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PUBLIC UTILITY COMMISSION OF OREGON

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Public Utility Commission of Oregon
Administrative Hearings Division

UM 1129

STAFF TESTIMONY

OF

JACK P. BREEN, III
LISA SCHWARTZ
STEVE CHRISS
THOMAS MORGAN

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

August 3, 2004

DOCKETED

CASE: UM 1129
WITNESS: Jack P. Breen III

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 100

Direct Testimony

August 3, 2004

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

A. My name is Jack P. Breen III. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97310-1380. I am employed by the Public Utility Commission of Oregon (Commission) as Program Manager of Electric Rates and Planning.

Q. HAVE YOU PREPARED AN EXHIBIT?

A. Yes, I prepared Staff/101, which is a summary of my educational and work experience, and Staff/102, a summary of staff's recommendations.

Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I provide an overview of the staff testimony and present a summary of staff's recommendations. I discuss the requirements and incentives faced by the electric utilities. I address the third issue, Utility Tariff Content, except for the area of credit requirements. I also address the fourth issue, Avoided Cost Calculation Methods, the fifth issue, Applicability of Oregon PURPA Administrative Rules, and the sixth issue, Dispute Resolution.

Q. PLEASE PROVIDE AN OVERVIEW OF STAFF'S TESTIMONY.

A. In Staff/200 and supporting exhibits, staff witness Lisa Schwartz addresses the first two issues, Contract Length/Price Structure and Size Threshold for Standard Rates. In Staff/300 and supporting exhibits, staff witness Steve Chriss provides testimony in support of the first two issues regarding gas price indexing and risk implications of using fixed price streams or indexed prices for standard contracts. In Staff/400, staff witness Thomas Morgan provides testimony in support of the first issue, regarding financing requirements, and in support of the third issue, regarding credit requirements.

Summary of Staff's Recommendations

Q. PLEASE SUMMARIZE STAFF'S POSITION.

A. A summary is provided in Staff/102. Some of staff's recommendations are based on qualifying facility (QF) size and summarized in the following table:

	Eligible for fixed rates?	Eligible for fully indexed rates? (Gas Market Method)	Eligible for indexed rates with 90/110% bands? (Deadband Method)	Eligible for standard rates and contract?
Up to and including 2 MW	Yes	Yes	Yes	Yes
Over 2 MW up to and including 10 MW	No	Yes	Yes	Yes
Over 10 MW	Negotiated	Negotiated	Negotiated	Eligible for avoided costs with adjust-ments.

Requirements and Incentives Faced by the Electric Utilities

Q. WHAT ARE THE REQUIREMENTS FOR UTILITIES WITH REGARD TO QUALIFYING FACILITIES?

A. The Public Utility Regulatory Policies Act of 1978 (PURPA) was designed to encourage the efficient use of fossil fuels in electric power production through cogenerators and the use of renewable resources through small power producers. To implement PURPA, utilities are required to interconnect with Qualifying Facilities (QFs) and to pay for power based on avoided costs.[1] Despite these requirements, utilities have well known incentives for not embracing QFs, particularly the financial harm from reduced sales associated with self-generation and the reduced need for new utility-owned resources and the related return on investment.

Q. WHAT ARE THE APPLICABLE FEDERAL AND STATE LAWS AND RULES THAT FORM THE BASIS FOR REGULATING PURCHASES FROM QUALIFYING FACILITIES?

A. In addition to Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978, the applicable laws and rules include:

1. Code of Federal Regulations, Title 18, Chapter 1, Part 292 (18 CFR Sections 292.101 through 292.602) (hereafter, "Federal PURPA");

[1] Code of Federal Regulations, Title 18--Conservation of Power and Water Resources, Part 292--Regulations Under Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 with Regard to Small Power Production.

2. Oregon Revised Statutes (ORS) Chapter 758 (ORS 758.505 through 758.555) (hereafter, "Oregon PURPA"); and

3. Oregon Administrative Rules Division 29 (OAR 860-029-0001 through 860-029-0090) (hereafter, "Rules").

Issue 3. Utility Tariff Content

Q. HOW IS THIS ISSUE STATED IN THE ISSUES LIST?

A. It is stated as:

> What prices, terms and conditions should be included in utility tariffs? How should the Commission ensure that all terms and conditions it approves in the avoided cost filings are publicly available? Current practice is to include only basic pricing, terms and conditions in the tariff for small qualifying facilities (1 MW or less). The other avoided cost information approved by the Commission is contained in the utility's filing.

Q. DO YOU ADDRESS ALL ASPECTS OF THIS ISSUE?

A. No. Staff witness Thomas Morgan addresses credit requirements.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS ON THIS ISSUE.

A. My recommendations are:

1. Approved 20-year avoided costs should be published in the utility's tariffs.
2. QFs eligible for standard rates should receive standard contract terms and conditions, and the contracting utility should file the standard contract form for Commission approval, along with the avoided cost tariff.
3. The utility's tariff should indicate that prices for QFs eligible for standard rates are determined upon initial execution of the contract for the term of the contract.
4. The utility's tariff should specify that for QFs exceeding the size threshold for standard rates, the 20-year avoided costs form the

basis for contract negotiations, as well as specify the factors that the utility may consider in adjusting the avoided costs upward or downward to reflect the project characteristics.

5. Tariffs and contracts for QFs eligible for standard rates should not allow adjustments for project-specific characteristics related to delivery of energy and capacity to the purchasing utility.
6. The utilities should not be allowed to terminate a contract with a QF if the federal PURPA law is repealed.
7. The utilities should not be allowed to mandate the type and level of QF insurance coverage for QFs eligible for standard rates and a standard contract.

Q. PLEASE SUMMARIZE THE CONTENT OF THE UTILITY COMPANIES' EXISTING TARIFFS RELATED TO PURCHASES FROM QUALIFYING FACILITIES.

A. The existing tariffs, per OAR 860-027-0040(4)(a), provide standard rates for purchases from QFs with a nameplate capacity of one megawatt or less. In addition, the tariffs specify conditions for purchase, mostly safety related conditions.

Q. IS THIS UTILITY TARIFF CONTENT SUITABLE FOR THE EFFECTIVE ADMINISTRATION OF PURPA?

A. No. There are ambiguities and omissions that should be addressed. The 20-year avoided costs that form the basis for negotiating a QF contract are filed with the Commission, but are not published with the utility's tariffs. This hampers developers' efforts to evaluate projects. The approved 20-year avoided costs should be published in the utility's tariffs. Terms and conditions related to QF purchases also need to be publicly available to ensure such terms and conditions are consistently applied across all QF projects. Accordingly, the standard contract terms and conditions for QFs eligible for standard rates should be filed with the Commission for its approval and made readily available to the public in the same manner as the tariffs.

Q. WHAT OTHER ISSUES ARE FACED BY QF DEVELOPERS AND OPERATORS AND WHAT ARE YOUR RECOMMENDATIONS FOR MODIFYING THE CONTENT OF THE UTILITIES' TARIFFS?

A. Developers and operators deserve consistent treatment by the utilities. This is needed for the provisions related to the applicability of the rates over the term of the contract. Portland General Electric Company (PGE) and Idaho Power Company (Idaho Power) have historically updated QF contract rates when the Commission approves new tariffs; PacifiCorp has historically set the rates for the term of the contract. To allow developers to effectively evaluate projects, standard rates should be determined upon the initial execution of the contract and the tariff should describe that practice. The tariff should list the standard rate for each year of the contract term or in the case of indexing, the method and data source for calculating the rate. Even though QFs that exceed the size threshold for standard contract rates are required to negotiate rates, the tariff should specify the avoided costs that form the basis for contract negotiations (i.e., the 20-year avoided costs) and a description of the factors that the utility may consider in adjusting the avoided costs upward or downward to reflect the project characteristics. QF developers and operators look to the Commission for fairness from the utilities. The staff needs to evaluate and monitor the provisions included by utilities in QF contracts. As such, the utilities should file with the Commission the templates used for standard rate contracts. There is Commission precedent for filing these types of agreements – it is currently required for Service Agreements for Electricity Service Suppliers. The filing of the templates and review of subsequent QF agreements would preclude the utilities from inserting provisions that constitute unwarranted barriers to QF development.

Q. SHOULD THE UTILITIES BE ALLOWED TO ADJUST THEIR STANDARD RATES TO TAKE PROJECT-SPECIFIC CHARACTERISTICS INTO ACCOUNT?

A. No. Such a tariff or contract provision would allow the utility to unilaterally alter the avoided costs for QFs eligible for standard rates, subverting the intent of standard rates and contract terms – to provide transparency and a simple, inexpensive and timely contracting process that does not require negotiation.

Q. SHOULD THE UTILITIES BE ALLOWED TO TERMINATE A CONTRACT WITH A QF IF THE FEDERAL PURPA LAW IS REPEALED?

A. No. A QF should be able to rely on the full contract term to evaluate the feasibility of a project and finance it. The utility will be acquiring a resource for a specific term, and it is not appropriate to include provisions for early termination due to changes in PURPA.

Q. SHOULD THE UTILITIES BE ALLOWED TO MANDATE THE TYPE AND LEVEL OF QF LIABILITY INSURANCE COVERAGE?

A. No. It is prudent for a QF to maintain appropriate liability insurance coverage, but the QF, not the utility, should determine the type and level of insurance.

Q. DO DEVELOPERS PERCEIVE THESE INSURANCE REQUIREMENTS AS A BARRIER TO THE DEVELOPMENT OR CONTINUED EXISTENCE OF QF PROJECTS?

A. Yes. PacifiCorp, for example, has been requiring developers to name PacifiCorp as an additional named insured on the QF's policy and obtain certain types of insurance. I have been contacted regarding the unfairness of allowing the utilities to impose these requirements. A developer may carry liability insurance that is obtainable at a reasonable cost, but the utility requirements impose an additional cost. This may make the project uneconomic.

Q. WHAT IS YOUR RESPONSE TO UTILITY CONCERNS THAT THEY ARE EXPOSED TO RISK BECAUSE THEY HAVE THE DEEP POCKETS?

A. The event would need to transpire in the first place. Historically, QF energy production has been very safe. Second, the legal system would need to fail and a judgment would need to be entered against the utility when it was not negligent.

Q. HAVE THE UTILITIES BEEN ABLE TO POINT TO ANY SITUATIONS, WITHIN THEIR OWN SERVICE TERRITORIES, OR EVEN NATIONALLY, WHERE A CONTRACTING UTILITY WAS LIABLE FOR DAMAGES BECAUSE OF THE ACTIONS OF A QF?

A. No. Staff asked this question of each utility in a data request and no utility was able to provide an example where it was liable for damages because of the actions of a QF.

Q. IN OCTOBER 2003, THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS (NARUC) PUBLISHED ITS "MODEL INTERCONNECTION PROCEDURES AND AGREEMENT FOR SMALL DISTRIBUTED GENERATION RESOURCES." DOES NARUC RECOMMEND A MANDATORY INSURANCE REQUIREMENT?

A. No. Section 7 of the model interconnection agreement provides:

> The Interconnection Customer is not required to provide general liability insurance coverage as part of this Agreement, or any other Interconnection Provider

> requirement. Due to the risk of incurring damages, the State regulatory commission may recommend that every Interconnection Customer protect itself with insurance or other suitable financial instrument sufficient to meet its construction, operating and liability responsibilities pursuant to this Agreement. At no time shall the Interconnection Provider require that the Interconnection Customer negotiate any policy or renewal of any policy covering any liability through a particular insurance Interconnection Provider, agent, solicitor, or broker.

Q. DO OTHER JURISDICTIONS PROHIBIT UTILITIES FROM MANDATING INSURANCE COVERAGE FOR QFS?

A. Yes. According to the Interstate Renewable Energy Council, "Interconnection Regulations for Non-Net-Metered Distributed Generation" (June 2004), the following states and utilities do not mandate insurance coverage for QFs, or have draft rules or consensus positions that do not include an insurance requirement: California, Colorado coops, Hawaii, Idaho Power in Idaho, ComEd in Illinois, Michigan, New Jersey, North Carolina, Ohio, Texas, Virginia and Wisconsin.

Q. WHEN UTILITIES PURCHASE ELECTRICITY FROM CUSTOMERS UNDER THE NET METERING LAW, CAN THEY MANDATE INSURANCE REQUIREMENTS?

A. No. ORS 757.300(4)(c) prohibits utilities from imposing such requirements. That statute provides:

> An electric utility may not require a customer-generator whose net metering facility meets the standards in paragraphs (a) and (b) of this subsection to comply with additional safety or performance standards, perform or pay for additional tests or purchase additional liability insurance. However, an electric utility shall not be liable directly or

> indirectly for permitting or continuing to allow an attachment of a net metering facility, or for the acts or omissions of the customer-generator that cause loss or injury, including death, to any third party.

Q. WHAT ARE THE STANDARDS IN PARAGRAPHS 757.300 (a) AND (b)?

A. The standards require:

> (a) A net metering facility shall meet all applicable safety and performance standards established in the state building code. The standards shall be consistent with the applicable standards established by the National Electrical Code, the Institute of Electrical and Electronics Engineers and Underwriters Laboratories or other similarly accredited laboratory.
>
> (b) Following notice and opportunity for public comment, the commission, for a public utility, or the governing body, for a municipal electric utility, electric cooperative or people's utility district, may adopt additional control and testing requirements for customer-generators to protect public safety or system reliability.

Q. DO YOU SUPPORT THE INCLUSION OF LANGUAGE IN QF AGREEMENTS THAT LIMITS THE UTILITIES' LIABILITY SIMILAR TO THAT PROVIDED IN ORS 757.300(4)(C) AND IMPOSES THE STANDARDS INCLUDED IN 757.300(4)(A) AND (B)?

A. Yes.

Issue 4. Avoided Cost Calculation Methods

Q. HOW IS THIS ISSUE STATED IN THE ISSUES LIST?

A. It is stated as:

> What is the appropriate method for calculating avoided costs? Current practice is to use (1) the variable costs of operating existing generating facilities until projected supply deficits occur and (2) when new resources are needed, their estimated capacity and energy costs.

Q. PLEASE SUMMARIZE YOUR FINDINGS ON ISSUE 4.

A. Historically, Oregon utilities have calculated avoided costs using: (1) the variable costs of operating existing generating facilities until projected supply deficits occur and (2) the estimated capacity and energy costs of new resources when they are needed. The Commission should maintain this methodology, with three requirements: First, avoided cost payments for QFs eligible for standard purchase rates should include both energy and capacity costs, even if the QF uses an intermittent resource. Second, avoided capacity-cost rates for QFs eligible for standard rates should be levelized in the event a utility is resource sufficient. Third, avoided costs should be developed for a fixed set of prices and an indexed set of prices.

Q. WHAT RULES GOVERN FILING OF AVOIDED COSTS IN OREGON?

A. Federal regulations require regulated utilities to file an avoided cost study with the Commission at least once every two years. (*See* 18 CFR 292.302(b).) Oregon administrative rules require regulated utilities to file avoided cost information within 30 days of acknowledgment of their least-cost plan, to be effective 30 days after filing (*See* OAR 860-029-0080(3)).

The federal regulations define avoided costs as "...the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." (*See* 18 CFR 292.101(b)(6).)

Q. HOW ARE STANDARD AVOIDED COST RATES DETERMINED TODAY?

A. The regulated utilities conduct analysis in their integrated resource plans using a 20-year planning horizon. The plans must be filed every two years. (*See* Order No. 89-507.)

After the Commission acknowledges the plan, the utility makes an avoided cost filing for Commission review. The filing includes any updates to information in the resource plan as well as a revised tariff for standard purchase rates for QFs 1 MW or less. Rates are distinguished by on-peak and off-peak hours and may be differentiated by season. For projects over 1 MW, the utility negotiates rates based on the Commission-approved avoided costs and adjustment factors outlined in PURPA.

The avoided cost filing includes a long-term forecast that estimates when new resources will be needed to meet projected load growth. The filing also identifies the type of resource the utility plans to use to meet load growth, as defined in its acknowledged resource plan. New resources may be purchased power or generating plants, or both. The utilities calculate avoided costs for 20 to 25 years, consistent with the time horizon considered in their resource plans.

Q. PLEASE PROVIDE YOUR RECOMMENDATION ON RETAINING THE CURRENT AVOIDED COST METHODOLOGIES THAT THE REGULATED UTILITIES USE.

A. Staff recommends that the current methodologies continue to be used with minor modifications that will be discussed later in my testimony. To support my recommendation, I believe it is important to provide some background on the current process.

Historically, avoided costs in Oregon have been calculated using: (1) the variable costs of operating existing generating facilities until projected supply deficits occur and (2) the estimated capacity and energy costs of new resources when they are needed.

Specifically, during a period of resource *sufficiency*, the avoided energy costs typically are based on the displacement of purchased power and existing thermal resources as modeled by the company. The model inputs include the monthly load and resource data. For example, PacifiCorp calculates these short-run avoided costs using the difference in costs between two production-cost studies. One of the studies assumes 50 average megawatts more in system resources than the other study, at zero operating cost, to serve as a proxy for QF generation.

The utilities typically have determined avoided costs for the period of resource *insufficiency* based on the fixed and variable costs of the planned resource that could be avoided or deferred. The utilities currently use a natural gas-fired combined-cycle combustion turbine (CCCT) as a proxy for future resource costs.

Fixed costs of this unit are assigned to capacity and energy requirements. To determine the portion of fixed costs that are assigned to capacity, PacifiCorp, for example, uses the fixed cost of a single-cycle combustion turbine (SCCT), because that type of generating unit represents the cost of capacity resources. Fixed costs of a CCCT in excess of SCCT costs are assigned to energy, and added to the variable production (fuel) costs of the CCCT, to determine the total avoided energy costs. For natural gas costs, the utility uses the same forecasting methodology and trading hubs as in its resource plan, with updated prices. Calculations assume a specified heat rate and plant capacity factor, such as 85 percent.

Avoided energy costs are then differentiated between on-peak and off-peak periods. All capacity costs are assumed to meet on-peak load requirements.

PGE's 2001 filing, specifying its currently approved avoided costs, differed from this historical approach. The company's filing based avoided costs on projections of wholesale market prices for power deliveries to its system. Payments for QFs over 1 MW, which are not eligible for standard rates, were to be based through 2002 on a published electricity index and thereafter on a specified heat rate and natural gas index, adjusted by a correlation factor to reflect the relationship between electricity and gas prices. PGE noted in its filing that long-term market prices fully reflected the fixed costs of new resources added over time. Thus, the company did not separate capacity and energy components of avoided costs.

Idaho Power's 2003 avoided cost filing used the assumed input and cost variables associated with a "surrogate" CCCT approved by the Idaho Public Utility Commission for avoided cost estimates in Idaho. Inputs include a specified heat rate, natural gas costs based on the Northwest Power and Conservation Council's forecast, specified construction, operation and maintenance costs, and a 92 percent capacity factor. Off-peak prices reflect variable costs; peak prices reflect both fixed and variable costs.

Q. SHOULD UTILITIES BE ALLOWED TO PAY ENERGY-ONLY AVOIDED COST RATES FOR QUALIFYING FACILITIES, UNLESS THEY COMMIT TO PROVIDE FIRM POWER?

A. No. The utilities should be required to pay both avoided energy and capacity costs for QFs, regardless of whether the QF uses an intermittent resource such as wind or hydro. These resources are, on average, available during the system peak and should receive capacity credit. As staff states in Staff/400, weather should not trigger default security. Further, the utilities should not provide energy-only payments in the event a QF delivers less energy than expected unless the operation of the facility is so sporadic that the utility is not able to obtain a reasonable estimate of QF energy deliveries. The appropriate requirement for determining whether a QF eligible for standard rates should receive capacity payments is whether the facility meets a mechanical availability guarantee, not a specified minimum net output. Such a guarantee takes into account the capability of the facility to produce power and events that preclude it from making deliveries, such as scheduled maintenance, system emergencies or a force majeure event.

Q. PLEASE EXPLAIN THE LEVELIZATION PROCESS?

A. Levelization expresses rates or costs on an equal, per unit basis, taking into account a discount rate. The utilities' authorized cost of capital would be used for the discount rate. Levelization is similar to the process used to establish monthly home mortgage payments. The lender establishes an annuity that yields an equal rate or cost over the time horizon and yields the same present value as the rate or cost stream that is being levelized. For example, if the actual rate being paid to the developer is being levelized and is higher than the unlevelized rate in the early years, then interest is charged because the difference between the higher levelized rate and the lower unlevelized rate acts like a loan. The interest is paid off in the later years.

Q. PLEASE EXPLAIN WHY STAFF PROPOSES TO LEVELIZE AVOIDED CAPACITY PAYMENTS OVER THE CONTRACT TERM FOR SMALL QUALIFYING FACILITIES ELIGIBLE FOR A STANDARD POWER PURCHASE AGREEMENT IN THE EVENT A UTILITY IS RESOURCE-SUFFICIENT.

A. The Commission's traditional practice of recognizing periods of utility resource sufficiency appropriate for determining avoided costs is reasonable. At the same time, when a utility is resource-sufficient, avoided capacity payments should be levelized over the contract term to bring forward the value of future avoided capacity costs. There are two reasons: 1) It appropriately compensates QF projects for helping the utility meet expected increases in electricity demand in the future; and 2) It is necessary for development of QF projects.

At any given moment, a utility may not have immediate plans to add capacity. That is largely because the traditional utility model is to add capacity in large blocks, rather than incrementally.

Incremental capacity additions may provide more benefit to ratepayers. The addition of large power plants typically overshoots demand, leaving substantial amounts of capacity idle until demand catches up. Even though it is not in the utility's control, small QF units can better match gradual increases in demand, as well as reduce risk, including forecasting risk related to load/resource balance and fuel prices, technological obsolescence, and regulatory risk. Small resources diversify the resource base, mitigating the risks associated with typical utility central generation facilities.

Further, without levelization, the QF would receive energy-only payments during the early years of the contract. That may be insufficient to enable investment in the QF project.

In the event a utility expects to be resource-sufficient for a period of time, levelizing over the contract term only the avoided capacity costs, and not the avoided energy costs, limits risk to ratepayers. (As noted in Staff/200, the risk is that ratepayers might overpay for capacity in the early years of a QF contract should the facility not operate as expected over the contract term.) In addition, utilities typically are resource-sufficient only for a short period. That also limits the risk of levelization. Staff discusses in Staff/400 appropriate credit requirements that further mitigate this risk.

Finally, staff points out that treatment of avoided capacity costs for small QFs also affects net metering customers. They receive credit for net excess generation at the same published rates as small QFs. Unless capacity costs are levelized when a utility is resource-sufficient, net metering customers would get a lower rate for their net excess generation than they currently receive. This may also affect the decision to install their photovoltaic system, wind turbine or other eligible equipment.

Q. SHOULD AVOIDED COSTS BE DEVELOPED FOR A FIXED SET OF PRICES AND AN INDEXED SET OF PRICES?

A. Yes. The avoided costs should be developed in a manner that is consistent with the pricing structures.

Issue 5. Applicability of Oregon PURPA Administrative Rules

Q. HOW IS THIS ISSUE STATED IN THE ISSUES LIST?

A. It is stated as:

> Since federal PURPA still applies to all electric companies and the Commission is responsible for its implementation, what is the practical effect of the 757.612 exemption for PGE and Pacific? The administrative rules need further review to differentiate the rules that implement federal PURPA from the rules that were specific to Oregon PURPA law.

Q. PLEASE SUMMARIZE YOUR FINDINGS ON ISSUE 5.

A. Federal PURPA should drive the content and application of the Division 29 Administrative Rules. The Commission should open a temporary rulemaking to modify the Rules.

Q. HOW DOES FEDERAL PURPA, OREGON PURPA, AND THE DIVISION 29 ADMINISTRATIVE RULES APPLY TO THE THREE OREGON INVESTOR OWNED UTILITIES?

A. The Federal PURPA (18 CFR 292.101 through 292.602) is applicable to all three utilities, and the Commission is charged with implementing those regulations. With the advent of electric industry restructuring, PGE and PacifiCorp are now exempt from Oregon PURPA (ORS 758.505 through 758.555) by virtue of ORS 757.613(4). The Division 29 Oregon Administrative Rules should now implement Federal PURPA, and where applicable, Oregon PURPA.

Q. WHAT OCCURRED UPON IMPLEMENTATION OF ELECTRIC INDUSTRY RESTRUCTURING WHEN PGE AND PACIFICORP WERE GRANTED AN EXEMPTION FROM OREGON PURPA?

A. They were also granted an exemption from the Rules. In retrospect this was incorrect because the Rules also implement Federal PURPA requirements that still apply to PGE and PacifiCorp.

Q. SHOULD THE RULES BE MODIFIED TO CORRECT THIS SITUATION?

A. Yes. When the Commission issues its order in this investigation, I recommend that the Commission also open a temporary rulemaking to correct the Rules.

Q. IS A TEMPORARY RULE JUSTIFIED?

A. Yes. QFs may suffer financial harm if the Rules are not corrected.

Q. WHAT TYPES OF CHANGES ARE NECESSARY?

A. The purpose of the Rules needs to be modified to acknowledge Federal PURPA as the primary basis.

Q. DO YOU HAVE A PRELIMINARY RECOMMENDATION IN THAT REGARD?

A. Yes, I recommend the following language for OAR 860-029-0001:

> The purpose of this Division is to implement regulations as provided under 18 Code of Federal Regulations (CFR), Part 292 in effect on April 1, 2004, for electric utilities. This Division also implements ORS 758.505 through 758.555 (Oregon PURPA) for electric companies, with the exception of

> public utilities that satisfy their public purpose obligations under ORS 757.612.

Q. ARE OTHER CHANGES NEEDED?

A. Yes. There is inconsistency between the definition of avoided costs in Federal PURPA and Oregon PURPA. FERC regulations state that a utility is "...not required to pay more than..." avoided costs for purchases (*See* [18 CFR 292.304(a)(2).) Oregon statutes require that the QF purchase price "...shall not be less than..." avoided costs (*See* ORS 758.525(2).) Historically, however, this inconsistency has not been a source of controversy. Because Federal PURPA is the primary set of regulations, the federal definition should be used in the Rules. Federal PURPA gives broad latitude to the Commission to establish regulations and is broader than the Rules. Therefore, Federal PURPA provides adequate jurisdiction for the Rules even in the absence of applicability of Oregon PURPA to utilities that satisfy their public purpose obligations. The primary effect of the ORS 757.613(4) exemption is that if Federal PURPA were repealed, Oregon PURPA would only apply to Idaho Power Company, and thus PGE and PacifiCorp would be relieved in the future of PURPA-type obligations.

Issue 6. Dispute Resolution

Q. PLEASE SUMMARIZE YOUR FINDINGS ON ISSUE 6.

A. Issue 6 asks: What should be the Commission and staff roles in mediating or litigating PURPA-related disputes?

In regard to negotiations for utility/QF power purchase agreements, current Commission policy prohibits staff from providing informal dispute resolution services. Dispute resolution services can be offered only through the Commission's formal complaint process provided by ORS 756.500. 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. In the absence of a formal complaint proceeding, however, staff does not participate in discussions involving both parties to a dispute. This requirement is detailed in the Commission report SJR 27 Report to the Sixty Fifth Legislative Assembly and the Energy Policy Review Committee, November 1, 1988.

In utility regulation, fairness requires that views advocated by interested parties be presented in an open forum where others can be present and have the opportunity to offer their views on the subject in question. The Commission's formal complaint process provides this type of forum. Informal dispute mediation by OPUC staff does not provide a proper open forum for reviewing utility/QF contract issues and, therefore, is potentially subject to criticism. In addition, staff rate case recommendations regarding PURPA issues may be perceived differently if staff has participated in utility/QF contract negotiations.

Staff recommends that the Commission retain the current policy regarding staff participation in utility/QF contract disputes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UM 1129
WITNESS: Jack P. Breen III

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

August 3, 2004

WITNESS QUALIFICATIONS STATEMENT

NAME:	JACK P. BREEN III
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	PROGRAM MANAGER, ELECTRIC RATES AND PLANNING
ADDRESS:	550 CAPITOL ST. NE, SUITE 215, SALEM, OR 97310-1380
EDUCATION:	Master of Business Administration from California State University, Sacramento (1984). Bachelor of Arts degree, major in Communication Studies, from California State University, Sacramento (1981).
EXPERIENCE:	Employed with the Oregon Public Utility Commission as Program Manager, Electric Rates and Planning since March, 1999, as a Senior Telecommunications Analyst from July, 1992 to February, 1999, and as an Affiliated Interest Analyst from April, 1990 to June, 1992. Held increasingly responsible accounting, financial analysis and budgeting positions at Pacific Bell, a California telecommunications provider, between 1984 and 1990. Employed by ADM Associates, Inc. (an engineering and economics research consultant) and the California Energy Commission in energy-related research and analysis between 1981 and 1984.

CASE: UM 1129
WITNESS: Jack P. Breen III

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 102

Exhibit in Support of Direct Testimony

August 3, 2004

SUMMARY OF STAFF'S POSITION

Issue 1. Contract Length and Price Structure

- The utilities should be required to offer QFs a contract term up to 15 years, at the QF's discretion.
- The utilities should use two pricing methodologies to calculate the energy cost portion of avoided cost calculations. The Deadband Method uses a natural gas forecast with floor and ceiling prices. The Gas Market Method uses a monthly indexed price with no forecast. QFs up to and including 2 MW should be able to choose the Deadband Method, the Gas Market Method, or a fixed pricing option based on forecast natural gas prices. QFs over 2 MW up to and including 10 MW, should be able to choose either the Deadband or Gas Market option.
- Utilities should not be required to offer levelized rates to QFs. (*see* Issue 4.)
- QF payments should be established for the entire term upon execution of the power purchase agreement, based on the utility's approved avoided cost stream at that time. Payment amounts for existing contracts should not be updated when the Commission approves new avoided cost filings.

Issue 2. Size Threshold for Standard Rates

- QFs up to and including 10 MW (nameplate capacity) should be eligible for standard, non-negotiated purchase rates and a standard power purchase agreement.

Issue 3. Utility Tariff Content

- Approved 20-year avoided costs should be published in the utility's tariffs.

- QFs eligible for standard rates should receive standard contract terms and conditions, and the contracting utility should file the standard contract form for Commission approval, along with the avoided cost tariff.
- The utility's tariff should indicate that prices for QFs eligible for standard rates are determined upon initial execution of the contract for the term of the contract.
- The utility's tariff should specify that for QFs exceeding the size threshold for standard rates, the 20-year avoided costs form the basis for contract negotiations, as well as specify the factors that the utility may consider in adjusting the avoided costs upward or downward to reflect the project characteristics.
- Tariffs and contracts for QFs eligible for standard rates should not allow adjustments for project-specific characteristics related to delivery of energy and capacity to the purchasing utility.
- The utilities should not be allowed to terminate a contract with a QF if the federal PURPA law is repealed.
- The utilities should not be allowed to mandate the type and level of QF insurance coverage for QFs eligible for standard rates and a standard contract.

- The standard form of power purchase agreement (PPA) for QFs that are eligible for standard rates should include risk management provisions consistent with the following:
  - A performance bond may be required to ensure timely completion of project construction. A letter of credit or escrow deposit should not be required.
  - A letter of credit or escrow deposit should not be required as default security for operational risk.
  - Weather-related reductions in resource availability should not trigger default events.

Issue 4. Avoided Cost Calculation Methods

- The Commission should maintain the historical methodology of calculating avoided costs using (1) the variable costs of operating existing generating facilities until projected supply deficits occur and (2) the estimated capacity and energy costs of new resources when they are needed, with three requirements: First, avoided cost payments for QFs eligible for standard purchase rates should include both energy and capacity costs, even if the QF uses an intermittent resource. Second, avoided capacity costs for QFs eligible for standard rates should be levelized in the event a utility is resource-sufficient. (*see* Issue 1.) Third, avoided costs should be developed for a fixed set of prices and an indexed set of prices.

Issue 5. Applicability of Oregon PURPA Administrative Rules

- The Commission should open a temporary rulemaking to modify the Division 29 Administrative Rules to acknowledge federal PURPA as the primary basis and to correct inconsistencies between federal and state definitions of avoided costs.

Issue 6. Dispute Resolution

- The Commission should retain its current policy where staff does not participate in informal mediation in utility/QF contract disputes.

CASE: UM 1129
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Direct Testimony

August 3, 2004

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

A. My name is Lisa Schwartz. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97310-1380. I am employed by the Public Utility Commission of Oregon as a senior analyst in the Electric Rates and Planning Section.

Q. HAVE YOU PREPARED AN EXHIBIT?

A. Yes. I prepared Staff/201, consisting of one page, which is a summary of my educational and work experience. Staff/202 consists of a letter from the Oregon Department of Energy, the department's response to a staff data request, and a two-page table I prepared in support of my testimony.

Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I address the first two issues in this proceeding, contract length/price structure and size threshold for standard rates and contracts.

Q. WHAT ADDITIONAL STAFF TESTIMONY SUPPORTS YOUR FINDINGS?

A. Jack Breen provides supporting testimony (Staff/100) on levelization of capacity rates when a utility is in a period of resource sufficiency. Steve Chriss provides supporting testimony (Staff/300) on natural gas price indexing for QFs and the financial implications of using fixed prices vs. indexed prices for standard rates and contracts. Thomas Morgan provides supporting testimony (Staff/400) in the areas of financing requirements and appropriate security provisions to mitigate ratepayer risk of long-term standard contracts for QFs up to 10 MW.

<u>Issue 1. Contract Length and Price Structure</u>

Q. PLEASE SUMMARIZE YOUR FINDINGS ON ISSUE 1.

A. Issue 1 addresses the appropriate contract length for QFs, considering federal PURPA requirements and balancing the interests of QF development and utility customers. Issue 1 also addresses the appropriate pricing structure for QFs and whether the Commission should specify that structure.

My analysis shows that the appropriate contract length for QFs is up to 15 years, at the QF's discretion. To mitigate risk to ratepayers of must-take, long-term contracts, payments under a standard contract to QFs larger than 2 MW nameplate capacity should be tied in part to a natural gas price index. To enable financing, the QF should have the option of a floor and ceiling based on forecasted prices. Natural gas indexing should be optional for QFs 2 MW or smaller; they also should have a choice of simple fixed pricing.

The utilities should not be required to offer levelized rates to QFs, except that avoided capacity rates for QFs eligible for standard purchase rates should be levelized in the event a utility is resource-sufficient. Otherwise, the utility would offer no capacity payments in the early years of the contract, hindering QF development.

Finally, QF payments should be established for the entire term upon execution of the power purchase agreement, based on the utility's approved avoided cost stream at that time. Payment amounts for existing contracts should not be updated when the Commission approves new avoided cost filings.

Q. WHAT IS THE CURRENT CONTRACT LENGTH FOR QUALIFYING FACILITIES, AND WHAT IS ITS ORIGIN?

A. The current contract length for QFs is five years. The Commission first adopted the five-year limit in 1996 through approval of PGE's avoided cost filing. (*See* PGE Advice No. 96-21, adopted Dec. 17, 1996.) The five-year term was intended to keep contract prices relatively consistent with the utility's actual costs of new resource acquisition.

In support of a five-year term, PGE stated that most of the long-term power purchase contracts it was executing at that time were for three to five years. PGE asserted that longer QF contracts posed significant risk to the company and its ratepayers.

In recommending approval of a five-year term limit at that time, staff cited the movement toward a competitive marketplace for electricity and the prevalence of wholesale transactions for terms of five years or less.

PacifiCorp and Idaho Power Company subsequently adopted the five-year term in their avoided cost filings, citing reasons similar to PGE and staff's. (*See* PacifiCorp Advice No. 99-004 and Idaho Power Advice No. 99-02.)

Q. WHAT OTHER DEVELOPMENTS CONTRIBUTED TO ADOPTION OF THE FIVE-YEAR CONTRACT TERM?

A. The Commission's 1988 report to the Legislature on QFs in Oregon provided support for adoption of a five-year term limit. (*See* Oregon Public Utility Commission, *SJR-27 Report to the Sixty-Fifth Legislative Assembly and Energy Policy Review Committee: In the Matter of an Investigation Into the Impact of Cogeneration and Small Power Production Facilities*, Nov. 1, 1988.) The report concluded that electric rates were higher than they would have been in the absence of QFs. The reasons were inaccurate load forecasts and resource cost estimates used to determine avoided costs. A key problem was requiring a 35-year projection of avoided costs — and fixed payments based on that projection — over the same contract term.

Beginning in the mid-1980s, market prices began to deviate substantially from the avoided cost estimates, resulting in excessive payments to QFs and substantial costs to ratepayers.

Largely in response and to help spur competition in the electric industry, in 1989 the Commission began an investigation into the use of competitive bidding. (*See* Order No. 91-1383.) The Commission expected that market price information from the bidding process could be used to improve the accuracy of avoided cost projections.

However, the competitive energy marketplace where QFs can compete successfully without PURPA contracts has not evolved the way the Commission envisioned it would, either through the wholesale market or utility resource solicitations.

Q. HOW MANY NEW QUALIFYING FACILITIES HAVE EXECUTED POWER PURCHASE AGREEMENTS WITH THE REGULATED UTILITIES SINCE THE ESTABLISHMENT OF THE FIVE-YEAR TERM?

A. Since the five-year term for QF contracts was established in 1996, only one QF power purchase agreement has been executed with any of the regulated utilities — for a very small (65 kW) wind machine in PacifiCorp's service area in 2003. Prior to that, the last power contract the company signed for an Oregon QF was in 1989. Idaho Power signed its most recent contract for an Oregon QF in 1985. PGE signed its most recent contract in 1984.

While the availability of low-cost power on the wholesale market in the 1990s was a major factor in the lack of QF development during that time, the five-year contract term continues to hinder QF development.

Q. PLEASE DESCRIBE HOW A FIVE-YEAR TERM LIMIT ON QUALIFYING FACILITY CONTRACTS AFFECTS PROJECT FINANCING.

A. Lenders look at which term is shorter — the utility power purchase agreement or the economic life of the resource — and typically will not offer a loan term beyond the shorter of the two without significant additional collateral. It is common to use 20 years as the economic life for wind resources.[1] The State Energy Loan Program[2] uses the following

[1] For example, see PacifiCorp's 2003 Integrated Resource Plan, page 370.
[2] The program provides low-interest, fixed-rate loans for renewable resource and cogeneration projects, which are eligible for Qualifying Facility status under PURPA.

economic life for projects it finances: 20 to 25 years for wind projects, 25 to 35 years for hydro resources, 25 to 30 years for natural gas-fired cogeneration projects, and 20 to 30 years for biomass digesters. After that time, projects may require additional investments to stay in operation.

Thus, when the utility contract is for a term less than 20 years, it is the limiting factor in the establishment of the loan term. QF projects are unable to obtain five-year financing to match the five-year utility contract because monthly power sales cannot cover the monthly loan payments that would be required to repay the loan in such a short time.

In his letter to the Commission in December 2003, Jeff Keto, loan program manager for the Oregon Department of Energy, stated: "As a lender, it is important to have a power purchase contract that equals the loan term, usually fifteen years." (*See* Staff/202, Schwartz/1.)

Mr. Keto explains in response to staff Data Request 3 that in order to have sufficient funds to make payments to bond holders, as well as to cover operating expenses and bad debt expense, the State Energy Loan Program must ensure that the generating projects it funds have sufficient revenue over the life of the loan. He states, "A principal method for reducing default risk is to require that electricity generating projects have a known market and acceptable price for the power sales in the form of a power purchase contract of at least as long as the loan term."

Mr. Keto also states that the 15-year requirement he cited in his letter to the Commission was based on the term requested by several recent project developers. However, he points out that many of the QF projects the State Energy Loan Program has financed have had a loan term of 20 to 25 years, and they required power purchase contracts of comparable length. Mr. Keto further states, "Some current projects may require a 20-year financing and power purchase agreement term." (*See* Staff/202, Schwartz/2-4.)

The State Energy Loan Program is a major financing source for Oregon QF projects. To date, the program has financed 21 QF projects, ranging in size from 30 kW to 19.6 MW. All but two of those projects have had a PURPA agreement with the regulated utilities. The loan program also financed a 12 MW natural gas-fired cogeneration project.

Q. WOULD A FIVE-YEAR CONTRACT TERM AFFECT QUALIFYING FACILITIES FINANCED FROM THE INTERNAL FUNDS GENERATED BY A GOING CONCERN, SUCH AS AN INDUSTRIAL PLANT?

A. The impact of a five-year contract on the financial feasibility of a potential QF project developed by an industrial firm with access to internal funds depends in part on the firm's specific characteristics. Staff witness Thomas Morgan discusses the impact of a short contract term on QF financing. (*See* Staff/400.)

Q. WHAT CONTRACT TERMS ARE THE UTILITIES PROPOSING FOR RESOURCES THEY HAVE RECENTLY ACQUIRED, OR PROPOSE TO ACQUIRE IN THEIR MOST RECENT RESOURCE PLANS?

A. At the time the Commission adopted the five-year term limit on new power purchase agreements with QFs, the utilities were signing long-term contracts for only three to five years and were planning to rely on the wholesale market for much of their energy and capacity needs. That is no longer the case.

Today, utility resource plans and resource solicitations are calling for contracts longer than five years:

PGE's recent Request for Proposals (RFP) for all types of power supply sources gave most weight to resources with terms of 10 to 20 years. The company chose its 30-year Port Westward project along with a mix of contracts ranging from five to 20 years. The company is planning to increase its resources with a term *greater than* 20 years from 40 percent to 52 percent of its supply portfolio. PGE recently signed its first contract resulting from the RFP — a 10-year agreement for 100 MW of energy from the Centralia coal plant owned by TransAlta Energy Marketing.[3] PGE is currently negotiating long-term contracts for wind and natural gas resources.

PacifiCorp's 2003-A RFP for East-side resources, stemming from its January 2003 resource plan, solicited peaking and base-load resources for a term of up to 20 years. The company chose to own 30-year resources to meet those needs: Currant Creek is a 525 MW natural gas-fired peaker; Lake Side is a 534 MW base-load gas plant that PacifiCorp will own after third parties develop and build the facility. PacifiCorp's RFP for renewable resources on the East and West sides of its system calls for contract terms up to 20 years.

[3] "PGE announces power purchase agreement to help meet future energy needs of PGE customers," PGE news release, May 25, 2004.

Idaho Power's most recent RFP for resources sought a minimum initial term of 10 years. The company chose its own 30-year, rate-based, resource – the Bennett Mountain Project.

Q. WHAT IS THE APPROPRIATE CONTRACT TERM FOR QUALIFYING FACILITIES?

A. FERC regulations require that a state's PURPA policy be just and reasonable to utility customers, in the public interest and not discriminate against QFs. (*See* 18 CFR 292.304(a).) Compared to the strategies that utilities are using today to acquire resources, a five-year term for power purchase agreements discriminates against QFs.

The utilities should be required to offer a contract term up to 15 years, at the QF's discretion, in order to avoid discrimination against QFs and allow for financing of QF projects. The QF should have the authority to determine the duration of the contract so long as the term does not exceed 15 years.

While that contract length is less than the maximum term the utilities sought in their most recent resource solicitations, and the 30-year, utility-owned resources the companies are acquiring, 15 years falls within the range of long-term contracts the utilities are choosing to enter — five to 20 years for thermal resources and 20 years for renewable resources.

Q. WHAT PRICING STRUCTURE SHOULD APPLY TO THE SMALLEST QUALIFYING FACILITIES?

A. QFs 2 MW or smaller should have two options: 1) fixed prices over the contract term, based on the approved avoided-cost filing in place at the time the contract is executed, and 2) payments in part tied to a natural gas price index, with a choice of having a floor and ceiling based on forecasted prices.

These options provide a simple, predictable set of prices for the smallest QFs to help developers easily assess project feasibility, while more sophisticated developers of small projects can choose payments better tied to the actual market value of the power over the term of the contract. Because eligibility for fixed pricing would be limited to the smallest projects, ratepayers would not be subject to undue risk.

Q. WHAT PRICING STRUCTURE SHOULD APPLY TO QUALIFYING FACILITIES LARGER THAN 2 MW THAT RECEIVE STANDARD RATES AND A STANDARD CONTRACT?

A. Payments to QFs larger than 2 MW (up to and including 10 MW) that receive standard rates and a standard power purchase agreement should be based in part on a natural gas price index — currently an option for QFs, not a requirement. With a longer (e.g., 15-year) contract term, this practice would ensure that QFs and ratepayers equitably share the risk of deviations from natural gas price forecasts.

A floor (and ceiling) based on forecasted natural gas prices would facilitate financing of QF projects. Without such a floor, lenders may not have sufficient confidence in the QF's ability to make its loan payments. Therefore, staff recommends that QFs larger than 2 MW have a choice of full indexing or indexing with a floor and ceiling.

Q. WHAT IS THE RATIONALE FOR CHOOSING 2 MW AS THE THRESHOLD BEYOND WHICH NATURAL GAS PRICE INDEXING SHOULD APPLY FOR STANDARD RATES?

A. Staff's proposal to include natural gas price indexing in standard rates for QFs larger than 2 MW limits risk to ratepayers over a long contract term. Staff/202, Schwartz/5-6 illustrates these risks.

I use as examples wind facilities with a capacity factor of 33 percent and cogeneration facilities with a capacity factor of 85 percent, at several sizes: 1 MW, 2 MW, 10 MW and 25 MW. Data are for the period July 2001 through June 2004.

I compare PacifiCorp's filed avoided cost rates for each month during that period with rates that QFs would have received if staff's proposed Deadband Method were in effect. That method incorporates natural gas price indexing with a floor and ceiling based on forecasted prices. (*See* Staff/300.) I calculate the Deadband rates on a monthly basis based on a weighted average of on- and off-peak monthly prices from Staff/302, Chriss/8. Forward natural gas prices are based on an average at the Sumas, Opal and Stanfield hubs.

Staff/202, Schwartz/5-6 also shows the difference in costs between PacifiCorp's filed QF rates, which represent the historical method for calculating avoided costs, and rates under staff's proposed Deadband Method. I illustrate the difference in avoided cost payments per QF for the three-year period and per QF over 15 years, assuming the three years of data are representative of a longer contract period. I also show the difference in total payments between the historical and Deadband methods if 25 QF units of a particular size (e.g., 2 MW) were under contract during that period and in the event that 100 QF units were under contract.

In the three-year period that staff used for its analysis, actual natural gas prices were lower overall than forecast prices. That trend was carried forward into the example 15-year period in Staff/202, Schwartz/5-6. Thus, the utility would pay QFs more during that period under fixed pricing than under a natural gas indexing strategy. A limitation of analysis based on only three years of data is that it represents only three years of natural gas price variation. For the three-year period reviewed, average monthly prices at the combined Sumas, Opal and Stanfield hubs ranged from $1.42/MMBtu to $5.62/MMBtu. Actual variation in natural gas prices over a future 15-year period could be higher or lower. Staff witness Steve Chriss discusses in Staff/300 the variation in natural gas prices over the three-year data period as well as differences in QF rates under historical versus natural gas-indexing methods for calculating avoided costs.

In my example 15-year period, the utility would have paid a 2 MW wind facility $10,753 more under fixed pricing than under the Deadband Method over a 15-year period, and a 2 MW cogeneration facility $27,698 more under fixed pricing.

These higher payments can add up for a utility. For example, if the utility had 25 2-MW wind QFs under contract during the 15-year period, it would have paid them a total of $268,831 more under fixed pricing than under the Deadband Method. If the utility had 25 2-MW cogeneration facilities under contract during that period, it would have paid them a total of $692,442 more under fixed pricing.

Say, instead, QFs up to 10 MW were eligible for fixed rates (with no natural gas price indexing) during the example 15-year period. In that case, if the utility had 25 10-MW wind facilities under contract during the period, it would have paid them a total of about $1.3 million more under fixed pricing than under the Deadband Method. If the utility had 25 10-MW cogeneration facilities under contract during that period, it would have paid them a total of about $3.5 million more under fixed pricing.

Staff landed on a 2 MW eligibility threshold for fixed rates because our analysis illustrates that ratepayers could pay, for example, a quarter of a million dollars more over 15 years for 25 wind facilities that size and nearly three-quarters of a million dollars more over that period for 25 2-MW cogeneration facilities. Staff believes that this level of risk is reasonable in order to allow the smallest QFs an option for simple, predictable fixed pricing.

At the same time, staff recognizes that customers may *benefit* from fixed pricing if the actual cost of natural gas exceeds the forecast price used to determine avoided cost rates. On balance, however, staff finds that for must-take contracts for QFs over 2 MW, including natural gas price indexing in standard rates, with an option for floor and ceiling prices, is the best solution for ratepayers and QFs.

Staff provides detailed recommendations on natural gas price indexing in Staff/300.

Q. IS REQUIRING INDEXING FOR QFS LARGER THAN 2 MW, IF THEY RECEIVE STANDARD RATES AND A STANDARD CONTRACT, CONSISTENT WITH UTILITY PRACTICE FOR NON-PURPA CONTRACTS FOR RENEWABLE RESOURCES?

A. No. In its resource plan, PGE modeled wind resources as fixed-price commitments. Similarly, PacifiCorp prefers fixed energy prices for its recent solicitation for up to 1,100 MW of renewable resources system-wide.

However, QF purchases are mandatory, regardless of the utility's load/resource balance. The Commission also has determined that QFs of a certain size, currently 1 MW and less, are eligible for standard, non-negotiated rates. Further, staff's position is that QFs eligible for standard rates also should be eligible for standard contract terms approved by the Commission. (*See* Staff/100.)

In contrast, prices for renewable resources that the utility acquires through RFPs are based on negotiation of terms and conditions, and resource selection is based on the utility's determination that the facility is among a portfolio of resources with the best combination of cost and risk.

Indexing for QFs larger than 2 MW (up to and including 10 MW) is appropriate for must-take, long-term, standard PURPA contracts. Further, staff's proposal for a 90/110 indexing band, at the QF's option, offers pricing that is not considerably different from fixed payments. (*See* Staff/300.)

Q. HOW SHOULD PRICING BE STRUCTURED FOR QUALIFYING FACILITIES LARGER THAN THE SIZE THRESHOLD ESTABLISHED FOR STANDARD RATES?

A. Payments for QFs above the size threshold for standard rates should be negotiated based on the utility's approved avoided cost filing in place at the time the power purchase agreement is executed, with adjustments for factors outlined in federal PURPA requirements, such as dispatchability, reliability, savings from reduced line losses and the value of smaller capacity additions. (*See* OAR 860-029-0040(5) for Idaho Power. *See* 18 CFR 292.304(e) for PGE and PacifiCorp.) The utility and the QF developer may mutually agree to apply natural gas price indexing to contract prices. These are current practices approved by the Commission.

Q. SHOULD UTILITIES BE REQUIRED TO OFFER LEVELIZED AVOIDED COST RATES FOR QUALIFYING FACILITIES?

A. Levelized rates (front-loading of the price stream) increase the risk that ratepayers will overpay for the resource if the QF does not perform as expected over the entire contract term. The utilities should not be required to offer levelized rates except during a period of resource sufficiency in order to bring forward to the beginning of the contract term the value of future avoided capacity costs. In that case, QFs of all sizes should be eligible for levelized avoided capacity rates. (*See* Staff/100.)

Q. FOR QUALIFYING FACILITIES ELIGIBLE FOR STANDARD RATES TODAY, ARE PAYMENTS ESTABLISHED FOR THE ENTIRE FIVE-YEAR TERM THAT IS CURRENTLY IN PLACE?

A. The answer depends on the utility. For QFs 1 MW and less, PacifiCorp establishes in the contract the payments for the entire five-year term. PGE and Idaho Power change payments during the five-year term as the Commission updates the utility's avoided costs.

Q. SHOULD PRICES BE ESTABLISHED AT THE TIME OF EXECUTION OF THE CONTRACT, REGARDLESS OF WHETHER THE CONTRACT TERM IS FIVE OR 15 YEARS?

A. Yes. Even a 15-year contract term will not enable financing of a QF project unless revenues for its estimated output are known, at least within a range of natural gas prices. The Commission should require the utilities to establish prices for the entire contract term upon execution of the power purchase agreement, based on the utility's approved avoided cost stream at that time. Payment amounts for existing contracts should *not* be updated when the Commission approves new avoided cost filings.

Issue 2. Size Threshold for Standard Rates

Q. PLEASE SUMMARIZE YOUR FINDINGS ON ISSUE 2.

A. Issue 2 asks what size QFs should be eligible for standard purchase rates and a standard power purchase agreement. My analysis shows that QFs up to and including 10 MW (nameplate capacity) should be eligible for standard, non-negotiated purchase rates and a standard power purchase agreement.

Q. WHAT IS THE CURRENT SIZE THRESHOLD FOR STANDARD AVOIDED COST RATES, AND WHAT IS ITS ORIGIN?

A. The Commission established in 1991 the current size threshold of 1 MW for standard avoided-cost rates. (*See* Order No. 91-1605.) In its order, the Commission stated, "...[T]he transaction costs associated with negotiating a QF/utility power purchase agreement could be prohibitive for small QFs and effectively eliminate them from the marketplace." (*Order 91-1605 at 2*.) Prior to that time, the size threshold in Oregon for standard rates was 100 kW, the minimum size required under federal rules implementing PURPA. (*See* 18 CFR § 292.304(c)(1).)

Q. WHAT IS THE PURPOSE OF ESTABLISHING STANDARD AVOIDED COST RATES AND A STANDARD POWER PURCHASE AGREEMENT?

A. The negotiating process for QFs not eligible for published rates lacks transparency and is a barrier to QF development, particularly for small projects. The long delays and high costs in negotiating a contract with the utility, including technical consultant and legal fees, may not make the effort worthwhile for small QFs.

Standard, non-negotiated rates, and a standard power purchase agreement, make pricing and other terms and conditions transparent to the QF developer and allow for a timely and inexpensive contracting process.

Q. ARE UTILITY RESOURCE SOLICITATIONS A SUFFICIENT OPPORTUNITY FOR QUALIFYING FACILITIES LARGER THAN 1 MW TO SELL THEIR POWER?

A. No. At the time the Commission set standard rates at 1 MW, it assumed that larger QFs would be able to compete in utility solicitations. However, the availability of low-cost power on the wholesale market in the 1990s, and electric industry restructuring, created little interest in competitive bidding until 2003.

Utility resource solicitations in 2003 and 2004 reveal other problems in relying on competitive bidding for QF development. First, small QFs were unable to participate. It is difficult for the utilities to review bids from small projects when the companies are seeking to acquire hundreds or thousands of megawatts of capacity. So they set minimum size requirements.

For example, PGE's RFP required renewable resources to meet a standard of 5 MWa expected output each year. Other types of projects, including cogeneration facilities, had to be capable of producing 25 MW every hour of the year. PacifiCorp's RFP for renewable resources required projects to be capable of delivering 70,000 MWh per year.[4] That

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[4] On an expected basis, accounting for planned and unplanned outages.

represents a 24 MW facility for a wind resource with a 33 percent capacity.

Further, the timing of utility solicitations may not coincide with the needs of customers and third-party developers. Cogeneration projects, for example, may make most sense when a company first develops a site, expands its production line or replaces equipment.

Q. **PLEASE DESCRIBE CURRENT QUALIFYING FACILITY TECHNOLOGIES AND TYPICAL PROJECT SIZES.**

A. Renewable resources and cogeneration facilities that meet certain efficiency standards are eligible for QF status.

Among them, commercial-scale wind turbines for onshore applications range from 660 kW to nearly 2 MW. Offshore, 3 MW and 3.6 MW machines are being introduced. Wind turbine technology has continuously increased in size over the past two decades, and it is expected that 3 MW to 4 MW turbines will soon become common in onshore applications.

Recently proposed or constructed "niche" biomass projects in the Northwest range in size from under 1 MW to 30 MW, with most to date less than 5 MW. Proposed Oregon projects include a 4.4 MW manure digester at Threemile Canyon Farms in Boardman.

Combustion turbines for cogeneration projects range in size from 500 kW to 46 MW, occasionally paired, and microturbines range up to 500 kW, with multiple units often installed. Reciprocating engines can exceed 5 MW. The capacity of small (1 MW to 15 MW) and micro-scale (under 1 MW) hydroelectric projects is based on streamflow characteristics, operating head and standard equipment sizes.

Q. CAN SMALL QUALIFYING FACILITIES SELL THEIR POWER IN THE WHOLESALE MARKET?

A. No, not easily. There are many barriers, especially for small QFs. First, their small generating output may be an issue. They also will have difficulty obtaining agreement with marketers on assignment of risks and responsibilities. Further, it can be difficult to get sufficient firm transmission rights to move the power outside the utility's system, and it's highly complex to execute a transmission agreement – something that's difficult for small QFs to do. And the cost of transmission system studies, additional grid upgrades for interconnection, transmission services, and losses for wheeling the power outside the utility may make the QF project uneconomic.

Q. CAN QUALIFYING FACILITIES SELL THEIR POWER DIRECTLY TO NON-RESIDENTIAL CUSTOMERS OF PGE AND PACIFICORP?

A. Yes and no. Theoretically, QFs could sell directly to retail customers. But, like selling to a marketer, selling to retail customers adds another layer of requirements, contracts and costs, compared to selling to the utility. Under the state's direct access rules, the generator would have to meet a host of Commission and utility requirements for Electricity Service Suppliers. Depending on the point of interconnection, the QF would need to buy distribution and/or transmission service from the utility. The QF also would need to provide a scheduling coordinator for the transport of power with the utility and pay imbalance charges for under- and over-deliveries.

Q. SHOULD THE COMMISSION INCREASE THE SIZE THRESHOLD FOR STANDARD, NON-NEGOTIATED RATES AND A STANDARD CONTRACT?

A. Yes. Small QFs in particular have limited ability to participate in the current energy marketplace. PURPA is the remaining venue for entering into a power purchase agreement.

It is too costly and time-consuming for developers of small QF projects to negotiate rates and other terms and conditions with the utility, and negotiations are often unsuccessful. For example, 15 potential QF project applications (or inquiries) for financing from the State Energy Loan Program are on hold at least in part pending resolution of pricing, contract length, and other terms and conditions for selling to the regulated utilities. All but two of these projects are under 10 MW.

Further, the 1 MW threshold for standard rates and contracts is not in accordance with today's technologies and the scale of recently built and proposed projects, nor does it enable many projects to achieve a sufficient scale to be economic. For example, only four of the pending QF projects cited by the State Energy Loan Program are 1 MW or less. Among the remainder are five projects larger than 1 MW and up to 5 MW, four projects between 6 MW and 10 MW, and two projects larger than 10 MW (12 MW and 25 MW).

The Commission should require the utilities to offer standard, non-negotiated rates and a standard power purchase agreement for QFs with a nameplate capacity of 10 MW or less. That would facilitate development of small projects — a few wind turbines, niche biomass projects and small cogeneration applications, for example — at an appropriate economy of scale.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

CASE: UM 1129
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualification Statement

August 3, 2004

WITNESS QUALIFICATION STATEMENT

NAME:	Lisa Schwartz
EMPLOYER:	Oregon Public Utility Commission
TITLE:	Senior Analyst, Electric Rates and Planning Division
ADDRESS:	550 Capitol Street NE #215 Salem, OR 97301-2551
EDUCATION:	Master of Science, Land Resources (1982) University of Wisconsin Madison, Wisconsin Bachelor of Science, Environmental Studies (1980) George Washington University Washington, D.C.
EXPERIENCE:	I have been employed by the Oregon Public Utility Commission since May 2002. My primary responsibilities are to provide expert analysis of issues related to distributed generation, demand response, pricing options, renewable resources, and resource planning and acquisition. From November 1995 to April 2002, I worked for the Oregon Department of Energy as an analyst in the Energy Resources and Conservation divisions. Duties included analysis of energy usage and savings data, state and utility programs, rate design and policy options. From March 1987 through October 1995, I was a researcher and assistant administrator for the Oregon State University (OSU) Extension Energy Program. Earlier work experience includes research and analysis at the OSU College of Engineering, the Wisconsin Water Resources Center, an Oregon economics consulting firm and a Washington, D.C., law firm.

CASE: UM 1129
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibit in Support of
Direct Testimony

August 3, 2004

Oregon
Theodore R. Kulongoski, Governor

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Date: December 3, 2003

To: Commissioners
Oregon Public Utility Commission

From: Jeff Keto
Oregon Department of Energy
Loan Manager

Subject: December 4 Public Meeting – QF Contract Terms

I would like to comment on what I understand to be the PUC's current policy on contract terms for qualifying facilities (QF).

The Oregon Department of Energy's Small Scale Energy Loan Program works with local cogeneration and small power production project developers to increase distributed generation in Oregon. The project developers are local utility customers who are seeking a reasonable power purchase contract for their project.

Distributed generation projects can meet a local load and help reduce transmission needs and losses. Local ownership can also have a positive economic benefit to the local communities. Opportunities for improved technologies and enhanced energy security exist with distributed generation and it should continue to be part of the future energy mix in Oregon, However, distributed generation is threatened by the inability to obtain power purchase contracts in line with those offered for larger central generation facilities.

As a lender, it is important to have a power purchase contract that equals the loan term, usually fifteen years. Our loan program passes on the lowest possible interest rate to borrowers and thus is unable to take the risk that a five-year power purchase contract poses. The uncertainty of a project's revenue beyond year five is a major obstacle

PUC policy is to ensure QF purchases are just and reasonable to utility customers and do not discriminate against QFs. The current five-year term does discriminate when judged against longer-term contracts offered larger generation facilities. I recommend the PUC establish in policy a fifteen-year term for QF power purchase agreements.

Oregon

Theodore R. Kulongoski, Governor

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OREGON DEPARTMENT OF ENERGY

625 Marion St. NE
Salem, OR 97301-3737
Phone: 503-378-4040
Toll Free: 1-800-221-8035
FAX: 503-373-7806
www.energy.state.or.us

July 13, 2004

Oregon Public Utility Commission
Attn: Vikie Bailey-Goggins
PO Box 2148
Salem, OR 97308-2148

Re: UM 1129 Data Request 1-3

Staff Request #1: Please provide a list with the following information on all loans that the State Energy Loan Program has made to date for Qualifying Facilities:

a. **Project name**
b. **Resource Type**
c. **Contract size**
d. **Loan term**
e. **Date loan term began**
f. **Utility purchasing output**

Attached is a spreadsheet from our loan program data base that lists financed electricity generation facilities. Most of these facilities appear on one of the utility lists of qualifying facilities (QF). We do not have a consistent record to show if individual generators are registered as PURPA facilities but we believe those listed have power purchase contracts under PURPA law.

Staff Request #2: Please review the lists of Oregon Qualifying Facility contracts since the inception of PURPA provided by Portland General Electric, PacifiCorp and Idaho Power in response to staff's first data request. Please indicate which of these Qualifying Facility projects the Oregon Department of Energy's State Energy Loan Program has financed.

The Oregon Department of Energy financed the following facilities that appear on the utility lists of QF projects provided in response to your data request #1:

Idaho Power: Owyhee Dam and Owyhee Tunnel Project #1

PacifiCorp: Projects number 3, 5, 8, 10, 14, 15, 16, 17, 18, and 19 on the PacifiCorp "Current Oregon QF Contracts" list, plus the Pine Products and Warm Springs projects on the PacificCorp supplemental list.

Portland General Electric: We found no projects on the PGE list that corresponded to our loan data base. However, in our response to data request # 1 above, we show loans for several small projects with power sales to PGE.

Staff Request #3: In its letter to the OPUC on December 3, 2002, the Oregon Department of Energy "recommend[s] the PUC establish in policy a fifteen-year term for QF power purchase agreements." In support of that recommendation, Jeff Keto, loan manager for the State Energy Loan Program, states: "As a lender, it is important to have a power purchase contract that equals the loan term, usually fifteen years." Please explain the financial requirements of Qualifying Facility projects that led to this conclusion.

The Department of Energy's loan program supports renewable generation projects by offering long-term, fixed-rate financing. Loan funds are raised through the sale of State general obligation bonds. We set loan rates at a small spread above our cost of funds to cover program administrative costs and provide a loan loss reserve. It is imperative that our program has sufficient funds to make payments to bond holders and cover operating expenses as well as any bad debt expense.

To maintain our program we must ensure that generating projects have sufficient revenue over the life of the loan. A principal method for reducing default risk is to require that electricity generating projects have a known market and acceptable price for the power sales in the form of a power purchase contract of at least as long as the loan term. In my letter, I stated 15 years, because several recent project developers have requested 15-year financing. Many of the projects listed in response #1 above were financed for 20 to 25 years and required comparable length power purchase contracts. Some current projects may require a 20-year financing and power purchase agreement term.

Jeff Keto

Jeff S. Keto
Loan Manager

Oregon Department of Energy, Energy Loan Program QF Projects						
Applicant Name	**Location**	**Resource**	**Size (kW)**	**Term (years)**	**Loan Date**	**Utility**
Cove, City of	Cove	hydro	625	22	19-Jul-84	CP National/OTEC
Owyhee Dam Project	Nyssa	hydro	5,000	22	19-Jul-84	Idaho Power
Owyhee Irr. Dist./Tnl Pjt	Nyssa	hydro	6,000	30	11-Jun-87	Idaho Power
Central Oregon Irrigation District	Bend	hydro	5,500	27	13-Oct-87	PacifiCorp
Confederated Tribe of Warm Sprin	Warm Springs	hydro	19,600	21	20-Jul-81	PacifiCorp
Curtiss Livestock	Klamath Falls	hydro	75	20	23-Feb-84	PacifiCorp
Deschutes Valley Water Dist.	Madras	hydro	4,300	22	08-Aug-83	PacifiCorp
Eagle Point Irrigation Dist.	Eagle Point	hydro	720	14	12-Apr-94	PacifiCorp
Farmers Irrigation Dist Pjt 3	Hood River	hydro	1,800	22	30-Dec-85	PacifiCorp
Farmers Irrigation District	Hood River	hydro	1,800	21	08-Aug-84	PacifiCorp
Frontier Technology, Inc.	Eugene	hydro	3,770	24	13-Apr-84	PacifiCorp
Middle Fork Irrigation Dist.	Parkdale	hydro	3,250	21	01-Nov-84	PacifiCorp
Mountain Energy Inc	Cave Junction	hydro	50	20	14-Dec-82	PacifiCorp
Pine Products Corporation	Prineville	biomass (CHP)	5,750	11	30-Sep-87	PacifiCorp
Prairie Wood Products	Riddle	biomass (CHP)	8,500	11	14-Oct-85	PacifiCorp
Price, Gari & Joanne	La Grande	hydro	90	22	12-Aug-83	PacifiCorp
Santiam Water Control District	Stayton	hydro	160	21	10-Apr-85	PacifiCorp
Anderson, Iris	Mollala	hydro	60	20	23-Aug-82	PGE
Horning, Jane	Cornelius	hydro	30	20	02-Nov-82	PGE
Sanders, Paul	Rhododendron	hydro	74	20	02-May-82	PGE
Little Butte Ranch, Coe, M.	Wilsonville	hydro	n/a	20	16-Aug-82	n/a
PUC_QF_Request.xls 7-13-04						

Staff/202
Schwartz/4

Avoided Cost Rates: Historical vs. Proposed Deadband Method (SOSA)[1]

Date	Pacific Avoided Cost Filing - Wind @ 33% CF[2]				Pacific Avoided Cost Filing - Cogeneration @ 85% CF			
	1 MW	*2 MW*	*10 MW*	*25 MW*	*1 MW*	*2 MW*	*10 MW*	*25 MW*
Jul-01	$10,164.58	$20,329.17	$101,645.83	$254,114.57	$26,181.50	$52,363.00	$261,815.01	$654,537.53
Aug-01	10,164.58	20,329.17	101,645.83	254,114.57	26,181.50	52,363.00	261,815.01	654,537.53
Sep-01	10,164.58	20,329.17	101,645.83	254,114.57	26,181.50	52,363.00	261,815.01	654,537.53
Oct-01	10,164.58	20,329.17	101,645.83	254,114.57	26,181.50	52,363.00	261,815.01	654,537.53
Nov-01	10,164.58	20,329.17	101,645.83	254,114.57	26,181.50	52,363.00	261,815.01	654,537.53
Dec-01	10,164.58	20,329.17	101,645.83	254,114.57	26,181.50	52,363.00	261,815.01	654,537.53
Jan-02	10,472.84	20,945.68	104,728.38	261,820.96	26,975.49	53,950.99	269,754.93	674,387.32
Feb-02	10,472.84	20,945.68	104,728.38	261,820.96	26,975.49	53,950.99	269,754.93	674,387.32
Mar-02	10,472.84	20,945.68	104,728.38	261,820.96	26,975.49	53,950.99	269,754.93	674,387.32
Apr-02	10,472.84	20,945.68	104,728.38	261,820.96	26,975.49	53,950.99	269,754.93	674,387.32
May-02	10,472.84	20,945.68	104,728.38	261,820.96	26,975.49	53,950.99	269,754.93	674,387.32
Jun-02	10,472.84	20,945.68	104,728.38	261,820.96	26,975.49	53,950.99	269,754.93	674,387.32
Jul-02	10,472.84	20,945.68	104,728.38	261,820.96	26,975.49	53,950.99	269,754.93	674,387.32
Aug-02	10,472.84	20,945.68	104,728.38	261,820.96	26,975.49	53,950.99	269,754.93	674,387.32
Sep-02	10,472.84	20,945.68	104,728.38	261,820.96	26,975.49	53,950.99	269,754.93	674,387.32
Oct-02	10,472.84	20,945.68	104,728.38	261,820.96	26,975.49	53,950.99	269,754.93	674,387.32
Nov-02	10,472.84	20,945.68	104,728.38	261,820.96	26,975.49	53,950.99	269,754.93	674,387.32
Dec-02	10,472.84	20,945.68	104,728.38	261,820.96	26,975.49	53,950.99	269,754.93	674,387.32
Jan-03	10,364.34	20,728.67	103,643.37	259,108.43	26,696.02	53,392.04	266,960.20	667,400.49
Feb-03	10,364.34	20,728.67	103,643.37	259,108.43	26,696.02	53,392.04	266,960.20	667,400.49
Mar-03	10,364.34	20,728.67	103,643.37	259,108.43	26,696.02	53,392.04	266,960.20	667,400.49
Apr-03	10,364.34	20,728.67	103,643.37	259,108.43	26,696.02	53,392.04	266,960.20	667,400.49
May-03	10,364.34	20,728.67	103,643.37	259,108.43	26,696.02	53,392.04	266,960.20	667,400.49
Jun-03	10,364.34	20,728.67	103,643.37	259,108.43	26,696.02	53,392.04	266,960.20	667,400.49
Jul-03	10,364.34	20,728.67	103,643.37	259,108.43	26,696.02	53,392.04	266,960.20	667,400.49
Aug-03	10,364.34	20,728.67	103,643.37	259,108.43	26,696.02	53,392.04	266,960.20	667,400.49
Sep-03	10,364.34	20,728.67	103,643.37	259,108.43	26,696.02	53,392.04	266,960.20	667,400.49
Oct-03	10,364.34	20,728.67	103,643.37	259,108.43	26,696.02	53,392.04	266,960.20	667,400.49
Nov-03	10,364.34	20,728.67	103,643.37	259,108.43	26,696.02	53,392.04	266,960.20	667,400.49
Dec-03	10,364.34	20,728.67	103,643.37	259,108.43	26,696.02	53,392.04	266,960.20	667,400.49
Jan-04	10,171.86	20,343.72	101,718.58	254,296.45	26,200.24	52,400.48	262,002.40	655,006.01
Feb-04	10,171.86	20,343.72	101,718.58	254,296.45	26,200.24	52,400.48	262,002.40	655,006.01
Mar-04	10,171.86	20,343.72	101,718.58	254,296.45	26,200.24	52,400.48	262,002.40	655,006.01
Apr-04	10,171.86	20,343.72	101,718.58	254,296.45	26,200.24	52,400.48	262,002.40	655,006.01
May-04	10,171.86	20,343.72	101,718.58	254,296.45	26,200.24	52,400.48	262,002.40	655,006.01
Jun-04	10,171.86	20,343.72	101,718.58	254,296.45	26,200.24	52,400.48	262,002.40	655,006.01
Three-year total	**$372,064.75**	**$744,129.50**	**$3,720,647.50**	**$9,301,618.76**	**$958,348.60**	**$1,916,697.20**	**$9,583,485.99**	**$23,958,714.98**
Historical - Deadband Rates	**1,075.32**	**2,150.64**	**10,753.22**	**26,883.05**	**2,769.77**	**5,539.54**	**27,697.69**	**69,244.22**
Difference over 15 years	**5,376.61**	**10,753.22**	**53,766.10**	**134,415.26**	**13,848.84**	**27,697.69**	**138,488.45**	**346,221.12**
X 25 units	**134,415.26**	**268,830.52**	**1,344,152.60**	**3,360,381.50**	**346,221.12**	**692,442.25**	**3,462,211.24**	**8,655,528.10**
X 100 units	**$537,661.04**	**$1,075,322.08**	**$5,376,610.40**	**$13,441,526.00**	**$1,384,884.50**	**$2,769,768.99**	**$13,848,844.96**	**$34,622,112.41**

[1]Forward Sumas/Opal/Stanfield Average
[2]CF = capacity factor
[3]Based on a weighted average of on- and off-peak monthly prices, from Staff/302, Chriss/8, columns G and I. Assumes 57% of hours are on-peak; 43% of hours are off-peak.

Deadband Method - Wind @ 33% CF[3]				Deadband Method - Cogeneration @ 85% CF[3]			
1 MW	*2 MW*	*10 MW*	*25 MW*	*1 MW*	*2 MW*	*10 MW*	*25 MW*
$8,387.58	$16,775.17	$83,875.83	$209,689.57	$21,604.38	$43,208.76	$216,043.80	$540,109.50
8,481.41	16,962.82	84,814.10	212,035.24	21,846.05	43,692.11	218,460.55	546,151.37
8,549.17	17,098.35	85,491.73	213,729.33	22,020.60	44,041.20	220,205.98	550,514.95
8,976.61	17,953.21	89,766.06	224,415.15	23,121.56	46,243.12	231,215.61	578,039.02
11,233.66	22,467.32	112,336.59	280,841.48	28,935.18	57,870.37	289,351.83	723,379.58
11,530.78	23,061.55	115,307.77	288,269.43	29,700.49	59,400.97	297,004.87	742,512.17
11,832.31	23,664.62	118,323.09	295,807.73	30,477.16	60,954.32	304,771.60	761,929.00
11,618.59	23,237.19	116,185.93	290,464.82	29,926.68	59,853.36	299,266.78	748,166.96
11,305.84	22,611.67	113,058.37	282,645.93	29,121.10	58,242.19	291,210.96	728,027.39
8,871.56	17,743.11	88,715.56	221,788.89	22,850.98	45,701.95	228,509.77	571,274.42
8,762.09	17,524.18	87,620.91	219,052.28	22,569.02	45,138.05	225,690.23	564,225.57
8,824.64	17,649.28	88,246.42	220,616.06	22,730.14	45,460.28	227,301.39	568,253.48
8,876.77	17,753.54	88,767.68	221,919.21	22,864.40	45,728.81	228,644.03	571,610.08
8,902.83	17,805.66	89,028.31	222,570.78	22,931.53	45,863.07	229,315.35	573,288.37
8,928.89	17,857.79	89,288.94	223,222.35	22,998.67	45,997.33	229,986.67	574,966.67
8,944.53	17,889.06	89,445.32	223,613.30	23,038.95	46,077.89	230,389.46	575,973.65
10,273.74	20,547.49	102,737.43	256,843.59	26,462.67	52,925.35	264,626.73	661,566.81
10,492.67	20,985.34	104,926.72	262,316.81	27,026.58	54,053.16	270,265.81	675,664.51
10,844.30	21,688.60	108,443.00	271,107.50	27,932.29	55,864.58	279,322.88	698,307.20
11,623.58	23,247.17	116,235.84	290,589.60	29,939.53	59,879.07	299,395.35	748,488.36
11,332.24	22,664.48	113,322.39	283,305.98	29,189.10	58,378.20	291,891.01	729,727.53
10,546.88	21,093.75	105,468.75	263,671.88	27,166.19	54,332.39	271,661.93	679,154.83
10,521.54	21,043.08	105,215.41	263,038.52	27,100.94	54,201.88	271,009.38	677,523.45
10,597.54	21,195.09	105,975.44	264,938.59	27,296.70	54,593.41	272,967.03	682,417.59
10,698.88	21,397.76	106,988.81	267,472.02	27,557.72	55,115.45	275,577.24	688,943.09
10,755.88	21,511.77	107,558.83	268,897.08	27,704.55	55,409.10	277,045.48	692,613.69
10,781.22	21,562.44	107,812.18	269,530.44	27,769.80	55,539.61	277,698.03	694,245.07
10,819.22	21,638.44	108,192.19	270,480.48	27,867.69	55,735.37	278,676.85	696,692.14
10,995.02	21,990.04	109,950.21	274,875.52	28,320.51	56,641.02	283,205.08	708,012.69
11,338.57	22,677.15	113,385.73	283,464.32	29,205.41	58,410.83	292,054.15	730,135.37
11,402.11	22,804.22	114,021.10	285,052.75	29,369.07	58,738.14	293,690.71	734,226.79
11,186.77	22,373.54	111,867.68	279,669.21	28,814.40	57,628.81	288,144.03	720,360.08
10,946.09	21,892.18	109,460.92	273,652.30	28,194.48	56,388.96	281,944.80	704,862.00
10,591.41	21,182.82	105,914.12	264,785.29	27,280.91	54,561.82	272,809.09	682,022.72
10,572.41	21,144.82	105,724.11	264,310.27	27,231.97	54,463.93	272,319.67	680,799.18
10,642.08	21,284.16	106,420.80	266,052.01	27,411.42	54,822.84	274,114.19	685,285.47
$370,989.43	**$741,978.86**	**$3,709,894.28**	**$9,274,735.70**	**$955,578.83**	**$1,911,157.66**	**$9,555,788.30**	**$23,889,470.75**

Staff/202
Schwartz/6

CASE: UM 1129
WITNESS: Steve Chriss

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 300

Direct Testimony

August 3, 2004

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

A. My name is Steve Chriss. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97310-1380. I am employed by the Public Utility Commission of Oregon as an Economist in the Economic and Policy Analysis Section.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. My Witness Qualifications Statement is found on Exhibit Staff/301, Chriss/1.

Q. HAVE YOU PREPARED EXHIBITS?

A. Yes, I prepared Staff/301, consisting of one page, Staff/302, consisting of twelve pages, Staff/303, consisting of one page, Staff/304, consisting of one page and Staff/305, consisting of one page.

<u>Purpose of Testimony</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I provide testimony in support of the first two issues, Contract Length/Price Structure and Size Threshold for Standard Rates. I also address the areas of natural gas price indexing and risk implications of using fixed price streams or indexed prices for standard contracts.

Natural Gas Price Indexing

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. The use of a natural gas price index for calculating the fuel price component of payments to Qualifying Facilities (QFs) can potentially mitigate harm to customers, while the use of floor and ceiling prices tied to a forecast of natural gas prices should enable QF financing. Staff proposes that two pricing methodologies be used to calculate the energy portion of avoided cost calculations for standard rates. The Deadband Method uses a natural gas price forecast with floor and ceiling prices. The Gas Market Method uses a monthly indexed price with no forecast. QFs over 2 MW would be able to choose between the Deadband and Gas Market pricing options. QFs up to and including 2 MW would be able to choose either of these pricing options as well as a fixed pricing option.

Staff recommends that each utility continue to file its natural gas price forecasts for the specified hub(s) in the context of its avoided cost proceedings. Staff will consider any changes to this procedure that are proposed.

Staff also recommends the continuation of the current Commission policy that allows contracting parties to tie negotiated contract prices to a mutually agreeable natural gas price index. Staff recommends that only QFs greater than 10 MW be required to negotiate such terms and conditions with the utilities.

Q. WHY IS IT APPROPRIATE TO TIE QF PAYMENTS TO NATURAL GAS PRICE INDEXING?

A. Linking QF payments to a natural gas index allows prices to reflect market conditions. From a utility perspective, using fixed avoided cost components may be inferior to natural gas price indexing because avoided costs are based on long-term natural gas price forecasts, which have historically proven to be inaccurate. The problem is exacerbated due to the lack of a mechanism that adjusts QF payments when it is determined that the long-term natural gas forecast is no longer reasonable. The longer the QF contract, the greater the problem can become. Even QF contracts of 15 years, as proposed in Staff/200, should incorporate a mechanism for QFs greater than 2 MW so that the prices do not rely solely on long-term forecasts alone. In this way, indexing can help ensure customers are not harmed by overpriced QF contracts. On the other hand, fixed prices provide a hedge to the utility against future natural gas price increases.

Q. HOW COULD A RELIANCE ON A FORECAST, BY ITSELF, HARM CUSTOMERS?

A. If the natural gas prices forecasted over the life of a QF contract are higher than the actual market prices of natural gas for the same period, customers will overpay for the QF-supplied power. For instance, under the avoided cost methodology PacifiCorp used in its filing in docket UM1129 (see Exhibit C), a $1/MMbtu change in the price of natural gas results in a $6.98/MWh change in the price of power purchased from QFs.

In this instance, customers would be charged $698,000 more for the QF contract, assuming PacifiCorp purchased 100,000 MWh of power from QFs for the year.

Q. ARE CUSTOMERS BETTER OFF IF THE ACTUAL PRICE OF NATURAL GAS IS HIGHER THAN IN THE FORECAST?

A. Yes. If the actual price of natural gas for a given time period is higher than the forecast price of gas, the customers may benefit. However, customers benefit at the detriment of the owners of the QF facilities, because the QFs are deprived of the opportunity to take advantage of higher prices. A better solution is for QFs to receive prices that reflect the actual market conditions at the time power is delivered.

Q. HOW DOES TYING PRICES TO A NATURAL GAS PRICE INDEX REFLECT CONDITIONS IN THE MARKET FOR POWER?

A. There is a correlation between the price of natural gas and the price of power (see Staff/305.) Generally, when the price of natural gas is high, the price of power is high, and when the price of natural gas is low, the price of power is low. The prices also tend to move in the same direction at any given time. The correlation coefficient for Mid-C and Sumas, during the time period of the dataset, is 0.65.

Q. SHOULD THE UTILITIES BE FORCED TO ABANDON LONG-TERM FIXED PRICE CONTRACTS?

No. It is to the benefit of each utility to have a portfolio of resources that includes fixed price contracts. Staff recommends in this docket that QFs no bigger than 2 MW have the option to take a fixed price contract.

Because QFs are contracted on a must-take basis, staff does not want to force utilities to offer fixed pricing for QFs larger than 2 MW.

Q. HOW DOES A PAYMENT TIED TO NATURAL GAS INDEXING DIFFER FROM A TRADITIONAL AVOIDED COST PAYMENT?

A. The total avoided energy cost of the traditional avoided cost payment is replaced by two index components, the actual natural gas price used (AGPU) and a factor for other costs not covered by the index (non-indexed costs, or NIC), such as shrinkage, transportation, and capitalized energy costs.

The traditional avoided cost payment includes a total avoided energy cost, which accounts for the cost of energy and capitalized energy costs at a certain capacity factor. The cost of energy includes a natural gas price forecast, with the prices modified to account for shrinkage and transportation costs.

The actual calculation of the payment that is tied to the natural gas index is similar to that of the traditional avoided cost payment. To calculate the off-peak energy price on a $/MWh basis, AGPU and NIC are added together. The on-peak price of energy is the sum of the off-peak price of energy plus the avoided capacity costs allocated to on-peak hours. To take advantage of using natural gas price indexing, prices paid to QFs may best be calculated monthly instead of annually.

Q. HOW SHOULD THE AGPU BE DETERMINED?

A. I propose two methods for determining the AGPU: the Deadband Method and the Gas Market Method. QFs that tie their payments to natural gas indexing should be able to choose between the two methods after determining which method best meets their needs.

Q. PLEASE DESCRIBE THE DEADBAND METHOD.

A. The Deadband Method incorporates floor and ceiling prices around an index derived from a natural gas forecast. For example, in Staff/302, Chriss/3, the June 2004 forecast price for natural gas from the Sumas hub is $4.05/MMbtu. To calculate the fuel index price, the forecast price is multiplied by 6,980 btu/kWh, the assumed heat rate of a combined-cycle combustion turbine (CCCT).[1] The fuel index price for that month is calculated to be $28.27/MWh.

Next, the floor and ceiling prices are calculated. The deadbands around the forecast price of natural gas serve a dual purpose. First, they allow AGPU to reflect natural gas market prices in relation to the forecast price of natural gas. Second, they contain this relationship within given bounds in order to retain some stability in prices for QF financing purposes. In my analysis, I use deadbands of 90 percent and 110 percent of the forecast natural gas price. For June 2004, the resulting deadbands are a floor of $25.44/MWh and a ceiling of $31.10/MWh.

Once the forecast price and deadbands are calculated, the price of natural gas for Sumas in June 2004 is brought in to the analysis (see Staff/302, Chriss/7.) The weighted monthly average for Sumas for June 2004 is $5.20/MMbtu, and this translates into an actual gas price of $36.33/MWh. This price is over the ceiling of $31.10/MWh, so AGPU is

[1] PacifiCorp UM1129 Filing, Exhibit C, Table 7.

$31.10/MWh, and the calculated on-peak price paid to QFs is $53.98/MWh and the off-peak price is $39.07/MWh. If the actual natural gas price is under $25.44/MWh, then AGPU equals $25.44. If the actual natural gas price is between $25.44/MWh and $31.10/MWh, then AGPU is the actual natural gas price.

Q. HOW WERE THE DEADBANDS OF 90 PERCENT AND 110 PERCENT DETERMINED?

A. The deadbands were determined by an analysis of the coefficients of variation[2] of the natural gas price forecasts (Staff/302, Chriss/12) provided by PacifiCorp in its filing in docket UM1129 (see Exhibit C). The coefficient of variation for the average of the Sumas, Opal, and Stanfield hubs (SOSA) is 0.10, which means that 68 percent[3] of the values from the forecast fall within 10 percent above or below the average. Staff feels that, for this docket, bands equal to the SOSA coefficient of variation strike a reasonable balance by capturing the majority of the volatility of the forecast and not introducing a great deal of price uncertainty for QFs.

Q. HOW DOES THE GAS MARKET METHOD DIFFER FROM THE DEADBAND METHOD?

A. The Gas Market Method does not use deadbands around a forecast. Instead, AGPU is simply the monthly indexed gas price, multiplied by the heat rate of the applicable CCCT plant.[4] This is illustrated in Columns (3)

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[2] Coefficient of variation is the measure of the degree to which a variable is distributed around its average value. It is calculated by dividing the standard deviation of a variable by the average of that variable.
[3] This value is more precise the closer the distribution of the variables is to the normal distribution.
[4] The heat rate of the applicable CCCT plant is traditionally defined in the IRP process of each utility.

and (4) of Staff/302, Chriss/7. For June 2004, the Sumas weighted monthly average of $5.20/MMbtu is multiplied by 6.980, the assumed heat rate, and the resulting price of $36.33/MWh is used in Columns (13) through (15) to calculate the on-peak price of $59.22/MWh and the off-peak price of $44.30/MWh.

Q. WHY SHOULD BOTH THE DEADBAND METHOD AND GAS MARKET METHOD BE OFFERED TO QFS?

A. The choice between the two methods should be offered because of the diversity in fuel, financing needs, market access, and levels of risk aversion among QF developers.

For instance, hydro and wind projects may desire more stable pricing due to the variation in fuel availability and generator output, and may prefer the Deadband Method with its known forecast prices, floors, and ceilings. The bottom two rows of Staff/302, Chriss/7 show that, over the three years of the analysis, the Deadband Method average prices paid to QFs for both on-peak and off-peak hours are similar to, though slightly lower than, prices calculated using the PacifiCorp avoided cost methodology applied on a monthly basis. The standard deviation of prices for the Deadband Method was also slightly lower than the prices calculated using PacifiCorp's avoided cost methodology. It can be inferred then, using standard deviation as a measure of risk[5], that during the limited sample period, the Deadband Method was less risky to QFs

[5] Standard deviation, the measure of the degree to which a variable is spread around its mean value, is often used to measure risk.

than even a monthly application of PacifiCorp's avoided cost methodology.

On the other hand, a QF developer with a natural gas-fired cogeneration plant may have greater access to natural gas markets and financial hedges. The developer may also be willing to take the risk of prices lower than the deadband floor in order to have the opportunity to sell power at prices above the deadband ceiling. The data in Staff/302, Chriss/7 show that, for the Gas Market Method during the limited sample period of the analysis, the average of prices paid to QFs was lower than both the Deadband Method and the monthly application of PacifiCorp's avoided costs methodology. The data also show that the standard deviation was higher for the period, implying higher risk. An analysis of individual months shows where the advantage of this method lies for a QF developer that has market and operational flexibility. During months with high natural gas prices, there exists an opportunity to sell power for a greater price with the Gas Market Method than with either of the other two methods of price calculation.

Q. PLEASE COMPARE THE EFFECTS OF THE DIFFERENT CALCULATION METHODS OVER THE SAMPLE PERIOD IN YOUR ANALYSIS.

A. Over the sample period of July 2001 through June 2004, using the Sumas hub, the total of on-peak/off-peak weighted prices paid to QFs calculated by the monthly application of PacifiCorp's avoided costs methodology was the highest at $1,692, followed by the Deadband Method at $1,667, a reduction of 1.5 percent, and the Gas Market Method at $1,507, a reduction of 10.9 percent (Staff/302, Chriss/10.) These values assume a single QF selling a single aMW a month for each month between July 2001 and June 2004.

Calculating the same values, but using SOSA, resulted in the same relationship between the three methods (Staff/302, Chriss/10.) Substituting PacifiCorp's avoided cost filing on-peak prices for the monthly application of their methodology resulted in a total of $1,544. The Deadband Method's total was $1,540, a reduction of 0.29 percent, and the Gas Market Method's total was $1,481, a reduction of 4.1 percent.

As I discuss below, this analysis may not be representative of the totals over a 15 year contract.

Q. WHAT ARE THE LIMITATIONS OF THE ANALYSIS?

A. Due to staff's limited access to data, the analysis only covers three years and excludes the effects of the gas price spikes of 2000 and early 2001. The analysis may not be representative of the level or volatility of prices going forward. The average price of natural gas for SOSA for the period is $3.61/MMbtu with a standard deviation of 1.36 (Staff/302, Chriss/6.) For Sumas, the average is $3.91/MMbtu with a standard deviation of 1.33 (Staff/302, Chriss/7.)

Also, using calculated weighted averages of daily data from the Intercontinental Exchange (ICE) may not be representative of how and where the utilities purchase their natural gas. As a result, this may not be representative of the avoided fuel cost of the utilities.

Q. WHY ARE THE NATURAL GAS PRICE SPIKES OF 2000 AND 2001 EXCLUDED FROM THE ANALYSIS?

A. Including the natural gas price spikes would have skewed the analysis. While price spikes are certainly part of doing business within a market, using data from price spikes, in a short time period, the price spike appears more important than it would actually be under a long-term contract.

Q. HOW CAN THESE METHODS PROTECT CUSTOMERS FROM HARM?

A. The two methods protect customers from harm in that they better reflect the actual market price for electricity, so utilities and customers will pay prices to QFs that reflect their opportunity costs.[6] This is predicated on the relationship between the price of natural gas and the price of power, which I discussed earlier. For example, the opportunity cost to utilities and customers, if the market price for power is lower than the fixed price in the QF contract, is the loss of the ability to choose alternate means of purchasing power.

Q. IS IT IMPORTANT FOR PRICES PAID TO QFS TO REFLECT ACTUAL MARKET CONDITIONS?

A. Yes. The QFs will receive prices that reflect their opportunity costs. An example of the opportunity cost to QFs is that, if the market price for power is higher than the fixed price in the QF contract, the QF loses the

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[6] The opportunity cost of an action is the value of a foregone alternative action. In this case, the action is purchasing power from QFs and the alternative actions are utility self-generation and purchasing power from the market.

ability to receive a higher price for their power, either from the utility or alternative buyers.

Q. WHICH NATURAL GAS PRICE FORECAST SHOULD THE UTILITIES USE?

A. Each utility should specify in its avoided cost filing the natural gas price forecast for the hub, or combination of hubs, that it uses in its calculations to best represent its system. For example, a utility may choose to only use Sumas or Opal, or it may choose to use some weighted combination of Sumas, Opal, and Stanfield. The utilities should also specify the published natural gas prices index they will use for determining actual QF payments tied to an index in the tariff.

Staff also recommends the continuation of the current Commission policy that allows contracting parties to tie negotiated contract prices to a mutually agreeable natural gas price index. Staff recommends that only QFs greater than 10 MW be required to negotiate such terms and conditions with the utilities.

Staff recommends that each utility continue to file its natural gas price forecasts for the specified hub(s) in the context of its avoided cost proceedings. Staff will consider any changes to this procedure that are proposed.

Risk Implications of Using Fixed Price Streams or Indexed Prices for Standard Contracts

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. My analysis shows that changing from the traditional avoided cost methodology to a pricing methodology tied to natural gas indexing changes the nature of risk to customers, utilities, and QFs. Using the Deadband and Gas Market Methods to determine the fuel component of avoided cost prices shifts the risk from prices being tied to static pre-determined values to prices being based on market forces.

Q. HOW DOES THE RISK TO CUSTOMERS AND UTILITIES CHANGE IF PRICES ARE TIED TO A NATURAL GAS PRICE INDEX?

A. Utilities and customers face the prospect of paying prices higher than the traditional avoided cost price for a given period of time (see Staff/303.) At the same time, switching to prices tied to a natural gas price index would benefit the utilities and customers. If the market allows, indexed QF payments may be lower than the traditional avoided cost methodology payments in a given period of time. Because utilities would be paying prices that reflect their opportunity cost, even if the price of QF power goes up, that will be reflective of the price of alternative supplies of power.

On balance, staff believes that natural gas price indexing will lower risk to the utilities and customers because QF payments will better reflect the opportunity cost of power to the utilities.

Q. DO QFS FACE SIMILAR RISKS?

A. Yes. QFs face the prospect of receiving prices lower than the traditional avoided cost price for a given period of time. At the same time, switching to prices tied to a natural gas price index would provide QFs the opportunity, if the market allows, of receiving a price higher than the traditional avoided cost methodology in a given period of time. Because the QFs would receive prices that reflect their opportunity costs, even if the price of QF power goes down, that will reflect the price the QF would have received from the utility outside of the QF contract or from alternative buyers.

Q. DOES THE AMOUNT OF RISK TO RATEPAYERS, UTILITIES, AND QFS DIFFER BETWEEN THE DEADBAND METHOD AND THE GAS MARKET METHOD?

A. Yes. The Gas Market Method is subject to more volatility than the Deadband Method.

Staff/303 illustrates, for the time period July 2001 through June 2004, the calculated prices for the Deadband Method and the Gas Market Method versus PacifiCorp's avoided cost prices. The graph shows the spread for prices calculated by the Gas Market Method is much larger than that of the Deadband Method.

Q. WHAT ARE THE REPERCUSSIONS OF THE LARGER SPREAD WITH THE GAS MARKET METHOD?

A. During periods of low natural gas prices (where the price of natural gas is more than 10 percent lower than the forecasted natural gas price), QFs that chose the Gas Market Method would receive lower prices than QFs that chose the Deadband Method. On the other hand, during periods of high natural gas prices (where the price of natural gas is more than 10 percent higher than the forecast gas price), QFs that chose the Gas Market Method would receive higher prices than QFs that chose the Deadband Method.

Q. WHAT PRICING INFORMATION WILL A QF HAVE AT THE TIME IT SIGNS A CONTRACT UNDER STAFF'S INDEXING PROPOSAL

A. The QF will have complete avoided cost prices, based on the natural gas price forecast and its floor and ceiling deadbands (see Staff/304.) These prices will also include the NIC and capacity components. Only the NIC and capacity components will be available to QFs opting for the Gas Market Method.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UM 1129
WITNESS: Steve Chriss

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualification Statement

August 3, 2004

WITNESS QUALIFICATIONS STATEMENT

NAME: STEVE W. CHRISS

EMPLOYER: PUBLIC UTILITY COMMISSION OF OREGON

TITLE: ECONOMIST

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 Oregon Public Utility Commission as Economist in the Economic Research and Financial Analysis Division since June, 2003.

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
WITNESS: Steve Chriss

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibit in Support of
Direct Testimony

August 3, 2004

Table 1. Natural Gas Price Adjustment

Date	Forward Sumas/Opal/ Stanfield Average (SOSA) ($/MMbtu)	3.0% Shrinkage	Local Transport	**Forecast SOSA CCCT Fuel Cost ($/MMbtu)**	Open	Sumas Forward Gas Curve ($/MMbtu)	3.0% Shrinkage	Local Transport	**Forecast Sumas CCCT Fuel Cost ($/MMbtu)**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		(1) * 3%		(1) + (2) + (3)			(6) * 3%		(6) + (7) + (8)
Jul-01	$ 3.10	$ 0.09	$ 0.40	$ 3.59		$ 3.57	$ 0.11	$ 0.40	$ 4.08
Aug-01	3.16	0.09	0.40	3.65		3.64	0.11	0.40	4.15
Sep-01	3.20	0.10	0.40	3.70		3.69	0.11	0.40	4.20
Oct-01	3.48	0.10	0.40	3.98		4.01	0.12	0.40	4.53
Nov-01	4.92	0.15	0.40	5.47		6.04	0.18	0.40	6.62
Dec-01	5.11	0.15	0.40	5.66		6.27	0.19	0.40	6.86
Jan-02	5.26	0.16	0.41	5.82		6.45	0.19	0.41	7.05
Feb-02	5.12	0.15	0.41	5.68		6.28	0.19	0.41	6.88
Mar-02	4.92	0.15	0.41	5.48		6.04	0.18	0.41	6.63
Apr-02	3.36	0.10	0.41	3.87		3.74	0.11	0.41	4.26
May-02	3.29	0.10	0.41	3.80		3.66	0.11	0.41	4.18
Jun-02	3.33	0.10	0.41	3.84		3.71	0.11	0.41	4.23
Jul-02	3.37	0.10	0.41	3.88		3.74	0.11	0.41	4.26
Aug-02	3.38	0.10	0.41	3.89		3.76	0.11	0.41	4.28
Sep-02	3.40	0.10	0.41	3.91		3.78	0.11	0.41	4.30
Oct-02	3.41	0.10	0.41	3.92		3.79	0.11	0.41	4.31
Nov-02	4.26	0.13	0.41	4.80		4.81	0.14	0.41	5.36
Dec-02	4.40	0.13	0.41	4.94		4.97	0.15	0.41	5.53
Jan-03	4.30	0.13	0.42	4.85		4.87	0.15	0.42	5.44
Feb-03	4.18	0.13	0.42	4.72		4.73	0.14	0.42	5.29
Mar-03	4.02	0.12	0.42	4.56		4.56	0.14	0.42	5.12
Apr-03	3.61	0.11	0.42	4.14		4.11	0.12	0.42	4.65
May-03	3.60	0.11	0.42	4.12		4.09	0.12	0.42	4.63
Jun-03	3.64	0.11	0.42	4.17		4.14	0.12	0.42	4.68
Jul-03	3.69	0.11	0.42	4.22		4.20	0.13	0.42	4.75
Aug-03	3.72	0.11	0.42	4.25		4.23	0.13	0.42	4.78
Sep-03	3.73	0.11	0.42	4.27		4.25	0.13	0.42	4.80
Oct-03	3.75	0.11	0.42	4.29		4.27	0.13	0.42	4.82
Nov-03	3.89	0.12	0.42	4.42		4.42	0.13	0.42	4.97
Dec-03	4.03	0.12	0.42	4.57		4.58	0.14	0.42	5.14
Jan-04	4.02	0.12	0.43	4.57		4.50	0.14	0.43	5.07
Feb-04	3.91	0.12	0.43	4.45		4.37	0.13	0.43	4.93
Mar-04	3.78	0.11	0.43	4.32		4.23	0.13	0.43	4.79
Apr-04	3.59	0.11	0.43	4.13		4.02	0.12	0.43	4.57
May-04	3.58	0.11	0.43	4.12		4.01	0.12	0.43	4.56
Jun-04	3.62	0.11	0.43	4.16		4.05	0.12	0.43	4.60

(1) 8. Data, Column 11
(2) Pacificorp UM1129 Filing Exhibit C, Table 8
(3) Pacificorp UM1129 Filing Exhibit C, Table 8
(4) (1) + (2) + (3)
(5) Open
(6) 6. Data, Colum 1
(7) Pacificorp UM1129 Filing Exhibit C, Table 8
(8) Pacificorp UM1129 Filing Exhibit C, Table 8
(9) (6) + (7) + (8)

Table 2. Total Avoided Energy Cost

	SOSA					Sumas			
Date	Forecast SOSA CCCT Fuel Cost ($/MMbtu)	Energy Cost (6,980btu/kWh)	Capitalized Energy Costs 85% CF ($/MWh)	Total Avoided Energy Cost ($/MWh)	Open	Forecast Sumas CCCT Fuel Cost ($/MMbtu)	Energy Cost (6,980btu/kWh)	Capitalized Energy Costs 85% CF ($/MWh)	Total Avoided Energy Cost ($/MWh)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		(1) * 6.980		(2) + (3)			(6) * 6.980		(7) + (8)
Jul-01	$ 3.59	$ 25.08	$ 3.89	$ 28.97		$ 4.08	$ 28.46	$ 3.89	$ 32.35
Aug-01	3.65	25.51	3.89	29.40		4.15	28.96	3.89	32.85
Sep-01	3.70	25.82	3.89	29.71		4.20	29.32	3.89	33.21
Oct-01	3.98	27.79	3.89	31.68		4.53	31.62	3.89	35.51
Nov-01	5.47	38.16	3.89	42.05		6.62	46.22	3.89	50.11
Dec-01	5.66	39.53	3.89	43.42		6.86	47.87	3.89	51.76
Jan-02	5.82	40.65	3.96	44.61		7.05	49.23	3.96	53.19
Feb-02	5.68	39.67	3.96	43.63		6.88	48.01	3.96	51.97
Mar-02	5.48	38.23	3.96	42.19		6.63	46.29	3.96	50.25
Apr-02	3.87	27.04	3.96	31.00		4.26	29.75	3.96	33.71
May-02	3.80	26.54	3.96	30.50		4.18	29.18	3.96	33.14
Jun-02	3.84	26.83	3.96	30.79		4.23	29.53	3.96	33.49
Jul-02	3.88	27.07	3.96	31.03		4.26	29.75	3.96	33.71
Aug-02	3.89	27.19	3.96	31.15		4.28	29.89	3.96	33.85
Sep-02	3.91	27.31	3.96	31.27		4.30	30.04	3.96	34.00
Oct-02	3.92	27.38	3.96	31.34		4.31	30.11	3.96	34.07
Nov-02	4.80	33.49	3.96	37.45		5.36	37.44	3.96	41.40
Dec-02	4.94	34.50	3.96	38.46		5.53	38.59	3.96	42.55
Jan-03	4.85	33.85	4.04	37.89		5.44	37.94	4.04	41.98
Feb-03	4.72	32.96	4.04	37.00		5.29	36.94	4.04	40.98
Mar-03	4.56	31.86	4.04	35.90		5.12	35.72	4.04	39.76
Apr-03	4.14	28.89	4.04	32.93		4.65	32.48	4.04	36.52
May-03	4.12	28.79	4.04	32.83		4.63	32.34	4.04	36.38
Jun-03	4.17	29.08	4.04	33.12		4.68	32.70	4.04	36.74
Jul-03	4.22	29.46	4.04	33.50		4.75	33.13	4.04	37.17
Aug-03	4.25	29.68	4.04	33.72		4.78	33.34	4.04	37.38
Sep-03	4.27	29.77	4.04	33.81		4.80	33.49	4.04	37.53
Oct-03	4.29	29.92	4.04	33.96		4.82	33.63	4.04	37.67
Nov-03	4.42	30.87	4.04	34.91		4.97	34.71	4.04	38.75
Dec-03	4.57	31.88	4.04	35.92		5.14	35.86	4.04	39.90
Jan-04	4.57	31.90	4.12	36.02		5.07	35.35	4.12	39.47
Feb-04	4.45	31.09	4.12	35.21		4.93	34.42	4.12	38.54
Mar-04	4.32	30.18	4.12	34.30		4.79	33.41	4.12	37.53
Apr-04	4.13	28.84	4.12	32.96		4.57	31.90	4.12	36.02
May-04	4.12	28.76	4.12	32.88		4.56	31.83	4.12	35.95
Jun-04	4.16	29.03	4.12	33.15		4.60	32.12	4.12	36.24

(1) 1. Nat Gas Price Adjustment, Column (4)
(2) Pacificorp UM1129 Filing Exhibit C, Table 3
(3) 8. Data, Column 10
(4) (2) + (3)
(6) 1. Nat Gas Price Adjustment, Column (9)
(7) Pacificorp UM1129 Filing Exhibit C, Table 3
(8) 8. Data, Column 10
(9) (7) + (8)

Table 3. Gas Index

	SOSA							Sumas					
Date	Forward Sumas/Opal/ Stanfield Average (SOSA) ($/MMbtu)	Fuel Index ($/MWh)	*Fuel Index Floor ($/MWh)*	*Fuel Index Ceiling ($/MWh)*	*Fuel Index Floor*	*Fuel Index Ceiling*	Open	Sumas Forward Gas Curve ($/MMbtu)	Fuel Index ($/MWh)	*Fuel Index Floor ($/MWh)*	*Fuel Index Ceiling ($/MWh)*	*Fuel Index Floor*	*Fuel Index Ceiling*
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
		(1) * 6.980	(2) * (5)	(2) * (6)	.9	1.1			(8) * 6.980	(9) * (12)	(9) * (13)	.9	1.1
Jul-01	$ 3.10	$ 21.64	$ 19.47	$ 23.80	.9	1.1		$ 3.57	$ 24.92	$ 22.43	$ 27.41	.9	1.1
Aug-01	3.16	22.06	19.85	24.26	.9	1.1		3.64	25.41	22.87	27.95	.9	1.1
Sep-01	3.20	22.36	20.12	24.60	.9	1.1		3.69	25.76	23.18	28.33	.9	1.1
Oct-01	3.48	24.27	21.84	26.69	.9	1.1		4.01	27.99	25.19	30.79	.9	1.1
Nov-01	4.92	34.34	30.91	37.78	.9	1.1		6.04	42.16	37.94	46.38	.9	1.1
Dec-01	5.11	35.67	32.10	39.23	.9	1.1		6.27	43.76	39.39	48.14	.9	1.1
Jan-02	5.26	36.69	33.02	40.36	.9	1.1		6.45	45.02	40.52	49.52	.9	1.1
Feb-02	5.12	35.74	32.16	39.31	.9	1.1		6.28	43.83	39.45	48.22	.9	1.1
Mar-02	4.92	34.34	30.91	37.78	.9	1.1		6.04	42.16	37.94	46.38	.9	1.1
Apr-02	3.36	23.48	21.13	25.82	.9	1.1		3.74	26.11	23.49	28.72	.9	1.1
May-02	3.29	22.99	20.69	25.29	.9	1.1		3.66	25.55	22.99	28.10	.9	1.1
Jun-02	3.33	23.27	20.94	25.59	.9	1.1		3.71	25.90	23.31	28.49	.9	1.1
Jul-02	3.37	23.50	21.15	25.85	.9	1.1		3.74	26.11	23.49	28.72	.9	1.1
Aug-02	3.38	23.62	21.25	25.98	.9	1.1		3.76	26.24	23.62	28.87	.9	1.1
Sep-02	3.40	23.73	21.36	26.11	.9	1.1		3.78	26.38	23.75	29.02	.9	1.1
Oct-02	3.41	23.80	21.42	26.18	.9	1.1		3.79	26.45	23.81	29.10	.9	1.1
Nov-02	4.26	29.73	26.76	32.71	.9	1.1		4.81	33.57	30.22	36.93	.9	1.1
Dec-02	4.40	30.71	27.64	33.78	.9	1.1		4.97	34.69	31.22	38.16	.9	1.1
Jan-03	4.30	30.01	27.01	33.02	.9	1.1		4.87	33.99	30.59	37.39	.9	1.1
Feb-03	4.18	29.15	26.24	32.07	.9	1.1		4.73	33.02	29.71	36.32	.9	1.1
Mar-03	4.02	28.08	25.27	30.89	.9	1.1		4.56	31.83	28.65	35.01	.9	1.1
Apr-03	3.61	25.20	22.68	27.72	.9	1.1		4.11	28.69	25.82	31.56	.9	1.1
May-03	3.60	25.10	22.59	27.62	.9	1.1		4.09	28.55	25.69	31.40	.9	1.1
Jun-03	3.64	25.38	22.85	27.92	.9	1.1		4.14	28.90	26.01	31.79	.9	1.1
Jul-03	3.69	25.76	23.18	28.33	.9	1.1		4.20	29.32	26.38	32.25	.9	1.1
Aug-03	3.72	25.97	23.37	28.56	.9	1.1		4.23	29.53	26.57	32.48	.9	1.1
Sep-03	3.73	26.06	23.45	28.66	.9	1.1		4.25	29.67	26.70	32.63	.9	1.1
Oct-03	3.75	26.20	23.58	28.82	.9	1.1		4.27	29.80	26.82	32.79	.9	1.1
Nov-03	3.89	27.13	24.42	29.84	.9	1.1		4.42	30.85	27.77	33.94	.9	1.1
Dec-03	4.03	28.11	25.30	30.92	.9	1.1		4.58	31.97	28.77	35.17	.9	1.1
Jan-04	4.02	28.06	25.25	30.87	.9	1.1		4.50	31.41	28.27	34.55	.9	1.1
Feb-04	3.91	27.27	24.54	30.00	.9	1.1		4.37	30.50	27.45	33.55	.9	1.1
Mar-04	3.78	26.38	23.75	29.02	.9	1.1		4.23	29.53	26.57	32.48	.9	1.1
Apr-04	3.59	25.08	22.57	27.59	.9	1.1		4.02	28.06	25.25	30.87	.9	1.1
May-04	3.58	25.01	22.51	27.51	.9	1.1		4.01	27.99	25.19	30.79	.9	1.1
Jun-04	3.62	25.27	22.74	27.79	.9	1.1		4.05	28.27	25.44	31.10	.9	1.1

(1) 8. Data, Column 11
(8) 8. Data, Column 1

Table 4. Non-Indexed Costs

	SOSA				Sumas		
Date	Total Avoided Energy Cost ($/MWh)	Fuel Index ($/MWh)	Non-Indexed Costs ($/MWh)	Open	Total Avoided Energy Cost ($/MWh)	Fuel Index ($/MWh)	Non-Indexed Costs ($/MWh)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
			(1) - (2)				(5) - (6)
Jul-01	$ 28.97	$ 21.64	$ 7.33		$ 32.35	$ 24.92	$ 7.43
Aug-01	29.40	22.06	7.34		32.85	25.41	7.44
Sep-01	29.71	22.36	7.35		33.21	25.76	7.45
Oct-01	31.68	24.27	7.41		35.51	27.99	7.52
Nov-01	42.05	34.34	7.71		50.11	42.16	7.95
Dec-01	43.42	35.67	7.75		51.76	43.76	7.99
Jan-02	44.61	36.69	7.92		53.19	45.02	8.17
Feb-02	43.63	35.74	7.89		51.97	43.83	8.14
Mar-02	42.19	34.34	7.85		50.25	42.16	8.09
Apr-02	31.00	23.48	7.53		33.71	26.11	7.60
May-02	30.50	22.99	7.51		33.14	25.55	7.59
Jun-02	30.79	23.27	7.52		33.49	25.90	7.60
Jul-02	31.03	23.50	7.53		33.71	26.11	7.60
Aug-02	31.15	23.62	7.53		33.85	26.24	7.61
Sep-02	31.27	23.73	7.53		34.00	26.38	7.61
Oct-02	31.34	23.80	7.54		34.07	26.45	7.62
Nov-02	37.45	29.73	7.71		41.40	33.57	7.83
Dec-02	38.46	30.71	7.74		42.55	34.69	7.86
Jan-03	37.89	30.01	7.87		41.98	33.99	7.99
Feb-03	37.00	29.15	7.85		40.98	33.02	7.96
Mar-03	35.90	28.08	7.81		39.76	31.83	7.93
Apr-03	32.93	25.20	7.73		36.52	28.69	7.83
May-03	32.83	25.10	7.72		36.38	28.55	7.83
Jun-03	33.12	25.38	7.73		36.74	28.90	7.84
Jul-03	33.50	25.76	7.74		37.17	29.32	7.85
Aug-03	33.72	25.97	7.75		37.38	29.53	7.86
Sep-03	33.81	26.06	7.75		37.53	29.67	7.86
Oct-03	33.96	26.20	7.76		37.67	29.80	7.87
Nov-03	34.91	27.13	7.79		38.75	30.85	7.90
Dec-03	35.92	28.11	7.81		39.90	31.97	7.93
Jan-04	36.02	28.06	7.96		39.47	31.41	8.06
Feb-04	35.21	27.27	7.94		38.54	30.50	8.04
Mar-04	34.30	26.38	7.91		37.53	29.53	8.01
Apr-04	32.96	25.08	7.87		36.02	28.06	7.96
May-04	32.88	25.01	7.87		35.95	27.99	7.96
Jun-04	33.15	25.27	7.88		36.24	28.27	7.97

(1) 2. Total Avoided Energy Cost, Column (4)
(2) 3. Gas Index, Column (2)
(3) (1) - (2)
(4) Open
(5) 2. Total Avoided Energy Cost, Column (9)
(6) 3. Gas Index, Column (9)
(7) (5) - (6)

Table 5. Capacity Cost Allocation

Date	Pacificorp Avoided Firm Capacity Costs ($/kW-yr)	Capacity Cost Allocated to On-Peak Hours ($/MWh)
	(1)	(2)
		(1)/(8.76 * 0.85 * 0.57)
Jul-01	$ 59.66	$ 14.06
Aug-01	59.66	14.06
Sep-01	59.66	14.06
Oct-01	59.66	14.06
Nov-01	59.66	14.06
Dec-01	59.66	14.06
Jan-02	60.85	14.34
Feb-02	60.85	14.34
Mar-02	60.85	14.34
Apr-02	60.85	14.34
May-02	60.85	14.34
Jun-02	60.85	14.34
Jul-02	60.85	14.34
Aug-02	60.85	14.34
Sep-02	60.85	14.34
Oct-02	60.85	14.34
Nov-02	60.85	14.34
Dec-02	60.85	14.34
Jan-03	62.07	14.62
Feb-03	62.07	14.62
Mar-03	62.07	14.62
Apr-03	62.07	14.62
May-03	62.07	14.62
Jun-03	62.07	14.62
Jul-03	62.07	14.62
Aug-03	62.07	14.62
Sep-03	62.07	14.62
Oct-03	62.07	14.62
Nov-03	62.07	14.62
Dec-03	62.07	14.62
Jan-04	63.31	14.92
Feb-04	63.31	14.92
Mar-04	63.31	14.92
Apr-04	63.31	14.92
May-04	63.31	14.92
Jun-04	63.31	14.92

(1) 8. Data, Column 9

(2) (1)/(8.76 * 85% * 57%)

Table 6. Calculation of Payments to QFs (SOSA)

Date	Costs Common to All Methods: Capacity Cost Allocated to On-Peak Hours ($/MWh) (1)	NIC ($/MWh) (2)	Sumas/Opal/Stanfield ICE Average ($/MMbtu) (3)	Actual Natural Gas Price (4)	Open (5)
				(3) * 6.980	
Jul-01	$ 14.06	$ 7.33	$ 2.39	$ 16.69	
Aug-01	14.06	7.34	2.45	17.10	
Sep-01	14.06	7.35	1.60	11.17	
Oct-01	14.06	7.41	2.25	15.69	
Nov-01	14.06	7.71	2.07	14.44	
Dec-01	14.06	7.75	2.40	16.76	
Jan-02	14.34	7.92	2.03	14.15	
Feb-02	14.34	7.89	2.08	14.55	
Mar-02	14.34	7.85	2.87	20.01	
Apr-02	14.34	7.53	2.62	18.29	
May-02	14.34	7.51	2.44	17.03	
Jun-02	14.34	7.52	1.88	13.09	
Jul-02	14.34	7.53	1.42	9.91	
Aug-02	14.34	7.53	1.92	13.41	
Sep-02	14.34	7.53	2.27	15.88	
Oct-02	14.34	7.54	3.02	21.05	
Nov-02	14.34	7.71	3.43	23.93	
Dec-02	14.34	7.74	3.78	26.36	
Jan-03	14.62	7.87	4.13	28.81	
Feb-03	14.62	7.85	5.62	39.25	
Mar-03	14.62	7.81	5.26	36.69	
Apr-03	14.62	7.73	4.24	29.60	
May-03	14.62	7.72	4.92	34.33	
Jun-03	14.62	7.73	4.88	34.07	
Jul-03	14.62	7.74	4.39	30.62	
Aug-03	14.62	7.78	4.54	31.70	
Sep-03	14.62	7.75	4.29	29.96	
Oct-03	14.62	7.76	4.23	29.51	
Nov-03	14.62	7.79	4.23	29.52	
Dec-03	14.62	7.81	5.38	37.53	
Jan-04	14.92	7.96	5.55	38.75	
Feb-04	14.92	7.94	4.60	33.47	
Mar-04	14.92	7.91	4.77	33.33	
Apr-04	14.92	7.87	5.05	35.27	
May-04	14.92	7.67	5.41	37.74	
Jun-04	14.92	7.68	5.29	36.90	
Average			$ 3.61		
Standard Deviation			1.36		

Date	Deadband Method: Fuel Index Floor 90% (6)	Fuel Index Ceiling 110% (7)	Floor, Ceiling, or Within Range? (8)	AGPU ($/MWh) (9)	On-Peak Price Paid to QF ($/MWh) (10)	Off-Peak Price Paid to QF ($/MWh) (11)	Open (12)
					(1) + (2) + (9)	(2) + (9)	
Jul-01	$ 19.47	$ 23.80	Floor	$ 19.47	$ 40.86	$ 26.81	
Aug-01	19.85	24.26	Floor	19.85	41.25	27.19	
Sep-01	20.12	24.60	Floor	20.12	41.53	27.48	
Oct-01	21.64	26.69	Floor	21.64	43.31	29.25	
Nov-01	30.91	37.78	Floor	30.91	52.68	38.62	
Dec-01	32.10	39.23	Floor	32.10	53.91	39.85	
Jan-02	33.02	40.36	Floor	33.02	55.28	40.94	
Feb-02	32.16	39.31	Floor	32.16	54.30	40.06	
Mar-02	30.91	37.78	Floor	30.91	53.10	38.76	
Apr-02	21.13	25.82	Floor	21.13	42.99	28.65	
May-02	20.69	25.29	Floor	20.69	42.54	28.20	
Jun-02	20.94	25.59	Floor	20.94	42.80	28.46	
Jul-02	21.15	25.85	Floor	21.15	43.01	28.68	
Aug-02	21.25	25.98	Floor	21.25	43.12	28.78	
Sep-02	21.36	26.11	Floor	21.36	43.23	28.89	
Oct-02	21.42	26.18	Floor	21.42	43.29	28.96	
Nov-02	26.76	32.71	Floor	26.76	48.81	34.48	
Dec-02	27.64	33.78	Floor	27.64	49.72	35.38	
Jan-03	27.01	33.02	Within Range	28.81	51.30	36.68	
Feb-03	26.24	32.07	Ceiling	32.07	54.54	39.91	
Mar-03	25.27	30.89	Ceiling	30.89	53.33	38.71	
Apr-03	22.68	27.72	Ceiling	27.72	50.07	35.45	
May-03	22.59	27.62	Ceiling	27.62	49.96	35.34	
Jun-03	22.85	27.92	Ceiling	27.92	50.28	35.66	
Jul-03	23.18	28.33	Ceiling	28.33	50.70	36.08	
Aug-03	23.37	28.56	Ceiling	28.56	50.94	36.31	
Sep-03	23.45	28.66	Ceiling	28.66	51.04	36.42	
Oct-03	23.58	28.82	Ceiling	28.82	51.20	36.58	
Nov-03	24.42	29.84	Within Range	29.52	51.93	37.31	
Dec-03	25.30	30.92	Ceiling	30.92	53.36	38.73	
Jan-04	25.25	30.87	Ceiling	30.87	53.75	38.83	
Feb-04	24.54	30.00	Ceiling	30.00	52.85	37.93	
Mar-04	23.75	29.02	Ceiling	29.02	51.86	36.94	
Apr-04	22.57	27.59	Ceiling	27.59	50.38	35.46	
May-04	22.51	27.51	Ceiling	27.51	50.30	35.38	
Jun-04	22.74	27.79	Ceiling	27.79	50.59	35.67	
Average					$ 49.01	$ 34.32	
Standard Deviation					4.61	4.47	

Date	Gas Market Method: AGPU ($/MWh) (13)	On-Peak Price Paid to QF ($/MWh) (14)	Off-Peak Price Paid to QF ($/MWh) (15)	Open (16)
		(1) + (2) + (13)	(2) + (13)	
Jul-01	$ 16.69	$ 38.08	$ 24.02	
Aug-01	17.10	38.50	24.44	
Sep-01	11.17	32.58	18.52	
Oct-01	15.69	37.16	23.10	
Nov-01	14.44	36.21	22.15	
Dec-01	16.76	38.57	24.51	
Jan-02	14.15	36.41	22.07	
Feb-02	14.55	36.78	22.44	
Mar-02	20.01	42.20	27.86	
Apr-02	18.29	40.16	25.82	
May-02	17.03	38.88	24.54	
Jun-02	13.09	34.95	20.61	
Jul-02	9.91	31.78	17.44	
Aug-02	13.41	35.27	20.94	
Sep-02	15.88	37.75	23.41	
Oct-02	21.05	42.92	28.59	
Nov-02	23.93	45.98	31.64	
Dec-02	26.36	48.44	34.10	
Jan-03	28.81	51.30	36.68	
Feb-03	39.25	61.72	47.10	
Mar-03	36.69	59.13	44.51	
Apr-03	29.60	51.95	37.32	
May-03	34.33	56.68	42.06	
Jun-03	34.07	56.43	41.81	
Jul-03	30.62	52.99	38.37	
Aug-03	31.70	54.07	39.45	
Sep-03	29.96	52.34	37.71	
Oct-03	29.51	51.89	37.26	
Nov-03	29.52	51.93	37.31	
Dec-03	37.53	59.97	45.34	
Jan-04	38.75	61.63	46.72	
Feb-04	33.47	56.33	41.41	
Mar-04	33.33	56.16	41.24	
Apr-04	35.27	58.06	43.14	
May-04	37.74	60.53	45.61	
Jun-04	36.90	59.70	44.78	
Average		$ 47.37	$ 32.89	
Standard Deviation		9.63	9.59	

Date	Avoided Cost Method: Total Avoided Energy Cost ($/MWh) (17)	On-Peak Price Paid to QF ($/MWh) (18)	Off-Peak Price Paid to QF ($/MWh) (19)
		(1) + (17)	(17)
Jul-01	$ 28.97	$ 43.03	$ 28.97
Aug-01	29.40	43.46	29.40
Sep-01	29.71	43.77	29.71
Oct-01	31.68	45.73	31.68
Nov-01	42.05	56.11	42.05
Dec-01	43.42	57.48	43.42
Jan-02	44.61	58.95	44.61
Feb-02	43.63	57.97	43.63
Mar-02	42.19	56.53	42.19
Apr-02	31.00	45.34	31.00
May-02	30.50	44.84	30.50
Jun-02	30.79	45.12	30.79
Jul-02	31.03	45.36	31.03
Aug-02	31.15	45.48	31.15
Sep-02	31.27	45.60	31.27
Oct-02	31.34	45.67	31.34
Nov-02	37.45	51.79	37.45
Dec-02	38.46	52.79	38.46
Jan-03	37.89	52.51	37.89
Feb-03	37.00	51.62	37.00
Mar-03	35.90	50.52	35.90
Apr-03	32.93	47.55	32.93
May-03	32.83	47.45	32.83
Jun-03	33.12	47.74	33.12
Jul-03	33.50	48.13	33.50
Aug-03	33.72	48.34	33.72
Sep-03	33.81	48.44	33.81
Oct-03	33.96	48.58	33.96
Nov-03	34.91	49.54	34.91
Dec-03	35.92	50.84	35.92
Jan-04	36.02	50.94	36.02
Feb-04	35.21	50.12	35.21
Mar-04	34.30	49.21	34.30
Apr-04	32.96	47.87	32.96
May-04	32.88	47.80	32.88
Jun-04	33.15	48.06	33.15
Average		$ 49.17	$ 34.63
Standard Deviation		4.20	4.21

(1) 5, Capacity Cost Allocation, Column 2
(2) 4, Non-indexed Costs, Column 3
(3) 6, Data, Column 12
(4) (3) * 6.980
(5) Open
(6) 3, Gas Index, Column 3
(7) 3, Gas Index, Column 4
(8) If((4)<(6),"Floor",IF((4)>(7),"Ceiling","Within Range"))
(9) If((8)="Floor",(6),IF((8)="Ceiling",(7),(4)))
(10) (1) + (2) + (9)
(11) (2) + (9)
(12) Open
(13) Equals (3)
(14) (1) + (2) + (13)
(15) (2) + (13)
(16) Open
(17) 2, Total Avoided Energy Costs (4)
(18) (1) + (17)
(19) (17)

Table 6a. Calculation of Payments to QFs (Sumas)

	Costs CoMMon to Both Methods					Deadband Method							Gas Market Method				Avoided Cost Method		
Date	Capacity Cost Allocated to On-Peak Hours ($/MWh)	NIC ($/MWh)	ICE Sumas Weighted Monthly Average ($/MMbtu)	Actual Natural Gas Price	Open	Fuel Index Floor 90%	Fuel Index Ceiling 110%	Floor, Ceiling, or Within Range?	AGPU ($/MWh)	On-Peak Price Paid to QF ($/MWh)	Off-Peak Price Paid to QF ($/MWh)	Open	AGPU ($/MWh)	On-Peak Price Paid to QF ($/MWh)	Off-Peak Price Paid to QF ($/MWh)	Open	Total Avoided Energy Cost ($/MWh)	On-Peak Price Paid to QF ($/MWh)	Off-Peak Price Paid to QF ($/MWh)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
				(3) * 6.980						(1) + (2) + (9)	(2) + (9)			(1) + (2) + (13)	(2) + (13)			(1) + (17)	(17)
Jul-01	$ 14.06	$ 7.43	$ 2.38	$ 16.62		$ 22.43	$ 27.41	Floor	$ 22.43	$ 43.91	$ 29.86		$ 16.62	$ 38.11	$ 24.05		$ 32.35	$ 46.40	$ 32.35
Aug-01	14.06	7.44	2.44	17.05		22.87	27.95	Floor	22.87	44.37	30.31		17.05	38.55	24.50		32.85	46.91	32.85
Sep-01	14.06	7.45	1.56	10.92		23.18	28.33	Floor	23.18	44.69	30.64		10.92	32.43	18.38		33.21	47.27	33.21
Oct-01	14.06	7.52	2.26	15.76		25.19	30.79	Floor	25.19	46.77	32.71		15.76	37.34	23.28		35.51	49.57	35.51
Nov-01	14.06	7.95	2.17	15.16		37.94	46.38	Floor	37.94	59.95	45.89		15.16	37.17	23.11		50.11	64.16	50.11
Dec-01	14.06	7.99	2.46	17.20		39.39	48.14	Floor	39.39	61.44	47.38		17.20	39.25	25.19		51.76	65.82	51.76
Jan-02	14.34	8.17	2.05	14.32		40.52	49.52	Floor	40.52	63.03	48.69		14.32	36.83	22.49		53.19	67.53	53.19
Feb-02	14.34	8.14	2.08	14.53		39.45	48.22	Floor	39.45	61.92	47.59		14.53	37.00	22.67		51.97	66.31	51.97
Mar-02	14.34	8.09	2.89	20.18		37.94	46.38	Floor	37.94	60.37	46.03		20.16	42.60	28.27		50.25	64.58	50.25
Apr-02	14.34	7.60	2.95	20.62		23.49	28.72	Floor	23.49	45.44	31.10		20.62	42.56	28.22		33.71	48.05	33.71
May-02	14.34	7.59	2.70	18.87		22.99	28.10	Floor	22.99	44.92	30.58		18.87	40.80	26.46		33.14	47.47	33.14
Jun-02	14.34	7.60	2.10	14.68		23.31	28.49	Floor	23.31	45.24	30.90		14.68	36.61	22.27		33.49	47.83	33.49
Jul-02	14.34	7.60	1.39	9.68		23.49	28.72	Floor	23.49	45.44	31.10		9.68	31.62	17.28		33.71	48.05	33.71
Aug-02	14.34	7.61	2.16	15.07		23.62	28.87	Floor	23.62	45.57	31.23		15.07	37.02	22.68		33.85	48.19	33.85
Sep-02	14.34	7.61	2.83	19.78		23.75	29.02	Floor	23.75	45.70	31.36		19.76	41.71	27.37		34.00	48.38	34.00
Oct-02	14.34	7.62	3.42	23.90		23.81	29.10	Within Range	23.90	45.85	31.51		23.90	45.85	31.51		34.07	48.41	34.07
Nov-02	14.34	7.83	3.62	25.24		30.22	36.93	Floor	30.22	52.38	38.06		25.24	47.41	33.07		41.40	55.74	41.40
Dec-02	14.34	7.88	4.15	28.95		31.22	38.16	Floor	31.22	53.42	39.08		28.95	51.14	36.81		42.55	56.89	42.55
Jan-03	14.62	7.99	4.53	31.59		30.59	37.39	Within Range	31.59	54.21	39.58		31.59	54.21	39.58		41.98	56.61	41.98
Feb-03	14.62	7.96	6.21	43.33		29.71	36.32	Ceiling	36.32	58.90	44.28		43.33	65.92	51.29		40.98	55.60	40.98
Mar-03	14.62	7.93	5.50	38.42		28.65	35.01	Ceiling	35.01	57.56	42.94		38.42	60.97	46.34		39.70	54.38	39.76
Apr-03	14.62	7.83	4.54	31.68		25.82	31.56	Ceiling	31.56	54.01	39.39		31.68	54.13	39.51		36.52	51.14	36.52
May-03	14.62	7.83	4.81	33.56		25.69	31.40	Ceiling	31.40	53.86	39.23		33.56	56.01	41.39		36.38	51.00	36.38
Jun-03	14.62	7.84	4.76	33.21		26.01	31.79	Ceiling	31.79	54.25	39.63		33.21	55.68	41.05		36.74	51.36	36.74
Jul-03	14.62	7.65	4.26	29.70		26.38	32.25	Within Range	29.70	52.18	37.35		29.70	52.18	37.55		37.17	51.79	37.17
Aug-03	14.62	7.86	4.41	30.77		26.57	32.48	Within Range	30.77	53.26	38.63		30.77	53.26	38.63		37.36	52.01	37.38
Sep-03	14.62	7.86	4.19	29.25		26.70	32.63	Within Range	29.25	51.74	37.11		29.25	51.74	37.11		37.53	52.15	37.53
Oct-03	14.62	7.87	4.15	28.98		26.82	32.79	Within Range	28.98	51.47	36.85		28.98	51.47	36.85		37.07	52.29	37.07
Nov-03	14.62	7.90	4.22	29.43		27.77	33.94	Within Range	29.43	51.95	37.33		29.43	51.95	37.33		38.75	53.37	38.75
Dec-03	14.62	7.93	5.39	37.61		28.77	35.17	Ceiling	35.17	57.72	43.10		37.61	60.16	45.54		39.90	54.52	39.90
Jan-04	14.92	8.06	5.54	38.63		28.27	34.55	Ceiling	34.55	57.53	42.61		38.63	61.62	46.70		39.47	54.39	39.47
Feb-04	14.92	8.04	4.75	33.14		27.45	33.55	Within Range	33.14	56.09	41.18		33.14	56.09	41.18		38.54	53.46	38.54
Mar-04	14.92	8.01	4.69	32.75		26.57	32.48	Ceiling	32.48	55.40	40.49		32.75	55.68	40.76		37.53	52.45	37.53
Apr-04	14.92	7.96	4.94	34.49		25.25	30.87	Ceiling	30.87	53.75	38.83		34.49	57.37	42.45		36.02	50.94	36.02
May-04	14.92	7.96	5.30	36.96		25.19	30.79	Ceiling	30.79	53.67	38.75		36.96	59.84	44.92		35.95	50.87	35.95
Jun-04	14.92	7.97	5.20	36.33		25.44	31.10	Ceiling	31.10	53.98	39.07		36.33	59.22	44.30		36.24	51.16	36.24
Average			$ 3.69							$ 52.55	$ 38.07			$ 48.10	$ 33.61			$ 53.25	$ 38.77
Standard Deviation			1.33							5.70	5.62			9.64	9.40			5.81	5.84

(1) 6. Capacity Cost Allocation, Column 2
(2) 4. Non-Indexed Costs, Column 3
(3) 8. Data, Column 1
(4) (3) * 6.980
(5) Open
(6) 3. Gas Index, Column 3
(7) 3. Gas Index, Column 4
(8) If((4)<(6),"Floor",IF((4)>(7),"Ceiling","Within Range"))
(9) If((8)="Floor",(6),IF((8)="Ceiling",(7),(4)))
(10) (1) + (2) + (9)
(11) (2) + (9)
(12) Open
(13) Equals (3)
(14) (1) + (2) + (13)
(15) (2) + (13)
(16) Open
(17) 2. Total Avoided Energy Cost (9)
(18) (1) + (17)
(19) (17)

Staff/302
Chriss/7

Table 7. Month by month comparison of different payment methods (SOSA)

Date	Pacificorp Avoided Cost Filing On-Peak ($/MWh)	Pacificorp Avoided Cost Filing Off-Peak ($/MWh)	Deadband Method On-Peak ($/MWh)	Deadband Method Off-Peak ($/MWh)	Gas Market Method On-Peak ($/MWh)	Gas Market Method Off-Peak ($/MWh)	Mid-C On-Peak ($/MWh)	Mid-C Off-Peak ($/MWh)	Avoided Cost Method On-Peak ($/MWh)	Avoided Cost Method Off-Peak ($/MWh)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Jul-01	$ 48.24	$ 34.18	$ 40.66	$ 26.81	$ 38.08	$ 24.02	$ 64.61	$ 41.36	$ 43.03	$ 28.97
Aug-01	48.24	34.18	41.25	27.19	38.50	24.44	45.38	29.84	43.46	29.40
Sep-01	48.24	34.18	41.53	27.48	32.58	18.52	24.37	20.28	43.77	29.71
Oct-01	48.24	34.18	43.31	29.25	37.15	23.10	25.81	21.31	45.73	31.68
Nov-01	48.24	34.18	52.68	38.62	38.21	22.15	23.46	19.85	56.11	42.05
Dec-01	48.24	34.18	53.91	39.85	38.57	24.51	26.83	21.87	57.48	43.42
Jan-02	49.64	35.30	55.28	40.94	36.41	22.07	19.59	17.14	58.95	44.61
Feb-02	49.64	35.30	54.39	40.06	38.78	22.44	20.85	19.41	57.97	43.63
Mar-02	49.64	35.30	53.10	38.76	42.20	27.66	35.49	31.12	56.53	42.19
Apr-02	49.64	35.30	42.99	28.65	40.16	25.82	22.21	15.81	45.34	31.00
May-02	49.64	35.30	42.54	28.20	38.68	24.54	21.55	14.87	44.84	30.50
Jun-02	49.64	35.30	42.80	28.46	34.95	20.61	10.30	4.16	45.12	30.79
Jul-02	49.64	35.30	43.01	28.68	31.78	17.44	11.87	8.44	45.36	31.03
Aug-02	49.64	35.30	43.12	28.78	35.27	20.94	18.36	16.49	45.48	31.15
Sep-02	49.64	35.30	43.23	28.89	37.75	23.41	25.18	22.73	45.60	31.27
Oct-02	49.64	35.30	43.29	28.96	42.92	28.59	30.52	24.68	45.67	31.34
Nov-02	49.64	35.30	48.81	34.48	45.93	31.64	32.08	29.54	51.79	37.45
Dec-02	49.64	35.30	49.72	35.38	48.44	34.10	40.13	32.55	52.79	38.46
Jan-03	49.31	34.69	51.30	36.68	51.30	38.68	38.89	33.01	52.61	37.69
Feb-03	49.31	34.69	54.54	39.91	61.72	47.10	52.11	44.60	51.62	37.00
Mar-03	49.31	34.69	53.33	38.71	59.13	44.51	46.35	42.77	50.52	35.90
Apr-03	49.31	34.69	50.07	35.45	51.95	37.32	32.20	29.50	47.55	32.93
May-03	49.31	34.69	49.96	35.34	56.68	42.08	33.01	21.01	47.45	32.83
Jun-03	49.31	34.69	50.28	35.66	56.43	41.81	38.52	23.58	47.74	33.12
Jul-03	49.31	34.69	50.70	38.08	52.99	38.37	47.06	38.99	48.13	33.50
Aug-03	49.31	34.69	50.94	36.31	54.07	39.45	41.90	35.84	48.34	33.72
Sep-03	49.31	34.69	51.04	38.42	52.34	37.71	42.68	33.02	48.44	33.81
Oct-03	49.31	34.69	51.20	36.58	51.89	37.26	37.45	29.93	48.58	33.96
Nov-03	49.31	34.69	51.93	37.31	51.93	37.31	37.05	31.50	49.54	34.91
Dec-03	49.31	34.69	53.38	38.73	59.97	45.34	40.79	36.84	50.55	35.92
Jan-04	48.64	33.72	53.75	38.83	61.63	46.72	46.33	40.96	50.94	36.02
Feb-04	48.64	33.72	52.85	37.93	68.33	41.41	41.84	39.21	50.12	35.21
Mar-04	48.64	33.72	51.85	36.94	56.16	41.24	38.63	33.91	49.21	34.30
Apr-04	48.64	33.72	50.38	35.46	58.06	43.14	42.48	36.38	47.87	32.96
May-04	48.64	33.72	50.30	35.38	60.53	45.61	48.13	39.42	47.80	32.88
Jun-04	48.64	33.72	50.59	35.67	59.70	44.78	31.05	27.68	48.06	33.15
Total[1]	$ 1,768.68	$ 1,247.28	$ 1,764.21	$ 1,242.83	$ 1,705.40	$ 1,184.02	$ 1,233.07	$ 1,009.59	$ 1,770.01	$ 1,248.63

Deadband Method Floor %:	90
Deadband Method Ceiling %:	110

[1] Sum If a QF sold one MWh a month for each month between July 2001 and June 2004
(1) Pacificorp UM1129 Filing Exhibit C, Table 5
(2) Pacificorp UM1129 Filing Exhibit C, Table 5
(3) 6. Calculation of QF Payments, Column 10
(4) 6. Calculation of QF Payments, Column 11
(5) 6. Calculation of QF Payments, Column 14
(6) 6. Calculation of QF Payments, Column 15
(7) 8. Data, Column 7
(8) 8. Data, Column 8

Table 7a. Month by month comparison of different payment methods (Sumas)

Date	Deadband Method On-Peak ($/MWh)	Deadband Method Off-Peak ($/MWh)	Gas Market Method On-Peak ($/MWh)	Gas Market Method Off-Peak ($/MWh)	Mid-C On-Peak ($/MWh)	Mid-C Off-Peak ($/MWh)	Avoided Cost Method On-Peak ($/MWh)	Avoided Cost Method Off-Peak ($/MWh)
	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Jul-01	$ 43.91	$ 29.86	$ 38.11	$ 24.05	$ 64.61	$ 41.36	$ 46.40	$ 32.35
Aug-01	44.37	30.31	38.55	24.50	45.38	29.84	46.91	32.85
Sep-01	44.69	30.64	32.43	18.38	24.37	20.28	47.27	33.21
Oct-01	46.77	32.71	37.34	23.28	25.81	21.31	49.57	35.51
Nov-01	59.95	45.89	37.17	23.11	23.48	19.85	64.16	50.11
Dec-01	61.44	47.38	39.25	25.19	26.83	21.87	65.82	51.76
Jan-02	63.03	48.69	36.83	22.49	19.59	17.14	67.53	53.19
Feb-02	61.92	47.59	37.00	22.87	20.85	19.41	66.31	51.97
Mar-02	60.37	46.03	42.60	28.27	35.49	31.12	64.58	50.25
Apr-02	45.44	31.10	42.56	28.22	22.21	15.81	48.05	33.71
May-02	44.92	30.58	40.80	26.46	21.55	14.87	47.47	33.14
Jun-02	45.24	30.90	36.61	22.27	10.30	4.16	47.83	33.49
Jul-02	45.44	31.10	31.62	17.28	11.87	8.44	48.05	33.71
Aug-02	45.57	31.23	37.02	22.68	18.36	16.49	48.19	33.85
Sep-02	45.70	31.36	41.71	27.37	25.18	22.73	48.33	34.00
Oct-02	45.85	31.51	45.85	31.51	30.52	24.68	48.41	34.07
Nov-02	52.38	38.05	47.41	33.07	32.08	29.54	55.74	41.40
Dec-02	53.42	39.08	51.14	36.81	40.13	32.55	56.89	42.55
Jan-03	54.21	39.58	54.21	39.58	38.89	33.01	56.61	41.98
Feb-03	58.90	44.26	65.92	51.29	52.11	44.60	55.60	40.98
Mar-03	57.56	42.94	60.97	46.34	46.35	42.77	54.38	39.76
Apr-03	54.01	39.39	54.13	39.51	32.20	29.50	51.14	36.52
May-03	53.86	39.23	56.01	41.39	33.01	21.01	51.00	36.38
Jun-03	54.25	39.63	55.68	41.05	36.52	23.58	51.38	36.74
Jul-03	52.18	37.55	52.18	37.55	47.06	38.99	51.79	37.17
Aug-03	53.26	38.63	53.26	38.63	41.90	35.84	52.01	37.38
Sep-03	51.74	37.11	51.74	37.11	42.68	33.02	52.15	37.53
Oct-03	51.47	36.85	51.47	36.85	37.45	29.93	52.29	37.67
Nov-03	51.95	37.33	51.95	37.33	37.05	31.50	53.37	38.75
Dec-03	57.72	43.10	60.16	45.54	40.79	36.84	54.52	39.90
Jan-04	57.53	42.61	61.62	46.70	46.33	40.96	54.39	39.47
Feb-04	56.09	41.18	56.09	41.18	41.84	39.21	53.46	38.54
Mar-04	55.40	40.49	55.68	40.76	38.63	33.91	52.45	37.53
Apr-04	53.75	38.83	57.37	42.46	42.48	36.38	50.94	36.02
May-04	53.67	38.75	59.84	44.92	48.13	39.42	50.87	35.95
Jun-04	53.98	39.07	59.22	44.30	31.05	27.68	51.16	36.24
Total[1]	$ 1,891.93	$ 1,370.55	$ 1,731.50	$ 1,210.12	$ 1,233.07	$ 1,009.59	$ 1,917.01	$ 1,395.63

Deadband Method Floor %:	90
Deadband Method Ceiling %:	110

[1] Sum if a QF sold one MWh a month for each month between July 2001 and June 2004

(1) Pacificorp UM1129 Filing Exhibit C, Table 5

(2) Pacificorp UM1129 Filing Exhibit C, Table 5

(3) 6. Calculation of QF Payments (SUMAS), Column 10

(4) 6. Calculation of QF Payments (SUMAS), Column 11

(5) 6. Calculation of QF Payments (SUMAS), Column 14

(6) 6. Calculation of QF Payments (SUMAS), Column 15

(7) 8. Data, Column 7

(8) 8. Data, Column 8

(9) 6. Calculation of QF Payments (SUMAS), Column 18

(10) 6. Calculation of QF Payments (SUMAS), Column 19

Table 8. Comparison of On-Peak/Off-Peak Weighted Prices Over the Three Year Period

Date	SOSA: PacifiCorp Avoided Cost Filing Weighted ($/MWh)	SOSA: Deadband Method Weighted ($/MWh)	SOSA: Gas Market Method Weighted ($/MWh)	SOSA: Mid-C Weighted ($/MWh)	Open	Sumas: Avoided Cost Method Weighted ($/MWh)	Sumas: Deadband Method Weighted ($/MWh)	Sumas: Gas Market Method Weighted ($/MWh)	Sumas: Mid-C Weighted ($/MWh)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Jul-01	$ 42.19	$ 34.82	$ 32.03	$ 64.61		$ 40.36	$ 37.87	$ 32.06	$ 54.61
Aug-01	$ 42.19	$ 35.21	$ 32.46	$ 38.70		$ 40.86	$ 38.32	$ 32.51	$ 38.70
Sep-01	$ 42.19	$ 35.49	$ 26.63	$ 22.61		$ 41.22	$ 38.65	$ 26.39	$ 22.61
Oct-01	$ 42.19	$ 37.26	$ 31.11	$ 23.88		$ 43.52	$ 40.72	$ 31.30	$ 23.88
Nov-01	$ 42.19	$ 46.63	$ 30.17	$ 21.91		$ 58.12	$ 53.90	$ 31.12	$ 21.91
Dec-01	$ 42.19	$ 47.87	$ 32.62	$ 24.70		$ 69.77	$ 55.40	$ 33.21	$ 24.70
Jan-02	$ 43.47	$ 49.12	$ 30.25	$ 16.54		$ 61.37	$ 56.86	$ 30.67	$ 18.54
Feb-02	$ 43.47	$ 48.23	$ 30.61	$ 20.23		$ 60.14	$ 55.76	$ 30.84	$ 20.23
Mar-02	$ 43.47	$ 48.93	$ 36.03	$ 33.61		$ 58.42	$ 54.20	$ 36.44	$ 33.61
Apr-02	$ 43.47	$ 36.83	$ 33.99	$ 19.46		$ 41.88	$ 39.27	$ 38.39	$ 19.46
May-02	$ 43.47	$ 36.37	$ 32.72	$ 16.68		$ 41.31	$ 38.76	$ 34.63	$ 18.68
Jun-02	$ 43.47	$ 36.63	$ 28.78	$ 7.66		$ 41.67	$ 39.08	$ 30.45	$ 7.66
Jul-02	$ 43.47	$ 36.85	$ 25.61	$ 10.39		$ 41.88	$ 39.27	$ 25.46	$ 10.39
Aug-02	$ 43.47	$ 36.96	$ 29.11	$ 17.56		$ 42.03	$ 39.40	$ 30.65	$ 17.56
Sep-02	$ 43.47	$ 37.06	$ 31.68	$ 24.13		$ 42.17	$ 39.63	$ 35.65	$ 24.13
Oct-02	$ 43.47	$ 37.13	$ 38.76	$ 28.01		$ 42.24	$ 39.68	$ 39.68	$ 28.01
Nov-02	$ 43.47	$ 42.65	$ 39.81	$ 30.99		$ 49.57	$ 46.22	$ 41.24	$ 30.99
Dec-02	$ 43.47	$ 43.56	$ 42.27	$ 36.87		$ 50.73	$ 47.26	$ 44.98	$ 36.87
Jan-03	$ 43.02	$ 45.02	$ 45.02	$ 36.36		$ 50.32	$ 47.92	$ 47.92	$ 38.36
Feb-03	$ 43.02	$ 48.25	$ 55.43	$ 48.88		$ 49.31	$ 52.62	$ 59.63	$ 48.88
Mar-03	$ 43.02	$ 47.04	$ 52.84	$ 44.81		$ 48.09	$ 51.27	$ 54.68	$ 44.81
Apr-03	$ 43.02	$ 43.78	$ 45.66	$ 31.04		$ 44.86	$ 47.72	$ 47.84	$ 31.04
May-03	$ 43.02	$ 43.68	$ 50.40	$ 27.85		$ 44.71	$ 47.57	$ 49.72	$ 27.85
Jun-03	$ 43.02	$ 43.99	$ 50.14	$ 30.96		$ 45.07	$ 47.96	$ 49.39	$ 30.96
Jul-03	$ 43.02	$ 44.41	$ 46.70	$ 43.69		$ 45.60	$ 45.69	$ 45.69	$ 43.69
Aug-03	$ 43.02	$ 44.65	$ 47.78	$ 39.29		$ 45.72	$ 46.97	$ 46.97	$ 39.29
Sep-03	$ 43.02	$ 44.75	$ 48.05	$ 38.53		$ 45.86	$ 45.45	$ 45.45	$ 38.63
Oct-03	$ 43.02	$ 44.91	$ 45.60	$ 34.22		$ 46.01	$ 45.18	$ 45.18	$ 34.22
Nov-03	$ 43.02	$ 45.64	$ 45.64	$ 34.66		$ 47.08	$ 45.67	$ 45.67	$ 34.68
Dec-03	$ 43.02	$ 47.07	$ 53.68	$ 39.09		$ 48.24	$ 51.43	$ 53.87	$ 39.09
Jan-04	$ 42.22	$ 47.33	$ 55.22	$ 44.02		$ 47.98	$ 51.12	$ 55.20	$ 44.02
Feb-04	$ 42.22	$ 48.44	$ 49.91	$ 40.71		$ 47.04	$ 49.68	$ 49.68	$ 40.71
Mar-04	$ 42.22	$ 45.44	$ 49.74	$ 36.61		$ 46.04	$ 48.99	$ 49.26	$ 36.61
Apr-04	$ 42.22	$ 43.97	$ 51.64	$ 39.86		$ 44.53	$ 47.33	$ 50.96	$ 39.86
May-04	$ 42.22	$ 43.89	$ 54.11	$ 44.38		$ 44.45	$ 47.25	$ 53.43	$ 44.38
Jun-04	$ 42.22	$ 44.18	$ 53.28	$ 29.60		$ 44.74	$ 47.57	$ 52.80	$ 29.60
Total[1]	$ 1,544.48	$ 1,540.01	$ 1,481.21	$ 1,136.98		$ 1,692.81	$ 1,667.74	$ 1,507.30	$ 1,136.98
Percent reduction from traditional avoided cost	-	0.29%	4.10%	26.38%		-	1.48%	10.96%	32.84%

[1] Sum if one QF sold one aMW per month for every month in the three year period.

(1) Table 7, Columns (1) and (2) weighted 57% on-peak and 43% off-peak

(2) Table 7, Columns (3) and (4) weighted 57% on-peak and 43% off-peak

(3) Table 7, Columns (5) and (6) weighted 57% on-peak and 43% off-peak

(4) Table 7, Columns (7) and (8) weighted 57% on-peak and 43% off-peak

(5) Open

(6) Table 7a, Columns (9) and (10) weighted 57a% on-peak and 43% off-peak

(7) Table 7a, Columns (3) and (4) weighted 57a% on-peak and 43% off-peak

(8) Table 7a, Columns (5) and (6) weighted 57a% on-peak and 43% off-peak

(9) Table 7a, Columns (7) and (8) weighted 57a% on-peak and 43% off-peak

Table 9. Data for UM1129 Gas Index Analysis

Date	Sumas Forward Gas Curve ($/MMbtu)	ICE Sumas Weighted Monthly Average ($/MMbtu)	Opal Forward Gas Curve ($/MMbtu)	ICE Opal Weighted Monthly Average ($/MMbtu)	Stanfield Forward Gas Curve ($/MMbtu)	ICE Stanfield Weighted Monthly Average ($/MMbtu)	Mid-C Weighted Peak Price ($/MW)	Mid-C Weighted Off Peak Price ($/MW)	Pacificorp Avoided Firm Capacity Costs ($/kW-yr)	Pacificorp Capitalized Energy Costs ($/MWh)	Forward Sumas/Opal/ Stanfield Average ($/MMbtu)	Sumas/Opal/ Stanfield ICE Average ($/MMbtu)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Jul-01	$ 3.57	$ 2.38	$ 2.63	$ 2.36	$ 3.10	$ 2.43	$ 64.61	$ 41.36	$ 59.66	$ 3.89	$ 3.10	$ 2.39
Aug-01	3.64	2.44	2.68	2.42	3.16	2.49	45.38	29.84	59.68	3.89	3.16	2.45
Sep-01	3.69	1.66	2.72	1.63	3.20	1.60	24.37	20.28	59.66	3.89	3.20	1.60
Oct-01	4.01	2.26	2.94	2.06	3.48	2.42	25.81	21.31	59.66	3.89	3.48	2.25
Nov-01	6.04	2.17	3.80	1.87	4.92	2.16	23.46	19.85	59.66	3.89	4.92	2.07
Dec-01	6.27	2.46	3.95	2.24	5.11	2.49	26.83	21.87	59.66	3.89	5.11	2.40
Jan-02	6.45	2.05	4.06	1.97	5.26	2.07	19.69	17.14	60.85	3.96	5.26	2.03
Feb-02	6.28	2.08	3.96	2.02	5.12	2.15	20.85	19.41	60.85	3.96	5.12	2.08
Mar-02	6.04	2.89	3.80	2.71	4.92	3.00	35.49	31.12	60.85	3.96	4.92	2.87
Apr-02	3.74	2.95	2.99	1.89	3.36	3.02	22.21	15.61	60.85	3.96	3.36	2.62
May-02	3.66	2.70	2.93	1.79	3.29	2.83	21.55	14.87	60.85	3.96	3.29	2.44
Jun-02	3.71	2.10	2.96	1.28	3.33	2.26	10.30	4.16	60.85	3.96	3.33	1.88
Jul-02	3.74	1.39	2.99	1.35	3.37	1.63	11.87	8.44	60.85	3.96	3.37	1.42
Aug-02	3.76	2.16	3.01	1.37	3.38	2.23	16.36	16.49	60.85	3.96	3.38	1.92
Sep-02	3.78	2.63	3.02	1.09	3.40	2.90	25.18	22.73	60.85	3.96	3.40	2.27
Oct-02	3.79	3.42	3.03	2.05	3.41	3.67	30.62	24.68	60.85	3.96	3.41	3.02
Nov-02	4.81	3.62	3.71	3.03	4.26	3.84	32.08	29.54	60.85	3.96	4.26	3.43
Dec-02	4.97	4.15	3.83	3.13	4.40	4.05	40.13	32.65	60.85	3.96	4.40	3.78
Jan-03	4.87	4.53	3.73	3.13	4.30	4.72	38.89	33.01	62.07	4.04	4.30	4.13
Feb-03	4.73	6.21	3.62	4.65	4.18	6.01	52.11	44.60	62.07	4.04	4.18	5.62
Mar-03	4.56	5.60	3.49	4.41	4.02	5.85	40.35	42.77	62.07	4.04	4.02	5.26
Apr-03	4.11	4.64	3.11	3.47	3.61	4.72	32.20	29.60	62.07	4.04	3.61	4.24
May-03	4.09	4.81	3.10	4.84	3.60	5.11	33.01	21.01	62.07	4.04	3.60	4.92
Jun-03	4.14	4.76	3.13	4.68	3.64	5.01	36.52	23.58	62.07	4.04	3.84	4.88
Jul-03	4.20	4.26	3.18	4.43	3.69	4.47	47.06	38.99	62.07	4.04	3.69	4.39
Aug-03	4.23	4.41	3.21	4.62	3.72	4.59	41.90	35.84	62.07	4.04	3.72	4.54
Sep-03	4.25	4.19	3.22	4.32	3.73	4.37	42.68	33.02	62.07	4.04	3.73	4.29
Oct-03	4.27	4.15	3.24	4.26	3.75	4.27	37.45	29.93	62.07	4.04	3.75	4.23
Nov-03	4.42	4.22	3.35	4.22	3.89	4.26	37.05	31.60	62.07	4.04	3.89	4.23
Dec-03	4.56	5.39	3.47	5.43	4.03	5.31	40.79	36.84	62.07	4.04	4.03	5.38
Jan-04	4.60	5.54	3.54	5.51	4.02	5.61	46.33	40.96	63.31	4.12	4.92	5.55
Feb-04	4.37	4.75	3.44	4.83	3.91	4.61	41.84	39.21	63.31	4.12	3.91	4.60
Mar-04	4.23	4.69	3.33	4.60	3.78	4.63	38.63	33.91	63.31	4.12	3.78	4.77
Apr-04	4.02	4.94	3.17	5.07	3.59	5.15	42.48	30.38	63.31	4.12	3.59	6.05
May-04	4.01	5.30	3.16	5.40	3.58	5.52	48.13	39.42	63.31	4.12	3.58	5.41
Jun-04	4.05	5.20	3.19	6.30	3.62	5.35	31.05	27.68	63.31	4.12	3.62	5.29

(1) Pacificorp UM1129 Filing Exhibit C, CG05312001PowerCurveSuMMary.xls
(2) Calculated from http://www.theice.com
(3) Pacificorp UM1129 Filing Exhibit C, CG05312001PowerCurveSuMMary.xls
(4) Calculated from http://www.theice.com
(5) Pacificorp UM1129 Filing Exhibit C, CG05312001PowerCurveSuMMary.xls
(6) Calculated from http://www.theice.com
(7) Calculated from Dow Jones Index
(8) Calculated from Dow Jones Index
(9) Pacificorp UM1129 Filing Exhibit C, Table 2
(10) Pacificorp UM1129 Filing Exhibit C, Table 3
(11) Average of (1) (3) (5)
(12) Average of (2) (4) (6)

Table 10. Sumas, Opal, Stanfield, and SOSA Averages, Standard Deviations, and Coefficients of Variation

Hub	Average	Standard Deviation	Coefficient of Variation
	(1)	(2)	(3)
			(2) / (1)
Sumas	$ 3.71	0.58	0.16
Opal	$ 3.45	0.28	0.08
Stanfield	$ 3.67	0.35	0.09
SOSA	$ 3.61	0.36	0.10

(1) Calculated average of forecast values from PacifiCorp's UM1129 filing, Exhibit C
(2) Standard deviation of forecast values from PacifiCorp's UM1129 filing, Exhibit C
(3) (3) = (2)/(1)

CASE: UM 1129
WITNESS: Steve Chriss

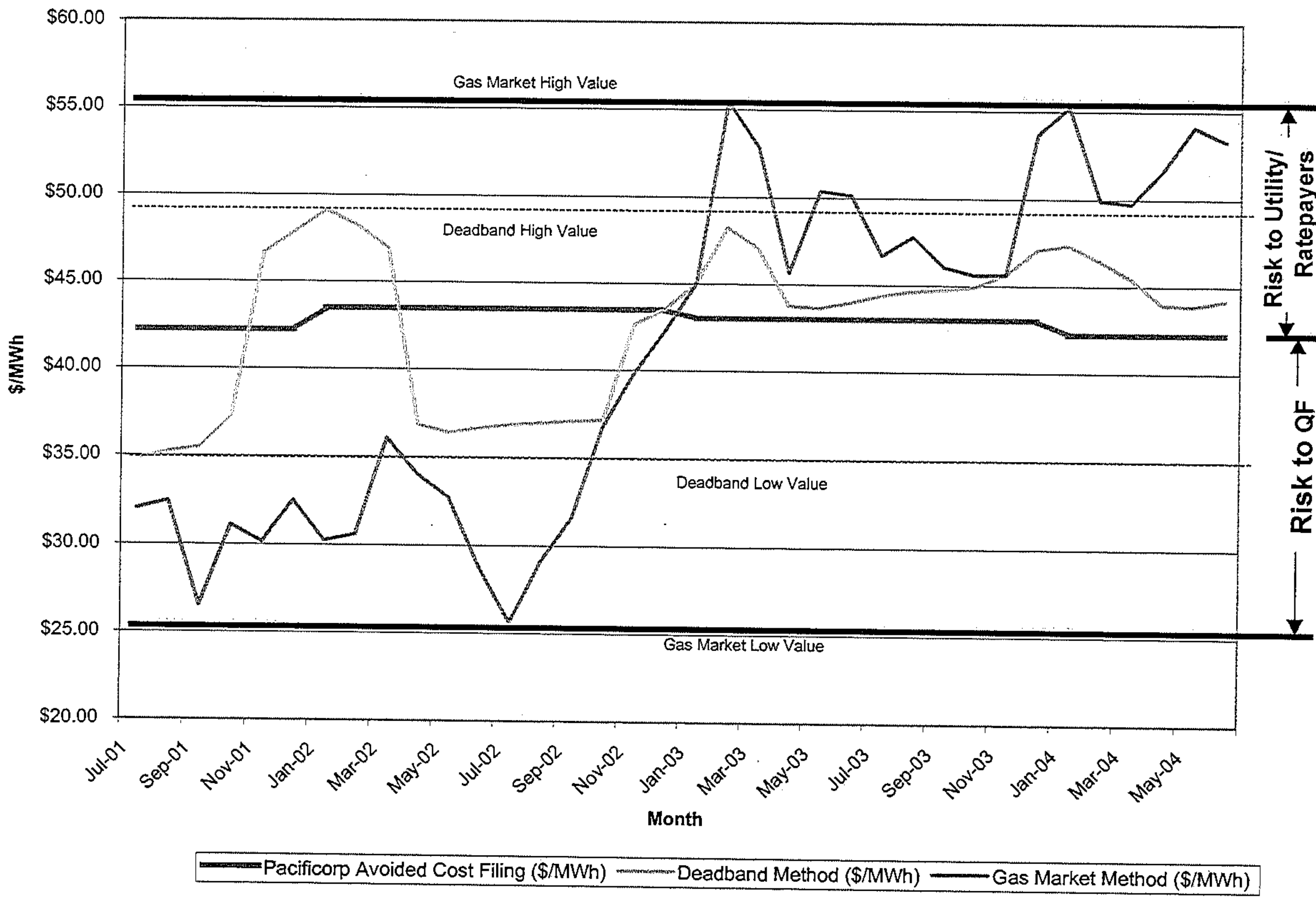
PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 303

Exhibit in Support of
Direct Testimony

August 3, 2004

Comparison of On-Peak/Off-Peak Weighted Prices (SOSA)



Staff/303
Chriss/1

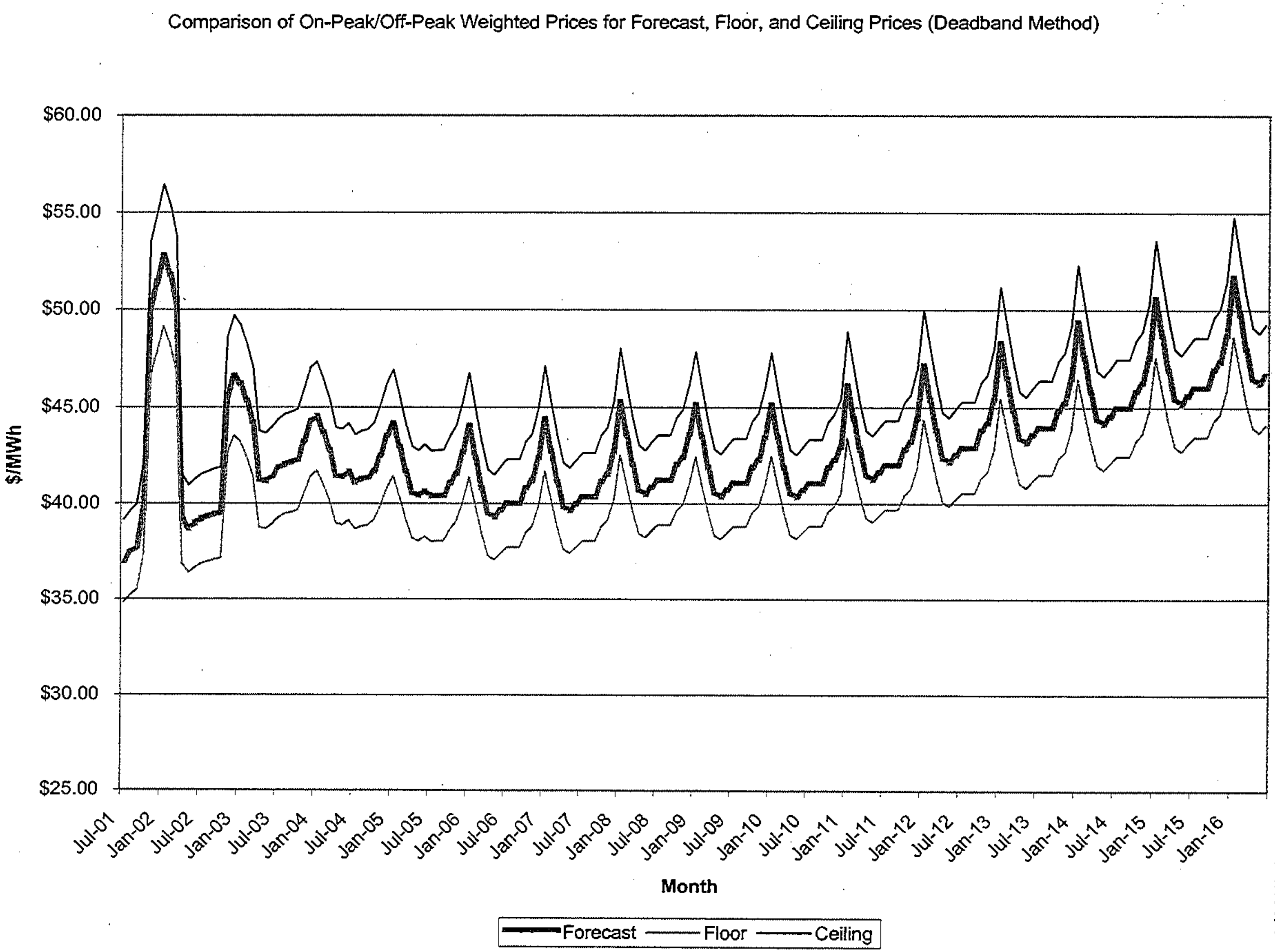
CASE: UM 1129
WITNESS: Steve Chriss

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 304

Exhibit in Support of Direct Testimony

August 3, 2004



Staff/304
Chriss/1

CASE: UM 1129
WITNESS: Steve Chriss

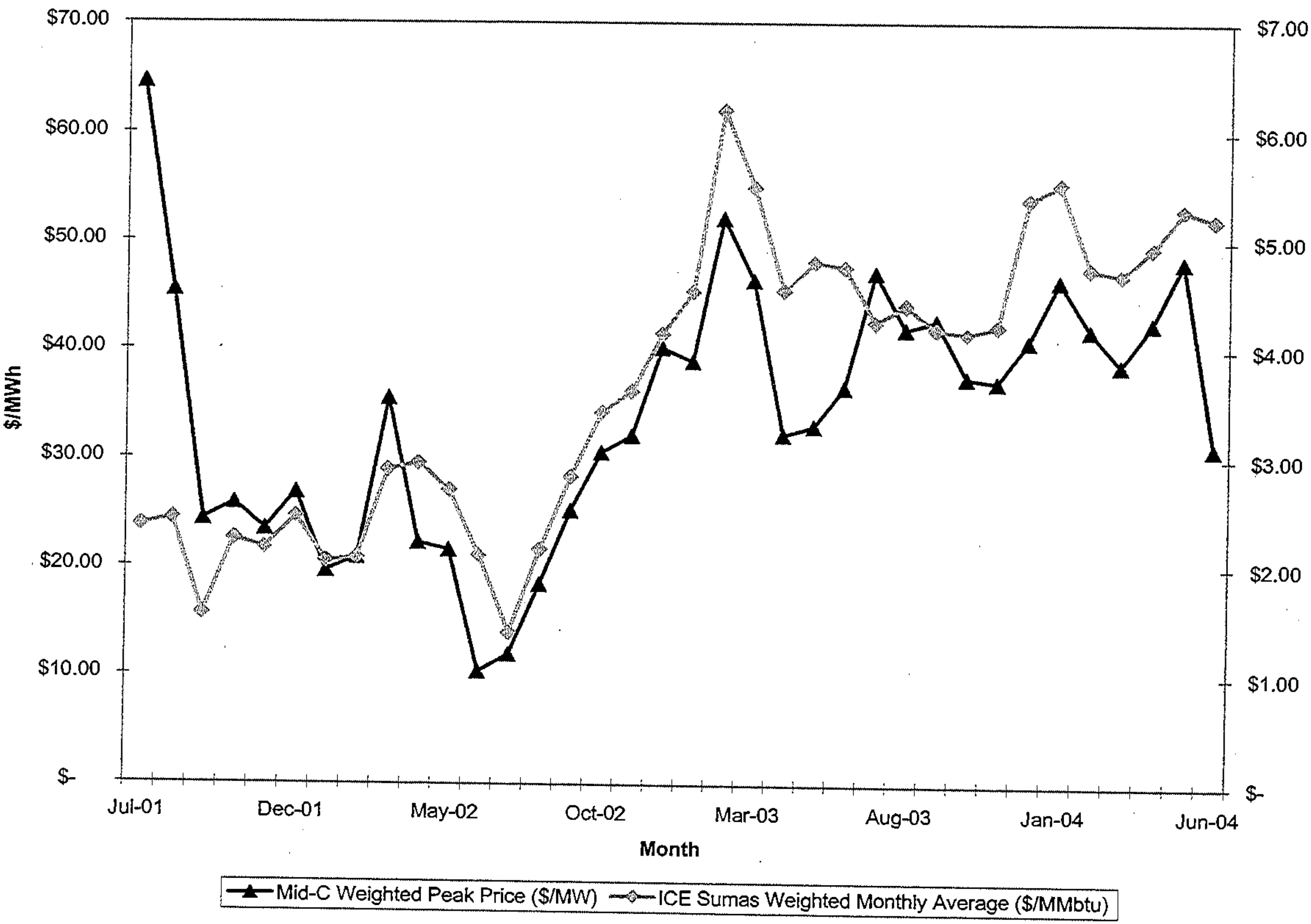
PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 305

Exhibit in Support of Direct Testimony

August 3, 2004

Comparison of Weighted Mid-C Peak Price ($/MWh) and ICE Sumas Weighted Monthly Average Price ($/MMbtu)



Staff/305
Chriss/1

CASE: UM 1129
WITNESS: Thomas Morgan

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 400

Direct Testimony

August 3, 2004

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

A. My name is Thomas Morgan. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97310-1380. I am employed by the Public Utility Commission of Oregon as the Senior Financial Economist.

Q. HAVE YOU PREPARED AN EXHIBIT?

A. Yes, I prepared Staff/401, consisting of one page, my Witness Qualifications Statement.

Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I address an aspect of the first issue, Contract Length, pertaining to financing of projects. I also address one aspect of the third issue, Utility Tariff Content, pertaining to credit requirements utilities should be allowed to impose on small QFs that are eligible for a standard form of contract.

Required Contract Length and Internal Financing

Q. PLEASE DISCUSS THE IMPACT OF CONTRACT LENGTH AND THE FINANCIAL FEASIBILITY OF QF PROJECTS.

A. First of all, larger companies, including a potential QF, generally have access to the capital markets for most internal uses. Because a company with a strong credit profile can provide a "backstop" on a loan that might be provided to a subsidiary or affiliate for QF development, any specific energy project may not be required as collateral for the loan. In these situations, the large company's overall credit quality provides support for the loan to the subsidiary/affiliate.

As I will explain next, regardless of the project financing sources (i.e., financing from funds from operations, or external sources such as debt), the length of a Power Purchase Agreement (PPA) is important and could affect the decision to undertake development.

Q. IF A COMPANY CAN GENERATE SUFFICIENT PROFITS TO INTERNALLY FUND A PROJECT OR TO OBTAIN ITS OWN FINANCING SOURCES, COULD SHORT CONTRACT TERMS (I.E., FIVE YEARS OR LESS) LIMIT DEVELOPMENT OF A QF PROJECT?

A. It depends. A company undertaking a project would look at the expected returns generated over the entire economic life of the project. Because the financing decision is a result of the overall expected return, the term of the contract, by itself, is only material to the extent that the developing company's management may be risk averse.

An important question is whether the QF project will have commercial viability after the termination of the power contract with the utility. For example, at the end of an initial five-year contract term, the company would then be required to decide whether to contract for another term with the utility, sell on the wholesale market, or whether increased load could absorb the additional capacity.

Relatively short-term contracts (i.e., five years or less) introduce the risk of whether PURPA would still provide a mechanism for contractual requirements with utilities for renewal upon termination of the initial contract. Based on the history of these contracts, it appears that the initial investment decision may require longer-term certainty. It could be argued that the riskiness of the investment decision then is contingent on risk tolerance.

Some companies may be averse to a five-year contract commitment simply because, for example, they do not have the proper level of sophistication to sell their power in the wholesale market or do not foresee the need at their facility for additional power that the QF could produce at that later date. Other potential producers may simply desire long-term cash flow that is more certain.

Because of the uncertainty under a short-term contractual regime, it is likely that some potential large firms would not enter the QF market.

Q. SO YOU ARE SAYING THE IMPACT ON THE FEASIBILITY OF A QF PROJECT MAY DEPEND ON THE SIZE OF THE COMPANY?

A. Yes, it is likely that affirmative decisions to enter the QF market under a short-term contract scenario are sensitive to firm size. The main limitation on smaller firms is their relatively limited access to internal capital. Accessing sufficient profits to support a large investment may be difficult for smaller firms. There would also be limitations on accessing the commercial loan market for these firms. The Oregon Department of Energy's (ODOE) loan program may be the only resource available to provide funding for the resource developer. Small companies could be left out of the marketplace because, according to ODOE staff, its loan program will not finance a project longer than the life of the contract and it is unlikely that an entire project could be fully paid-off within, for example, a five-year term.

Large firms might be expected to have access to sufficient capital and/or have the credit quality to provide a guarantee from the revenues that are unrelated to the energy project. Therefore, 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.

Q. CAN FIVE-YEAR QF CONTRACTS BE PROFITABLE?

A. Yes. There is no question that short-term QF contracts can be profitable. The issue is whether the long-term risks that I have identified would outweigh potential short-term profits. As I have indicated, whether a project is financially feasible is a result of the long-term expectations regarding the shape and timing of the cash flows.

Even if we assume a project is funded with external financing, with the expectation that the entire project would be paid-off over a five-year period, it is highly likely that there would be short-term capital commitments required to fund shortfalls in cash flow available to pay the debt service. A company would have to be willing and able to provide those cash infusions as may be anticipated in the earlier years.

Credit Requirements

Q. WHAT IS THE PURPOSE OF UTILITY SECURITY REQUIREMENTS FOR POWER PURCHASE AGREEMENTS WITH QFS?

A. One reason utilities require security for QFs is to guard against their concern that a QF's generation may fall below the contract capacity or guaranteed output due to construction delays, weather-related reductions in resource availability (a poor water year, for example), operating problems, mismanagement or bankruptcy. The companies argue that this could harm the utility and ratepayers if they caused the utility to buy replacement power at a higher price.

However, this concern is mitigated for the following reasons. First, it is difficult for small projects to sell on the market, especially on a spot basis. Second, the project owner has every incentive to maintain generation levels in order to earn maximum revenue and service project debt.

Q. PLEASE SUMMARIZE THE ISSUE.

A. The credit issue revolves around the matter of risk mitigation tactics that may be used in the standard contractual relationship between the utilities and small QFs. Although specific requirements vary by utility, generally, the contracting utilities desire that not only should a QF entity provide financial security to ensure timely completion of project construction, but that there also be a requirement for a letter of credit or escrow deposit as default security for operational risk.

Finally, there is an issue surrounding the cause for reduced production by weather-related resources. Should a contract clause allow these actions to trigger a "default event"?[1] For example, output from a QF may be reduced because of weather-related reductions in wind, streamflows, or other motive energy forces.

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. If the Commission's goal is to support and encourage entrants into the QF market, my review supports staff's determination that the standard form PPA for small QFs, which are eligible for standard rates, should include risk management provisions that provide more flexibility than some utilities presently allow. It is clear that some of the current contract provisions discourage entry by some QF entities, especially smaller firms. I recommend the Commission authorize such contracts to have terms consistent with the following:

- A contracting utility may require a performance bond to ensure timely completion of project construction. A utility should not require a letter of credit or escrow deposit.

  I recommend this position because a performance bond would provide similar protection to the utility and ratepayers as a letter of credit or escrow deposit, at a more affordable cost to small QFs.

- A contracting utility should not require a letter of credit or escrow deposit as default security for operational risk.

[1] A default event would be any occurrence conflicting with the contractual obligations between the parties.

I recommend this position because small QFs do not have funds available to meet a requirement for a large default security deposit, and there are other reasonable alternatives for providing default security that will allow development of QF projects.

- Weather-related reductions in resource availability should not trigger default events.

I recommend this position because if the cause of the generator's reduced output (e.g., a poor weather year) is beyond the QF's control, such a default trigger could put the project into bankruptcy. The situation would be even worse should a utility seek reimbursement and funding for the default security (escrow) account at a time when QF revenues were lowest.

Q. WHAT TYPES OF SECURITY DO THE UTILITIES CURRENTLY REQUIRE IN POWER PURCHASE AGREEMENTS FOR QFS?

A. The security requirements take two forms. The first is "project development security," which is a monetary amount that is required during project development and construction. This is designed to provide funds that the utility can draw from if there is a delay in commercial operation.

For example, for projects over 1 MW, PacifiCorp requires the QF to deposit funds into an escrow account. The amount was not clearly specified in the company's generic PPA for QFs over 1 MW provided in the informational filing in this proceeding. However, the company's PPA that accompanied its recent RFP for renewable resources specified an amount equal to two years' worth of expected energy multiplied by the price per MWh specified in the first contract year.

The second form is a "default security" that would provide some reimbursement upon certain events that would trigger a default once a facility is operational. The PPA typically sets a flat capacity output, or an annual energy output for intermittent renewable resources, as the threshold before the utility can tap default security. Weather events can trigger default provisions.

Q. WHAT ARE THE AVAILABLE ALTERNATIVES THAT WOULD PROVIDE NECESSARY SECURITY OR SUPPORT?

A. One option to meet the utility's default security requirements is to maintain a senior unsecured debt rating at a specified level. For example, for contracts over 1 MW, PacifiCorp requires a rating of BBB or better from Standard & Poor's in lieu of posting default security. A QF's credit rating may be linked to the counterparty risk, depending on the concentration of the QF's transactions with that counter-party.

In lieu of a satisfactory credit rating, QFs may meet default security requirements in other ways, including:

- Letters of credit, which allow the utility to draw up to the face amount for the purpose of paying amounts that the QF owes under the PPA.
- Cash escrows, which provide a "reserve" for the utility to secure payment and performance of the QF's obligation under the PPA. Escrows may be established on a general basis or maintained on a

margining basis. For example, margining on the basis of forward market prices for power requires an ongoing assessment of the difference between those prices and the contract price. If market prices spike, the required security could change significantly.

Q. COULD YOU PROVIDE DETAILS ON THE DYNAMICS OF THE ISSUES YOU JUST DESCRIBED?

A. Yes. The required default security for PacifiCorp's generic PPA for QFs 1 MW and less is five times the seller's projected average monthly gross sales under the contract. As I have already noted in my testimony, the required default security amount is unspecified in the company's generic PPA for QFs greater than 1 MW.

However, in the generic PPA that accompanied PacifiCorp's RFP for renewable resources, the company required an amount equal to the *positive* difference between 1) the contract purchase price and 2) 110 percent of the forward power prices at the appropriate market hub for the next 18 months, multiplied by the estimated monthly outputs under the contract. I will provide a specific example of the pricing impact on a QF later in my testimony.

In response to staff Data Request 7, Idaho Power states that it does not have a standard contract for purchasing energy from QFs, but that it would likely use as a starting point for QF negotiations the pro forma Firm Energy Sales Agreement the company currently offers QFs in Idaho. The Idaho Public Utilities Commission is addressing objections by several QFs to a number of provisions in that agreement. Among them is the "Shortfall Energy" provision, which requires that QFs pay Idaho Power the difference between the contract price and 85 percent of the mid-Columbia index rate – if higher – for any shortfall in monthly energy deliveries below 90 percent of scheduled monthly power deliveries. The contract that Idaho Power sent in response to staff Data Request 7 caps the Shortfall Energy price at 150 percent of the Base Energy Purchase Price.

PGE's "representative" power purchase agreement for standard QF purchase rates states: "Performance Assurance to mitigate risks is to be supplied by the Customer prior to execution in form and manner acceptable to PGE...pursuant to the Term Sheet," but does not make transparent the type of security that must be provided.

Q. WHAT ARE THE LIMITATIONS OF THESE SECURITY REQUIREMENTS?

A. I will provide examples of the problems that have been identified with each of the provisions that I have addressed.

- Most small QFs would have limited available funds they could use for a cash escrow. It could be difficult for small QFs to meet a large security requirement, particularly one that can change dramatically over time, as would occur when security is tied to forward market prices for power.
- To the extent that smaller QFs require external financing, it is highly likely that covenants that are onerous would preclude access to necessary funds. The Oregon Department of Energy loan program may be the only

funding source for smaller QFs and it has indicated that it would not provide loans with inflexible contractual requirements.

- Smaller companies and startup ventures may not be rated by the major credit rating agencies. QFs could incur significant costs to acquire a rating, if it could be acquired at all. It may be difficult for QF developers that are not a subsidiary of a financially secure parent to obtain such a rating.
- Regarding the relationship between the contracting parties and the potential linkage in ratings, any reduction in the utility's rating could affect the QF, especially if it owns only a single project that is contracted to that utility. This association could unfairly impact the QF by requiring increased credit support to the benefit of the utility's *own* credit outlook.
- Regarding the alternative of having the QFs provide letters of credit, the limitation is that letters of credit are generally not available for small companies or startup ventures. These instruments require banking support that is generally not accessible to smaller entities, absent their being a subsidiary or affiliate of a larger company.
- Regarding the margining issue, the volatility of market prices would require a QF to increase its security within a contractually-specified time period. The QF presumably would have the right to the return of the cash collateral upon a drop in forward prices (i.e., the market price in the future), although this result is not clear. Further, there is not a symmetrical relationship pertaining to this clause. If the market price fell

far below the contract price, the utility would not be required to deposit a "balancing escrow."

Q. COULD THE UTILITIES' SECURITY REQUIREMENTS HAMPER DEVELOPMENT OF QFS?

A. Yes. For example, the developer of the 5 MW Arlington wind project planned for PacifiCorp's service area states that for a 15-year (non-PURPA) contract, the utility requires project development security in the amount of $961,902, calculated as the value of two years' worth of expected output. That represents 13 percent of the estimated installed cost of the project.

While meeting security requirements is most difficult for small QF projects, the requirements also are a major concern for larger QFs. Wind and geothermal developers participating in PacifiCorp's recent RFP for renewable resources raised concerns that credit requirements in the generic PPA, included with the solicitation, were "extremely expensive" and would be difficult for small developers to meet.[2] Jeff Keto, credit manager for the State Energy Loan Program, provided information on 15 QF projects that have applied for, or inquired about, financing. Most of these are on hold at least in part pending acceptable terms and conditions for PPAs with the regulated utilities. Mr. Keto indicates that the developers' funds would be tied up in meeting project equity and working capital needs and would have difficulty meeting the requirements of large default security deposits.

Q. WHAT SECURITY PROVISIONS MIGHT BE RECOMMENDED TO UTILITIES FOR SMALL QFS THAT ARE ELIGIBLE FOR A STANDARD POWER PURCHASE AGREEMENT?

A. Absent a determination of significant potential harm to a utility, it is difficult to make an assessment. However, to ensure timely completion of construction, I recommend that utilities require a performance bond[3] in lieu of a letter of credit or escrow deposit. Performance bonds are commonly used in the construction industry for a similar purpose, and would provide similar protection to the utility and ratepayers as a letter of credit or escrow deposit, at a more affordable cost to small QFs.

I further recommend that a letter of credit or escrow deposit not be required as default security for operational risk. Instead, to address the risk that generation might fall below the contract capacity or guaranteed output, the PPA could specify, for example, that in the event market prices during the default period exceed the contract price, future payments to the QF under the contract will be reduced over a reasonable time period.

Q. COULD YOU PROVIDE AN EXAMPLE THAT WOULD ILLUSTRATE THE IMPACT OF THE ALTERNATIVE YOU ARE PROPOSING?

A. Yes. The impact of adopting this alternative can be addressed in the following example. If there were a 10 percent penalty for non-performance, and a contract price set at $40 per MWh, payments would

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[2] To be eligible for the renewable resources solicitation, projects had to be capable of delivering at least 70,000 MWh per year. For wind plants, that's a facility with a capacity of about 24 MW.
[3] Sometimes called a "construction bond." This is a bond issued at the request of one party to a contract in favor of the other party to the contract to protect the other party against loss in the event of default on the contract by the requesting party. The bonding agent may undertake to fulfill the contract or may simply

be reduced to $36 per MWh for some period of time. Thus, the project pays only if it is in default; a large up-front deposit would not be required.

Q. WHAT ARE YOUR RECOMMENDATIONS ON THE ISSUE OF WEATHER-RELATED PRODUCTION SHORTFALL?

A. Relating to power producers that have projects that require natural motive force for generation, I recommend that default provisions not relate to, or be triggered by, weather-related reductions in resource availability. A poor weather year could put a project into bankruptcy, because the utility would be seeking reimbursement and additional funding of the default security escrow account at a time when QF revenues are lowest. This could effectively limit the ability of the QF to procure financing for its project.

If QFs receive levelized avoided cost rates, staff recognizes the need for default security requirements in addition to reducing future payments under the contract for a period of time, as described above. That is because ratepayers would bear the risk of overpaying the QF in the early years if the facility goes bankrupt. In that case, the utility should require one of the following default security measures: credit rating requirements, a senior lien on the facility, step-in rights, a cash escrow or letter of credit. QFs eligible for a standard contract should be able to *choose* among these types of default security. A large industrial customer may have the appropriate credit rating, or be able to obtain a letter of credit, whereas a small QF developer may not.

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undertake to pay a specific amount in monetary damages. A standby letter of credit or demand guarantee is often used as a performance bond with the latter characteristics. *From* www.maxtrad.com/glossary.html

Q. DOES THE QF HAVE THE SAME LEVEL OF PROTECTIONS AS A PUBLIC UTILITY?

A. No. If we assume that contract prices are fixed, any increases in QF costs that were not properly predicted would shift to the shareholders of the QF. Because a QF does not have the opportunity to initiate a re-pricing of the contract, similar to if a public utility were to initiate a rate case, it would be at potentially greater risk.

A risk of long-term contracts is fluctuating wholesale market prices and technological improvements in electrical generation. A contract may be "in the money" or "out of the money," meaning that it has an intrinsic market value due to market movements over time. One risk that the public utility company may bear is the risk that a project no longer generates the capacity that was contracted in a time of increasing prices. In that event, the public utility would likely be exposed to the market and could incur additional expenses. The potential additional costs could be eventually shifted to ratepayers.

Alternatively, from the QF's standpoint, the generating project would be defunct if it is out of the money – for example, if a natural-gas cogeneration facility is exposed to fuel prices far in excess of forecasts. In that event, the QF would not have benefited from the same type of protections that a public utility might have, such as a rate case, annual net variable power cost mechanism, or some other type of adjustment.

Q. ARE THE ALTERNATIVE SECURITY REQUIREMENTS YOU RECOMMEND FOR SMALL QFS REASONABLE, GIVEN THE LEVEL

OF RISK EXPOSURE AGAINST WHICH THE UTILITIES ARE INSULATED BY EMPLOYING VARIOUS ADJUSTMENT MECHANISMS?

A. Yes. Among the regulatory tools that utilities have available to them in the event that output from their plants is less than expected are general rate cases, the Resource Valuation Mechanism, deferred accounting and automatic adjustment clauses. These mechanisms provide a way for utilities to reduce their cost recovery risk, and ratepayers are exposed to that volatility. QFs should not be required to bear operational risk to a greater extent than the utilities and their stockholders do.

My recommendations would not discriminate among potential market participants based on their size or access to capital markets and would balance ratepayers' interests with the interest of the public overall as envisioned in federal PURPA.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

CASE: UM 1129
WITNESS: Thomas Morgan

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 401

Witness Qualification Statement

August 3, 2004

WITNESS QUALIFICATIONS STATEMENT

NAME: Thomas D. Morgan

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Financial Economist, Economic & Policy Analysis

ADDRESS: 550 Capitol St NE Suite 215, Salem, Oregon 97301-2551.

EDUCATION: Master of Finance (MSc), in progress, University of Leicester, United Kingdom.

Bachelor of Science in Business Administration, Finance; 1993, University of Oregon, *summa cum laude*.

RELEVANT WORK EXPERIENCE: Since August 2001, I have been employed by the Public Utility Commission of Oregon as the financial analyst in the Economic Research & Financial/Policy Analysis Division. My current responsibilities include conducting research and providing technical support for cost of equity issues for electric, telecommunications, and gas utilities. I also provide support relating to utility property transactions, financial auditing activities, and financially-related affiliate interest matters.

From 1997 to 2001, I worked for the Oregon Department of Revenue as a Senior Appraiser Analyst in the Valuation Section of the Property Tax Division. Duties included appraising public utility (e.g., gas, electric and telecommunication companies) and transportation properties (e.g., railroad and airline companies.) The valuation process included developing cost of capital studies for use in the Income Capitalization Approach to valuation.

I have provided professional services as a commercial property appraiser, performed valuations on properties such as apartments, shopping centers, office buildings and industrial properties including machinery and equipment.

PROFESSIONAL CREDENTIALS: State of Oregon Certified Commercial Appraiser