

Q. PLEASE SUMMARIZE THE ISSUE.

A. In Phase I of this proceeding, the Commission adopted a contract term for standard contracts of up to 20 years, at the QF's discretion. Standard contracts are available only to QFs 10 MW and smaller. To limit the risk that standard contract rates exceed actual avoided costs over time, the Commission required that QFs take a market pricing option beyond year 15. *See* Order No. 05-584 at 20. The Commission declined at that time to adopt parameters for contract length for QFs larger than 10 MW and directed the parties to address negotiation parameters in Phase II. *Ibid* at 3 and 17.

Q. WHAT IS THE CONTRACT TERM AVAILABLE FOR LARGE QFS TODAY?

A. Based on a review of previous tariff filings for Portland General Electric (PGE), PacifiCorp and Idaho Power, and associated public meeting memos, it is Staff's view that the Commission approved a *minimum* five-year term for Idaho Power and PacifiCorp, which may be increased through negotiations that include consideration of adjustment factors described in 18 C.F.R. § 292.304(e). We view the language in PGE's approved tariff filing as providing more discretion in offering a shorter or a longer contract term than five years, based on negotiations.

Q. WHAT IS YOUR RECOMMENDATION REGARDING CONTRACT TERM FOR QFS LARGER THAN 10 MW?

A. I recommend that the Commission establish a contract term of up to 20 years, at the QF's discretion.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I testified previously that compared to the strategies utilities are using to acquire resources, a five-year term for contracts under the Public Utility Regulatory Policies Act (PURPA) discriminates against QFs, and that a long-term contract was necessary to enable financing. *See* Staff/200, Schwartz/2-9. Staff Witness Thomas Morgan further testified on the impact of a short contract term on financing QFs both small and large. *See* Staff/400, Morgan/1-4.

I also described in my previous testimony the long-term thermal resources the utilities had recently acquired. *See* Staff/200, Schwartz/8-9. Over the past year, the utilities have continued to acquire long-term resources. For example, PGE signed a 30-year contract for the 75 MW Klondike II wind project; PacifiCorp executed two 20-year contracts, one for a 64.5 MW wind project in Idaho and one for a 42 MW geothermal project in Utah. *See* Pacific Power & Light and Portland General Electric; Update on Renewable Resource Acquisitions, OPUC public meetings, September 13 and December 6, 2005.

The Commission determined in Phase I of this proceeding that a 20-year contract is required to enable adequate financing of QFs up to 10 MW. *See* Order No. 05-584 at 20.

In Utah, PacifiCorp testified that a 20-year term for "large" QFs[1] "represents an appropriate balance between a term that allows the QF to

[1] Cogeneration facilities larger than 1 MW and small power production facilities larger than 3 MW.

secure financing and limiting the risks that accompany long-range power price forecasting," according to the Utah Commission. The Utah Commission agreed with PacifiCorp's position, including a provision that parties may petition the Commission for a longer-term contract. *See* Report and Order, Docket No. 03-035-14, October 31, 2005, pp. 28-29.

Oregon Staff concluded in earlier testimony that "limiting the contract term may affect a decision to invest in a project simply because of the riskiness of the project, regardless of whether the equity return would be adequate." *See* Staff/400, Morgan/4.

Weyerhaeuser testified that new combined heat and power (CHP) facilities require capital investments "upwards of $1 million per installed MW." *See* Weyerhaeuser/100, Beach/6. Weyerhaeuser also testified that a 20-year term would assist QF projects in obtaining reasonable financing. In addition, Weyerhaeuser pointed out that avoided cost rates are based on a utility-owned, natural gas-fired combined-cycle combustion turbine (CCCT) whose capital costs are assumed to be amortized over a longer time horizon, and CHP projects use similar technology.

To avoid discrimination against QFs relative to non-PURPA utility acquisitions, and to facilitate investment in renewable resources and cogeneration, Staff recommends the Commission set a contract term up to 20 years, at the QF's discretion, for QFs larger than 10 MW.

DIFFERENTIATION OF FIRM VS. NON-FIRM SUPPLY COMMITMENTS IN DEFAULT AND DAMAGE PROVISIONS

Q. PLEASE DEFINE "FIRM" VS. "NON-FIRM" SUPPLY COMMITMENTS.

A. OAR 860-029-0010 defines these terms as follows:

> (13) "Firm energy" means a specified quantity of energy committed by a qualifying facility to an electric utility.
>
> (16) "Nonfirm energy" means:
>
> (a) Energy to be delivered by a qualifying facility to an electric utility on an "as available" basis; or
>
> (b) Energy delivered by a qualifying facility in excess of its firm energy commitment.

These definitions are similar to the definitions of "legally enforceable obligation" (firm) and "as available" (non-firm) in Federal Energy Regulatory Commission (FERC) rules. *See* 18 C.F.R. § 292.304(c)(3)(d).

Q. HOW SHOULD DEFAULT AND DAMAGE PROVISIONS REFLECT FIRM VS. NON-FIRM SUPPLY COMMITMENTS?

A. Negotiated contracts for QFs that make firm supply commitments should include default and damage provisions that keep the utility and its ratepayers whole in the event the QF fails to meet its minimum net output obligation to the utility.

Staff agrees with PGE that a QF that does not wish to make a firm supply commitment should receive market-based pricing. *See* PGE/300, Kuns-Drennan/5; Staff/1900, Chriss/2-3. A contract for energy delivered on an "as available" basis should provide exemptions from minimum delivery requirements, default damages for construction delay, default damages for under-delivery, and default damages for the QF choosing to terminate the contract early. It follows that default security should not be required for these purposes.

Q. PLEASE EXPLAIN WHY THESE EXEMPTIONS ARE APPROPRIATE.

A. The utility is not counting on the QF's non-firm output. Further, the QF should receive payments for energy deliveries based on current market prices. The utility generally can buy any shortfall energy, and sell any surplus energy, at that price. Therefore, the utility and its ratepayers are not harmed if the QF resource fails to show up on time; delivers less energy than expected based on its nameplate rating, station use and any host use on-site; or if the QF owner chooses to terminate the contract early.

NEGOTIATION PARAMETERS FOR NON-STANDARD CONTRACTS

Q. HOW SHOULD AVOIDED COSTS FOR A QF'S SPECIFIC ATTRIBUTES BE ADJUSTED FOR FACTORS DESCRIBED IN 18 C.F.R. § 292.304(e)?

A. FERC rules for avoided cost purchase rates require that particular factors be taken into account, to the extent practicable, in determining avoided costs.[2]

I agree with Weyerhaeuser that some of these factors should be addressed through contract provisions, rather than through pricing adjustments. *See* Weyerhaeuser/104, Beach/4.

Weyerhaeuser also indicated that widely used templates such as the Edison Electric Institute (EEI) Master Agreement can serve as a foundation for *standard* QF contracts. *See* Weyerhaeuser/100, Beach/3. I find this approach particularly applicable to *negotiated* QF contracts because these templates are typically used for transactions larger than 10 MW. As I stated in previous testimony, the EEI and Western System Power Pool agreements typically are used for power purchases in blocks of 25 MW. I also stated, "If the provisions in the standard contracts for QFs are consistent with these master agreements, that is an indication that the provisions are standard business practice." *See* Staff/1000, Schwartz/4.

Q. PLEASE PROVIDE YOUR INITIAL COMMENTS ON NEGOTIATION PARAMETERS.

A. Following are my initial comments on negotiation parameters for non-standard PURPA contracts, organized by FERC adjustment factor. My comments are

[2] Except for QFs receiving standard rates under 18 C.F.R. § 292.304(c).

not intended to limit the terms and conditions the utilities and QFs can negotiate for PURPA contracts. As parties did not wish to make settlement proposals in the second phase of this proceeding until opening testimony was filed, Staff reserves the right to further address this issue in rebuttal testimony.

a. *Data filed with avoided cost filing, including state review of data* (18 C.F.R. § 292.304(e)(1)) – Avoided costs for the utility's resource deficiency period are based on the fixed and variable costs of the utility's proxy plant – today a natural gas-fired CCCT. Characteristics of that plant, such as heat rate and fuel costs, are detailed in the avoided cost filing. The Commission reviews the data to ensure consistency with the next base-load resource identified in the utility's most recently acknowledged Integrated Resource Plan (IRP), as well as in the context of updated information, such as fuel prices. Any net costs or benefits of the QF, relative to the proxy plant data in the utility's approved avoided cost filing, and as approved for consideration by the Oregon Commission in adjusting avoided costs, should be taken into account in negotiating avoided cost rates.

b. *Availability of QF capacity or energy during the system daily and seasonal peak periods* (18 C.F.R. § 292.304(e)(2)) – This section includes several factors:

   i. *Ability of the utility to dispatch* – The proxy plant that serves as the basis for avoided cost calculations during the utility's resource deficiency period is utility-owned and dispatchable. In other words, the utility can shut down the plant when it is more expensive to operate it than buy power from the market. Tolling agreements can give the utility similar dispatch value in exchange for fixed capacity payments.

As Weyerhaeuser notes, CHP facilities need to provide reliable thermal energy to their hosts. Therefore, they offer a limited opportunity to the utility for physical dispatch. Weyerhaeuser recommends time of use (TOU) pricing for energy as the economic equivalent to dispatch: "With TOU energy prices, lower off-peak prices can keep ratepayers indifferent to QF generation in the event that the utility must sell excess off-peak power on the market. Conversely, higher on-peak prices provide the QF with a strong incentive to be on-line generating when the utility most needs the power." *See* Weyerhaeuser/104, Beach/4.

Standard avoided cost rates approved by the Commission are differentiated into on- and off-peak periods. During the utility's resource sufficiency period, these prices reflect forward market prices. During the deficiency period, they reflect capacity and energy in on-peak rates; off-peak rates reflect only the energy value.

Theoretically, off-peak rates for QFs that cannot be dispatched could be set to reflect the reduced value to the utility. Rates could vary by month or by season. At the same time, such a rate structure would not reflect the value of real-time dispatchability to the utility unless rates are tied to real-time prices. Thus, Staff finds TOU energy rates a poor substitute for real-time economic dispatch. Further, economic dispatch is not limited to off-peak hours. Dispatchability for on-peak hours also would need to be addressed.

A potential alternative to addressing the reduced value of a non-dispatchable, “24/7” natural gas-fired CHP facility is stochastic IRP-type modeling under various futures (market prices, fuel prices, hydro, etc.). The value of dispatchability can be estimated by comparing the revenue requirements of a portfolio with a dispatchable CHP facility to a portfolio with a non-dispatchable CHP facility.

ii. *Reliability* – I agree with Weyerhaeuser that QF contracts for firm power can provide strong incentives for high reliability through fixed capacity payments (in dollars per kilowatt-year) that are tied to performance during the utility’s peak period. *See* Weyerhaeuser/104, Beach/4.

iii. *Contract terms, including duration, termination notice and sanctions for noncompliance* – Pursuant to Order No. 05-584, the utilities file avoided costs for a 20-year period. Negotiated prices for non-standard contracts should use these yearly prices as the starting point for negotiations. As I stated previously, the QF should have the discretion to choose a contract term up to the maximum allowed by the Commission.

My recommendations regarding termination provisions for non-standard contracts generally are the same as for standard contracts. *See* Staff/1000, Schwartz/36-38, 41-43, 48-49; Staff/1500, Schwartz/21-22. The exception is, given the potential risk to the utility and ratepayers related to termination due to default by large QFs (over 10 MW), Staff does not recommend that the Commission prescribe the time period over which the utility may seek termination damages.

Avoided cost rates are based on a firm proxy utility resource. If sanctions for noncompliance in the negotiated QF contract "provide energy or capacity pursuant to a legally enforceable obligation for the delivery of [a specified amount of[3]] energy or capacity over a specified term," it is a contract for firm power. *See* 18 C.F.R. § 292.304(d)(2).

iv. *Extent to which scheduled outages can be usefully coordinated with scheduled outages of the utility's facilities* – Scheduled outages should be coordinated with expected market prices. The utility and the QF can negotiate the time periods when the QF may schedule outages and the advance notification required. Provisions in the

[3] Staff adds this clarification on how it interprets this rule.

utilities' standby rate tariffs may provide guidance. *See* PGE Schedule 75 and PacifiCorp Schedule 247.

v. *Usefulness of QF energy and capacity during system emergencies* - The contract should require the Seller to meet its delivery obligations to the utility during system emergencies.

vi. *Individual and aggregate value of energy and capacity of the QFs on the utility's system* – An IRP or production cost model could assess the aggregate value of various types of QFs on the utility's system. For example, because wind conditions vary throughout the control area, the utility can rely on a greater percentage of the wind QFs' nameplate capacity in any hour as the geographical dispersion of wind facilities on the system increases. However, the QF should receive no more of the aggregate value than the incremental value it brings.

vii. *Value of smaller capacity increments and shorter lead times* – Staff stated in previous testimony the benefits of these QF characteristics to the utility system, including reduction in forecasting risk related to load/resource balance, technological obsolescence, and regulatory risk. *See* Staff/100, Breen/20-21. Theoretically, the value of these factors in reducing risk for a specific QF, or QFs in aggregate, could be quantified in IRP-type modeling with stochastic parameters.

c. *Ability of the utility to avoid costs, including deferral of capacity additions and reduction of fossil fuel use, due to the availability of energy and capacity from the QF* (18 C.F.R. § 292.304(e)(3)) - If the utility can rely on capacity from the QF, the QF can contribute toward deferral of utility capacity additions. Therefore, QF payments should reflect avoided capacity costs. Dispatchable QFs should receive fixed capacity payments (in dollars per kW-year), reflecting the avoided capacity costs of the proxy utility plant. Wind QFs can receive fixed pricing per MWh, varying by year or by month, and reflecting the expected shape of the project's output during on- and off-peak periods, similar to pricing for PacifiCorp's renewable resources RFP (Docket No. UM 1118).

Regarding the value of reduced fossil fuel use, the Commission is addressing how to determine the risk mitigation value of non-fossil fuel resources in the resource planning and competitive bidding proceedings (Docket Nos. UM 1056 and UM 1182). When the utility's proxy plant for determining avoided costs is a natural gas-fired CCCT, the negotiated avoided cost rates for wind and other renewable resource QFs should reflect avoided natural gas price risk. The Commission should aim to make utilities and ratepayers neutral regardless of whether the utility's resource planning goals are achieved through acquisition of QF contracts, competitively-sourced contracts or utility-owned resources.

d. *Variations in line losses* (18 C.F.R. § 292.304(e)(4)) – Many QFs are located at or near customer sites. In these cases, the utility should reflect in negotiated avoided cost rates the reduction in transmission costs and line losses relative to the utility proxy plant, which typically is expected to be sited in a remote location. The utility should perform line loss and transmission studies to determine these values.

Q. CAN THE UTILITY NEGOTIATE THE PURCHASE OF GREEN TAGS?

A. Yes. The Commission has previously determined that the avoided costs paid under PURPA contracts do not convey the Tradable Renewable Certificates, or green tags, associated with generation from renewable resource QFs. *See* Order No. 05-1229 (Docket AR 495). However, the utilities can negotiate ownership of the green tags, and associated tag payments, when negotiating PURPA contracts for QFs over 10 MW. A constraint on PGE and PacifiCorp in this regard is that the total contract cost must not be “above market,” in compliance with a statutory prohibition against including in rates the above-market costs of new renewable resources. *See* ORS 757.612(3)(g). The utility should consider the value of owning the green tags to meet a Renewable Portfolio Standard (RPS) then in place, or for mitigating the risk of future RPS requirements.

Q. CAN THE UTILITY ADJUST AVOIDED COSTS FOR QFS OVER 10 MW BASED ON FACTORS THAT HAVE NOT BEEN APPROVED BY THE OREGON COMMISSION?

A. No. Staff reads the FERC rules as specifying *all* the factors that can be taken into account. The rules state: “In determining avoided costs, the following factors shall, to the extent practicable, be taken into account." *See* 18 C.F.R. § 292.304(e). In other words, it is an all-inclusive list.[4]

Second, the Oregon Commission ordered a second phase of this proceeding in large part to determine negotiation parameters and guidelines for nonstandard QF contracts, including adjustments to standard avoided cost rates. To the extent a utility foresees the need to address a particular factor in determining the appropriate avoided cost rates for negotiated QF contracts, the utility should raise that issue in this proceeding for a Commission decision.

[4] It is fair to observe that Staff could find no case law that addressed this matter.

SIMULTANEOUS SALE AND PURCHASE CONTRACTS

Q. PLEASE SUMMARIZE THIS ISSUE.

A. The Commission recognized in its initial order in this proceeding that a QF may sell no more than its "net output" under a PURPA contract with the utility. At the same time, a QF may sell the utility its *full* net output, as opposed to surplus power only – that is, generation in excess of the host's on-site power needs. *See* Order No. 05-584 at 53.

Under the second case, the utility would meet the full energy requirements of the QF customer, less "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…. " *See* Order No. 05-584 at 53.[5] In this situation, the QF host buys from the utility all the energy it requires, other than the amount related to power generation. In this docket we refer to this transaction as a "simultaneous purchase and sale" arrangement.

The specific issue raised in this proceeding relates to the *term* of the arrangement. Specifically, should the QF be allowed to switch back and forth between a simultaneous purchase and sale arrangement (full requirements customer), and a surplus sale arrangement (partial requirements customer)? PacifiCorp initially raised concerns regarding the QF not paying for this optionality, or not paying its fair share of demand charges. However, the

[5] Quoting from *Occidental Geothermal, Inc.,* 17 F.E.R.C. ¶61, 444 (1981).

Company does not oppose this arrangement so long as the host load complies with all terms and conditions of the utility's applicable retail tariffs, including minimum term of service. *See* PacifiCorp/100, Widmer/28-29; PacifiCorp Opening Brief at 21.

This issue is appropriately addressed through demand charges, and requirements for minimum term, and notification requirements for changes in service, in the utilities' partial requirements (also called "standby") tariffs, rather than in this forum.

The Commission recently approved revised standby tariffs for both PGE (Docket No. UE 158) and PacifiCorp (Docket No. UE 170). More recently, a tariff filing by PGE (Advice No. 05-17), and subsequent complaint by a QF that does not make sales under a PURPA agreement (Docket No. UM 1235), raised issues regarding tariff interpretation and term and notification requirements. Parties agreed to review these issues in PGE's forthcoming rate case.

Q. DOES THE AVOIDED COST CALCULATION REQUIRE MODIFICATION TO ACCURATELY REFLECT A "NET OUTPUT SALE"?

A. No. The avoided costs reflect the costs the utility would incur but for the QF purchase. The avoided costs are not dependent on whether the purchase is the QF's full net output, or only surplus output.

Q. DOES THE AVOIDED COST CALCULATION REQUIRE MODIFICATION TO ACCURATELY REFLECT A SIMULTANEOUS PURCHASE AND SALE ARRANGEMENT?

A. No. Utilities typically are resource-sufficient in the short term. The Commission determined that the appropriate basis for avoided costs during a resource sufficiency period is on- and off-peak forward market prices. Because these prices are not based on the deferral value of a utility base-load resource out in the future, these rates appropriately reflect the utility's avoided costs for short-term simultaneous purchase and sale arrangements.

For long-term contracts under such an arrangement, the QF would be contributing toward deferral of the utility base-load resource that the utilities use for avoided cost calculations during their resource deficiency period. Therefore, the Commission's proxy plant methodology for determining avoided costs is appropriately applied in this case.

PACIFICORP SCHEDULE 38

Q. ARE THE SCHEDULE 38 PROCEDURES AND TIMELINES FOR NEGOTIATING AVOIDED COSTS, AND REQUIREMENTS FOR INFORMATION EXCHANGE, REASONABLE?

A. What is included generally appears to be reasonable, with a few exceptions.

First, the Commission is addressing in this phase of UM 1129 any requirements for the types of pricing (e.g., fixed, deadband or gas indexed) that should be offered to QFs over 10 MW. Therefore, references to these pricing options are premature. *See* Schedule 38, section B.2.i., p. 2.

Second, the utilities should be flexible in their requirements for completion of interconnection studies prior to providing a draft power purchase agreement to the QF. The utility, rather than the QF, may be the hold-up in completing these studies. Further, there often are many issues to resolve once the QF receives the draft power purchase agreement, and that takes time. Therefore, the utility should not require that interconnection studies be completed prior to providing the QF with a draft power purchase agreement. *See* Schedule 38, section B.4.f. and B.5., p. 4.

Third, the tariff does not specify a timeline for providing a final draft agreement after the Company has received any additional or clarifying project information it needed to prepare the agreement. Nor is a timeline specified for providing the final executable agreement, after parties are in full agreement on terms and conditions. The tariff should specify these timelines. I recommend specific timelines for these events in my previous testimony. *See* Staff/1500, Schwartz/59-62.

Finally, the Commission has indicated that it wants to provide additional parameters and guidelines for negotiating non-standard contracts. The Commission's decision on this matter should be reflected in the utilities' compliance filings following the Commission's order in the Phase II proceeding.

INTEGRATION COSTS

Q. PLEASE SUMMARIZE THE INTEGRATION COST ISSUE IN ISSUE 3A.

A. Issue 3a addresses in part how avoided cost calculations should take into account integration costs for intermittent resources such as wind.[6] Such consideration appears to fit under the FERC adjustment factors described in 18 C.F.R. § 292.304(e)(2)(iv), "The individual and aggregate value of energy and capacity supplied from qualifying facilities on the electric utility's system," and 18 C.F.R. § 292.304(e)(3), "The relationship of the availability of energy or capacity from the qualifying facility … to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use."

Q. PLEASE SUMMARIZE STAFF'S POSITION ON TREATMENT OF INTEGRATION COSTS IN AVOIDED COST CALCULATIONS.

A. Staff's position is that in negotiating avoided cost pricing for QFs over 10 MW, the utility should take into account estimated integration costs for the specific QF project. Further, such cost estimates should not be based on the cost of integrating the company's *long-range planning* target for wind. Instead, these costs should be based on integrating the wind QF in the *existing* utility system, by control area and at current wind penetration levels, with progressively higher integration costs through year five of the QF contract based on the utility's

[6] "Integration" means accommodating the variable generating output of intermittent resources such as wind in the utility system to meet retail load and long-term firm sales obligations. Integration costs cover regulation – using automatic generation control to control system voltage, load following – ramping dispatchable generators up and down, and altering unit commitment on an hourly or longer basis.

projected trajectory of wind acquisitions and associated integration costs. Integration costs should be fixed at the year five level (adjusted for inflation) for the remainder of the contract.

Regarding standard contracts for QFs up to 10 MW, the methodology the Commission adopted in Order No. 05-584 for calculating standard avoided costs is a reasonable estimate of the costs the utility will avoid by purchasing from the small QF, even taking into account integration costs. As I testified previously, actual costs the utility avoids for a particular project may be higher or lower than the estimates. Benefits of the small QF vs. the utility's proxy plant, as well as any higher costs, are not taken into account for standard contracts. *See* Staff/600, Schwartz/7. For example, wind generation offers benefits such as fuel diversity and reduction in emission costs that are not currently captured in avoided cost estimates. *See* Staff Reply Brief at 5.

Further, my previous testimony shows that the integration costs for adding a 10 MW wind project to PacifiCorp's system, for example, are less than a dollar per MWh for imbalance costs and near zero for reserve requirements. *See* Staff/600, Schwartz/3; Staff/601, Schwartz/1-4. I continue to recommend the Commission not adjust avoided costs for integration for QFs up to 10 MW.

Q. HOW SHOULD THE UTILITIES ESTIMATE INTEGRATION COSTS FOR ADJUSTING AVOIDED COST PRICING FOR QFS OVER 10 MW?

A. Integration cost analysis in each utility's most recent IRP is an appropriate starting point. However, cost assignment to the QF should be based on integrating it into the *existing* utility system, by control area and at current wind penetration levels, with progressively higher integration costs through year five of the QF contract based on the utility's projected trajectory of wind acquisitions and associated integration costs. Integration costs should be fixed at the year five level (adjusted for inflation) for the remainder of the contract because of the high level of uncertainty related to resource actions, including acquisition of additional wind resources, beyond a five-year period.

Take, for example, a utility that has 100 MW of wind in one of its control areas today, but that expects to add 100 MW each year in the control area over years two through five of the QF contract. The first-year cost for integrating a 100 MW wind QF should be based on integrating 200 MW in the control area (the existing 100 MW of wind plus the 100 MW QF), the second-year integration cost should be based on integrating 300 MW in the control area, and so forth through year five. Integration costs for years six through 20 of the QF contract would be fixed at year five levels, escalating with inflation.

Staff recommends three additional considerations:

First, if the QF chooses to contract for integration services with a third party, the utility should make no downward adjustment in avoided cost payments due to integration costs. This is consistent with the methodology PGE and PacifiCorp used in evaluating bids for their RFPs (Docket Nos. UM 1080 and UM 1118).

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

Finally, the analysis of incremental reserves costs associated with integrating intermittent QFs needs refinement, as I testified previously.

Q. PLEASE SUMMARIZE THE ISSUES RELATED TO INTEGRATION COSTS THAT YOU RAISED IN PREVIOUS TESTIMONY.

A. In Staff/600, Schwartz/2-4, I discussed the $5.50/MWh integration cost that PacifiCorp used in its analysis of wind QFs in Phase I of this proceeding, based on the Company's 2003 IRP.[7] The cost breakdown was $3.00 per MWh for imbalance services and $2.50 per MWh for reserve requirements. I explained two problems with the use of this *planning* figure for avoided cost calculations.

The first issue is that these estimated integration costs are based on the addition of 1,000 megawatts of wind resources to PacifiCorp's system. Today, the Company has only 41 MW of wind resources (Combine Hills) on the West side of its system, and 140.5 MW of wind resources (Foote Creek, Rock River and Wolverine Creek) on the East side serving PacifiCorp customers. The Company also integrates wind for others. The amount reported in PacifiCorp's 2004 IRP is 200 MW. *See* Technical Appendix, p. 139. Even if these integration services for others are considered, the Company is still far from a penetration level of 1,000 MW.

As I demonstrated in Staff Exhibit 601, the Company estimated the imbalance cost for integrating wind resources on the West side of its system at only about a dollar per MWh at wind penetration levels of about 200 MW.

[7] PacifiCorp's 2004 IRP used a wind integration cost of $4.64 per MWh, based on updated market prices for reserves.

(Imbalance costs were even lower the East side.) I further discussed that the modeling used to estimate these imbalance costs did not account for changes in the dispatch of hydro resources that can reduce imbalance costs. Exhibit 601 also showed that the incremental reserve requirements for integrating several hundred megawatts of wind in each control area are minimal.

The second issue is that the utilities are not paying QFs for reserves through avoided cost rates. Both the QF and the proxy utility plant would pose additional costs for reserves. *See* Staff/600, Schwartz/2.

The point is that the utilities should *compare* the reserves costs for the wind QF with the reserves costs for the utility proxy plant that serves as the basis for calculating avoided costs. Avoided cost payments for the wind QF should be adjusted based on the difference in reserves costs for the two types of facilities.

Q. HAVE OTHER JURISDICTIONS RAISED SOME OF THE SAME CONCERNS?

A. Yes. The Public Service Commission of Utah agreed with the Utah Division of Public Utilities that “the assumption of 1,000 megawatts wind penetration is too high and overstates wind integration costs at this time.” The Utah Commission adopted an integration cost of $3/MWh, the midpoint of the cost range of $2 to $4 per MWh from an Xcel Energy study showing that integration costs increase with the penetration level of wind resources. The Commission will revisit this assumption after 300 MW, or 10 new wind projects, are added to the

Company's Eastern control area, whichever comes first. *See* Report and Order, Docket No. 03-035-14, October 31, 2005, pp. 23-24.

Q. WHAT INTEGRATION COSTS ARE OTHER STUDIES ESTIMATING?

A. Staff Exhibit 1802 shows a variety of integration cost estimates used in resource planning or determined through stand-alone studies. *See* Mark Bolinger and Ryan Wiser, *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Resource Plans*, LBNL-58450, August 2005; also published in the Jan./Feb. 2006 issue of *The Electricity Journal*. Several of the studies show that integration costs vary by wind penetration level.

Q. WHAT OTHER OPTIONS DID YOU CONSIDER IN MAKING YOUR RECOMMENDATION REGARDING INTEGRATION COSTS?

A. I already discussed why I rejected PacifiCorp's assumed wind QF integration costs based solely on the Company's long-range planning assumption for installed wind capacity. Following are alternatives I considered, in addition to the methodology I recommend the Commission adopt:

- *Integration costs today*, based on the current penetration level of wind in the utility's system and assuming the wind QF comes on line, by control area. This would be consistent with standard ratemaking practice to use only known and measurable loads and resources when setting cost-of-service rates. This assumption also may be reasonable if the federal production tax credit is not extended in a timely manner and under a scenario of prolonged scarcity and high prices for wind turbines.

- *Midpoint in integration costs* - The midpoint between integration costs today – at the current wind penetration level plus the capacity of the wind QF – and integration costs for the utility's long-term planning target for wind acquisitions. This is somewhat similar to the Utah Commission decision. One key difference is that the Utah Commission used analysis based on an unrelated utility system.
- *Midpoint in installed wind capacity* - The cost for integrating the level of wind resources (in MW) that is half-way between today's installed wind capacity, plus the capacity of the wind QF, and the utility's long-term planning target for wind acquisitions.

Q. WHY IS YOUR RECOMMENDATION SUPERIOR TO THE OTHER ALTERNATIVES YOU CONSIDERED?

A. The utilities' acknowledged IRPs put them on a path to acquire sizable levels of wind resources. Until such time as IRP updates or other forums indicate a significant change in direction, the Commission should assume that over the 20-year contract term of the wind QF, wind penetration levels in the utilities' systems will increase. Staff's recommendation for estimating integration costs strikes a balance between each utility's current wind penetration levels, and its planned acquisition levels. While the "midpoint in integration costs" and "midpoint in installed wind capacity" alternatives would be slightly simpler to administer, they would not provide as accurate an estimate as Staff's recommendation and do not address uncertainty related to resource actions beyond five years.

MECHANICAL AVAILABILITY GUARANTEE

Q. SHOULD THE UTILITIES USE A MECHANICAL AVAILABILITY GUARANTEE (MAG) FOR STANDARD CONTRACTS FOR QFS 10 MW OR LESS?

A. The Commission should require the utilities to include in standard contracts a MAG for intermittent resources such as wind and run of the river hydro. Staff testified previously that a MAG would allow the utility to count on the QF power as firm, as well as resolve the dilemma of the QF predicting a reliable amount of wind (or hydro) over the term of the contract, or even six months out.

Under the currently approved standard contracts, the QFs base their minimum delivery obligation on the output predicted under worst-case motive force conditions. That provides less value to the utility and ratepayers than commitments under a MAG. That is because the delivery obligation under a MAG is based on fixed, high percentages of the QF's *full* output when the wind is blowing (or the river is running), except for excused events such as scheduled maintenance and force majeure.

Compared to a minimum delivery obligation based on worst-case motive force conditions, a MAG gives the QF an incentive to maximize the facility's availability. Further, a MAG would avoid disputes over determination of the QF's minimum delivery obligation and mitigate many of the concerns related to weather, long-range resource forecasting, and default and damage provisions that parties have raised in this docket. Contracts for QFs that choose a non-firm power supply commitment should not include a MAG. *See* Staff/100, Breen/18-19; Staff/500, Breen/13-15; Staff/1000, Schwartz/25-32.

Q. HOW ARE FACTORS THAT REDUCE A QF'S CAPABILITY TO PRODUCE POWER CONSIDERED IN A MAG?

A. A QF is not obligated to deliver power to the utility under a MAG for lack of wind or water, scheduled maintenance and force majeure events.

Scheduled maintenance provisions, including the number of hours, time periods allowed, and notification requirements, can be easily standardized under each utility's MAG. Staff recommends the requirements match each utility's partial requirements tariff.[8] PGE Schedule 75 allows up to 744 hours (one month) of scheduled maintenance per calendar year. PacifiCorp Schedule 247 allows up to two events of scheduled maintenance each calendar year, for a total of up to 31 days. For both utilities, maintenance must be scheduled at least one month before delivery for a time period mutually agreeable to the utility and the customer.[9]

Q. DID PACIFICORP PROPOSE TO USE A MAG FOR A PURPA WIND CONTRACT IN ANOTHER JURISDICTION?

A. Yes. I describe the MAG PacifiCorp proposed for the 17.5 MW Schwendiman wind project in Idaho in Staff/1000, Schwartz/25-26.

[8] Idaho Power does not have a partial requirements tariff in Oregon. We recommend the scheduled maintenance provisions in the Company's MAG be similar to PGE's and PacifiCorp's partial requirements tariffs.

[9] PacifiCorp may extend the number of scheduled maintenance events at its discretion. The Company may cancel scheduled maintenance at any time with seven days' notice prior to the beginning of a scheduled maintenance period if resource, market, or other system conditions deviate significantly from expected conditions at the time the Company accepted the scheduled maintenance request. If

Q. WHAT MAG PROVISIONS DO YOU RECOMMEND AT THIS TIME?

A. Pending review of other MAGs presented in this proceeding, and parties' initial comments, I find the MAG PacifiCorp proposed for the Schwendiman wind project to be a reasonable template.

Q. SHOULD AVOIDED COST PRICES FOR STANDARD CONTRACTS BE AFFECTED IF THE UTILITY USES A MAG?

A. No. A MAG reinforces the Commission's previous order that intermittent and non-intermittent resources should be valued equally, and that intermittent resources receive full avoided costs delivered under a standard QF contract. *See* Order No. 05-584 at 28.

Q. WHAT OTHER CONTRACT PROVISIONS ARE REQUIRED TO IMPLEMENT A MAG?

A. The utility will need to know the facility availability[10] at the end of each period over which the delivery obligation is made — annually under PGE's and PacifiCorp's standard contracts, and as Staff has recommended in this proceeding. For the proposed MAG for the Schwendiman QF contract, PacifiCorp included the following "Availability Reporting Obligation," as well as audit provisions and shortfall damages and termination provisions for failure to meet the minimum availability obligation:

---

canceled, the Company will make its best effort to reschedule scheduled maintenance and waive the 30-day advance notice requirement.

[10] PacifiCorp defines availability as "the percentage of time that the Facility is actually producing Net Energy compared to the total amount of time that the Facility could have produced Net Energy. The total amount of time that the facility could have produced Net Energy is determined by taking the total hours in the measurement period and deducting the total number of hours of non-generation due to lack of sufficient wind, force majeure, and scheduled maintenance. *See* PacifiCorp Application, Section 1.2, Idaho Public Utilities Commission, Case No. PAC-E-05-9.

> By January 31 of each Contract Year, Seller shall provide an annual report documenting Facility Availability during the previous Contract Year. In determining Availability, Seller shall use wind speed data and generation data collected from Facility SCADA. Seller shall certify the accuracy of the Report, and the Report shall include an electronic copy of the data used to calculate Availability, in a standard format specified by PacifiCorp ("Annual Availability Report"). If Seller fails to deliver the Annual Availability Report and accompanying data by January 31, PacifiCorp shall pay Seller 85% of Net Output Purchase Price as shown in 5.1, until the Annual Availability Report has been satisfactorily provided. *See* Idaho Public Utilities Commission, Case No. PAC-E-05-9, PacifiCorp Application, Section 4.4.

As in standard contracts today, the QF also would provide an annual energy delivery schedule by month, and update it throughout each year of the contract.

Q. SHOULD AVOIDED COST PRICES FOR LARGER QFS BE AFFECTED IF THE NEGOTIATED CONTRACT INCLUDES A MAG?

A. Whether the QF contract includes a MAG *or* a minimum delivery obligation (a specified amount of power in MWh per month or per year), the QF is making a firm power commitment, and avoided cost payments should reflect that. If the QF does not want to make such a commitment, it is providing power on an "as available" basis, and avoided cost payments should be based on market prices at the time of delivery.

Q. DO THE UTILITIES USE A MAG IN ANY OF THEIR CONTRACTS PURSUANT TO RFPs?

A. Yes. PacifiCorp used a MAG for two 20-year non-PURPA negotiated wind contracts: one executed in April 2005 for the 64.5 MW Wolverine Creek project that is just coming on-line in Idaho, and one executed in June 2003 for the 41

MW Combine Hills project in Oregon. PGE used a MAG for one non-PURPA negotiated contract. The companies have requested that additional details be treated as confidential. *See* Staff/1801, Schwartz/1-4, for the non-confidential portions of their responses to Staff data requests.

NAMEPLATE CAPACITY

Q. WHAT IS YOUR RECOMMENDATION FOR A DEFINITION OF NAMEPLATE CAPACITY?

A. I recommend a definition similar to one of the following:

The full-load continuous rating of a generator under specified conditions as designated by the manufacturer. *See* Public Utility Commission of Texas Web site (www.puc.state.tx.us/electric/forms/pgc/pgc_inst.rtf).

The full-load electrical quantities assigned by the designer to a generator and its prime mover or other piece of electrical equipment, such as transformers and circuit breakers, under standardized conditions, expressed in amperes, kilovoltamperes, kilowatts, volts, or other appropriate units. Usually indicated on a nameplate attached to the individual machine or device. *See* Bonneville Power Administration Web site, (http://www.bpa.gov/corporate/pubs/definitions/no.cfm).

DISPUTE RESOLUTION

Q. PLEASE SUMMARIZE THE ISSUE RELATED TO STAFF'S ROLE IN INFORMAL DISPUTE RESOLUTION.

A. The Commission asked the parties to further explore whether Staff can play a role in informal resolution of QF contract negotiation disputes that would not compromise Staff's objectivity, or the perception of its objectivity, in formal proceedings such as formal disputes or rate cases. *See* Order No. 05-584 at 54-55.

Q. WHAT ARE STAFF'S RECOMMENDATIONS IN THIS REGARD?

A. Today, the Commission has chosen to restrict Staff from informal involvement in dispute resolution. However, Staff is still able to provide some assistance in the negotiation of non-standard contracts. As we noted in Staff's opening testimony, "Commission staff is able to provide information about QFs in Oregon, state statutes, and Commission rules. Staff may interpret administrative rules, for example, by answering questions about the consistency of a proposed action with current rules." *See* Staff/100, Breen/26.

Staff also can provide its interpretation of approved tariffs and relevant Commission's orders.

However, Staff remains concerned that going beyond this level of assistance would compromise the appearance of its objectivity in the event a QF files a formal complaint with the Commission over contract negotiations, or in rate case disputes over utility administration of QF contracts.

As stated in Staff's earlier testimony, only the Commission's formal complaint process provides the appropriate, open forum for reviewing QF contract disputes. Any closed process, where all parties are unable to participate, is potentially subject to criticism. Staff also expressed concern that its rate case recommendations regarding PURPA issues may be perceived differently if Staff participated in QF contract negotiations. *See* Staff/100, Breen/26-27.

Q. PLEASE ADDRESS THE OTHER ASPECT OF ISSUE 10, THE ROLE OF THE COMMISSION IN DISPUTE RESOLUTION DURING NEGOTIATIONS AND DURING THE TERM OF THE CONTRACT.

A. Dispute resolution is through the Commission's formal complaint process provided by ORS 756.500. Depending upon the facts and issues presented, a QF complaint case requiring a full procedural schedule with an evidentiary hearing may take up to a year to complete.

Rather than involve Staff in informal dispute mediation during contract negotiations, Staff recommends the Commission work to develop expedited procedures for formal resolution of contract negotiation disputes.

EFFECT OF EPACT 2005

Q. HOW DOES EPACT 2005 AFFECT QFS?

A. Among the provisions in the Energy Policy Act of 2005 (EPAct 2005) are efficiency requirements for cogeneration QFs, removal of the 50% limitation on utility ownership of QFs, and a provision for utilities to request an exemption from FERC of the mandatory obligation to purchase under PURPA if certain market conditions prevail in its service area.

Q. DOES EPACT 2005 AFFECT OREGON'S RULES RELATED TO QFS?

A. Yes. Rules defining eligible cogeneration facilities need to be changed, and references to limitations on utility ownership of QFs need to be removed. The Commission also may wish to add language regarding the ability of a utility to receive an exemption from FERC from its mandatory purchase obligation. Staff plans to ask the Commission to open a rulemaking to revise Division 29 rules at the conclusion of the UM 1129 proceeding. As we stated in previous testimony, "Staff recommends that the Commission revise its Oregon PURPA regulations based on federal PURPA requirements. To the extent that certain Oregon PURPA rules are also authorized under federal PURPA, staff recommends that those regulations carry over to the new rules." *See* Staff/500, Breen/17.

Q. WOULD AN OREGON UTILITY BE REQUIRED TO ENTER INTO A NEW CONTRACT WITH A QF LOCATED IN THE SERVICE TERRITORY OF ANOTHER UTILITY THAT HAS BEEN RELIEVED BY FERC OF A MANDATORY PURCHASE OBLIGATION UNDER PURPA?

A. Section 1253(a) of EPAct 2005 provides for termination of an electric utility's obligation to purchase energy and capacity under PURPA, on a service territory-wide basis, if FERC finds that certain conditions are met. To seek relief from this obligation, the utility must file an application with FERC.

FERC has proposed rules to carry out this provision. *See New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities,* Notice of Proposed Rulemaking, Docket No. RM06-10-000, Issued January 19, 2006; 71 FR 4532-4541 (January 27, 2006).[11]

Staff interprets the proposed rules such that an Oregon utility remains obligated to purchase from a QF within or outside its service territory until FERC has relieved the utility of its mandatory purchase obligation under PURPA. In other words, utility "A" is not relieved of its obligation to purchase from a QF simply because utility "B," which serves the area where the QF is located, has obtained its own exemption from PURPA's QF purchase requirements. *See* Proposed Rule 18 C.F.R. § 292.303, 292.310. Regardless, this is a matter under federal, rather than state, jurisdiction.

[11] Comments are due February 27, 2006; Reply Comments are due March 28, 2006.

COMPETITIVE BIDDING FOR QFS OVER 100 MW

Q. SHOULD COMPETITIVE BIDDING BE USED TO SET PRICING FOR QFS GREATER THAN A CERTAIN SIZE – FOR EXAMPLE, LARGER THAN 100 MW – IF THE UTILITY HAS RECENTLY COMPLETED AN RFP, OR A BIDDING PROCESS IS IN PROGRESS OR IMMINENT?

A. Conceptually, yes, and the Commission's 1991 order on competitive bidding contemplated this. It states:

> [W]hile resources acquired in the bid solicitation should be considered in the calculation of avoided costs, other resources — such as utility constructed plants, wholesale purchases, or efficiency measures — are also potential variables in the calculation procedure.
>
> Resources acquired through a competitive bid may impact the timing of projected load deficits and the need for new resources. In addition, to improve the accuracy of avoided-cost estimates, the calculation of new resource costs which are incorporated into the utility's revised avoided-cost filing will include information learned in the bid solicitation.
>
> The utility's revised avoided-cost filing should reflect the results of a bid solicitation which may impact the need for new resources and the estimated costs of new resources…. The Commission expects the accuracy of avoided-cost estimates to be improved by incorporating market information gained through bidding.
>
> *See* Order No. 91-1383, Appendix II.

As I noted in previous testimony, however, there was little interest in competitive bidding until 2003 because of low-cost power on the wholesale market in the 1990s and electric industry restructuring. *See* Staff/200, Schwartz/18. To the extent that recent solicitations have informed the proxy utility plant characteristics and costs, bidding results may be reflected to some extent in the utilities' recent avoided cost filings.

Using competitive bidding results *directly* to determine avoided costs for very large cogeneration QFs may be reasonable.[12] However, such a process raises several issues.

Q. PLEASE DESCRIBE ISSUES RELATED TO TIMING OF THE RFP.

A. As stated in the issues list, using an RFP process for determining pricing for very large QFs is feasible only when the utility has recently completed, or will soon complete, such a process.

Further, if bid prices are not as current as the utility's avoided cost filing, it may be inappropriate to use the bid prices. The prudence standard requires the utility to use the most recent information known (or knowable). In addition, the market may have shifted significantly since the RFP was concluded.[13]

Q. ALSO RELATED TO TIMING, DO THE RESOURCES SELECTED THROUGH A COMPETITIVE BIDDING PROCESS APPROPRIATELY REPRESENT THE RESOURCE THE UTILITY WILL AVOID THROUGH PURPA PURCHASES?

A. I cannot answer that question definitively. If the winning bid is an independent power producer, and the utility signs a contract with that producer to acquire the resource, the resource may well be unavoidable — due its relative size compared to the QF and the utility's resource needs, and considering contract termination damages. If instead a utility-built resource is the winning "bid,"

[12] PURPA limits small power production facilities such as wind plants to 80 MW or less; there are no size limits for cogeneration facilities under PURPA.
[13] That also may be the case with the avoided cost filing, but the Commission may revisit avoided costs if appropriate. *See* Order No. 05-584 at 29.

relative size is still a factor, and termination damages may be an issue with an Engineering, Procurement and Construction contract. However, the prudence standard requires the utility to continually review its resource decisions in light of changing circumstances and information.

Another important consideration is whether the results of the RFP are likely to better reflect the costs of the *next* resource the utility could avoid, compared to its approved avoided cost filing.

Q. SHOULD RFP-BASED PRICES BE USED TO DETERMINE AVOIDED COSTS DURING THE RESOURCE SUFFICIENCY PERIOD?

A. No. On- and off-peak forward market prices, as approved by the Commission pursuant to the utility's avoided cost filing, should apply during the utility's resource sufficiency period. Therefore, if the Commission adopts RFP-based pricing for very large QFs, only pricing during the utility's resource *deficiency* period should be affected. As the Commission determined in Phase I of this proceeding, forward market prices appropriately reflect the energy and capacity value of a QF during the resource sufficiency period. *See* Order No. 05-584 at 28.

Q. WHAT TYPES OF RFPS SHOULD THE COMMISSION CONSIDER FOR THIS PURPOSE?

A. RFP practices vary by utility. PGE's 2004 RFP was an "all-source" process, where all types of resources participated, and the Company selected both fossil fuel and wind plants, including the Company's Port Westward plant.

PacifiCorp and Idaho Power, on the other hand, issue separate RFPs for fossil-fuel plants and renewable resources.[14]

If the Commission approves RFP-based pricing for very large cogeneration QFs, typically fired by natural gas and operating 24/7, the Commission should require that the RFP used for this purpose be for a comparable resource that could be deferred or avoided. An RFP for a natural gas-fired CCCT would be reasonable for this purpose, if it is the avoidable resource. Given that coal-fired plants typically operate 24/7, it also may be reasonable to use the results of a coal plant RFP, if that is the resource that may be deferred. All-source RFPs also may be reasonable to use.

Q. IF THERE ARE MULTIPLE WINNING BIDS, WHICH BID OR BIDS SHOULD BE USED TO DETERMINE THE AVOIDED COSTS THAT SERVE AS THE BASIS FOR NEGOTIATIONS WITH QFS OVER 100 MW?

A. If there are multiple winning bids, the avoided costs that serve as the basis for negotiations could be calculated as: 1) a weighted average of the supply-side winning bids, as the Commission previously required for standard rates for QFs up to 1 MW (*see* Order No. 91-1383, Appendix III); 2) the marginal (most expensive) bid selected by the utility; or 3) the bid most closely aligned with the characteristics of the QF.

Q. PLEASE ADDRESS ISSUES RELATED TO HAVING TWO DIFFERENT METHODOLOGIES FOR DETERMINING AVOIDED COSTS DURING THE UTILITY'S RESOURCE DEFICIENCY PERIOD.

[14] Idaho Power's 2004 IRP action plan includes a separate RFP for cogeneration facilities (p. 84).

A. If the Commission adopts RFP-based pricing for very large cogeneration QFs, there will be two methodologies during the utility's resource deficiency period – one for small power production facilities (such as wind), as well as cogeneration facilities at or below a certain size, such as 100 MW; the other for very large cogeneration QFs.

Among the questions this raises is whether the utility should use the method that yields the lowest cost to the utility and its ratepayers. Staff recommends giving more weight to the results of a robust RFP that is more contemporary than the avoided cost filing, whether resulting avoided cost prices are higher or lower.

Very large cogeneration QFs are more like resources the utility is seeking to acquire through RFPs than are smaller QFs, whether they are renewable resources or cogeneration facilities. Further, as I testified previously, QFs below a certain size cannot participate at all in utility RFPs, or participate in a meaningful way. *See* Staff/200, Schwartz/8. Therefore, using a different methodology for avoided cost pricing for very large cogeneration QFs is justifiable.

Q. HAVE ADDITIONAL ISSUES BEEN RAISED IN OTHER JURISDICTIONS RELATED TO USING RFPS FOR AVOIDED COST PRICING?

A. Yes. In a proceeding before the Utah Public Service Commission, PacifiCorp recommended that pricing for QFs 100 MW or greater, and seeking a contract term of 10 years or more, be based on winning a competitive bid in the state's mandated RFP process.[15] Winning bidders would be entitled to avoided energy and capacity payments. Losing bidders, however, would be entitled only to avoided energy payments using a "Partial Displacement Differential Revenue Requirements" method and the Company's GRID model. They would receive no capacity payments. The Company further recommended that the QF be able to petition the Commission for a waiver of the 100 MW limit based on the provisions of Senate Bill 26. The Utah Commission adopted this recommendation. *See* Utah Public Service Commission, Report and Order, Docket No. 03-035-14, October 31, 2005, pp. 31-32.

Q. DO YOU AGREE WITH THESE PROVISIONS FOR OREGON QFS?

A. No. The Oregon Commission determined in Phase I of this proceeding that QFs have capacity value even during the utility's resource sufficiency period. The Commission further determined that forward market prices appropriately reflect the energy and capacity value of a QF during such periods. *See* Order No. 05-584 at 28.

The long-standing proxy plant method used by the Commission to determine avoided costs during the utility's resource *deficiency* period determines the capacity value based on the characteristics of the proxy utility plant. Further, the Commission's approved avoided cost methodology includes capacity value only in on-peak prices.

[15] *See* Energy Resource Procurement Act 54-17.

Assigning no capacity value to the QF, whether the utility is resource-sufficient or resource-deficient, runs counter to the Commission's previous decisions.

In negotiating avoided cost pricing with large QFs, the utilities should adjust the capacity portion of avoided cost prices – whether using RFP-based or utility proxy plant-based avoided costs – using the FERC adjustment factors described in 18 C.F.R. § 292.304(e).

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UM 1129 – Phase II
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1801

Exhibit in Support of Direct Testimony

February 27, 2006

UM-1129 II/PacifiCorp
February 22, 2006
OPUC Data Request 1

OPUC Data Request 1

Please provide the following information on each Mechanical Availability Guarantee (MAG) PacifiCorp has incorporated into an executed power purchase agreement:

a. A copy of the MAG as it appears in the power purchase agreement
b. For each MAG under item a. above, the type of resource (e.g., wind), the project size (in megawatts), the state in which the project is located, the Seller under the agreement, the date the agreement was executed, and the term (contract length) of the agreement
c. For each MAG under item a. above, indicate whether the project was executed under a PURPA or a non-PURPA negotiated agreement.

Response to OPUC Data Request 1

Contract #1

a-1. **"Availability"** means, for any Contract Year, the ratio of (x) the aggregate sum of the turbine-minutes in which each of the wind turbines at the Facility was available to operate during a Contract Year over (y) the product of XXX wind turbines multiplied by the number of minutes in such Contract Year. For purposes of determining Availability, a wind turbine shall be deemed to have been available to operate to the extent that it is unavailable due to (i) an event of Force Majeure; (ii) a default by PacifiCorp under this Agreement; (iii) a curtailment in accordance with Section 4.4.2 or Section 4.4.3; or (iv) inadequate or excessive wind speed at times when the wind turbine would otherwise be available.

b-1. Type of resource - Wind
Project size – 64.5 megawatts
State – Idaho
Seller - Wolverine Creek Energy LLC
Date the agreement was executed – April 29, 2005
Term (contract length) of the agreement – 20 years

c-1. Non-PURPA agreement

Contract #2

a-2. Please see Attachment OPUC 1 a.

b-2. Type of resource - Wind
Project size – 41 megawatts
State – Oregon

Seller – Eurus Combine Hills I LLC
Date the agreement was executed – June 19, 2003
Term (contract length) of the agreement – 20 years

c-2. Non-PURPA agreement

February 22, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Doug Kuns
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM-1129/ Phase II
PGE Response to OPUC Data Request
Dated February 9, 2006
Question No. 001

Request:

Please provide the following information on each Mechanical Availability Guarantee (MAG) PGE has incorporated into an executed power purchase agreement:

a. A copy of the MAG as it appears in the power purchase agreement
b. For each MAG under item a. above, the type of resource (e.g., wind), the project size (in megawatts), the state in which the project is located, the Seller under the agreement, the date the agreement was executed, and the term (contract length) of the agreement
c. For each MAG under item a. above, indicate whether the project was executed under a PURPA or a non-PURPA negotiated agreement.

Response:

a. Attachment 001-A contains the associated language in the only PGE power purchase contract with a MAG. This attachment is confidential and subject to Protective Order No. 04-378.

b. Response to section b. is also contained in Attachment 001-A.

c. The MAG contract language in section a. above is from a non-PURPA negotiated agreement.

CASE: UM 1129 – Phase II
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1802

Exhibit in Support of Direct Testimony

February 27, 2006

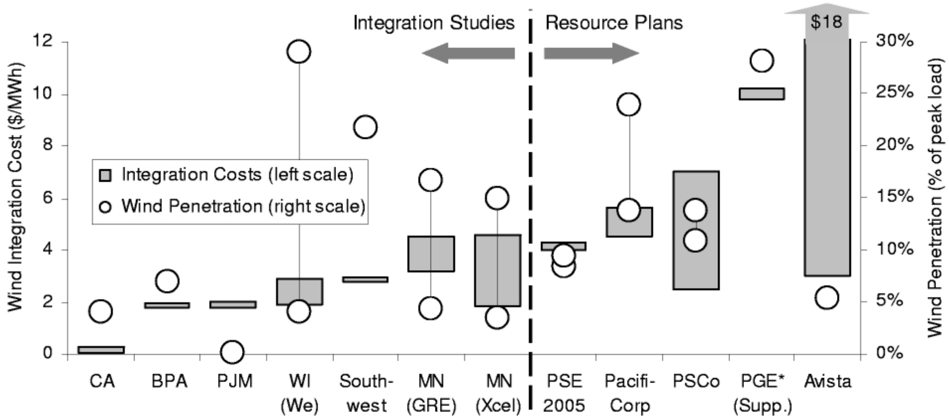

Figure 9. Comparison of Integration Cost Estimates in Resource Plans and Broader Integration Cost Literature

*PGE's supplemental IRP estimates the cost of creating a flat, base-load block of power out of variable wind production, rather than simply the cost of integrating variable wind production. As such, its cost estimates are not directly comparable to the others.

From: Mark Bolinger and Ryan Wiser, *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Resource Plans*, LBNL-58450, August 2005, p. 34; also published in the Jan./Feb. 2006 issue of *The Electricity Journal*.

CASE: UM 1129 - Phase II
WITNESS: Steve W. Chriss

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1900

Direct Testimony

February 27, 2006

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Steve W. Chriss. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551. I am employed by the Public Utility Commission of Oregon (OPUC) as a Senior Utility Analyst in the Electric and Natural Gas Division.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. Exhibit Staff/1901 is my updated Witness Qualification Statement.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS DOCKET?

A. Yes. I submitted Staff Exhibits 300-305, 700-701, 1100-1109, and 1600-1601.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I address issues 1b and 5a. My discussion of issue 5a includes a market pricing option for PacifiCorp and natural gas market-based pricing options for QFs over 10 MW. I also testify on issue 3a generally. Staff witness Schwartz addresses integration costs specifically.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

FIRM VS. NON-FIRM SUPPLY COMMITMENTS

Q. HOW SHOULD QF POWER SUPPLY COMMITMENTS DIFFERENTIATE BETWEEN "AS AVAILABLE" AND "LEGALLY ENFORCEABLE OBLIGATIONS" FOR DELIVERY OF ENERGY AND CAPACITY?

A. "Legally enforceable obligations" for delivery of energy and capacity should be treated as a firm commitment. "As available" delivery of energy and capacity should be treated as non-firm. This is consistent with federal regulations. *See* 18 CFR § 292.304(d).

Q. HOW SHOULD FIRM VS. NON-FIRM COMMITMENTS AFFECT THE CALCULATION OF AVOIDED COSTS?

A. FERC rules state that the avoided cost rates for a QF that provides energy and capacity on an "as available" basis (a non-firm commitment) "shall be based on the purchasing utility's avoided costs calculated at the time of delivery." *See* 18 CFR § 292.304(d)(1).

OAR 860-029-0080(4) requires electric utilities contracting to buy non-firm power from a QF to submit quarterly filings of avoidable energy costs.[1] For example, PGE's contract with the Covanta Marion solid waste facility in Brooks, Oregon, states that energy delivered in excess of 110% of scheduled delivery will be purchased at PGE's non-firm rate, based on quarterly forward market prices. PGE files these prices for Commission approval.

[1] Senate Bill 1149 (1999 Legislature) exempted PGE and PacifiCorp from Division 29 rules while the public purpose charge for conservation and renewable resources is in effect.

PGE also offers a market pricing option based on daily Mid-Columbia prices for QFs that do not wish to make a firm commitment to deliver energy and capacity.

FERC rules further state that QFs that "provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term" can choose, "prior to the beginning of the specified term," avoided cost rates "based on either: (i) The avoided costs calculated at the time of delivery; or (ii) The avoided costs calculated at the time the obligation is incurred." *See* 18 CFR § 292.304(d)(2). A market-based rate is appropriate under (i). The Commission determined the methodologies for calculating avoided costs for firm standard contracts for the utility's resource sufficiency and deficiency periods in Phase I of this proceeding. For QFs over 10 MW, these avoided costs form the basis for negotiations.

In addition, to the extent practicable, the factors listed in 18 CFR § 292.304(e) ("FERC factors") should be taken into account in negotiating avoided costs. The important FERC factors in regards to firm vs. non-firm commitments are:

> (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; and

(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.

PACIFICORP MARKET PRICING OPTION

Q. HAS THE COMMISSION DIRECTED PACIFICORP TO OFFER A MARKET INDEXED PRICING OPTION BASED ON ONE OR MORE POWER MARKET HUBS?

A. No. The Commission provided the following guidance in Order No. 05-584:

> "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."[2]

Q. HAS STAFF DETERMINED THE APPROPRIATENESS OF A MARKET INDEXED PRICING OPTION FOR PACIFICORP?

A. Yes. It would be appropriate for PacifiCorp to offer a market indexed pricing option. This offering would provide parity with PGE in terms of the pricing options offered to QFs in each utility's territory.

Q. HOW SHOULD PACIFICORP'S MARKET INDEXED PRICING OPTION BE STRUCTURED?

A. PacifiCorp should base its prices on published daily or monthly prices for the selected hub or combination of hubs plus any applicable wheeling or other charges.

Q. WHAT HUB OR COMBINATION OF HUBS SHOULD PACIFICORP USE?

A. Staff does not recommend a specific hub or combination of hubs at this time, pending review of PacifiCorp's testimony on this issue. However, it would be

[2] *See* Order No. 05-584 at 35.

reasonable for PacifiCorp to use the blend of hubs it has designated for the sufficiency period market forwards. Additionally, PacifiCorp may suggest another liquid hub at which the company purchases power in the course of its operations.

PRICING OPTIONS FOR QFS LARGER THAN 10 MW

Q. HAS STAFF PREVIOUSLY ADDRESSED WHETHER THE DEADBAND AND GAS MARKET METHOD PRICING OPTIONS COULD BE APPLIED TO QFS LARGER THAN 10 MW?

A. Yes. Staff witness Breen, during cross-examination by Weyerhaeuser, stated that while the pricing options specified in Staff/501, Breen/1, were applicable only to small QFs, gas indexed pricing could form a reasonable basis for negotiations with QFs larger than 10 MW. *See* Transcript (TR) at 179-180 (Breen).

Q. DO YOU AGREE WITH STAFF WITNESS BREEN?

A. Yes, gas indexed pricing options could be offered to QFs larger than 10 MW and the Commission should not preclude the utilities from offering these options. It is reasonable to keep the universe of options open for negotiations between QF developers and utilities.

Q. DO YOU RECOMMEND THAT THE COMMISSION REQUIRE THE UTILITIES TO OFFER GAS INDEXED PRICING OPTIONS TO QFS LARGER THAN 10 MW?

A. Not at this time.

Q. PLEASE EXPLAIN.

A. Due to the large potential diversity in the types and sizes of QF projects over 10 MW, a blanket recommendation that the Commission require the utilities to offer these options is not appropriate at this time. Staff is continuing its analysis and will further address this issue in rebuttal testimony.

Q. HOW DOES DIVERSITY IN THE TYPES AND SIZES OF QF PROJECTS AFFECT YOUR RECOMMENDATION?

A. Depending on the economics of a QF project, the application of the deadband or gas market pricing options could potentially benefit or harm the utilities and customers. Further analysis is required to determine if there is a subset of QF types and sizes that would constitute a "safe" range for the requirement of the two pricing options. For example, it may be most appropriate to offer a gas-indexed pricing option to a dispatchable, natural gas-fired QF, because this type of facility is similar to the utility proxy plant whose avoided costs serve as the basis for negotiations.

Q. WOULD THE IMPLEMENTATION OF THESE PRICING OPTIONS ASYMMETRICALLY BENEFIT THE QFS?

A. No. The utilities should employ the FERC factors in their negotiations. *See* 18 CFR § 292.304(e)(2). The FERC factors include those I mentioned earlier in my testimony and also include:

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

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

(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.

For example, if the QF cannot be dispatched to the same extent as the utility proxy plant, the utility should reduce the avoided cost rates based on gas indexed pricing to reflect the reduced value of the QF to the utility system.

Q. ARE THE UTILITIES PROTECTED FROM THE POTENTIAL OF HIGH GAS INDEX PRICES OVER THE LIFE OF QF CONTRACTS THAT UTILIZE THE DEADBAND AND GAS MARKET PRICING OPTIONS?

A. Yes. Both PGE and PacifiCorp employ sophisticated risk management and hedging programs with which they are able to manage gas price risk, even as it relates to QF contracts. The OPUC report "Public Utility Commission of Oregon Natural Gas Procurement Study," presented at the public meeting held on August 1, 2005, shows that from 1999 through 2004, both PGE and PacifiCorp capably managed their natural gas purchases and price risk. While this is not a guarantee of future performance, the report recommends that the Commission does not need to pre-approve hedging plans, transactions, or instruments. As Staff witness Breen testified in Phase I of this proceeding, "The Commission would consider a utility's proposal to use prudent hedging if both the benefits and costs are reflected in test period revenue requirements." *See* Staff/500, Breen/4.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UM 1129 - Phase II
WITNESS: Steve W. Chriss

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1901

Witness Qualification Statement

February 27, 2006

WITNESS QUALIFICATIONS STATEMENT

NAME: STEVE W. CHRISS

EMPLOYER: PUBLIC UTILITY COMMISSION OF OREGON

TITLE: SENIOR UTILITY ANALYST

ADDRESS: 550 CAPITOL ST. NE, SUITE 215, SALEM, OR 97310-1380

EDUCATION: Masters of Science degree, Agricultural Economics, from Louisiana State University (2001).

Bachelor of Science degree, Agricultural Development, from Texas A&M University (1997).

Bachelor of Science degree, Horticulture, from Texas A&M University (1997).

EXPERIENCE: Employed with the Public Utility Commission of Oregon (OPUC) as a Senior Utility Analyst in the Electric and Natural Gas Division. Previously employed with the OPUC as an Economist in the Economic Research and Financial Analysis Division from June, 2003 through February, 2006. Previously submitted testimony as the lead witness in Oregon docket UX 29 and as a supporting witness in Oregon docket UM 1129.

Employed as an Analyst and Senior Analyst at the Houston office of Econ One Research, Inc., a Los Angeles-based economic and regulatory consulting firm, between 2001 and 2003. Worked on regulatory and market issues in electricity, natural gas, and oil in both domestic and international markets.

Employed by North Harris College in Houston as an adjunct microeconomics instructor from January through May 2003.

CASE: UM 1129 – Phase II
WITNESS: Thomas D. Morgan

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2000

Direct Testimony

February 27, 2006

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Thomas D. Morgan. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/401.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to Issues 2, 6 and 13.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET, OTHER THAN YOUR WITNESS QUALIFICATIONS STATEMENT?

A. No.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

<u>ISSUE 2, DEFAULT SECURITY REQUIREMENT IF A QUALIFYING FACILITY CANNOT ESTABLISH CREDITWORTHINESS</u>

Q. IF A QF IS UNABLE TO ESTABLISH CREDITWORTHINESS BECAUSE IT DOES NOT HAVE A SPECIFIED MINIMUM RATING BY A MAJOR CREDIT RATING AGENCY, WHAT IS A SUFFICIENT AMOUNT OF SECURITY TO BE POSTED?

A. In the event that a QF is not able to establish sufficient credit, consistent with a public utility's normal parameters, Staff proposes the same standard for large QFs as was recommended for standard contracts. Staff recommended that the Commission approve contacts with terms comparable to those proffered by PGE and PacifiCorp. (*See* Staff/1000, Schwartz/19-22)

Staff Witness Schwartz concluded that the amount of security posting reflected in PGE's and PacifiCorp's standard contract was fair and reasonable. Staff proposes the same treatment should be afforded for large QFs as is afforded small QFs.

<u>ISSUE 6, LIMITS ON DEFAULT LOSSES THAT CAN BE RECOUPED, PURSUANT TO FUTURE CONTRACT PAYMENT REDUCTIONS</u>

Q. SHOULD THERE BE A LIMIT, OR CAP, ON DEFAULT LOSSES THAT COULD BE RECOUPED FROM A LARGE QUALIFYING FACILITY?

A. No. Large qualifying facilities (QFs over 10 MW) should be expected to maintain typical contractual obligations to other power producers. Providing any limits would not be in the best interest of ratepayers. However, the time period for recouping any losses should be negotiated in good faith between the QF and the utility.

Q. PLEASE EXPLAIN.

The potential risks associated with default of large QFs warrant increased safeguards to protect utility ratepayers. Further, large QFs generally have greater financing flexibility than small QFs and more stringent criteria should not impede access to capital markets. Low levels of equity involvement and non-recourse project financing may increase the probability that a non-utility developer (or QF) may choose to abandon a project. Capping default losses could also contribute to the likelihood of a QF abandoning a project. By not capping default losses, we can discourage a QF from abandoning a project and therefore help ensure greater reliability and protect customers from increased costs due to default. Damages due to under-delivery should fairly compensate the utility for any actual costs that are incurred.

ISSUE 13, DEBT IMPUTATION EFFECTS RESULTING FROM ACCOUNTING TREATMENT OF QUALIFYING FACILITY CONTRACTS

Q. SHOULD DEBT IMPUTATION BE CONSIDERED IN AVOIDED COST PAYMENTS FOR QF CONTRACTS?

A. No. There is no evidence that QF contracts require an adjustment for a "debt-imputation" effect. This argument is based on the assertion that, as contracting for power became more common during the late 1980s, the bond-rating agencies commenced evaluating the risks associated with this activity on the bond-rating of utilities buying purchased power. This issue is not affected by new accounting or credit rating treatment.

Q. WHAT IS THE UNDERLYING PREMISE TO THIS ARGUMENT?

A. The general argument is that Purchase Power Agreements (PPAs) require fixed payments that resemble interest and that a portion of the present value of the PPAs may be considered "debt-like" for rating agency purposes. These fixed payments may be considered similar to either operating or capital leases, each of which requires specific accounting treatment.[1] The argument is that, since there is a fixed payment, there would be an impact on the contracting utility's cost of capital and this cost should be included in the calculation of the avoided costs.

Q. IS THERE SUPPORT THAT THE INCREMENTAL COST OF CAPITAL WOULD INCREASE?

[1] If a contract is classified as a capital lease, the contract is considered to be an alternative to debt and the capacity payments would be reflected directly on a company's balance sheet. If a contract is classified as an operating lease, rating agencies may reflect a portion of the capacity payments in a

A. No. The cost of debt is the cost that is embedded in a utility's capital structure. The cost of equity is typically estimated from a grouping of similarly-situated utility companies in the industry. There is no support for a marginal impact on the cost of debt, and because all utilities can be expected to have PPAs with varying maturities and contract terms, there is no precise adjustment for the potential impact on the cost of equity.

Q. DO RATING AGENCIES RECOGNIZE THE IMPACT FROM PPAS ON THE UTILITY'S COST OF CAPITAL?

A. No. Credit rating agencies have historically considered the impact of PPAs in calculating a company's credit ratios. Agencies are concerned with the potential risk of default on debt. The rating agencies do not set the cost of capital. Moreover, their specific ratio calculations vary based on the specific terms of a contract. There is no specific impact on the interest rate based on PPA contracts. The debt markets determine the interest rate for companies and specific rating metrics are not used by investors. Investors are more generally concerned with the overall rating, which is broadly based on many factors. Furthermore, rating agencies have always been concerned with all required payments of a utility. The treatment afforded PPAs is not new and the impact of any power purchase agreement, on a utility's creditworthiness is imprecise.

Q. DOES A UTILITY'S COST OF CAPITAL REFLECT THE IMPACT OF PPAS?

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utility's financial ratios for the purpose of setting credit quality or ratings.

A. Yes. However, if a utility were to enter into a new PPA between rate cases that resulted in a large amount of debt imputation, it may not be compensated for that specific risk until after it is incorporated into rates through a general rate case or Resource Valuation Mechanism (RVM). However, it is likely that other risks have also changed since the last rate case. To single out one risk without reviewing the other risks may not result in just and reasonable rates.

Q. HOW IS THE COST OF DEBT ESTIMATED?

A. Embedded costs of debt reflect actual market interest costs at the time of a rate case. Since the utility's cost of debt is calculated using its embedded costs, the interest it pays on debt should fully reflect the riskiness of the utility up to the test period involved. Unless a new debt issuance were incurred as a result of a PPA, there is no practical reason to assume that the embedded cost of debt would change.

Importantly, Staff is not aware of any cases where a company has been downgraded solely due to entering into a PPA. The rating process considers the intermediate future prospects of all material issues that affect a company, including other liabilities, such as pensions and asset revaluations (asset impairment test, or mark-to-market accounting). The imputation of debt is important to be able to compare companies among themselves. The treatment afforded public utilities for PPAs is not different than other industries that sign leases or other long-term commitments, and the credit rating agencies have not altered their approach for at least two decades.

Q. HOW IS THE COST OF EQUITY ESTIMATED?

A. The cost of equity reflects the typical firm, which includes exposure to market contracts. With respect to cost of equity, since the utility's cost of equity is based on a comparable sample group of companies, and it is unlikely that the sample group is not similarly impacted by PPAs and debt imputation, it is difficult to make the case that an ROE premium should be granted. If a utility were truly unique with respect to PPAs, then this would most appropriately be dealt with in a general rate case and would likely manifest itself in the authorized capital structure.

Q. HAVE RATING AGENCIES COMMENTED ON THE IMPACT OF PPAS ON OVERALL CREDIT RATINGS?

A. Yes. Moody's Investment Service provides an idea of how it approaches the matter. Generally, it calculates the net present value of the stream of PPA payments and adds this figure to the adjusted obligations of the utility.

> In some circumstances, Moody's will adopt more than one method to estimate the potential obligations imposed by the PPA. This approach recognizes the *subjective nature* of analyzing agreements that can extend over a long period of time and can have a different credit impact when regulatory or market conditions change.[2]
>
> Under most PPAs, a utility is obliged to pay a capacity charge to the power station owner … this charge covers the portion of the IPP's fixed costs in relation to the power available to the utility. These fixed payments cover the debt service and are made irrespective of whether the utility requires the IPP to generate. … The most conservative treatment would be to treat the PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station.[3]

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[2] Moody's Investor Service, "Rating Methodology: Global Regulated Electric Utilities," March 2005, p. 10.

[3] Moody's Investor Service, p. 9 (emphasis added).

Moody's indicates that in deciding which combination of methodologies to use it will consider "the term to maturity of the PPA obligation, the ability to pass through costs and curtail payments, and materiality of the PPA obligation to the overall cash flows of the utility in assessing the affect of the PPA on the credit of the utility."[4]

Standard & Poor's also reflects its generic treatment for PPAs. Standard & Poor's has indicated that, in general, "a 50% risk factor is appropriate for long-term commitments."[5] This factor is to reflect the capacity components of both "take and pay" (TAP) and "take or pay" (TOP) PPAs.[6]

> Standard & Poor's Rating Services views electric utility purchased-power agreements (PPA) as debt-like in nature, and has historically capitialized these obligations on a sliding scale known as a "risk spectrum." Standard & Poor's applies a 0% to 100% "risk factor" to the net present value (NPV) of the PPA capacity payments, and designates this amount as the debt equivalent.[7] For utilities in supportive regulatory jurisdictions … a risk factor as low as 30% could be used.[8]

Standard & Poor's begins by taking the Net Present Value (NPV) of the annual capacity payments over the life of the contract. The rationale for not capitalizing the energy component, even though it is also a nondiscretionary fixed payment, is to equate the comparison between utilities that buy versus build – i.e., Standard & Poor's does not capitalize utility fuel contracts. The

[4] Moody's Investor Service, p.10.

[5] Standard & Poor's, May 12, 2003, p. 2.

[6] Standard & Poor's, "Buy Versus Build: Debt Aspects of Purchased-Power Agreements," October 2003, p. 39.

[7] Standard & Poor's, *Utilities & Perspectives,* May 12, 2003, p. 2.

[8] Standard & Poor's, May 12, 2003, p. 3.

discount rate is 10 percent. To determine the debt equivalent, the NPV is multiplied by the risk factor.[9]

Q. CAN YOU ACCURATELY QUANTIFY THE MARGINAL COST ASSOCIATED WITH THE CHANGE IN RISK DUE TO THE USE OF A PPA?

A. No. The impact on the credit rating metrics[10] from a PPA may be negligible and certainly will be subjectively considered by the credit analyst. The arbitrary adjustments proposed by S&P, for example, are not sufficiently precise enough to "mirror" for the purposes of the Commission, even if the argument were accepted that an adjustment is due.

Both Moody's and Standard & Poor's indicate that the utility's ability to recover the costs associated with the PPA mitigates the impact on their credit rating analysis. The overriding emphasis is on the risk of recovery, not the amount of PPAs.

Q. DO YOU HAVE SUPPORT FOR STAFF'S POSITION?

A. Yes. Authors of a report prepared by the Energy Information Administration indicate,

> "Based on an analysis using the discounted cash flow model, the earnings-price ratio model, and capital asset pricing model method, there does not appear to be any evidence to support the hypothesis that non-utility power purchases are equivalent to debt. Overall, based on the available financial data using two different approaches, there is no conclusive evidence that power purchases from nonutility

[9] Standard & Poor's, October 2003, p. 39.

[10] Key ratios include debt as a percentage of total capital; funds from operations (FFO); pretax interest coverage ratio; and FFO interest coverage.

> generators raised the cost of capital to the utilities which purchase the electricity."[11]

Likewise, authors of a report from Lawrence Berkeley Laboratory conclude,

> "Our principle finding is that we cannot detect any evidence to support the debt-equivalence hypothesis."[12]

> "The data did not support the hypothesis that utilities with significant power purchases incurred a higher cost of capital than did the utilities without such a commitment. In fact, the evidence shows that utilities with little or no power purchase commitments had to bear a slightly higher cost of capital in comparison with the cost borne by the other group.

The EIA also indicates,

> "In the area of allocation of earnings between debt and equity, utilities with significant power purchases paid slightly more for interest expenses than those without such purchases. However, it could not be determined whether the observed minor disparity resulted from power purchases.[13]

This indicates that there may be some impact on the cost of debt, though I cannot determine the basis of the assertions. However, if there is an increase in the cost of debt, it should be appropriately considered in a rate case and not mechanically through an arbitrary adjustment in a QF contract.

A Senior Vice President for Standard & Poor's indicates,

> "We did not attempt to compare the risks of purchasing with the risks of building. Suffice it to say that adding capacity is a risk regardless of how it is met. This underscores the fact that it is difficult to ascribe any

[11] "Financial Impacts of Nonutility Power Purchases on Investor-Owned Electric Utilities," report prepared by the Energy Information Administration, June 1994. (DOE/EIA-0580; www.eia.doe.gov/cneaf/electricity/pub_summaries/finance.html).

[12] Edward Kahn, Steven Stoft, and Timothy Belden, "Impact of Power Purchases from Nonutilities on the Utility Cost of Capital," Energy and Environment Division, Lawrence Berkeley Laboratory, March 1994 (LB-34741; UC 350).

[13] EIA-0580 Executive Summary.

> particular utility's credit rating, good or bad, to a single factor, such as the size of the utility's purchased power obligations."[14]

This statement reflects not only the difficulty in assessing the impact of a PPA on the overall risk of a company. Any attempt at mechanically figuring a "debt imputation effect" would ignore the risks of other potential alternatives. For example, if a self-build option could reduce the risk to a utility, how should the impact on the cost of capital be reflected at the time that the plant is put into rates?

Finally, Lawrence Berkeley Laboratory and the Energy Information Administration researchers conclude that relative to the debt-equivalence hypothesis, "we find more evidence to support the notion that utility construction raises the cost of capital than that [PPAs] do."[15]

Q. DO FERC'S ADJUSTMENT FACTORS FOR AVOIDED COST RATES INCLUDE CONSIDERATION OF "DEBT IMPUTATION"?

A. No. Debt imputation is not one of the factors delineated under 18 C.F.R. §292.304(e). *See* Staff Reply Brief at 5; Staff/1800, Schwartz/14.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

[14] Curtis Moultan, Electric Power Supply Association, "Buy or Build: Assessing the Impact of Power Purchase Agreements on Utility Credit Ratings and Balance Sheet Integrity," White Paper #2, July, 2004.

[15] Edward Kahn, et. al., p. 30.

CASE: UM 1129 - Phase II
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2100

Direct Testimony

February 27, 2006

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Michael Dougherty. I am employed by the Public Utility Commission of Oregon (Commission) as Program Manager, Corporate Analysis and Water Regulation Section of the Utility Program. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. HAVE YOU FILED TESTIMONY PREVIOUSLY IN THIS CASE?

A. Yes. I filed Staff 1300, Staff 1301, and Staff 1302 in the Phase I – Compliance proceeding. Additionally, I adopted and sponsored the testimony of Staff witness Jack Breen in Staff 100 and Staff 500 (filed in the now completed original Phase I proceeding) concerning insurance issues.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to discuss Issue 7 in the UM 1129 – Phase II, proceeding: Liability insurance for QFs with a design capacity at or under 200 kW.

Q. DID YOU PREPARE EXHIBITS?

A. Yes. Exhibit 2101 is a six-page table by the Interstate Renewable Energy Council (IREC) on net metering provisions by state, including eligible facility size, dated July 2005. Exhibit 2102 is a three-page table by IREC on interconnection rules for distributed generation, dated July 2005.

ISSUE 7 - INSURANCE

Q. PLEASE STATE ISSUE 7 AGAIN.

A. Issue 7 is liability insurance for QFs with a design capacity at or under 200 kW.

Q. SHOULD THE UTILITIES BE ALLOWED TO MANDATE LIABILITY INSURANCE COVERAGE FOR QUALIFYING FACILITIES AT OR UNDER 200 KW?

A. No. The utilities should not be allowed to mandate liability insurance coverage for qualifying facilities (QFs) at or under 200 kW. Although a QF at or under 200 kW may decide to maintain a certain level of liability insurance coverage based on its needs, the utilities should not be allowed to mandate the type and level of coverage.

Q. PLEASE SUMMARIZE WHY UTILITIES SHOULD NOT BE ALLOWED TO MANDATE LIABILITY INSURANCE COVERAGE FOR QUALIFYING FACILITIES AT OR UNDER 200 KW.

A. Liability Insurance should not be mandated for the following four reasons:

1. <u>Potential Costs and Relative Risk Compared to Net Metering Facilities</u>

Oregon Revised Statute (ORS) 757.300(4)(c) does not require net metering facilities to purchase additional liability insurance. Pursuant to the statute, net metering facilities include solar, wind, fuel cell, hydroelectric, and certain types of biomass electricity producers producing up to 25 kW. These are the same types of producers as the small QFs. So although a 25 kW net metered producer is not required to maintain additional insurance under the net metering statute, a small QF producing 30 kW under a PURPA power purchase agreement would need to maintain a certain level of liability insurance if the Commission allowed the utilities to mandate coverage. Even though the risks would not be appreciably different between the two facilities, the operating expense for the 30 kW QF could potentially be significantly higher because of insurance costs. This added cost may create a financial hardship on the small QF, preventing it from operating in an economical manner.

When trying to get an estimation of costs for liability insurance for this type of risk, I was informed by a representative of Energy Insurance Brokers[1] that an approximate *minimum* annual premium for $1 million in liability coverage[2] for a QF would be $5,500. I also note the cost of $10,000 annual cost for a $1 million liability policy that was stated in FRC Direct Testimony in Phase I of this proceeding, Sanders, Page 5.

Additionally, Staff witness Lisa Schwartz testified that the 2005 Legislature in Senate Bill 84 gave the Commission the authority to increase the net metering eligible facility size for PGE and PacifiCorp. *See* Staff/1500, Schwartz/4. Staff will ask the Commission to open a rulemaking on this matter shortly. In many states, the eligible facility size for net metering is at or above 100 kW. *See* Staff Exhibit 2101. If the Commission,

[1] According to its website, Energy Insurance Brokers "endeavors to utilize reliable insurance market facilities, offer fair competitive pricing, and conduct business with the highest degree of honesty and integrity." www.energyinsurancebrokers.com
[2] The $1 million liability coverage for QFs up to 10 MW is stated in PacifiCorp's PPA Section 13.2.1; Idaho Power's PPA Article XI, 11.2.1.1; and PGE's Schedule 201, Qualifying Facility Power Purchase Information, Section 12.

as a result of any rulemaking, was to increase the size of net metering facilities to 200 kW, there could be, depending upon the Commission's resolution of this issue, disparate treatment concerning liability insurance requirements for net metering facilities and those for small QFs at or under 200 kW under standard PURPA purchase power agreements. If the size of net metering facilities is increased, it is plausible that a larger net metering facility would not be required to maintain liability insurance, while a smaller QF under a PURPA purchase power agreement would have to show proof of insurance. I recommend the Commission treat each of these similar types of facilities in a similar manner and not require that either maintain liability insurance.

2. <u>Risk</u>

Staff Witness Jack Breen pointed out in UM 1129 Staff/100, Breen/10, that "no utility was able to provide an example where it was liable for damages because of the actions of a QF." Additionally, the American Wind Energy Association reported that:

> "In the 21 years since utilities have been required to allow small wind systems to interconnect with the grid there has never been a liability claim, let alone a monetary award, relating to electrical safety."[3]

This information is substantiated by Bergey WindPower Company,[4] whose president stated:

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[3] *See* American Wind Energy Association, *"Interconnection Requirements: Non-Technical."* www.awea.org

[4] According to its website, Bergey WindPower Company is the world's leading supplier of small wind turbines. *See* www.bergey.com

> "The industry has 6,000 – 7,000 machines interconnected in the U. S. all the way back to 1977. We have more than half a billion run hours on grid-intertied small-scale renewable energy systems, without any reported injuries or liability claims from the interconnected operation of these systems."[5]

Even though PGE, PacifiCorp, and Idaho Power were unable to provide an example where it was liable for damages because of an action of a QF, Idaho Power in its UM 1129 Opening Brief states:

> "Staff's argument is similar to an argument that you don't need to maintain fire insurance on your home because houses rarely burn down."[6]

I agree with this statement as it relates to the need for fire insurance, as all homes face some fire risk. But not all homeowners may need to maintain flood insurance if they do not live in a flood plain; or homeowners may not need earthquake insurance if they are located hundreds of miles from the closest fault line. The homeowner will weigh the risks of damage against the costs of insurance. A business will also weigh risks against costs and does this routinely when determining coverage and deductible levels for various types of insurance.

Idaho Power further argued in its UM 1129 Opening Brief that it was aware of several instances on its system where QFs have maintained dangerous conditions that *could* have resulted in serious personal injury or property damage.[7] Idaho Power failed to provide the number of instances,

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[5] Thomas J. Starrs and Robert K. Harmon, *"Allocating Risks: An Analysis of Insurance Requirements for Small-Scale PV Systems"*, presentation at the Annual Conference of the American Solar Energy Society, June 2000.
[6] UM 1129 Opening Brief of Idaho Power Company, December 24, 2004, page 14.
[7] *Ibid*, page 14. Emphasis added.

what the dangerous conditions were, how many QFs caused these conditions, what size the QFs (above or under 200 kW) were that caused these conditions, the magnitude of the necessary repairs to rectify these conditions, or actions taken against the QF by Idaho Power. Also, there is no comparison between the frequency of potential safety incidents related to small QFs versus net metering systems for which the utility is prohibited by law from mandating insurance.

The Commission's has no records to support Idaho Power's claim about several potential dangerous situations concerning QF interconnections with the Idaho Power system. Idaho Power and other electric utilities need to enforce their interconnection standards and tariffs to prevent safety and other problems. Idaho Power should support its claim with more information on the facts and specifics concerning these several potentially dangerous situations.

Additionally, there are various IEEE[8] and UL[9] standards that have been issued in recent years that address "islanding," safety, and damage prevention. To date, these standards have not been adopted in the Commission's Oregon Administrative Rules; however, a forthcoming docket will establish uniform interconnection standards, pursuant to the

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[8] According to its website, the IEEE (Institute of Electrical and Electronic Engineers), a non-profit organization, is the world's leading professional association for the advancement of technology. The IEEE is a leading developer of standards that underpin many of today's technologies. *See* www.ieee.org.

[9] According to its website, UL (Underwriters Laboratories) is the trusted source across the globe for product compliance. *See* www.ul.com.

Commission's objectives and requirements in the Energy Policy Act of 2005.

Idaho Power also stated that it has received from the Idaho Public Utility Commission's (IPUC) approval for 71 QF contracts.[10] The sheer number of QF contracts, coupled with the fact that Idaho Power has been unable to provide an example where it was liable for damages because of the interconnection actions of a QF, indicates a low level of risk resulting from the operations of a small QF.

Because there is no historical evidence to justify imposing insurance requirements for safety purposes, the decision to carry liability insurance should be established by each small QF as a business decision according to its needs and not mandated by the utilities.

3. Actions by Other Jurisdictions

Staff Witness Jack Breen testified in Staff/100, Breen/10-11, that the National Association of Regulatory Utility Commissioners (NARUC) does not recommend a mandatory insurance requirement in its *"Model Interconnection Procedures and Agreement for Small Distributed Generation Resources."* Although this model is for interconnection of small distributed generation resources, the underlying logic is easily transferred to purchase power agreements since the power that is purchased must interconnect directly or indirectly to the utility's system. The NARUC document states (emphasis added):

[10] UM 1129 Opening Brief of Idaho Power Company, December 24, 2004, page 13.

> "The Interconnection Customer is *not required to provide general liability insurance coverage as part of this Agreement, or any other Interconnection Provider requirement.*"[11]

In its UM 1129 Reply Brief, Idaho Power pointed out that NARUC may be modifying its stance on mandatory insurance for small generators in Docket No. RM02-12-000 ("Interim Report"). According to Idaho Power, a new consensus provision in the Interim Report requires both the transmission owner and the interconnection customer to maintain, at their own expense, general liability insurance in commercially reasonable amounts.[12]

The Federal Energy Regulatory Commission (FERC) in its *Standardization of Small Generator Interconnection Agreements and Procedures*, RM02-12-000, Order No. 2006, issued May 12, 2005, appears to have considered both NARUC' s initial model that does not require insurance and the Joint Commenters consensus position on insurance.

The FERC order discusses the initial NARUC position that requiring different types of insurance is excessive making federal interconnection rules incompatible with state rules and states:

> "The very act of requiring insurance would drive up prices because insurance companies would then have a captive market that must have insurance"[13]

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[11] National Association of Regulatory Utility Commissioners, *Model Interconnection Procedures and Agreement for Small Distributed Generation Resources*, page 38.
[12] UM 1129, Reply Brief of Idaho Power Company, January 28, 2005, pages 8 and 9.
[13] FERC, RM02-12-000, Order No. 2006, paragraph 303, page 81.

However in the order, FERC also acknowledges the Joint Commenters position requiring the Interconnection Customer to maintain insurance in an amount:

> "sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made."[14]

The statement speaks to foreseeable direct liabilities given the size of the generating equipment. It is important to note that FERC's standard for "small" generators is 20 megawatts or less. As previously pointed out, there has not been a reported interconnection liability claim against a small QF. So when considering the size of a QF 200 kW or less, and the low risk of an interconnection liability claim, a sufficient amount of insurance could easily be "zero."

As Staff previously stated, a QF may decide to maintain appropriate liability insurance coverage based on its business needs. However, with this said, the utilities should not be allowed to mandate the type and level of coverage. In the Commission Conclusion of Order No. 2006, FERC states (emphasis added):

> "The wide range of insurance recommendations points out the difficulties in establishing a set dollar amount or type of insurance appropriate to every Small Generating Facility. *Insurance can add significant costs to a Small Generating Facility and may affect the project's economic feasibility*."[15]

[14] FERC, RM02-12-000, Order No. 2006, paragraph 330, page 80.
[15] *Ibid,* paragraph 331, page 87. Emphasis added.

As such, utilities should not be allowed to set a level or even mandate liability insurance because of the potential uneconomical costs to a small QF at or under 200 kW. The liability insurance requirements imposed on QFs over 200 kW resulting from UM 1129 Phase I may be a misfit for QF's under 200 kW. As previously mentioned, ORS 757.300(4)(c) does not require insurance for net metering facilities.

In Order No. 2006 (RM02-12-000), FERC declined to impose a generic insurance requirement on interconnections for small distributed generation resources. In the order, FERC acknowledges that the risk of interconnecting small inverter-based generators is low and adopted the NARUC approach that each party to the interconnection follow state insurance requirements. Additionally, FERC stated that all insurance policies be maintained with insurers authorized to do business in the state the Point of Interconnection is located.[16] Because of the precedence established in ORS 757.300(4)(c), the Commission should not impose any liability insurance requirement on these small non-net metering QFs.

Additionally, Staff examined a summary table prepared by the Interstate Renewable Energy Council (IERC), *Connecting to the Grid Project Comprehensive Interconnection Rules for Distributed Generation (updated July 2005)." See* Staff Exhibit 2102*.* The table lists differing requirements, including insurance, based on various state rules. Although Idaho Power, in its UM 1129 Reply Brief, points out that its insurance

[16] FERC, RM02-12-000, Order No. 2006, paragraph 334, page 87. Inverter-based systems include solar photovoltaic systems and some wind and small hydro systems.

requirement was inaccurately listed in the table,[17] there is no indication that the other information concerning insurance requirements listed in the table is flawed. As substantiation of the IREC table, FERC in Order No. 2006 (RM02-12-000), refers to the NARUC argument that (emphasis added):

> "while California requires insurance for most projects, the *majority of other states* (including New York, Texas, and Ohio) do not. Therefore, requiring insurance would be inconsistent with the practice in most states."[18]

If the Commission adopts Staff's recommendation, Oregon would be in the majority of states who do not to place additional insurance requirements on the smallest QFs.

Because FERC, in Order No. 2006, has left insurance requirements to the states, many jurisdictions have not placed mandatory insurance requirements on small QFs, and Oregon does not allow utilities to impose additional insurance requirements on net metering facilities, the decision to carry liability insurance should not be mandated by the utilities, but be established by each small QF as a business decision according to its needs.

4. <u>Indemnification</u>

Insurance requirements should also not be placed on QFs under 200 kW because standard utility contracts for QFs up to 10 MW have indemnification language that state that each party will agree to hold harmless and to indemnify against all loss, damage, fines, penalties, expense, and liability to third persons for such instances as injury, death, or

[17] UM 1129, Reply Brief of Idaho Power, January 26, 2005, page 9.
[18] FERC, RM02-12-000, Order No. 2006, paragraph 303, page 81. Emphasis added.

property damage.[19] The indemnification clauses, if pursued aggressively by the utilities, are sufficient legal remedies and adequately protect the interest of the utility, its customers, and small QFs.

The utilities should rely on the indemnification clauses to ensure that the utility has sufficient legal remedy if any liability claims are pursued against the actions of the small QF.

Q. IN CONCLUSION, SHOULD SMALL QUALIFYING FACILITIES UNDER 200 KW HAVE MANDATED INSURANCE COVERAGE?

A. No. Although small QFs may decide to carry liability insurance because of business needs, insurance coverage should not be mandated by the utilities because of the reasons stated above (potential costs, net metering statute, low risk, actions in other jurisdictions, and indemnification). The small QF should be able to make the business decision, according to its needs, on how much and what type of insurance to obtain.

Q. EVEN THOUGH THERE IS NO HISTORY OF DAMAGE OR PROPERTY CLAIMS AGAINST A QUALIFYING FACILITY, IF A CLAIM WAS MADE, WOULD IT PLACE THE RISK AND COST BURDENS ON CUSTOMERS?

A. Likely not. All the utilities currently have insurance costs embedded in rates. These costs include premium costs, administrative and legal costs, uninsured costs, and claim costs. Uninsured costs include deductible

[19] Indemnification language for QFs up to 10 MW is stated in PacifiCorp's PPA Section 12; Idaho Power's PPA Section XI, 11.1; and PGE's Schedule 201, Qualifying Facility Power Purchase Information, Section 11.

payments, contested claims, and reserves set aside for future losses instead of purchasing insurance. As an example, in UE 170, PacifiCorp included over $19 million for property and liability uninsured losses in its rate application.

Because there is no history of reported injuries or liability claims against a QF and because insurance costs, including uninsured losses, are already included in rates, customers would likely not be paying higher levels for any uninsured losses related to QFs 200 kW or smaller than they are currently paying in rates. Additionally, during a rate case investigation, Commission Staff will closely examine any liability-related cost resulting from purchases from small QFs, under a standard PURPA purchased power agreement, to ensure that the utility aggressively pursued the indemnification clauses of the contract. The burden would be on the utility to demonstrate that it pursued the legal remedies in the indemnification clauses.

Q. IF THE COMMISSION DOES NOT IMPOSE MANDATORY LIABILITY INSURANCE FOR SMALL QUALIFYING FACILITIES AT OR UNDER 200 KW, SHOULD ANY ADDITIONAL EXPENSES INCURRED BY MULTI-STATE UTILITIES BE 100 PERCENT ALLOCATED TO OREGON?

A. No. Multi-state utilities should be required to maintain their current Oregon allocation concerning purchased power for any potential additional expenses that could have been covered by liability insurance. Again, it should be expected that all utilities will aggressively pursue the indemnification clauses of the approved standard contracts.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UM 1129 - Phase II
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 2101

Exhibit in Support of Direct Testimony

February 27, 2006

Interstate Renewable Energy Council (IREC) "Connecting to the Grid" Project
State and Utility Net-Metering Rules
(Updated July 2005)

Program	System Size Limit / Customer Classes Eligible	Eligible Technologies	Limit on Total Capacity	Treatment of Net Excess Generation (NEG)	Interconnection Standards for Net Metering	Utilities Involved
Arizona – Salt River Project	10 kW / Residential	Photovoltaics	None	Purchased monthly by utility at average monthly market price minus a price adjustment of $0.00017/kWh	No	Salt River Project
Arizona – Tucson Electric Power	10 kW / Commercial, Residential	Photovoltaics, Wind	500 kW peak aggregate	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	No	Tucson Electric Power
Arkansas	25 kW for residential systems; 100 kW for commercial systems	Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydro, Geothermal Electric, Fuel Cells, Microturbines	None	Granted to utility monthly	Yes	All utilities
California	1 MW / Commercial, Industrial, Residential	Photovoltaics, Landfill Gas, Wind, Anaerobic Digestion, Fuel Cells	0.5% of a utility's peak demand	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	Investor-owned utilities; municipal utilities may permit either net metering or co-metering
Colorado (*under development*)	To be determined / Commercial, Industrial, Residential	Photovoltaics (other technologies to be determined)	To be determined	Credited at retail rate to customer's next bill	Yes (*under development*)	Colorado utilities serving 40,000 or more customers
Colorado – Aspen Electric	None / Commercial, Industrial, Residential	Photovoltaics	50 kW	Credited at retail rate to customer's next bill	Yes	Aspen Electric
Colorado – Fort Collins Utilities	10 kW / Residential	Photovoltaics, Wind	25 customers	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	Fort Collins Utilities
Colorado – Gunnison County Electric	10 kW / Commercial, Residential	Photovoltaics, Wind	50 customers	Purchased by utility at wholesale rate	Yes	Gunnison County Electric
Colorado – Holy Cross Energy	None / Commercial, Industrial, Residential	Photovoltaics	50 kW	Credited at retail rate to customer's next bill	Yes	Holy Cross Energy
Colorado – Xcel Energy	< 10 kW / Commercial, Residential	Photovoltaics, Wind, Small Hydro	None	Credited at retail rate to customer's next bill	Yes	Xcel Energy
Connecticut	100 kW for renewables; 50 kW for fossil fuels / Residential, Commercial	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Fuel Cells, Municipal Solid Waste, Small Hydro, Tidal Energy, Wave Energy, Ocean Thermal	None	Purchased by utility at spot market energy rate	Yes	Investor-owned utilities only

Sources: The Interstate Renewable Energy Council (IREC) and the N.C. Solar Center (NCSC). "Connecting to the Grid" Project web site, http://www.irecusa.org/connect, 7/18/05; Database of State Incentives for Renewable Energy (DSIRE), http://www.dsireusa.org, 7/18/05. Additional information, including most legislative and regulatory source citations, is available via DSIRE.

Interstate Renewable Energy Council (IREC) "Connecting to the Grid" Project
State and Utility Net-Metering Rules
(Updated July 2005)

Program	System Size Limit / Customer Classes Eligible	Eligible Technologies	Limit on Total Capacity	Treatment of Net Excess Generation (NEG)	Interconnection Standards for Net Metering	Utilities Involved
Delaware	25 kW / Commercial, Residential	Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydro, Geothermal Electric	None	Varies by utility	Yes	All utilities (applicable to municipal utilities if they opt to compete outside their limits)
District of Columbia	100 kW / Commercial, Industrial, Residential	Renewables (unspecified), Fuel Cells, Microturbines, CHP	None	Credited at retail rate to customer's next bill	Yes (*under development*)	All utilities
Florida – JEA	10 kW / Residential	Photovoltaics, Wind	None	Credited at retail rate to customer's next bill	Yes (JEA standards)	JEA
Florida – New Smyrna Beach Utilities	None / Commercial, Industrial, Residential	Photovoltaics	None	Credited at retail rate to customer's next bill	Yes	New Smyrna Beach Utilities
Georgia	100 kW for commercial systems; 10 kW for residential systems;	Photovoltaics, Wind, Fuel Cells	0.2% of a utility's peak demand	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	All utilities
Hawaii	50 kW / Commercial, Residential, Government	Photovoltaics, Wind, Biomass, Hydro	0.5% of a utility's peak demand	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	All utilities
Idaho – Idaho Power	100 kW for large commercial and agricultural; 25 kW for residential and small commercial	Photovoltaics, Wind, Biomass, Hydro, Fuel Cells	2.9 MW (0.1% of utility's 2000 peak demand)	Purchased monthly by utility at retail rate for residential and small commercial customers; purchased at 85% of Mid-Columbia rates for large commercial and agricultural customers	Yes	Idaho Power
Idaho – Utah Power & Light	100 kW for large commercial and irrigation; 25 kW for residential and small commercial	Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydro	714 kW (0.1% of utility's Idaho retail peak demand in 2002)	Purchased monthly by utility at retail rate for residential and small commercial customers; purchased at 85% of Dow Jones index price for non-firm energy for large commercial and agricultural customers	Yes	Utah Power & Light
Idaho – Avista Utilities	25 kW / Commercial, Residential, Agricultural	Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydro, Fuel Cells	1.52 MW (0.1% of utility's 1996 peak demand)	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	Avista Utilities
Illinois – ComEd Wind and PV Generation Program	40 kW / Commercial, Industrial, Residential	Photovoltaics, Wind	0.1% of utility's annual peak demand	Purchased by utility at avoided-cost rate, plus an annual incentive payment	Yes	ComEd
Indiana	10 kW / Residential, Schools	Photovoltaics, Wind, Small Hydro	0.1% of a utility's most recent peak summer load	Credited at retail rate to customer's next bill	Yes	Investor-owned utilities
Iowa	500 kW / Commercial, Industrial, Residential	Photovoltaics, Wind, Biomass, Hydro, Municipal Solid Waste	None	Credited at retail rate to customer's next bill	No	Investor-owned utilities

Sources: The Interstate Renewable Energy Council (IREC) and the N.C. Solar Center (NCSC). "Connecting to the Grid" Project web site, http://www.irecusa.org/connect, 7/18/05; Database of State Incentives for Renewable Energy (DSIRE), http://www.dsireusa.org, 7/18/05. Additional information, including most legislative and regulatory source citations, is available via DSIRE.

Interstate Renewable Energy Council (IREC) "Connecting to the Grid" Project
State and Utility Net-Metering Rules
(Updated July 2005)

Program	System Size Limit / Customer Classes Eligible	Eligible Technologies	Limit on Total Capacity	Treatment of Net Excess Generation (NEG)	Interconnection Standards for Net Metering	Utilities Involved
Kentucky	15 kW Commercial, Residential, Nonprofit, Schools, Agricultural, Institutional, Government	Photovoltaics	0.1% of a utility's single-hour peak load during the previous year	Credit at retail rate to customer's next bill (no expiration)	Yes	Investor-owned utilities, cooperatives
Louisiana (*under development*)	100 kW for commercial and agricultural systems; 25 kW for residential systems	Photovoltaics, Wind, Biomass, Hydro, Geothermal Electric, Fuel Cells (Renewable Fuels), Microturbines	To be determined	To be determined	Yes (*under development*)	All utilities
Maine	100 kW / Commercial, Industrial, Residential	Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydro, Geothermal Electric, Fuel Cells, Municipal Solid Waste, CHP, Tidal Energy	None	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	No	All utilities
Maryland	200 kW (500 kW with MD PSC permission) / Commercial, Residential, Schools, Government	Photovoltaics, Wind, Biomass	34.7 MW (0.2% of state's adjusted peak load in 1998)	To be determined	Yes	All utilities
Massachusetts	60 kW / Commercial, Industrial, Residential	Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydro, Geothermal Electric, Fuel Cells, Municipal Solid Waste, CHP	None	Credited at average monthly market rate to customer's next bill	Yes	All utilities
Michigan	30 kW / Commercial, Industrial, Residential, Nonprofit, Schools, Government, Agricultural, Institutional	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydro, Geothermal Electric, Municipal Solid Waste	0.1% of a utility's peak load or 100 kW (whichever is greater)	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	Various utilities (voluntary participation)
Minnesota	40 kW / Commercial, Industrial, Residential	Photovoltaics, Wind, Biomass, Hydro, Municipal Solid Waste, CHP	None	Purchased at average retail utility energy rate	Yes	All utilities
Montana	50 kW / Commercial, Industrial, Residential	Photovoltaics, Wind, Hydro	None	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	Investor-owned utilities
Montana – Montana Electric Cooperatives	10 kW / Commercial, Residential	Photovoltaics, Wind, Geothermal Electric, Fuel Cells, Small Hydro	None	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	Most of MEC's 26 member cooperatives
Nevada	30 kW / Commercial, Industrial, Residential	Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydro, Geothermal Electric	1% of a utility's peak capacity	Credited at retail rate to customer's next bill; no expiration	Yes	Investor-owned utilities

Sources: The Interstate Renewable Energy Council (IREC) and the N.C. Solar Center (NCSC). "Connecting to the Grid" Project web site, http://www.irecusa.org/connect, 7/18/05; Database of State Incentives for Renewable Energy (DSIRE), http://www.dsireusa.org, 7/18/05. Additional information, including most legislative and regulatory source citations, is available via DSIRE.

Interstate Renewable Energy Council (IREC) "Connecting to the Grid" Project
State and Utility Net-Metering Rules
(Updated July 2005)

Program	System Size Limit / Customer Classes Eligible	Eligible Technologies	Limit on Total Capacity	Treatment of Net Excess Generation (NEG)	Interconnection Standards for Net Metering	Utilities Involved
New Hampshire	25 kW / Commercial, Industrial, Residential	Photovoltaics, Wind, Hydro	0.05% of a utility's peak demand	Credited at retail rate to customer's next bill	Yes	All utilities
New Jersey	2 MW / Commercial, Residential	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydro, Geothermal Electric, Fuel Cells (Renewable Fuels), Anaerobic Digestion, Tidal Energy, Wave Energy	None	Credited at retail rate to customer's next bill; purchased by utility at avoided-cost rate at end of 12-month billing cycle	Yes	All utilities
New Mexico	10 kW / Commercial, Industrial, Residential	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydro, Geothermal Electric, Fuel Cells, Municipal Solid Waste, CHP, Microturbines	None	Credited to customer's next bill or purchased by utility at avoided-cost rate	Yes	Investor-owned utilities, cooperatives
New York	400 kW for farm waste; 125 kW for farm-based wind; 25 kW for residential wind; 10 kW for solar	Photovoltaics, Biomass, Wind	Solar: 0.1% of a utility's demand in 1996; farm biogas: 0.4% of a utility's demand in 1996; wind: 0.2% of a utility's 2003 demand	Credited to customer's next bill. However, NEG from wind systems > 10 kW is credited to customer's next bill at the avoided-cost rate. All NEG is purchased by utility at avoided-cost rate at end of 12-month billing cycle	Yes	All utilities
North Dakota	100 kW / Commercial, Industrial, Residential	Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydro, Geothermal Electric, Municipal Solid Waste, CHP	None	Purchased by utility at avoided-cost rate	No	Investor-owned utilities
Ohio	100 kW for microturbines; no limit for other systems / Commercial, Industrial, Residential	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydro, Fuel Cells, Microturbines	1% of a utility's peak demand	Purchased by utility at unbundled-generation rate	Yes	All competitive utilities
Ohio – Bowling Green Municipal Utilities	25 kW / Commercial, Residential	Photovoltaics, Wind, Hydro, Fuel Cells	None	Negotiated with utility	No	Bowling Green Municipal Utilities
Oklahoma	100 kW or 25,000 kWh/year (whichever is less) / Commercial, Industrial, Residential	Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydro, Geothermal Electric, Municipal Solid Waste, CHP	None	Granted to utility monthly or credited to customer's next bill (varies by utility)	No	All utilities
Oregon	25 kW / Commercial, Industrial, Residential	Solar Thermal Electric, Photovoltaics, Wind, Hydro, Fuel Cells	0.5% of a utility's historic single-hour peak load	Credited at retail rate to customer's next bill or purchased by utility at avoided-cost rate	Yes	All utilities

Sources: The Interstate Renewable Energy Council (IREC) and the N.C. Solar Center (NCSC). "Connecting to the Grid" Project web site, http://www.irecusa.org/connect, 7/18/05; Database of State Incentives for Renewable Energy (DSIRE), http://www.dsireusa.org, 7/18/05. Additional information, including most legislative and regulatory source citations, is available via DSIRE.

Interstate Renewable Energy Council (IREC) "Connecting to the Grid" Project
State and Utility Net-Metering Rules
(Updated July 2005)

Program	System Size Limit / Customer Classes Eligible	Eligible Technologies	Limit on Total Capacity	Treatment of Net Excess Generation (NEG)	Interconnection Standards for Net Metering	Utilities Involved
Oregon – Ashland Electric	None / Commercial, Residential	Photovoltaics, Wind	None	Purchased by utility monthly at retail rate (1,000 kWh/month maximum)	Yes	Ashland Electric
Pennsylvania	Varies by utility / Commercial, Industrial, Residential	Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydro	Varies by utility	Varies by utility (granted to utility in most cases)	Varies by utility	All utilities
Rhode Island	25 kW / Commercial, Industrial, Residential	Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydro, Geothermal Electric, Fuel Cells, Municipal Solid Waste, CHP	1 MW (Narragansett territory)	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	No	Narragansett Electric
Texas	50 kW / Commercial, Industrial, Residential	Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydro, Geothermal Electric, Fuel Cells, Tidal Energy, Wave Energy, Microturbines	None	Purchased by utility monthly at avoided-cost rate	Yes	Most non-municipal utilities and non-cooperatives
Texas – San Antonio City Public Service	25 kW / Commercial, Residential	Photovoltaics, Wind, Biomass, Hydro, Geothermal Electric, Tidal Energy, Wave Energy	None	Credited at retail rate to customer's next bill at utility's seasonal avoided-cost rate	No	San Antonio City Public Service
Texas – Austin Energy	20 kW / Commercial, Residential	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydro, Geothermal Electric, Municipal Solid Waste	1% of utility's load	Credited at retail rate to customer's next bill	Yes	Austin Energy
Utah	25 kW / Commercial, Industrial, Residential	Solar Thermal Electric, Photovoltaics, Wind, Hydro, Fuel Cells	0.1% of a utility's 2001 peak demand	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	Investor-owned utilities, cooperatives
Vermont	150 kW for farm systems; 15 kW for commercial and residential / Commercial, Residential, Agricultural	Photovoltaics, Wind, Biomass, Fuel Cells	1% of a utility's 1996 peak demand or peak demand during most recent calendar year (whichever is less)	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	All utilities
Virginia	500 kW for non-residential; 10 kW for residential / Commercial, Residential, Nonprofit, Schools, Government, Institutional	Solar Thermal Electric, Photovoltaics, Wind, Hydro	0.1% of a utility's annual peak demand	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	All utilities
Washington	25 kW / Commercial, Industrial, Residential	Solar Thermal Electric, Photovoltaics, Wind, Hydro, Fuel Cells	0.1% of a utility's 1996 peak load	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	All utilities
Washington – Grays Harbor PUD	25 kW / Commercial, Industrial, Residential	Solar Thermal Electric, Photovoltaics, Wind, Hydro, Fuel Cells	0.1% of utility's 1996 peak load	Purchased by utility annually at 50% of retail rate	Yes	Grays Harbor PUD

Sources: The Interstate Renewable Energy Council (IREC) and the N.C. Solar Center (NCSC). "Connecting to the Grid" Project web site, http://www.irecusa.org/connect, 7/18/05; Database of State Incentives for Renewable Energy (DSIRE), http://www.dsireusa.org, 7/18/05. Additional information, including most legislative and regulatory source citations, is available via DSIRE.

Interstate Renewable Energy Council (IREC) "Connecting to the Grid" Project
State and Utility Net-Metering Rules
(Updated July 2005)

Program	System Size Limit / Customer Classes Eligible	Eligible Technologies	Limit on Total Capacity	Treatment of Net Excess Generation (NEG)	Interconnection Standards for Net Metering	Utilities Involved
Wisconsin	20 kW / Commercial, Industrial, Residential	Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydro, Geothermal Electric, Municipal Solid Waste, CHP	None	Purchased by utility at retail rate (renewables) or avoided-cost rate (non-renewables)	Yes	Investor-owned utilities
Wyoming	25 kW / Commercial, Industrial, Residential	Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydro	None	Credited at retail rate to customer's next bill; purchased by utility at avoided-cost rate at end of 12-month billing cycle	Yes	All utilities

Sources: The Interstate Renewable Energy Council (IREC) and the N.C. Solar Center (NCSC). "Connecting to the Grid" Project web site, http://www.irecusa.org/connect, 7/18/05; Database of State Incentives for Renewable Energy (DSIRE), http://www.dsireusa.org, 7/18/05. Additional information, including most legislative and regulatory source citations, is available via DSIRE.

CASE: UM 1129 - Phase II
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2102

Exhibit in Support of Direct Testimony

February 27, 2006

Interstate Renewable Energy Council (IREC) "Connecting to the Grid" Project
Comprehensive Interconnection Rules for Distributed Generation
(Updated July 2005)

State (Utility)[1]	Effective or in Progress (IP)[2]	Application Cost	Separate Rules for Small DG & Renewables[3]	Breakpoint for Small System (Simplified) Rules	Eligible Technologies	System Size Limit	Standard Agreement	Additional Insurance	External Disconnect Switch Required	Screening Process for Interconnection Studies	Network IC Addressed	Agency / Authority
Arizona	IP	10 kW: $20; 2 MW: $1/kW; for 10 MW non-export; $2/kW; others at cost	No	10 kW 500 kW 2 MW 10 MW non-export 10 MW	All DG	NA	Yes	No	No	Yes	Yes	Arizona Corporation Commission
Arizona (SRP)	2002		No	50 kW	All DG	NA	Yes	Yes	No	Yes	No	Utility
Arizona (APS)	2002		No	50 kW	All DG	NA	Yes	Yes	No	Yes	No	Utility
Arizona (TEP)	2002		No	50 kW	All DG	NA	Yes	Yes	No	Yes	No	Utility
California	2000	$800 (plus $600 for supp. review)	Yes	10 kW	All DG	10 MW	Yes	No	Yes (systems > 1 kW)	Yes	No	CA PUC
Colorado	IP	TBD[4]	No	10 kW 2MW 10 MW	All DG	10 MW	Yes	Yes	TBD	Yes	Yes	CO PUC
Colorado (Co-ops)	2002	None	Varies by utility	Varies by utility	Renewables	NA	No	No	Yes	No	No	CO Legislature
Colorado (Xcel)	1996	None	Yes	100 kW	All DG	NA	Yes	Yes	Yes	No	No	CO PUC
Connecticut	2004	Yes	Yes	10 kW	All DG	25 MW	Yes	Yes	Yes	Yes	Yes	CT DPUC
Delaware (Conectiv; DEC)	2000 (update IP)	None	Yes	25 kW	All DG	Conectiv: 1 MW; DEC: none	Yes (Conectiv)	Yes (DEC)	Yes (systems 25 kW - 1 MW)	No	No	DE PSC

[1] Interconnection rules that apply only to specific utilities or were developed by particular utilities are listed in parentheses.
[2] For states listed as in progress (IP), information is based either on draft rules or likely consensus positions among stakeholders.
[3] Many states and utilities have a separate set of interconnection rules for very small (e.g. < 25 kW) renewable and DG systems. Frequently, such rules are tied to a state's net-metering rules.
[4] TBD = To be determined. This applies to states or utilities with ongoing discussions, and particular aspects of the rules are still under consideration

Sources: The Interstate Renewable Energy Council (IREC) and the N.C. Solar Center (NCSC). "Connecting to the Grid" Project web site, www.irecusa.org/connect, 7/18/05; Database of State Incentives for Renewable Energy (DSIRE), www.dsireusa.org, 7/18/05. Additional information, including most legislative and regulatory source citations, is available via DSIRE.

Interstate Renewable Energy Council (IREC) "Connecting to the Grid" Project
Comprehensive Interconnection Rules for Distributed Generation
(Updated July 2005)

State (Utility)[5]	Effective or in Progress (IP)[6]	Application Cost[7]	Separate Rules for Small DG & Renewables[8]	Breakpoint for Small System (Simplified) Rules	Eligible Technologies	System Size Limit	Standard Agreement	Additional Insurance	External Disconnect Switch Required	Screening Process for Interconnection Studies	Network IC Addressed	Agency / Authority
Hawaii	2003		Yes	50 kW	All DG	NA	Yes	No	Yes	No	No	HI PUC
Idaho (Idaho Power)	2002		Yes	100 kW	All DG	> 1 MVA	No	No	Yes	No	No	ID PUC
Idaho (Avista Utilities)			Yes	25 kW	All DG	1 MW	Yes	No	Yes	No	No	ID PUC
Illinois (ComEd)	1999		Yes	25 kW (40 kW for net-metered systems)	All DG	NA	Yes	No	Yes (systems > 40 kW)	No	Not allowed (applies to downtown Chicago)	Utility
Indiana	IP	TBD	Yes	10 kW	All DG	TBD	TBD	TBD	TBD	TBD	No	IN URC
Iowa	IP	TBD	TBD	TBD	All DG	TBD	TBD	TBD	TBD	TBD	TBD	IA DNR
Kansas	2004	ND	No	ND	All DG	5 MW	Yes	ND	Yes	ND	No	KCC
Massachusetts	2004	$3 per kW; $2,500 max	Yes	10 kW	All DG	None	Yes	No	Utility discretion	Yes	Yes	MA DTE
Michigan	2003	$0.50 per kW; $500 max	Yes	30 kW	All DG	None	Yes	No	Yes	No	No	MI PSC
Minnesota	2004	Varies by system size and type	Yes	40 kW	All DG	10 MW	Yes	Yes (systems < 40 kW)	Yes	Yes	TBD	MN PUC
Missouri	2003		Yes	100 kW	All DG	100 kW	Yes	No	Yes	No	No	MO PSC
New Jersey	1999 (rules mandatory for Class I renewables)	10 kW: none; up to 2 MW: $50+$1/kW; other: $100+$2/kW	Yes	10 kW	All DG	20 MW	Yes	No	No	Yes	Yes	NJ BPU

[5] Interconnection rules that apply only to specific utilities or were developed by particular utilities are listed in parentheses.
[6] For states listed as in progress (IP), information is based either on draft rules or likely consensus positions among stakeholders.
[7] TBD = To be determined. This applies to states or utilities with ongoing discussions, and particular aspects of the rules are still under consideration.
[8] Many states and utilities have a separate set of interconnection rules for very small (e.g. < 25 kW) renewable and DG systems. Frequently, such rules are tied to a state's net-metering rules.

Sources: The Interstate Renewable Energy Council (IREC) and the N.C. Solar Center (NCSC). "Connecting to the Grid" Project web site, www.irecusa.org/connect,, 7/18/05; Database of State Incentives for Renewable Energy (DSIRE), www.dsireusa.org, 7/18/05. Additional information, including most legislative and regulatory source citations, is available via DSIRE.

Interstate Renewable Energy Council (IREC) "Connecting to the Grid" Project
Comprehensive Interconnection Rules for Distributed Generation
(Updated July 2005)

State (Utility)[9]	Effective or in Progress (IP)[10]	Application Cost[11]	Separate Rules for Small DG & Renewables[12]	Breakpoint for Small System (Simplified) Rules	Eligible Technologies	System Size Limit	Standard Agreement	Additional Insurance	External Disconnect Switch Required	Screening Process for Interconnection Studies	Network IC Addressed	Agency / Authority
New York	2000	Varies by system size	Yes	10 kW	All DG	300kW (2 MW limit considered)	Yes	Yes	Yes	Yes	Yes	NY PSC
North Carolina	2005	$100 residential; $250 non-residential	No	20 kW residential; 100 kW non-residential	All DG	100 kW	Yes	No	Yes	No	No	NCUC
Ohio	2001	Varies	Yes	25 kW	All DG	300 kW	Yes	No	Utility discretion	No	No	OH PUC
Pennsylvania	IP	TBD	Yes	2 MW	TBD	10 MW	Yes	TBD	TBD	Yes	TBD	CO AEPS (initiative)
Texas	2000	Varies	Yes	10 kW	All DG	10 MW	Yes	No	Yes	Yes	Yes	TX PUC
Vermont	IP	TBD	Yes	15 kW	All DG	50 MW	TBD	TBD	Yes	TBD	TBD	
Virginia	IP	TBD	Yes	10 kW residential; 25 kW non-residential	All DG	10 MW	Yes	No	Utility discretion	No	No	VA SCC
Wisconsin	2004	Varies	Yes	20 kW	All DG	15 MW	Yes	No	Yes	No	No	WI PSC
IREC Model[13]	*NA*	*Varies*	*Yes*	*25 kW*	*All DG*	*20 MW*	*Yes*	*No*	*No*	*Yes*	*Yes*	*NA*

[9] Interconnection rules that apply only to specific utilities or were developed by particular utilities are listed in parentheses.
[10] For states listed as in progress (IP), information is based either on draft rules or likely consensus positions among stakeholders.
[11] TBD = To be determined. This applies to states or utilities with ongoing discussions, and particular aspects of the rules are still under consideration.
[12] Many states and utilities have a separate set of interconnection rules for very small (e.g. < 25 kW) renewable and DG systems. Frequently, such rules are tied to a state's net-metering rules.
[13] See www.irecusa.org/connect/model_interconnection_rule.pdf.

Sources: The Interstate Renewable Energy Council (IREC) and the N.C. Solar Center (NCSC). "Connecting to the Grid" Project web site, www.irecusa.org/connect, 7/18/05; Database of State Incentives for Renewable Energy (DSIRE), www.dsireusa.org, 7/18/05. Additional information, including most legislative and regulatory source citations, is available via DSIRE.

CERTIFICATE OF SERVICE

UM 1129

I certify that I have this day served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-13-0070, to all parties or attorneys of parties.

Dated at Salem, Oregon, this 27th day of February, 2006.

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UM 1129
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