Oregon

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April 7, 2006

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

Enclosed for electronic filing in the above-captioned docket is the Public Utility Commission Staff's Rebuttal Testimony.

/s/ Kay Barnes

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PUBLIC UTILITY COMMISSION OF OREGON

UM 1129 - PHASE II

STAFF REBUTTAL TESTIMONY OF

Lisa Schwartz
Steve W. Chriss
Thomas D. Morgan
Michael Dougherty

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

April 7, 2006

CASE: UM 1129 – Phase II
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2300

Rebuttal Testimony

April 7, 2006

Q. PLEASE STATE YOUR NAME.

A. My name is Lisa Schwartz.

Q. ARE YOU THE SAME LISA SCHWARTZ THAT FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. DID YOU PREPARE AN EXHIBIT?

A. Yes. I prepared Staff/2301, which consists of 11 pages of responses to selected data requests.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. First, Staff notes its support of the settlement of issues 1a, 5b, 8 and 9. PacifiCorp is filing on behalf of parties a stipulated settlement on these issues.

Second, I provide rebuttal testimony on the following issues:

<u>Issue 1d</u>: Negotiation parameters for non-standard contracts

<u>Issue 3</u>: Firm vs. non-firm commitments; integration costs

<u>Issue 11</u>: Competitive bidding for Qualifying Facilities (QFs) over 100 MW

Third, Staff requests Commission clarification on a statement in the Commission's Order No. 05-584 (at 28).

Q. PLEASE START WITH YOUR THIRD AREA. PLEASE IDENTIFY THE STATEMENT FROM ORDER NO. 05-584 THAT YOU ASK THE COMMISSION TO CORRECT.

A. I would like the Commission to correct the following passage from Order No. 05-584:

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

Q. WHAT IS THE CORRECTION YOU WOULD LIKE THE COMMISSION TO MAKE TO THIS PASSAGE?

A. Staff believes that the Commission intended the last sentence to state:

> In such situations, utilities should use the methodology that has historically been used when utilities are in a resource *sufficient* position. [Emphasis added]

In other words, the QF receives the off-peak (energy only) rate for excess energy deliveries.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE ORDER IS INCORRECT IN THIS RESPECT.

A. Historically, for the utility's resource sufficiency (not deficiency) period, the Commission approved compensating the QF for energy only and not capacity. *See* Staff/100; Breen/16-17 (filed in the original UM 1129 proceeding). Given that, and the context of the statement in the order, I believe the Commission intended to state that excess energy — the energy deliveries over the nameplate rating — will be compensated with energy-only payments (no capacity payments).

Such a clarification, however, raises issues related to off-system contracts. Staff stands by its previous testimony (Staff/1000, Schwartz/68-69 — filed in the Phase I Compliance part of UM 1129; Staff/2200, Brown/5-8 — filed in Phase II of UM 1129) recommending payment of on-peak avoided cost rates during on-peak hours for deliveries above the nameplate rating solely for the purpose of accommodating hourly scheduling in whole megawatts by a third-party transmission provider. Therefore, we recommend the Commission further clarify that “excess energy” does not apply to such a situation.

Staff understands that PacifiCorp, Oregon Department of Energy, Sherman County/Simplot and Middle Fork Irrigation District agree with these clarifications. Staff has not heard objections by any party.

Further, Staff assumes that by "pursuant to the appropriate methodology" the Commission was referring to the methodologies spelled out in previous paragraphs for calculating avoided costs during both the sufficiency and deficiency periods. Thus, it appears to Staff that the Commission intended the utilities would pay off-peak prices for "excess energy" regardless of the utility's resource position. In other words, rates for excess energy would be based on approved off-peak rates in the utilities’ QF tariffs. During the period of resource sufficiency, those rates are based on monthly off-peak forward market prices.

During the period of resource deficiency, those rates are based on the energy costs of the utility proxy plant, exclusive of capacity costs.

ISSUE 1d: NEGOTIATION PARAMETERS FOR NON-STANDARD CONTRACTS

Q. DO YOU AGREE WITH PACIFICORP'S PROPOSED METHODOLOGY FOR ADJUSTING AVOIDED COST RATES FOR LARGE QFS FOR DISPATCHABILITY, RELIABILITY AND AVAILABILITY (PPL/404, GRISWOLD/6)?

A. Yes, in part. PacifiCorp proposes to modify avoided cost rates for these factors in a single adjustment by reducing capacity payments for the month if the QF's on-peak capacity factor, or "availability," is less than the availability of the proxy utility plant that serves as the basis for avoided cost rates. The on-peak capacity factor of PacifiCorp's proxy plant is 84.2%. *See* PacifiCorp Advice No. 05-06 work papers, Table 8.

Although PacifiCorp states that "the capacity contribution to avoided cost for the QF would be reduced on a linear basis as compared to the proxy," the Company actually is recommending a binary adjustment when it further states: "Below an availability level of 85%, the QF would receive no capacity contribution in its on-peak price and receive only off-peak prices for all energy delivered that month." *See* PacifiCorp's responses to ICNU Data Requests 11.4-11.5; Staff/2301, Schwartz/1-2.

In other words, the QF would receive 100% of the avoided capacity costs that are included in standard on-peak rates if the QF's average availability during the month is at or above 85%, and only the off-peak rate for all energy deliveries that month at any level below that. Availability is based on energy deliveries during prescheduled heavy-load hours.

Staff disagrees that the QF provides no capacity value if its availability is less than 85%. PacifiCorp's proposal also fails to recognize the difference in QF value based on its degree of availability – for example, between a QF with an on-peak capacity factor of 20% vs. one at 80%. Further, the proposal does not adjust for the additional value of a QF with a higher availability than the proxy unit.

In the unlikely case a QF delivers only during off-peak hours, the QF's on-peak capacity factor is zero and it should receive only off-peak energy rates. Using PacifiCorp's proxy plant as an example, at 84.2% availability, the on-peak capacity factor of the utility proxy plant, the QF should receive 100% of the avoided capacity cost. If the Commission approves this method for adjusting avoided costs for availability during on-peak periods, the utilities should develop a sliding scale model to calculate adjustments to capacity payments for actual monthly QF performance between these availability levels.

Q. DO YOU AGREE WITH WEYERHAEUSER-ICNU WITNESS MR. BEACH THAT A LARGE QF'S CAPACITY PAYMENTS SHOULD BE REDUCED PROPORTIONATELY TO THE EXTENT ITS CAPACITY FACTOR FALLS BELOW ITS CONTRACTED CAPACITY LEVEL (WEYERHAEUSER-ICNU/300, BEACH/12-13)?

A. No. The adjustment to standard avoided costs for availability should not be based on the QF's contracted capacity level. The adjustment should be made relative to the on-peak capacity factor of the utility proxy plant, as PacifiCorp recommends. This is consistent with Order No. 05-584 (at 27), which bases avoided cost calculations during the resource deficiency period on the costs of the utility proxy plant. The costs of the plant are based in part on its on-peak capacity factor, or availability.

Q. MR. BEACH ALSO RECOMMENDS THAT A QF'S CAPACITY BE DE-RATED IF IT FALLS BELOW THE CONTRACTED LEVEL UNTIL THE QF CAN DEMONSTRATE ITS ABILITY TO PROVIDE A HIGHER LEVEL OF CAPACITY (WEYERHAEUSER-ICNU/300, BEACH/12-13). DO YOU AGREE?

A. This provision is not necessary if the utility adjusts payments for avoided capacity costs each month based on actual QF performance (on-peak capacity factor) relative to the utility proxy plant. However, if capacity payments instead are fixed (in dollars per kW-year), de-rating the QF's contract capacity is a reasonable alternative to termination due to QF non-performance. If market prices during the non-performance period are higher than the QF contract price, and reduced payments to the QF for reduced availability do not keep the utility whole, damages may be appropriate for failure to meet the contracted capacity level.

Q. DO YOU AGREE WITH WEYERHAEUSER-ICNU WITNESS MR. BEACH THAT LARGE QFS SHOULD RECEIVE "BONUS" CAPACITY PAYMENTS FOR ON-PEAK PERFORMANCE SUPERIOR TO THE PROXY UTILITY PLANT THAT SERVES AS THE BASIS FOR AVOIDED COST CALCULATIONS (WEYERHAEUSER-ICNU/300, BEACH/12)?

A. Yes, to the extent a QF's availability during on-peak hours exceeds the availability of the utility proxy plant, the QF should receive a higher monthly capacity payment than is embedded in standard on-peak rates. However, the adjustment for superior QF availability should be made relative to the proxy plant availability, not the QF contract capacity level as Mr. Beach proposes.

The same sliding scale model I discussed previously should be used to calculate adjustments to capacity payments for monthly QF availability higher than the proxy utility plant.

Q. DO PACIFICORP'S OR ICNU'S PROPOSALS ADDRESS THE REAL-TIME VALUE OF DISPATCHABILITY?

A. No. The value of dispatchability during the utility's deficiency period is derived from its ability to decrease or increase proxy plant output in response to real-time electricity and natural gas prices. Staff noted that stochastic, IRP-type modeling under various futures is a potential alternative for addressing the reduced value of a non-dispatchable, "24/7" natural gas-fired combined heat and power (CHP) facility. *See* Staff/1800, Schwartz/11.

In some respects, the FERC adjustment factor addressing dispatchability appears to address only peak periods, not off-peak periods. *See* 18 C.F.R. § 292.304(e)(2). However, item (vi) under this factor includes "[t]he individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system." The value of dispatchability during off-peak periods also may fall under a separate FERC adjustment factor, "The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs…." *See* 18 C.F.R. § 292.304(e)(3).

Q. SHOULD ADJUSTMENTS RELATED TO DISPATCHABILITY BE MADE TO AVOIDED COST RATES DURING THE UTILITY'S RESOURCE SUFFICIENCY PERIOD?

A. No. Avoided costs during the resource sufficiency period are based on monthly on- and off-peak forward market prices, not the dispatchable utility proxy plant. *See* Order No. 05-584 at 28. Avoided cost adjustments for dispatchability should be limited to the utility's resource *deficiency* period, when avoided costs are based on the utility proxy plant.

Q. PLEASE DESCRIBE HOW STOCHASTIC MODELING COULD BE USED TO ADJUST A LARGE QF'S AVOIDED COST RATES FOR DISPATCHABILITY DURING THE UTILITY'S RESOURCE DEFICIENCY PERIOD.

A. The stochastic modeling approach to estimating the value of the difference in dispatchability between the utility proxy plant and the CHP facility is a comparison of average power costs for two resource portfolios under a range of natural gas and electricity prices, hydroelectric generation, loads and plant forced outages. The "base portfolio" is the utility's existing resource portfolio with the addition of the utility proxy plant with its dispatch characteristics.

To isolate the differential value of dispatchability, the second resource portfolio would modify the base portfolio by substituting the availability of the

CHP facility for the availability of the utility proxy plant, as well as the must-run constraint associated with providing thermal energy to the CHP host.

The difference in average present value revenue requirements (PVRR) in dollars per megawatt-hour between these two portfolios is an estimate of the differential value of dispatchability to the utility. The adjustment to avoided cost rates during the utility's resource deficiency period would reflect the difference in PVRR between the two portfolios.

PGE, PacifiCorp and Idaho Power perform stochastic analysis as part of their IRP processes. Thus they have models available to perform such analyses for avoided cost adjustments.

Q. ARE FRONT-LOADED OR LEVELIZED CAPACITY PAYMENTS THE ONLY POTENTIAL RISK TO THE UTILITY AND RATEPAYERS DUE TO TERMINATION OF THE QF CONTRACT (WEYERHAEUSER-ICNU/300, BEACH/14)?

A. No. Even if payments are not front-loaded or levelized, the utility and ratepayers, if costs are passed on, are at risk for the difference between the QF contract price and forward market prices beginning on the date of termination – if the QF contract is for firm energy. *See* Staff/1000, Schwartz/48-49; Staff/1800, Schwartz/6-7.

Q. IS A "BEST EFFORTS" STANDARD REASONABLE FOR A QF TO MEET ITS CAPACITY OBLIGATIONS DURING UTILITY SYSTEM EMERGENCIES (WEYERHAEUSER-ICNU/300, BEACH/15)?

A. Yes. A QF should be required to make best efforts to meet its capacity obligations during utility system emergencies. However, the QF should not be penalized for an unplanned outage during a utility system emergency, so long as the outage falls within other parameters in the contract.

Q. IS PACIFICORP'S PROPOSED METHOD FOR ADJUSTING AVOIDED COSTS FOR LINE LOSSES REASONABLE?

A. Yes. *See* PacifiCorp's response to ICNU Data Request No. 11.10; Staff/2301, Schwartz/3.

Q. SHOULD AVOIDED COSTS BE ADJUSTED FOR UTILITY DISTRIBUTION OR TRANSMISSION SYSTEM SAVINGS DUE TO THE LOCATION OF A LARGE QF?

A. Yes. I agree with Weyerhaeuser-ICNU and PacifiCorp that transmission costs that can be avoided or deferred as a result of the QF's location relative to the utility proxy plant should be eligible for an avoided cost payment. As Weyerhaeuser-ICNU points out, there also may be savings attributable to the QF at the distribution level. As PacifiCorp states, any savings is dependent on the reliability of the QF, and load shedding by the QF host may be required in the event of a QF outage during specified peak hours for the affected grid components. Staff further notes that any analysis of potential transmission and distribution (T&D) system savings should include projected load growth and associated T&D needs*. See* Staff/1000, Schwartz/14-15; Weyerhaeuser-ICNU/200, Beach/15; and PacifiCorp's responses to ICNU Data Requests No. 11.11-11.12, Staff/2301, Schwartz/4-5. *Also see* Order No. 06-029 at 55-56.

Q. SHOULD AVOIDED COSTS BE ADJUSTED FOR A LARGE QF FOR ITS ASSOCIATED COSTS TO THE UTILITY TRANSMISSION SYSTEM?

A. Any necessary transmission upgrades to accept QF power should be separately charged as part of the interconnection process and should not affect avoided cost rates. That may include cases where a QF is sited where there is insufficient local load to absorb the QF's output in all hours, particularly low-load hours, the QF is not associated with a retail customer or QF generation exceeds the customer's load, and transmission capacity is insufficient to move the QF power elsewhere. In such cases, the utility could make grid upgrades to enable transmission to other areas and charge the costs to the QF through the interconnection process. Or the utility could back down lower-cost resources to accept the QF power in hours of constraint. In the latter case, Staff agrees with PacifiCorp that avoided cost rates for large QFs should be adjusted to account for the must-take nature of PURPA contracts and the higher cost of non-dispatchable QF power. *See* PPL/404, Griswold/7-8.

Q. IS THERE A FERC FACTOR THAT SPECIFICALLY ADDRESSES THE ISSUE OF T&D COSTS AND SAVINGS?

A. No, other than for line losses. However, the Commission should consider that this issue may fall within the following FERC factor: "The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system." *See* 18 C.F.R. § 292.304(e)(2)(vi). If power from a QF is higher cost than power from other resources available to the utility, it can be considered to be of lower "value" than the lower cost power obtainable from the other resources. Another FERC factor also may be relevant, "The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs…." *See* 18 C.F.R. § 292.304(e)(3).

Q. SHOULD THE UTILITY STATE IN WRITING HOW IT HAS MODIFIED ITS STANDARD RATES AND STANDARD CONTRACT BASED ON THE COMMISSION'S ADOPTED GUIDELINES FOR NEGOTIATING LARGE QF CONTRACTS (WEYERHAEUSER-ICNU/300, BEACH/5-6, 23-24)?

A. Yes, the utility should do so for any modifications of standard avoided cost rates. Regarding the negotiated terms and conditions of the contract, however, the utility should simply comply with the Commission's adopted guidelines for negotiations, rather than make a written comparison between the negotiated QF contract and the Commission-approved standard contract. The standard contract is specifically designed for small QFs, not large QFs. At the same time, negotiated QF contracts should not impose terms and conditions beyond what is standard practice for the utility's other power transactions.

Q. DO YOU AGREE WITH PACIFICORP WITNESS MR. GRISWOLD THAT RATE CASE PROCEEDINGS PROVIDE A VENUE FOR THE COMMISSION TO REVIEW AVOIDED COST ADJUSTMENTS IT HAS NOT PREVIOUSLY APPROVED (PPL/404, GRISWOLD/11)?

A. No. It is unlikely that the Commission would seek to increase payments for a QF contract by finding in a rate case that a utility inappropriately made a downward adjustment to standard avoided cost rates for the project.

Q. DO YOU AGREE WITH PGE THAT EACH LARGE QF CONTRACT BE CONTINGENT ON OPUC APPROVAL (PGE/400, KUNS-SIMS/13)?

A. No. The Commission already decided this issue in Order No. 05-584 at 56.

ISSUE 3a

Firm vs. Non-firm Commitments

Q. HOW DO YOU RESPOND TO IDAHO POWER'S RECOMMENDATION THAT THE COMMISSION NOT RESTRICT THE COMPANY'S ABILITY TO NEGOTIATE REASONABLE TERMS AND CONDITIONS WITH LARGE QFS FOR FIRM ENERGY COMMITMENTS, RECOGNIZING THE NEED FOR "SOME ADDITIONAL FLEXIBILITY" FOR INTERMITTENT RENEWABLE RESOURCES (IDAHO POWER/300, GALE/8-9)?

A. While Staff finds that contracts with QFs relying on intermittent renewable resources constitute a firm power commitment if they include a Mechanical Availability Guarantee (MAG) or a minimum delivery obligation that specifies deliveries over a period of time (*see* Staff/1000, Schwartz/24-32; Staff/1800, Schwartz/29-33), Staff did not intend to limit the delivery scheduling requirements a utility may negotiate with a large QF. For example, PacifiCorp states that energy supplied by a QF under a day-ahead schedule qualifies as a firm product if the contract obligates the QF to deliver a specified minimum quantity of energy to the Company and the QF meets the day-ahead schedule. *See* PacifiCorp's responses to ICNU Data Request No. 12.2-12.3; Staff/2301, Schwartz/6-7.

Idaho Power has yet to execute a non-PURPA wind contract. Both PGE and PacifiCorp have employed a MAG in their recent contracts with non-PURPA wind projects. *See* Staff/1800, Schwartz/29-33. In addition, PacifiCorp has revised its generic power purchase agreement (PPA) for its Request for Proposals (RFP) for renewable generating resources to incorporate a MAG based on annual guaranteed availability. *See* PacifiCorp's March 21, 2006, filing to amend RFP 2003-B (Docket No. UM 1118), Appendix E-1, Section 6.12, at http://www.pacificorp.com/File/File63013.pdf.

Q. SHOULD THE COMMISSION TREAT IDAHO POWER DIFFERENTLY THAN THE OTHER UTILITIES REGARDING CALCULATION OF AVOIDED COST RATES FOR LARGE QFS?

A. Idaho Power did not request that it be treated differently than PacifiCorp or PGE in this respect. However, the Oregon Commission allowed Idaho Power to use the methodology approved by the Idaho Public Utilities Commission to calculate standard avoided cost rates. *See* Order No. 05-584 at 26-27. The Oregon Commission could similarly defer to the Idaho Commission's approved methodology for calculating avoided cost rates for negotiating with large QFs.

However, ICNU has raised concerns related to the avoided cost rates Idaho Power has calculated using this methodology, which are significantly lower than the Company's standard cost rates in Oregon. *See* Weyerhaeuser-ICNU's response to Idaho Power Data Request No. 2; Staff/2301, Schwartz/8-9. Further, the method approved by the Idaho Commission for calculating Idaho Power's avoided costs for large QFs may be a deviation from the Commission's order which states (at 12 and 59) that standard avoided costs serve as the starting point for negotiations with large QFs. The Company's approved methodology for standard avoided cost rates in Oregon (and Idaho) uses different inputs and is a different approach than the modeling performed under the Idaho Commission-approved method for calculating avoided costs for large QFs.

Q. PLEASE DESCRIBE IDAHO POWER'S APPROVED METHODOLOGY FOR CALCULATING AVOIDED COST RATES FOR LARGE QFS IN IDAHO.

A. Idaho Power performs two model runs to determine the difference in the present value of revenue requirements between 1) the utility's "base case" Integrated Resource Plan and 2) a modified resource plan that includes the QF resource, with its costs set to zero, and associated adjustments to the amount or timing of other new resources. Both resource plans are modeled over the lifetime of the QF contract.

Rates for energy and capacity for the QF are set to equal this difference in revenue requirements over the life of the contract, on a present value basis. The Idaho Commission allows the Company to update IRP data such as forecasted prices for natural gas for these avoided cost calculations. *See* Idaho Public Utilities Commission Order No. 26576 (Case No. IPC-E-95-9).

<u>Integration Costs</u>

Q. DO YOU AGREE WITH PACIFICORP WITNESS MR. GRISWOLD THAT THE COMPANY SHOULD REDUCE STANDARD AVOIDED COST RATES FOR WIND QFS BY $4.64/MWH TO REFLECT INTEGRATION COSTS (PPL/404, GRISWOLD/12-14)?

A. No. Avoided cost rates for wind QFs 10 MW and less should not be adjusted. For larger wind projects, under PURPA or non-PURPA contracts, estimates of first-year integration costs should be based on existing wind penetration levels with the addition of the proposed project. Integration costs through year five of the project should be based on the utility's projected trajectory of wind acquisitions in each year and associated integration costs. Integration costs should be fixed at the year-five level (adjusted for inflation) for the remainder of the project life. *See* Staff/1800, Schwartz/22-28.

ISSUE 11: COMPETITIVE BIDDING FOR QFS OVER 100 MW

Q. DO YOU AGREE WITH PACIFICORP WITNESS MR. GRISWOLD THAT QFS 100 MW OR LARGER WITH TERMS FIVE YEARS OR LONGER SHOULD BE ELIGIBLE FOR CAPACITY PAYMENTS ONLY IF THEY ARE SELECTED AS THE WINNING BIDDER IN A COMPETITIVE BIDDING PROCESS?

A. No, for the reasons I stated previously. *See* Staff/1800, Schwartz/44-45. Further, as Weyerhaeuser-ICNU witness Mr. Beach notes, federal PURPA requires the utility to purchase “any energy and capacity” that is “made available” to it by a QF, at rates equal to the utility’s avoided cost. *See* Weyerhaeuser-ICNU/300, Beach/29.

PacifiCorp states that if it is not in the midst of a competitive bidding process, it is in a capacity sufficient position and therefore it would not be prudent to acquire and pay for capacity. *See* PacifiCorp’s responses to Staff Data Request No. 8-9; Staff/2301, Schwartz/10-11.

PacifiCorp confuses the issue. First, assuming the completed bidding process fulfills the Company’s near-term capacity needs, it is highly likely that the utility still will project resource deficiency at some point in the next 20 years. Second, Order No. 05-584 (at 27-28) maintained the Commission’s historical approach of valuing QF power differently during the utility’s resource sufficiency period vs. its deficiency period. Further, the Commission determined that capacity has value even during the utility’s resource sufficiency period. Therefore, avoided costs during this period are based on on-peak and off-peak forward market prices at the time of filing.

Staff does not object to an alternative approach based on competitive bidding for calculating avoided costs for QFs 100 MW and larger. However, such an approach should maintain the general principle that QFs contribute capacity value even when a utility is resource sufficient. Further, if at any time during the 20 years over which the utility calculates avoided costs the utility expects to be resource-deficient, the large QF's capacity value should be treated appropriately during that period.

The state has the obligation under PURPA to ensure that the utilities accept any capacity and energy offered by a QF at the utility's avoided cost. Therefore, Staff views the competitive bidding issue not as an all or nothing approach, where the QF does not receive any capacity payments if it is not selected as a winning bidder. Instead, Staff views competitive bidding as a tool to determine the appropriate price for capacity during the utility's projected deficiency period. The utility may make a filing following a competitive bidding process to adjust both its projected resource sufficiency period and to update avoided costs based on bidding results.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

CASE: UM 1129 – Phase II
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 2301

Exhibit in Support of Rebuttal Testimony

April 7, 2006

ICNU Data Request 11.4

Regarding PPL/404, Griswold/6, please provide and describe the methodology hat PacifiCorp would use to adjust the avoided costs for a QF larger than 10 MW for dispatchability and reliability.

Response to ICNU Data Request 11.4

Dispatchability and reliability are included as a single adjustment to the standard avoided cost price. In any month, to the extent the QF is less available for dispatch than the proxy resource, the capacity contribution to avoided cost for the QF would be reduced on a linear basis as compared to the proxy. Below an availability level of 85%, the QF would receive no capacity contribution in its on-peak price and receive only off-peak prices for all energy delivered in that month.

ICNU Data Request 11.5

Regarding PPL/404, Griswold/6, please provide an example of how PacifiCorp has adjusted, or would adjust, a QF contract for dispatchability and/or reliability.

Response to ICNU Data Request 11.5

See Attachment ICNU 11.5 which contains a spreadsheet with the calculation for dispatchability adjustment.

ICNU Data Request 11.10

PPL/404, Griswold/5-6 and Griswold/11 lists four factors that PacifiCorp would utilize to adjust the avoided costs for non-standard QFs and states that there are additional factors. For each of the additional factors that PacifiCorp could utilize to adjust a large QF's avoided costs, please provide a historic or illustrative example of how the factor would adjust the large QF's avoided costs.

Response to ICNU Data Request 11.10

In the event that one of the additional factors applied to a QF in a non-standard contract, the parties would determine the adjustment, if any, through negotiations. Below is an example of one such adjustment for line losses.

Under PURPA, as set forth in 18 C.F.R. § 292.304(e), factor k is *"The variation in line losses between QF purchases and other energy generated or purchased by the utility."*

1. A proximity assessment would be completed as part of Schedule 38 when PacifiCorp prepares indicative prices for the individual QF. This preliminary assessment would be based on the physical proximity of the QF to both the proxy plant and the nearest load center, the type of power being delivered to PacifiCorp (i.e. firm dispatchable, non-firm, intermittent, etc.) and the voltage level at which the QF would be interconnected to PacifiCorp's system.
2. Line loss adjustments (both as an increase (cost) or reduction (benefit)) are calculated for a firm thermal QF's scheduled and/or dispatched power and any replacement power the Company must acquire to replace the QF's scheduled but non-delivered power.
3. For QF projects interconnected at the transmission level, the loss percentage factor would be applied per the then-current published PacifiCorp OATT rate at the QF interconnection transmission level. For those rare interconnections at the distribution level, the Company would use the distribution loss percentage factor from the OATT.
4. The Company would evaluate if the proxy resource is geographically closer to the load center than the QF. If the proxy resource is closer to the load area then the QF delivery volume, net of any station service and load self-served, is reduced by the loss factor because the Company incurs additional losses bringing the QF power to the load center in relationship to the proxy resource. If the QF is closer to the load center in relationship to the proxy resource, the delivery volume by the QF that meets the applicability criteria described above, net of station service, is grossed up by the appropriate loss percentage factor.

ICNU Data Request 11.11

Regarding PPL/404, Griswold/7-8, please identify the circumstances under which the Company would experience transmission savings associated with a QF project.

Response to ICNU Data Request 11.11

For a QF to displace planned transmission when its specific operational characteristics and location are considered, the QF must be reliable and dispatchable. If the QF is not reliable and dispatchable and transmission is not constructed, it is possible that the load would need to be shed to maintain system stability during QF outages or reduction in anticipated generating levels. Even if it can be shown that the costs of planned generation resources can be avoided, little if any planned main grid transmission developments may be avoided. The Company does not believe a QF smaller than 100 MW would have any impact on proposed transmission upgrades. The addition of small QF generators would have very little impact on the scope or timing of these high-voltage transmission plans because of the interconnected nature of the network and the high capacity of the main grid facilities.

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ICNU 11th Set Data Request 11.12

ICNU Data Request 11.12

Regarding PPL/404, Griswold/7-8, please identify the methodology that the Company would utilize to adjust a large QF's avoided costs to incorporate the transmission savings.

Response to ICNU Data Request 11.12

PacifiCorp Transmission conducts a system impact study as part of the interconnection process whereby the system study would determine the transmission requirements with and without the QF to reliably serve load. The study and assessment of each QF's reliability levels, ability to support voltage and reactive requirements, and the need for any associated transmission in support of the networks overall reliability is essential. Any transmission that can be avoided or deferred would be eligible for an avoided cost payment to the developer. Conversely, any associated cost of upgrade to transmission is borne by the QF.

ICNU Data Request 12.2

Regarding PPL/404, Griswold/3, please identify the circumstances under which the Company would define the delivery of energy to be a "firm product".

Response to ICNU Data Request 12.2

The QF has the obligation to deliver a specified minimum quantity of energy to the Company.

UM-1129/PacifiCorp
March 24, 2006
ICNU 12th Set Data Request 12.3

ICNU Data Request 12.3

Regarding PPL/404, Griswold/3, please clarify whether energy supplied under a day-ahead schedule qualifies as a "firm product" or is considered to be provided on an "as available" basis.

Response to ICNU Data Request 12.3

Energy supplied under a day-ahead schedule qualifies as a "firm product" if the energy supplied by QF meets the day-ahead hourly schedule of energy to be provided and is supplied under a contract which imposes a minimum energy delivery obligation on the QF.

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

DOCKET NO. UM 1129

WEYERHAEUSER-ICNU'S RESPONSE TO IDAHO POWER DATA REQUEST NO. 2

March 30, 2006

Data Request No. 2:

In his answer beginning on Page 10 at Line 16, Weyerhaeuser-ICNU witness Beach testifies that large QFs have been unsuccessful in their efforts to negotiate power purchase contracts with Idaho Power. Please identify those large QF projects that have attempted to negotiate power purchase contracts with Idaho Power but subsequently abandoned the negotiation process.

Response to Data Request No. 2:

Since Phase II testimony was filed in this case, Mr. Beach has become aware through discovery that Idaho Power recently has signed five new QF contracts with nameplate capacities larger than the 10 MW threshold in Idaho for standard rates and a standard contract. Four of these new contracts are with wind projects (three at 18 MW, one at 21 MW); one is a 17.5 MW biomass (woodwaste) QF. The wind projects do qualify for standard rates, as the Idaho PUC has re-defined the size threshold for standard rates to be the delivery of no more than 10 average MW ("aMW") over a period of a month. See Idaho PUC Order No. 29632 (Nov. 22, 2004); see also Orders Nos. 29948, 29949, 29950, and 29951 (approving the four wind projects). The contract for the 17.5 MW biomass project includes standard rates for the first 10 MW of production, then negotiated rates for all production over 10 MW. This project had the potential to split its project into two smaller projects, each less than 10 MW and each qualifying for standard rates, and this leverage appears to have been a significant factor in the Idaho PUC's approval of the negotiated contract. See Idaho PUC Order No. 29487 at 10-11 (May 4, 2004).

Mr. Beach is not aware of any specific QF projects larger than 10 MWs in Idaho Power's territory that have "abandoned the negotiation process." The question misstates Mr. Beach's testimony, which does not refer to the experience of specific large QFs in Idaho. Mr. Beach's testimony is based on the demonstrated results of the QF program in Idaho, at the time of the first phase hearings in UM 1129. It is clear from the record in the initial phase of UM 1129 that, although in 2004 Idaho Power purchased power from 71 QF projects, all were under standard rates and contracts, and none had successfully negotiated a non-standard contract. Idaho Power's witness John Gale testified that some of its QF projects could exceed 10 MWh per hour in deliveries, but all were under standard rate contracts. See UM 1129, Phase I transcript at 106-07. In other states, there are many QF contracts larger than 10 MW. Thus, Idaho's experience through 2004 suggested that there were impediments to the negotiation of non-standard QF contracts that discouraged the development of QF projects larger than 10 MW. Today, in 2006, as discussed above, there appears to be just one QF project in Idaho with negotiated rates for less than half of its output.

As an indication of why there may have been no larger-than-10-MW, non-standard QFs in Idaho, Mr. Gale testified that Idaho Power had calculated a project-specific, IRP-based "actual" avoided cost for a geothermal QF that was just 81% of standard avoided cost rates. This was presumably the price upon which Idaho Power would have insisted in negotiations with baseload QFs larger than 10 MW. Given the prospect of such dramatically lower avoided cost rates in a negotiated agreement, it was not surprising that no QFs larger than 10 MW, with non-standard contracts, had been developed in Idaho at the time of the UM 1129 hearing. See UM 1129, Phase I, Idaho Power Company Rebuttal Testimony of John R. Gale at 4, lines 6-18. Similarly, Idaho Power provided to staff in discovery in Phase II a production cost analysis of energy payments to a QF that approached Idaho Power in 2005 concerning a 111 MW cogeneration project in Idaho Power's Oregon service territory. This analysis shows that the project would be "overpaid" by more than 20% for energy at the utility's filed standard avoided cost rates in Oregon. Therefore, it appears that the methodology Idaho Power is utilizing to calculate avoided costs for non-standard contracts penalizes large QFs simply for being larger than 10 MW.

OPUC Data Request 8

Regarding PPL/404, Griswold/25, lines 5-7, please clarify whether PacifiCorp would purchase any capacity that is made available to the company by a QF 100 MW or larger outside of a competitive bidding process, or that was not selected through such a process.

Response to OPUC Data Request 8

No. The competitive bidding process is the Company process used to secure capacity in compliance with its IRP action plan. Outside of the competitive bidding process, the Company would be in a capacity sufficiency period and it would not be prudent to acquire and pay for capacity outside of the bidding process.

OPUC Data Request 9

If PacifiCorp agrees to purchase any capacity that is made available to the company by a QF 100 MW or larger outside of a competitive bidding process, or that was not selected through such a process, please explain how the company would use the results of the bidding process to determine the price the QF would be paid for such capacity.

Response to OPUC Data Request 9

If the QF was not the successful bidder in the competitive bidding process and the amount of capacity being sought in the bidding process had not been met, then the QF would be paid the price of capacity and energy as determined by the winning bid up to the amount of capacity sought in the competitive bid process. If the amount of capacity was met in the competitive bid process and/or the QF was seeking pricing outside of the competitive bid process, then PacifiCorp would not purchase capacity from the QF and pay an energy only price with no capacity contribution in the price.

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

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 2400

Rebuttal Testimony

April 7, 2006

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

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

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS DOCKET?

A. Yes. I submitted Staff Exhibits 300-305, 700-701, 1100-1109, 1600-1601, and 1900-1901.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to the direct testimonies filed by PacifiCorp witness Griswold (Exhibit PPL/404), Idaho Power witness Gale (Exhibit Idaho Power/300), and Weyerhaeuser-ICNU witness Beach (Exhibit Weyerhauser-ICNU/300).

Q. DID YOU PREPARE AN EXHIBIT?

A. Yes. I prepared Staff/2401, which consists of 3 pages of selected responses to data requests.

<u>PRICING FOR QFS LARGER THAN 10 MW</u>

Q. IN STAFF/1900, YOU RECOMMENDED THAT THE COMMISSION SHOULD NOT REQUIRE THE UTILITIES TO OFFER ALL PRICING OPTIONS TO QFS LARGER THAN 10 MW. *SEE* STAFF/1900, CHRISS/7. HAS THIS RECOMMENDATION CHANGED?

A. No. The Commission should not require the utilities to offer all of the available pricing options to QFs larger than 10 MW.

Q. WHAT DO YOU RECOMMEND AS AN ALTERNATIVE?

A. The Commission should not preclude the use of any of the available pricing options for QFs over 10 MW. However, the pricing option should be selected as part of the negotiation between the utility and QF developer, not unilaterally imposed by one party upon the other party.

Q. WHY IS YOUR RECOMMENDATION REASONABLE?

A. My recommendation is reasonable for two reasons. First, it protects the QFs by keeping the pricing options open, subject to the negotiation process. Second, it protects the utilities because they will have a reason and ability to object when the economics of a QF project could be harmful to the utility and its customers depending on the pricing option chosen.

Q. DOES IDAHO POWER'S EXAMPLE REGARDING A 111 MW NATURAL GAS-FIRED QF IN ITS OREGON TERRITORY ILLUSTRATE THE REASONING BEHIND YOUR RECOMMENDATION? *SEE* IDAHO POWER/300, GALE/2-5.

A. Yes. Without rendering judgment on the specific merits of Idaho Power's example, it illustrates that before a pricing option is chosen for a QF project, the economics of that project need to be analyzed to find an appropriate result for both the QF developer and the utility.

The example shows that it is not appropriate for the Commission to preclude the gas market pricing option, because, as Idaho Power notes, the review did not reflect any adjustment for dispatchability, reliability, or other criteria that would be considered in negotiating the long-term contract. *See* Idaho Power/300, Gale/3, Lines 7-9. As a result, the actual potential harm to customers is not known.

However, the example also shows that it is not appropriate for the Commission to require utilities to offer all pricing options to QFs over 10 MW. Idaho Power is clearly uncomfortable with the ramifications of bringing a base-load natural gas-fired resource online on its system, either QF-owned or utility-owned, and it would not be appropriate to require the company to offer a pricing option before it knows if it can handle the operational and financial benefits and costs. *See* Idaho Power/300, Gale/5, Lines 18-25.

Q. DO YOU AGREE WITH PACIFICORP THAT QF CONTRACTS PROVIDING ENERGY DELIVERIES ON AN "AS AVAILABLE," OR NON-FIRM, BASIS SHOULD ONLY RECEIVE AN "ENERGY PRICE?" *SEE* PPL/404, GRISWOLD/3.

A. No. The "energy price" is the Company's off-peak avoided cost rate in Schedule 37. *See* PacifiCorp's response to Staff Data Request No. 4; Staff/2401, Chriss/1.

A market-based rate is the appropriate basis for payment for "as available" energy deliveries. Such a rate is aligned with FERC rules which require pricing for as-available QFs to be based on the utility's avoided cost *at the time of delivery*. *See* Staff/1900, Chriss/2-3. The utility's Schedule 37 avoided cost rates are not determined at the time of QF delivery, but at the time the Commission approves the avoided cost filing. Historically, such filings have been made about every two years following acknowledgment of the utility's Integrated Resource Plan.

However, if a non-firm QF wishes to negotiate on the basis of the off-peak avoided cost rate because it provides more certainty than a fluctuating market index, such a rate could be a reasonable starting point.

Examples of market-based rates for QFs include PGE's market rate for the 13 MW Covanta Marion waste-to-energy facility, updated each quarter for the Commission's approval pursuant to OAR 860-029-0080(4). The rate is based on forward on- and off-peak prices. *See*, for example, the Staff report for consent agenda item 4, March 23, 2006, public meeting. PGE also offers a daily index rate for non-firm QFs 10 MW or less. Idaho Power proposes a monthly market index rate for small non-firm QFs. *See* Idaho Power/300, Gale/7; Exhibit 302.

Q. DO YOU AGREE WITH WEYERHAEUSER-ICNU WITNESS MR. BEACH THAT "AS AVAILABLE," OR NON-FIRM, QFS SHOULD RECEIVE CAPACITY PAYMENTS TO THE EXTENT THEY DELIVER POWER DURING PEAK PERIODS (WEYERHAEUSER-ICNU/300, BEACH/4, 22-23)?

A. Not exactly. "As available," or non-firm, QFs should receive pricing based on the utility's avoided costs at the time of delivery, as FERC requires. Non-firm QFs will receive capacity payments to the extent market index pricing available to them includes some capacity value embedded in on-peak rates.

Q. IS IDAHO POWER'S PROPOSAL FOR THE COMMISSION TO ADOPT IDAHO SCHEDULE 86 FOR NON-FIRM QFS 10 MW AND LESS REASONABLE? *SEE* IDAHO POWER/300, GALE/7, LINES 1-22; EXHIBIT 302.

A. Yes. Adopting Idaho Schedule 86 for Oregon has two advantages. First, it provides a non-firm delivery option for producers that want to sell their energy to Idaho Power without economic consequences for non-performance. Second, the schedule uses published market prices to set the prices paid to QFs. Specifically, non-firm QFs would receive 85 percent of the weighted average of the daily on-peak and off-peak Dow Jones Mid-C Index for non-firm energy, on average for the month.

Q. IS IT PUNITIVE TO PAY NON-FIRM QFS 85 PERCENT OF THE INDEX RATE?

A. No. The 15 percent discount of the index rate is for the operational and opportunity costs to Idaho Power of accepting the non-firm QF energy.

Q. WOULD MODIFICATIONS BE REQUIRED TO IDAHO SCHEDULE 86 FOR ADOPTION IN OREGON?

A. Yes. These include the availability clause, references to Idaho Schedule 72 – interconnection requirements, and the reference in condition 5 to Idaho Schedule 7 – standby and supplementary power. Condition 12 may require modification following final Commission decisions on liability insurance, including any requirements for QFs 200 kW and smaller. As previously noted, Staff intends to ask the Commission to open an investigation soon into interconnection standards, procedures and agreements. *See* Staff/1000, Schwartz/63, 68. Oregon Schedule 85 references the Company's current interconnection process.

PACIFICORP MARKET PRICING OPTION

Q. IS PACIFICORP WITNESS GRISWOLD'S EXPLANATION OF THE DIFFERENCE BETWEEN THE CURRENT COMMISSION APPROVED AVOIDED COST AND THE MARKET PRICING OPTION CORRECT? *SEE* PPL/404, GRISWOLD/20, LINES 5-15.

A. No. Mr. Griswold's explanation characterizes the Commission approved avoided costs as fixed for the entire term of the QF contract. This is only partially true. The Commission has approved and PacifiCorp offers two pricing options that are tied to actual monthly natural gas index prices. The first is the Gas Market Indexed Avoided Cost Prices option, which is described in PacifiCorp's Schedule 37[1] as follows:

> *Fixed prices apply during the resource sufficiency period (2005 through 2009), thereafter a portion of avoided cost prices are indexed to actual Opal monthly gas market index prices. The remaining portion of avoided cost prices will be fixed at the time that the contract is signed by both the Qualifying Facility and the Company and will not change during the term of the contract.*

The second pricing option is the Banded Gas Market Indexed Avoided Cost Prices option, which is described in PacifiCorp's Schedule 37 as follows:

> *Fixed prices apply during the resource sufficiency period (2005 through 2009), thereafter a portion of avoided cost prices are indexed to actual Opal monthly gas market index prices. The remaining portion of avoided cost prices will be fixed at the time that the contract is signed by both the Qualifying Facility and the Company and will not change during the term of the contract. The gas indexed portion of the avoided cost prices are banded to limit the amount that prices can vary with changes in gas prices.*

[1] *See* PacifiCorp's July 12, 2005, Compliance Filing in Docket UM 1129.

Ultimately, Mr. Griswold's statement regarding the proposed market pricing option – that "QF prices are tied to a market index or combination of market indexes so that the QF price will change from month to month" – accurately describes two pricing methods already offered by PacifiCorp. *See* PPL/404, Griswold/20, Lines 12-15.

Q. BECAUSE PACIFICORP ALREADY OFFERS PRICING OPTIONS TIED TO MONTHLY MARKET INDEX PRICES, ARE YOU ABLE TO IDENTIFY THE ADDITIONAL RISKS PLACED ON PACIFICORP BY A PRICING OPTION BASED ON A POWER MARKET INDEX PRICE? *SEE* PPL/404, GRISWOLD/20, LINES 16-19.

A. No. PacifiCorp is already assuming some risk of not recovering power costs because natural gas markets are inherently volatile. I do not know what the incremental risks are of adding another option based on the power markets, which are also inherently volatile.

Q. ARE PACIFICORP'S CONCERNS RELATED TO A POWER MARKET INDEX OPTION LIMITED TO LARGE QFS AND TO PRICES THAT WOULD FLUCTUATE DAILY OR MONTHLY?

A. No. PacifiCorp opposes a power market pricing option for any size QF. The Company also opposes an index option that would change annually based on forward market prices for the year, similar to the Commission's methodology for calculating avoided costs during the resource sufficiency period, for any size QF. *See* PacifiCorp's responses to Staff Data Requests No. 6-7; Staff/2401, Chriss/2-3.

Q. IS THIS DOCKET THE APPROPRIATE VENUE FOR DISCUSSION OF NET POWER COST VARIATIONS AND PACIFICORP'S POWER COST ADJUSTMENT MECHANISM? *SEE* PPL/404, GRISWOLD/20, LINES 18-23.

A. No. The Commission currently has an ongoing docket, UE 173, regarding PacifiCorp's proposed Power Cost Adjustment Mechanism.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2401

Exhibit in Support of Rebuttal Testimony

April 7, 2006

UM-1129 II/PacifiCorp
March 23, 2006
OPUC Data Request 4

OPUC Data Request 4

Regarding PPL/404, Griswold/3, line 12, please define "energy price."

Response to OPUC Data Request 4

Energy price was used in the context of Griswold's testimony on Issue 1.b on "as-available" deliveries by the QF. For Issue 1.b, energy price is defined as the price for non-firm energy. In terms of Schedule 37, it is the off-peak price which does not include the capacity contribution that is included in on-peak prices.

UM-1129 II/PacifiCorp
March 23, 2006
OPUC Data Request 6

OPUC Data Request 6

Regarding PPL/404, Griswold/20-21, PacifiCorp recommends the Commission not require the company to offer a market pricing option for Qualifying Facilities (QFs) such that "QF prices are tied to a market index or combination of market indexes so that the QF price will change from month to month." Please clarify whether this recommendation applies both to standard contracts and negotiated contracts.

Response to OPUC Data Request 6

This recommendation applies both to standard contracts and negotiated contracts.

UM-1129 II/PacifiCorp
March 23, 2006
OPUC Data Request 7

OPUC Data Request 7

Does PacifiCorp similarly oppose a market pricing option whereby QF pricing would change annually based on forward market prices for the year, both for standard contracts and for negotiated contracts? Please explain why or why not.

Response to OPUC Data Request 7

Yes, PacifiCorp opposes a market price option in general because the adoption of a market price option in any format would place more risk on the Company of not recovering additional net power cost variations from that level of risk included in rates the Company already bears.

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

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 2500

Rebuttal Testimony

April 7, 2006

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

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

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

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

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

ISSUE 2, DEFAULT SECURITY REQUIREMENT IF A QUALIFYING FACILITY CANNOT ESTABLISH CREDITWORTHINESS

Q. DO YOU HAVE ANYTHING FURTHER TO ADDRESS THIS ISSUE?

A. No. PGE indicates that, "The need for default security will be a function of, and integral to, the risk associated with a project, as defined by such factors as its size and the type of supply commitments the QF is making." See UM 1129/PGE Exhibit 400 Kuns-Sims/20. Staff agrees it is reasonable for a utility to expect default security for QF contracts when the QF cannot establish creditworthiness.

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

Q. DO YOU AGREE WITH PACIFICORP WITNESS SHAH'S CALCULATION THAT IMPUTES DEBT TO ADJUST THE COST OF CAPITAL FOR POWER PURCHASE AGREEMENTS (PPA)?

A. No. Even though there may be an imposition of costs due to the terms of a specific contract (*See* PPL/800 Shah/4), there is no precise, generic algorithm to adjust for potential costs. It is not certain that all PPAs would impose any additional costs that are not already recovered by the utility. Additionally, there could be situations where a PPA could actually serve to reduce overall costs as compared to utility-built plants. See Staff/2000 Morgan/10, lines 12-14 Staff/2000 Morgan/11, line 12-13.

Further, it would be administratively difficult, if not impossible to direct companies to calculate additional costs associated imputed debt on an agreement-by-agreement basis, as Mr. Shah proposes. *See* PPL/800 Shah/8, lines 15-17. Because there is an inherent question regarding the potential magnitude of any impact, Staff proposes no adjustment.

The "generic guidelines" that are proposed by Mr. Shah are based on the position of a single credit rating agency, Standard & Poor's (S&P). S&P indicates that it generally applies a 50% "risk factor" in estimating the potential impact on a company's cost of capital. This is not a "hard and fast" rule, and it only applies to the way S&P considers the fixed cost component of a PPA. In my direct testimony, I quoted an S&P report that indicated the "risk factor" could be anywhere from 0% to 100. See Staff/2000 Morgan/8, line 14. This calculus is unique to S&P and the potential variability reflects the imprecision in determining the actual, incremental impact of such agreements. *See* PPL/800 Shah/7, line 21. Moody's does not publish its "guidelines", but does recognize the subjective nature of any adjustment. See Staff/2000 Morgan/7, lines 15-28.

Q. IS THE POTENTIAL INCLUSION OF POWER PURCHASE AGREEMENTS WITHIN THE BALANCE SHEET OF A COMPANY A "NEW ACCOUNTING STANDARD"?

A. No. Mr. Shah refers to the potential inclusion of power purchase agreements within the balance sheet of a company as a "new accounting standard". *See* PPL/800 Shah/8.

However, the Financial Accounting Standards Board (FASB) "Statement 13" is not new. The Financial Accounting Standards Board developed the Financial Accounting Standard (FAS) 13, "Accounting for Leases" in November, 1976. This standard derives the proper analytical framework, or "lease test" to determine whether a contract is properly classified as a capital lease or an operating lease.[1] The reason this is important is because capital leases[2] are required to be consolidated on a company's financial statements, and are considered "owned assets" for accounting purposes (e.g., depreciation is deducted by the lessee, interest costs are specifically accounted, etc.) It

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[1] Emerging Issues Task Force (EITF) 01-08, "Determining whether an arrangement contains a lease" addresses these issues. EITF 01-08 does not apply to power purchase contracts that are not directly assigned to any one generation plant.

[2] FAS 85-16 details "Leveraged Leases"

would be difficult to expressly consider the impact of each individual lease, and their impact on companies' capital structures.

In 2000, FASB organized a task force to consider the "emerging issue" of "Determining Whether an Arrangement Contains a Lease."[3] An "Emerging Issues Task Force", or EITF, has the mission to "assist the FASB in improving financial reporting through the timely identification, discussion, and resolution of financial accounting issues within the framework of *existing authoritative literature*. The EITF is not empowered to amend or supersede higher-level authoritative literature (for example, FASB Statements and Interpretations or AcSEC Statements of Position.)[4]

These are not new standards. They only serve to provide additional guidance in the development of financial statements.

Q. IS THERE ADDITIONAL OBJECTIVE INFORMATION REGARDING ISSUE 13?

A. Yes. The Electric Power Supply Association (EPSA)[5] refelcted more than a decade ago on the issue of whether PPAs impacted the cost of capital:

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[3] Interpretation 46(R) is not a Statement, but provides additional guidance. This Interpretation of Accounting Research Bulletin No. 51, Consolidated Financial Statements, which replaces FASB Interpretation No. 46, Consolidation of Variable Interest Entities, In March 2005, the FASB Staff Position (FSP) issued FIN 46R-5, "Implicit Variable Interests under FASB Interpretation No. 46 (revised December 2003), Consolidation of Variable Interest Entities." This FSP was effective as of April 1, 2005 and requires a company to consider whether it holds an implicit variable interest in a variable interest entity (VIE) or potential VIE. An implicit interest involves the absorbing and/or receiving of variability indirectly from the VIE, and may take many different forms such as a lessee under a leasing arrangement or a party to a supply contract, service contract or derivative contract.

[4] http://www.fasb.org/eitf/comments_eitf.shtml

[5] Electric Power Supply Association (EPSA) is the national trade association representing competitive power suppliers, including generators and marketers. Excerpts were obtained from "Buy or Build? Assessing the Impact of Power Purchase Agreements on Utility Credit Ratings and Balance Sheet Integrity," White Paper #2, July 2004

"The Energy Policy Act of 1992 addressed the impact of purchase power obligations on utilities, by calling on each state to address the effect of power purchases on utilities' cost of capital and to consider the effects of leveraged capital structures on the reliability of wholesale markets.

"It was during this period that the rating agencies were issuing position papers on purchase power issues. A number of the rating agencies, including S&P, adjusted balance sheets and coverage ratios to reflect capitalization of a portion of the purchase contract costs. But even then, the agencies recognized these adjustments reflected only their evaluation of the risk of the buy options and that building had its own set of risks.

Q. WAS THE IMPACT FROM PPAS ON UTILITIES' COST OF CAPITAL ADDRESSED?

A. Yes. The report stated:

"In the 12 months following the enactment of the law state regulatory authorities *conducted* evaluations of the effect of wholesale power purchases on a utility's cost of capital. *All but one of the states decided that the potential impacts were uncertain due to relative risks involved in any decision to add resources and declined to assign a generic risk premium to purchased power.* They instead reserved the right to review actions in the context of integrated resource planning, least-cost planning or ratemaking proceedings." (emphasis added)

In June 1994, the Energy Information Administration issued a study titled "Financial Impacts of Nonutility Power Purchases on Investor-Owned Electric Utilities." One of the questions studied was whether an increase in the imputed debt of utilities as a result of power purchases from nonutility generators results in an overall increase in the riskiness of the firm. The study considered whether any increase in the cost of borrowing would also be reflected by an increase in the cost of raising equity.

The report concluded that:

"The results indicate that nonutility power purchases did not raise a utility's cost of equity capital. In fact, there was more evidence to support the notion that utility construction raises the cost of capital more than nonutility power purchases do. … There is no conclusive

evidence that power purchases from nonutility generators raised the cost of capital to the utilities which purchase the electricity[6]*.*

"Overall, based on the available financial data using two different approaches, there is no conclusive evidence that power purchases from nonutility generators raised the cost of capital to the utilities which purchase the electricity."[7]

These findings *underscore* the fact that it is difficult to ascribe any particular utility's credit rating, good or bad, to a single factor, such as the size of the utility's purchased power obligations. In addition, it is worth noting that utilities which have divested themselves entirely of generation, and depend exclusively on purchased power, can and do have excellent credit ratings, and do not necessarily rely more heavily on equity financing to "offset" the effect of debt imputation from the power purchase agreements.

Staff asserts the position that the potential impacts of PPAs on the cost of capital are uncertain and depend on the specifics of the company and contract terms.

Q. IF A COMPANY DETERMINES THAT ITS FINANCIAL METRICS (RATIOS) ARE IMPACTED DUE TO A PPA, WOULD IT BE REASONABLE TO ALLOW ADDITIONAL EQUITY TO BE IMPUTED TO OFFSET THE POTENTIAL EXPOSURE?

A. Not as a general rule. The variability in overall terms of a power contract makes it difficult to determine if an adjustment is warranted. Even though Mr. Shah provides a simple calculation to provide an "offset" for the impact of a

[6] DOE/EIA – 0580, June 1994, Executive Summary at viii.

[7] Ibid.

power purchase agreement, he does not explain how different contract terms may require alternative treatment. See PPL/800 Shah/9-10.

Even if a contract is viewed as impacting the credit risk of a company, i.e., as "debt-like", there are limits to which the imposition of additional leverage does not diminish the credit capacity of a utility. Companies can alter their capital structure within reasonably broad ranges without causing an impact on their credit ratings, or their cost of debt.

If companies have historically offset the impact of PPAs with additional equity, as Mr. Shah implies (*See* PPL/800 Shah/5) then the overall cost of capital calculation is already absorbing the average, aggregate influence of existing contracts. This is true because PPAs exist across the spectrum of companies used to estimate the cost of equity; and since the riskiness is already imbedded in companies' costs of debt calculation. The potential for a marginal cost to a company may exist depending on PPA contract terms. However, if a new contract is replacing capacity for expiring contracts, or if a new contract is on favorable terms, the result is that the company could actually benefit from the contract, and it could be considered credit supportive.

Q. ARE THERE OTHER REASONS WHY THE COST OF CAPITAL FOR A UTILITY MAY NOT INCREASE DUE TO PPAS?

A. Yes. The Electric Power Supply Association stated in its report titled, "Buy or Build? Power Purchases or Power Plant Ownership: Making the Best Choice for Customers":

> The choice by a regulated utility between buying power in the wholesale market and building new resources raises numerous issues, many of which present regulators, credit rating agencies and Wall Street with "apples to oranges" comparisons. Each option provides different risks and opportunities…that are often difficult to compare directly. Therefore, state regulators, in particular, need to be vigilant in assessing utility resource proposals to ensure that consumers get the best deal.

EPSA indicated that utilities may actually benefit from PPA agreements over the self-build option:

> "Although utility-built generation was the norm for decades, it has a number of potential risks and liabilities for consumers. For one thing, because of the lumpiness of resource additions,[8] resources that are built to serve load may not, at least initially, correspond to the levels of capacity needed, but the associated costs are, nevertheless, passed on to consumers. PPAs, on the other hand, can allow the purchaser to acquire the exact number of megawatts needed, without having to pay for unnecessary generation in the early years of the PPA.

EPSA also reflected the asymmetry of risks and incentives facing independent power producers over regulated public utilities:

> "In addition, utilities do not necessarily have the same incentives as Competitive Power Suppliers to develop and operate plants as efficiently and competitively as possible. For instance, most utilities earn a return on their construction expenditures through a CWIP (construction work in progress) account while the facility is under construction and before it is available to provide service to customers.
>
> "To evaluate utility and competitive power projects comparably, it is important that all proposed power projects face the same risks. Cost-recovery guarantees for one class of generation (utility-built or owned) versus another class of generation (competitively built and owned) reduce incentives to manage risks and fundamentally shift the competitive landscape when such guarantees are applicable to some (utility-owned), but not to others

[8] Industry jargon referring to the large increments of generating capacity that come with bringing a new facility into operation, which may not be well-matched — initially — with the actual incremental demand growth in the early years of the asset's life.

> (competitively owned). Essentially, the assets guaranteed cost recovery do not participate in the energy markets in a competitively meaningful way. Price signals are skewed, and merchant generation suffers, causing further erosion of competitive markets.

Q. WHAT IS YOUR CONCLUSION REGARDING THE POSITION THAT PPAS NEGATIVELY IMPACT THE COST OF CAPITAL FOR A COMPANY?

A. Although the calculation proposed by Mr. Shah appears straight-forward, the cost of capital applied in the avoided cost calculations includes the expected impact of a "normal" level of power purchase agreements maintained by a company. Any "one-off" adjustment may actually be prejudicial. There is no precise algorithm that can be objectively applied, and it is not clear that an additional "cost" is borne by the company with the commencement of each power purchase agreement. Removing the potential impact on the cost of capital in the manner that is asserted by Mr. Shaw would not be workable and the process is not as simple as Mr. Shah's testimony implies. The treatment afforded PPAs is not new and the impact of any power purchase agreement on a utility's creditworthiness is imprecise.

Q. WHAT IS IDAHO POWER'S POSITION REGARDING THE IMPUTATION OF DEBT AND THE IMPACT ON THE COST OF CAPITAL FOR POWER PURCHASE AGREEMENTS (PPA)?

A. Mr. Gale states that when a company "enters into a QF contract for purchased power…an increase in equity is needed to maintain credit quality." *See* Idaho Power/300 Gale/11, lines 13-14. Mr. Gale also suggests the Commission address imputed debt arising out of an increasing level of QF contract activity by increasing levels of imputed debt due to QF purchases since the obligation is not reflected in Idaho Power's financial statements.

Mr. Gale further indicates that "in reviewing its evaluation of the credit implications of QF related expenditures, S&P recently affirmed its position that such agreements are "debt-like in nature" and that the increased financial risk must be considered in evaluating a utility's credit risks." *See* Idaho Power/300 Gale/11, line 24 to Gale/12, line 1.

Q. WHAT IS YOUR RESPONSE TO IDAHO POWER'S ASSERTIONS ABOUT PPAS AND THEIR IMPACT ON A COMPANY'S CREDIT RATING?

A. As indicated in my Phase II Direct Testimony, credit rating agencies consider the impact of all financial obligations of a company. However, an impact on a credit rating metric does not necessarily impact the cost of capital.

Q. WHAT IS IDAHO POWER'S POSITION ON WHETHER THERE IS AN INCREASED COST OF CAPITAL RELATING TO POWER PURCHASE AGREEMENTS?

A. Mr. Gale states there is no question that there is an increased cost, but that "the only real issue is who will bear that additional cost?"

Q. DO YOU AGREE WITH IDAHO POWER'S CLAIM OF AN INCREASED COST OF CAPITAL RELATING TO PPAS?

A. No. There are companies, like Con Edison of New York, that rely extensively on market purchases for electricity. Depending on the manner in which these costs are passed through to customers, companies can maintain very strong credit, while at the same time not being "required" to reduce their debt load (leverage.)

Q. PLEASE DESCRIBE CON EDISON OF NEW YORK.

A. Con Edison of New York is Consolidated Edison's main subsidiary[9] and is primarily a "wires and pipes" energy delivery company[10] that has sold most of its electric generating capacity. The company provides its customers the opportunity to buy electricity and gas from other suppliers, purchases substantially all of the electricity and all of the gas it sells to its full-service customers (the cost of which is recovered pursuant to provisions approved by the PSC), and provides energy delivery services to customers pursuant to rate provisions approved by the PSC.

In 2005,[11] Consolidated Edison produced $11.69 billion of revenues with $4.74 billion in purchased power, reflecting a heavy reliance on purchased power (40.5 percent of revenues.) In 2005, the utilities operated by Consolidated Edison purchased substantially all of the energy they sold to customers pursuant to firm contracts and through the NYISO's wholesale electricity market.

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[9] Con Edison of New York generated $9.27 billion of $11.69 billion total operating revenues in 2005 (80 percent), down from 85 percent of revenues in 2004. Approximately 7.0 billion was generated from the electric segment of the company. In 2005, Con Edison of New York comprised $21.15 billion of $24.85 billion total assets (85 percent) with $15.6 billion comprising the electric segment; and it produced $694 million of the consolidated company's $719 million in net income (97 percent);

Source: 2005 SEC 10K ; http://library.corporate-ir.net/library/61/614/61493/items/187500/ED_10k.pdf

[10] Electric energy (MWH) generated: 2,261,680; Purchased from others: 29,055,402; Source: 10K

[11] Source: 2005 Report to the Financial Community; http://media.corporate-ir.net/media_files/nys/ed/10k/Financial10K2005ED.htm

Even with this high level of market purchases, and a typical 50% debt and 50% equity capital structure,[12] it has maintained a "Stable Outlook" and "A rating" grades from Standard and Poor's, Moody's Investors Service and Fitch Ratings.

Q. SO COMPANIES CAN RELY ALMOST EXCLUSIVELY ON POWER PURCHASE AGREEMENTS AND PURCHASED POWER WITHOUT A NEGATIVE EFFECT ON THEIR CREDIT RATING?

A. Yes. The issue of power purchase agreements and their impact on the cost of capital is one that has no definite answer. If there is an impact from PPAs on the cost of capital, then these costs, on average, are already, and have historically been, borne by utility customers.

Q. SINCE THIS IS AN ISSUE THAT HAS BEEN AROUND FOR QUITE SOME TIME, HAVE THE COMPANIES ARGUED FOR SUCH ADJUSTMENTS IN THE PAST?

A. Not to my knowledge. Although this issue has been addressed by the industry, I am not familiar with any adjustment used by the companies that do business in Oregon.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

[12] For each of the Companies, the common equity ratio at December 31st of the prior three years was:

Common Equity Ratio	2005	2004	2003
Con Edison	49.0	51.0	48.0
Con Edison of New York	50.7	52.9	49.3

Source: 2005 SEC 10K; http://library.corporate-ir.net/library/61/614/61493/items/187500/ED_10k.pdf

CASE: UM 1129 - Phase II
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2600

Rebuttal Testimony

April 7, 2006

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

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

Q. HAVE YOU FILED TESTIMONY PREVIOUSLY IN THIS CASE?

A. Yes. I filed Staff 2100, 2101, and 2102 in Phase II of this proceeding and Staff 1300, Staff 1301, and Staff 1302 in the Phase I – Compliance proceeding. Additionally, I adopted and sponsored the testimony of Staff witness Jack Breen in Staff 100 and Staff 500 (filed in the now-completed original Phase I proceeding) concerning insurance issues.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to Idaho Power's comments concerning Issue 7 in the UM 1129 – Phase II, proceeding: Liability insurance for QFs with a design capacity at or under 200 kW.

Q. DID YOU PREPARE ANY EXHIBITS?

A. No.

Q. DO YOU AGREE WITH IDAHO POWER'S STATEMENT THAT REQUIRING REASONABLE LEVELS OF LIABILITY INSURANCE IS NOT A BARRIER TO THE DEVELOPMENT AND ONGOING OPERATION OF VERY SMALL QF PROJECTS?

A. No.

Q. PLEASE EXPLAIN.

In Idaho Power/300, Gale 10, Idaho Power states:

> "It is important to remember that a 200 kW facility operating at an 85% capacity factor using Oregon Schedule 85, Option 1 pricing would have been paid approximately $100,000 during calendar year 2005."[1]

As a result of this statement, I calculated the approximate annual payments that would be made from Idaho Power to various size (kW nameplate) wind, cogeneration, and run of the river hydro QFs. This analysis was performed in order to compare approximate annual insurance costs against calculated revenues a small QF would receive under Option 1 of Idaho's Power Oregon Schedule 85, *Cogeneration and Small Power Production Standard Contract Rates*, for 2006. Staff used both the $5,500 annual liability premium cost Staff cited in direct testimony and the annual premium cost of $10,000 that was stated in FRC Direct Testimony in Phase 1 of this proceeding. See Staff/2100, Dougherty/3.

The following table highlights this comparison:

[1] UM 1129, Idaho Power/300, Gale/10.

Table 1 – Comparison of Insurance Costs and Annual Revenues

Size	Type[2]	Annual Revenue	$5,500 Insurance Cost as a Percent of Revenue	$10,000 Insurance Cost as a Percent of Revenue
25 kW	Wind	$4,152	132%	241%
25 kW	Hydro	$5,033	109%	198%
25 kW	Cogen	$10,694	51%	94%
50 kW	Wind	$8,304	66%	120%
50 kW	Hydro	$10,141	54%	99%
50 kW	Cogen	$21,551	26%	46%
75 kW	Wind	$12,456	44%	80%
75 kW	Hydro	$15,098	36%	66%
75 kW	Cogen	$32,083	17%	31%
100 kW	Wind	$16,608	33%	60%
100 kW	Hydro	$20,131	27%	50%
100 kW	Cogen	$42,778	13%	23%
150 kW	Wind	$24,912	22%	40%
150 kW	Hydro	$30,196	18%	33%
150 kW	Cogen	$64,166	8.6%	16%
200 kW	Wind	$33,215	17%	30%
200 kW	Hydro	$40,261	13%	27%
200 kW	Cogen	$85,555	6.4%	12%

As the above table indicates, as a result of the high cost of insurance as compared to potential revenues, insurance costs would be a barrier to the development and ongoing operations of very small QFs, especially small wind and run of the river QFs. In fact, there are six illustrative scenarios where the estimated cost of insurance equals or exceeds the possible

[2] Staff used a 33 percent capacity factor for small wind, an 85 percent capacity factor for small cogeneration, and a 40 percent capacity for small run of the river hydro qualifying facilities. Capacity factors for wind and cogeneration was provided by Resource Planning Staff; capacity factor for small run of the river hydro was provided by the Oregon Department of Energy (based on a sampling of eight projects that were financed by ODOE in the early 1980s).

revenues a small QF would receive under Idaho Power's Oregon Schedule 85.

For comparison purposes, Staff examined liability insurance premium costs as a percentage of revenue for PacifiCorp and PGE, both of which have recently filed applications to increase their overall rates (UE 179 and UE 180 respectively). Liability insurance premium costs for PacifiCorp, Oregon-allocated, are approximately $1,897,266 for the twelve month period ending December 31, 2007.[3] This liability premium cost is approximately 0.164 percent of PacifiCorp's Oregon adjusted revenues.[4] Liability insurance premium costs for PGE are approximately $6,948,000 for Forecast 2007 costs.[5] This liability premium cost is approximately 0.407 percent of PGE's 2007 Forecasted revenues.[6]

Additionally, according to Idaho Power's 2004 FERC Form 1, dated December 31, 2004,[7] Idaho Power recorded $30,516,650 in Oregon revenue and $282,857 in expense Account 925, *Injuries and damages* in calendar year 2004.[8] As a result, liability insurance costs only accounted for 0.927 percent of Idaho Power's Oregon revenue.

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[3] UE 179 Exhibit PPL/901, page 4.7.1. Premium cost was Oregon-allocated at a 28.442 percent factor.
[4] UE 179 Exhibit PPL/901, page 2.2 revenue amount of $1,159,185,079.
[5] UE 180/PGE/500, Piro-Tooman/13, Table 4. This amount includes Excess Liability, Director and Officer Liability, Fiduciary Liability, Fidelity, and Crime.
[6] UE 180 PGE/200, Revenue Requirement Work papers, page 3, revenue amount of $1,707,263,000.
[7] Idaho Power Company, Oregon Supplement to FERC Form 1, dated December 31, 2004, pages 1 and 11.
[8] Account 925 is the account commonly used for liability insurance. The Idaho Power costs may also include payments for injuries and damage.

So although all three electric utilities have Oregon-allocated liability insurance premium costs that are less than one percent of Oregon revenues, the utilities would place an extremely high insurance cost burden on small QFs if liability insurance is mandated for small QFs at or less than 200 kW. Even using the best case scenario under my table of a 200 kW Cogeneration QF with a $5,500 per year liability premium, the 6.4 percent insurance cost/revenue ratio is most likely restrictive when other operating expenses (e.g., labor, benefits, materials, utility expenses) and interest expenses are added to the total costs that a QF would likely be confronted in its development and ongoing daily operations.

Q. IN CONCLUSION, SHOULD SMALL QUALIFYING FACILITIES UNDER 200 KW BE REQUIRED TO MAINTAIN LIABILITY INSURANCE COVERAGE?

A. No. Although small QFs may decide to carry liability insurance because of business needs, insurance coverage should not be mandated by the utilities because of costs associated with insurance that could be a barrier to the development and ongoing operations of very small QF projects. The small QF should be able to make the business decision, according to its needs, on how much and what type of insurance to obtain.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

UM 1129

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

Dated at Salem, Oregon, this 7th day of April, 2006.

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UM 1129
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