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January 20, 2006

Via Electronic Filing and U.S. Mail

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

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

Enclosed for filing in the above-captioned docket is the Public Utility Commission Staff's Rebuttal Testimony. Please note that the electronic version of Exhibit 1701 is a redacted version. The confidential version will be filed hard copy and served hard copy only to those parties who have filed signatures to the protective order in this docket.

/s/ Kay Barnes

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PUBLIC UTILITY COMMISSION
OF OREGON

UM 1129
PHASE 1 COMPLIANCE

STAFF REBUTTAL TESTIMONY OF

LISA SCHWARTZ
STEVE W. CHRISS
MAURY GALBRAITH

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

REDACTED VERSION

January 20, 2006

CASE: UM 1129 Phase I Compliance
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1500

Rebuttal Testimony

January 20, 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 EXHIBITS?

A. Yes. I prepared Staff/1501, a summary of Staff's final recommendations in the investigation into the Phase I compliance filings. I also prepared Staff/1502, which consists of 27 pages of selected responses to data requests. Staff/1503 is a one-page spreadsheet that shows example calculations of a cap on default losses based on forward market prices. Staff/1504 is a one-page spreadsheet that shows example calculations of a cap on default losses based on the QF contract value.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I provide rebuttal testimony regarding provisions in the standard contracts for Qualifying Facilities (QFs) 10 MW or less. Specifically, I address the following issues, in order:

<u>Issue 5</u>: Security and default provisions

<u>Issue 6</u>: Timelines for providing standard contracts to QFs

<u>Issue 32</u>: Release for claims against the facility

<u>Issue 36</u>: Cap on default losses

Q. PLEASE SUMMARIZE STAFF'S FINAL RECOMMENDATIONS.

A. Staff/1501 is a summary of Staff's final recommendations to the Commission on the compliance filings in Phase I of UM 1129. Further, it is Staff's understanding that all parties agree to a settlement on Issue 4, regarding criteria for determining if multiple energy projects are in fact a single QF. We expect a stipulated settlement and supporting testimony to be filed shortly.

ISSUE 5: SECURITY AND DEFAULT PROVISIONS

Q. DOES PORTLAND GENERAL ELECTRIC (PGE) AGREE WITH STAFF'S RECOMMENDATION THAT IT SHOULD REMOVE FROM ITS STANDARD CONTRACT AN EXCEPTION FOR DAMAGES FOR UNDER-DELIVERY IF THE UTILITY IS RESOURCE-SUFFICIENT?

A. Yes. *See* PGE's response to Staff Data Request 71; Staff/1502; Schwartz/1.

Q. THE FAIR RATE COALITION (FRC) STATES THAT DEFAULT PENALTIES IN THE UTILITIES' STANDARD CONTRACTS HINDER THE CONTINUED OPERATION OF THE SMALLEST QFS AND ARE UNNECESSARY FOR PROTECTING RATEPAYERS. DO YOU AGREE?

A. Yes. FRC provides clear examples of how penalties associated with under-deliveries due to unplanned outages could eliminate these long-time small producers. *See* FRC Phase I-Testimony, Sanders/3, Lines 12-20, and Sanders/4, Lines 1-17; and Pegar/3, Lines 2-21.

A QF 100-kilowatt (kW) or smaller provides a *de minimis* amount of power to the utility system. For example, PacifiCorp's coincident peak load is about 12 million kW. *See* PacifiCorp's 2004 Integrated Resource Plan (IRP) Update at 16, filed November 3, 2005. During an unplanned outage of such a small QF, the loss of the generation to the utility system is dwarfed by normal variations in retail loads.

Ratepayers do not need protection from variances in generation 100 kW or less. FRC notes that long-time power purchase agreements between these very small QFs and the utilities did not include default penalties. *See* FRC Phase I-Testimony, Sanders/3, lines 6-11.

On a similar scale, and for similar reasons, the state's net metering law does not require residents or businesses to advise the utility if their net-metered facility goes off-line, or impose default damages on the customer for unplanned outages. The law sets the size of eligible facilities at 25 kW. *See* ORS 757.300. The 2005 Legislature gave the Commission the authority to increase the eligible facility size for PGE and PacifiCorp. *See* Senate Bill 84. A rulemaking on this matter will begin shortly. In many states, the eligible facility size for net metering is at or above 100 kW.

Q. WHY SHOULD THE COMMISSION TREAT QFS 100 KW OR LESS DIFFERENTLY THAN LARGER QFS REGARDING DEFAULT PROVISIONS?

A. Federal PURPA law sets 100 kW as the minimum threshold for which standard terms and avoided cost rates must be provided. *See* 18 CFR 292.304(c)(1). As such, QFs 100 kW and smaller are called out for special treatment. Further, the magnitude of the risk to the utilities and their ratepayers resulting from under-delivery is far smaller for projects 100 kW and less compared to large projects.

In recognition of the reduced risk, prior to Commission Order No. 05-584 PacifiCorp used a simplified contract for QFs 100 kW and smaller and another form of simplified contract for QFs up to 1 MW. In both of these contracts, the small QF was not in default for under-delivery unless it failed to deliver the minimum Net Output for two consecutive years, per Section 10.1.4. *See* Direct Filing of PacifiCorp, Exhibits G and H, March 5, 2004.

Q. WHAT IS YOUR RECOMMENDATION REGARDING DEFAULT PENALTIES FOR UNDER-DELIVERY FOR QFS 100 KW AND LESS?

A. I recommend the Commission require the utilities modify their standard contracts so that QFs 100 kW and smaller are not subject to damages for under-delivery. If the Commission does not adopt my recommendation, an alternative for its consideration is to require the standard contracts be modified so that the utility may impose damages for under-delivery on QFs 100 kW and smaller only for failure to deliver the minimum Net Output for two consecutive years, as in PGE's current standard contract for QFs up to 10 MW and PacifiCorp's previous simplified contracts for QFs up to 1 MW.

Q. DOES YOUR RECOMMENDATION APPLY TO NEW QFS 100 KW OR SMALLER, AS WELL AS EXISTING QFS OF THAT SIZE?

A. Yes, for the reasons stated above. However, if the Commission does not adopt Staff's recommendation for new QFs 100 kW or smaller, I recommend that the Commission adopt the recommendation for existing QFs that size. As a policy matter, the Commission may not want to jeopardize the continued operation of the long-time QFs we have in the state by adopting the utilities' proposed default terms for all size QFs, existing and new, at the same time the Commission is developing a variety of regulatory policies intended to expand the state's distributed resources.

The Commission also could adopt Staff's recommendation for existing QFs 100 kW and less, and for new QFs that size, the alternative provision that would not impose under-delivery damages unless the QF failed to deliver minimum Net Output for two consecutive years.

Q. WOULD QFS 100 KW OR SMALLER BE REQUIRED TO POST DEFAULT SECURITY IF THE COMMISSION ADOPTS STAFF'S RECOMMENDATION?

A. Yes. Damages for failure to meet commercial operation date, and for termination due to QF's default on other contract provisions, would still apply. If the Commission adopts staff's alternative option, security also would be available if the QF failed to meet minimum Net Output for two consecutive years.

Q. PLEASE CLARIFY STAFF'S POSITION REGARDING ADDITIONAL DEFAULT SECURITY THAT IS REQUIRED IN THE EVENT OF A MATERIAL ADVERSE CHANGE.

A. In direct testimony, I state: "Section 11.1.4, Material Adverse Change, requires performance assurances as reasonably requested by PacifiCorp, including the posting of additional default security, in the event of a default under any other agreement to which the QF is a party in cases where the default would have a material adverse effect on the QF project." *See* Staff/1000, Schwartz/39, Lines 12-16.

Order No. 05-584 states (at 45) that a QF that cannot demonstrate creditworthiness may select at its discretion among four default security options, including step-in rights and a senior lien. The Commission does not require a QF providing default security through step-in rights to post additional default security.

In testifying that Section 11.1.4 is reasonable, I assumed it applied only to QFs choosing the escrow account or letter of credit option for default security, not the step-in rights or senior lien options. I recommend that the Commission require PacifiCorp to make this clarification in its standard contract.

Q. DOES STAFF CONTINUE TO RECOMMEND THAT DAMAGE PROVISIONS FOR UNDER-DELIVERY BE BASED ON AN ANNUAL DELIVERY OBLIGATION?

A. Yes, as is the case for PacifiCorp's and PGE's standard contracts. In addition to the reasons provided previously, there are insufficient data in this proceeding to assess the impact on QFs of damage provisions based on monthly delivery obligations. Idaho Power states that only seven QFs with monthly kWh performance requirements are operating in Idaho. At least one of these projects is a cogeneration QF, which would not be affected by lack of water or wind. So far, one project has been assessed a Shortfall Energy penalty. *See* Idaho Power's response to Staff Data Request 37; Staff/1502, Schwartz/2-3.

Based on its experience as a primary lender for QFs, the Oregon Department of Energy (ODOE) states that it would be difficult for many generators to predict delivery of power on a monthly basis. *See* ODOE/Exhibit No. 6, Keto/7, Lines 9-23, and Keto/8, Lines 15-23, as well as ODOE's response to PacifiCorp Data Request 3; Staff/1502, Schwartz/4. It follows that lenders would not be able to predict penalties for under-delivery on a monthly basis, making financing difficult if not impossible.

Q. WHAT IS YOUR POSITION ON ODOE'S PROPOSAL TO SET MINIMUM DELIVERY OBLIGATIONS BASED ON SET PERCENTAGES?

A. ODOE did not provide sufficient information in order to determine whether the specific percentages recommended are reasonable. *See* ODOE/Exhibit No. 6, Keto/7, Lines 9-23, and ODOE's response to PacifiCorp Data Request 3; Staff/1502, Schwartz/4. As I understand the proposal, ODOE proposes to de-rate typical capacity factors for various QF resources. For example, a wind facility would be de-rated by about two-thirds if the capacity factor were set at 10% as ODOE proposes, compared to a typical capacity factor for wind of roughly 30%. I do not understand how ODOE's proposal would encourage accurate estimates of annual QF delivery to the utility to support firm avoided cost pricing.

Staff continues to support a Mechanical Availability Guarantee based on an annual delivery obligation. We understand that ODOE is interested in exploring such a mechanism. Until such time as a utility adopts a Mechanical Availability Guarantee, the utilities' standard contracts and responses to data requests indicate that they will accept a QF's appropriately documented designation of its minimum delivery obligation, which will take into account adverse natural motive force conditions and, if the QF will be supplying a customer's load, the potential load variation.

ISSUE 6: TIMELINES FOR PROVIDING STANDARD CONTRACTS TO QFS

Q. DO STAFF'S RECOMMENDED TIMELINES FOR PROVIDING THE QF WITH DRAFT AND FINAL CONTRACTS ALIGN WITH CURRENT UTILITY PRACTICE?

A. Yes, based on turnaround times for Idaho Power and PacifiCorp for QFs currently in the process of entering into a PURPA contract. PGE states that no QFs are in the process of entering into a PURPA contract with the Company. *See* Idaho Power's response to Staff Data Request 36, Staff/1502, Schwartz/6-7; PacifiCorp's response to Staff Data Request 70, Staff/1502, Schwartz/8-10; and PGE's response to Staff Data Request 65, Staff/1502, Schwartz/11.

<u>ISSUE 32: RELEASE FOR CLAIMS AGAINST FACILITY</u>

Q. PLEASE CLARIFY YOUR POSITION ON ISSUE 32 REGARDING CLAIMS AGAINST THE QF PRIOR TO CONTRACT EXECUTION.

A. I previously testified that Section 20.2 of PGE's contract is reasonable. Other parties are concerned that this provision would eliminate the ability of a QF to resolve a dispute related to PGE's requirements or costs for interconnection arising prior to the date the power purchase agreement is executed.

PGE clarifies that the primary intent of this provision is to address third-party claims, not claims by the QF. The Company proposes to modify Section 20.2 to read: "By executing this Agreement, Seller releases PGE from any third party claims related to the Facility, known or unknown, that may have arisen prior to the Effective Date." *See* PGE's Response to Staff Data Request 66; Staff/1502, Schwartz/12. Staff supports this modification.

ISSUE 36: CAP ON DEFAULT LOSSES

Q. HAVE THE UTILITIES PROVIDED ADDITIONAL INFORMATION ON THIS ISSUE SINCE YOU FILED YOUR DIRECT TESTIMONY?

A. Yes. On December 23, 2005, Staff received Idaho Power's responses to Staff's data requests. The Company states that it did not include a cap on default losses in its QF standard contract for two reasons: First, a cap could shift risks from QFs to customers. Second, the Company does not cap direct damages for default losses that can be recovered from counter-parties when it makes non-QF purchases in the wholesale market. Nor has the Company entered into contracts for power sales in the wholesale market that limit its liability for direct damages if it fails to perform.

Further, Idaho Power notes that its standard contract provides a 36-month repayment period for default losses. The Company states that it would provide a longer repayment period if necessary to allow the QF to continue to operate and maintain its project and make loan payments. *See* Idaho Power's responses to Staff Data Requests 31, 34 and 35; Staff/1502, Schwartz/13-15.

If the Commission finds it is in the public interest to establish a cap on the amount of default losses the utility may recover from the QF, Idaho Power recommends that the cap be equal to the default losses incurred by the utility that the QF can repay over the remaining term of the contract or 15 years, whichever is longer. *See* Idaho Power's response to Staff Data Request 32; Staff/1502, Schwartz/16.

Staff appreciates Idaho Power's intent that, through a longer repayment period, the QF would remain viable. However, we believe Idaho Power's proposed cap on default losses would be prone to disputes over what the QF could repay over 15 years (or the remaining term of the contract, if longer). There also may be no revenue stream available to the QF to repay the damages if the repayment period extends beyond the contract term. Further, such a cap likely would hinder QF financing because the maximum extent of damages is unknowable at the time of contract execution.

On January 13, 2006, Staff received a supplemental response from PGE to data requests on this issue. PGE states that it does not support a cap on default damages because it "potentially transfers an unknown amount of replacement power costs to the Company and ratepayers," and "transfers the operational risk of a QF to parties who get no financial reward for assuming that risk." PGE points out that its standard contract limits the potential for QF damages for under-delivery because they are calculated relative to the QF's minimum obligation, which is less than expected output under normal conditions. Further, damages are assessed only if the average Mid-C index price for the year in which under-delivery occurs is above the avoided cost price.

If the Commission determines that a cap is appropriate, PGE believes it should be 100% of the cost of replacement power, based on the forward market price curve or the Mid-C index, whichever is applicable at the time of the event of default. *See* PGE's supplemental response to Staff Data Request 51; Staff/1502, Schwartz/17-18.

Q. HAVE ANY OF THE UTILITIES' STANDARD CONTRACTS IN OTHER STATES INCLUDED A CAP ON DEFAULT LOSSES?

A. Yes. In response to Staff Data Request 7 in Phase I of this proceeding, Idaho Power provided a pro forma Firm Energy Sales Agreement offered to QFs in Idaho as a starting point for negotiations. The contract capped the Shortfall Energy price at 150% of the Base Energy Purchase Price. *See* Staff/400, Morgan/20, Lines 20-24, and Morgan/21, Lines 1-8. In other words, the contract capped the repayment price (in dollars per megawatt-hour) for under-deliveries at 150% of the avoided cost rates in the contract. *See* Staff's Supplemental Response to PGE Data Request 2; Staff/1502, Schwartz/19-21.[1]

Q. PLEASE EXPLAIN THE IMPORTANCE OF CAPPING DEFAULT LOSSES BASED ON PRICES ESTABLISHED AT THE TIME OF CONTRACT EXECUTION.

A. Staff and ODOE have testified throughout this proceeding on the importance for financing of knowing the maximum extent of damages that may be levied for QF default. For example, regarding reduction of future contract payments to the QF for a period of time to recoup default losses, Staff Witness Thomas Morgan stated: "The amount that payments are reduced would be specified in the contract, not tied to the market price of replacement power…. The penalty

[1] The Shortfall Energy price is the positive difference, if any, between the "Market Energy Cost" and the avoided cost rates in the contract. Market Energy Cost is 85% of the weighted average of the daily on-peak and off-peak Dow Jones Mid-C Index prices for non-firm energy.

amount and duration for payments should be set at a level that would not jeopardize project viability." *See* Staff/800, Morgan/5, Lines 3-6.

In ODOE/Exhibit No. 3, ODOE Witness Jeff Keto discusses the need for financing to have transparent contract provisions and a known quantity of net revenue for debt service, which must take into account potential reductions due to default damages, at Page 2, Lines 1-3; Page 3, Lines 1-2; Page 3, Lines 12-13; and Page 4, Lines 21-22. In direct testimony on the compliance filings, Mr. Keto explains that small QF projects have little financial reserves and thus require a power purchase agreement with limited risk of disruption to the revenue stream in order for SELP to finance the project. *See* ODOE/Exhibit No. 6, Keto/2, Lines 11-23, and Keto/3, Lines 1-5.

Following filing of direct testimony, Staff submitted additional data requests to ODOE. Mr. Keto states: "I would likely not recommend SELP finance most of the current QF projects we are reviewing if the power purchase contract's maximum default damages can not be quantified at the time the loan is advanced, usually upon execution of the power purchase agreement. Similarly, I would not recommend financing if projected maximum damages under the power purchase agreement could not be paid from a reduction in future revenue within a reasonable period of time while keeping expenses and debt service current." *See* ODOE's response to Staff Data Request 20; Staff/1502, Schwartz/22-23.

Regarding the damage clauses in the power purchase contract, Mr. Keto states: "When the amount of the penalty is difficult or impossible to quantify financing becomes much more difficult because SELP would estimate a worst case scenario. As a result, SELP would likely reduce the loan amount and increase project equity, which is usually not available on projects of this size, or decline to finance the project. This would result in fewer projects being approved for financing and likely fewer projects being constructed." *See* ODOE's response to Staff Data Request 21; Staff/1502, Schwartz/23.

Among the list of financial conditions ODOE states would cause SELP to deny QF financing are "insufficient projected revenue for the term of the loan to meet expenses, debt service and return to owners," "risk of significant revenue reduction because of power sales agreement penalties or damages," and "uncertain project revenue if power sales are tied to a market or variable price." *See* ODOE's response to PGE Data Request 4; Staff/1502, Schwartz/24-26. Uncapped damages for under-deliveries fall squarely within these conditions for denying QF financing.

Q. PLEASE PROVIDE EXAMPLES OF THE CAP ON DEFAULT LOSSES YOU PROPOSED IN DIRECT TESTIMONY PENDING FURTHER INVESTIGATION.

A. Staff Exhibit 1503 shows the dollar-per-megawatt-hour cap on default losses I proposed at that time. It is calculated as 110% of annual forward market prices determined at the time of contract execution. An adder to forward prices protects against upward movement in the market. If actual market prices at the time of QF default do not exceed 110% of forward market prices, a 110% cap on default losses would have no impact on the utility and its ratepayers.

Staff Exhibit 1503 shows examples of potential impacts of such a cap on the utility — and ratepayers if costs are passed through via a power cost adjustment or other mechanism — in the following three cases of market prices that exceed 110% of forward prices:

- Market prices at the time of default are 20% higher than forward prices
- Market prices at the time of default are 70% higher than forward prices
- Market prices at the time of default are set by FERC's $250/MWh cap

The examples assume the following:

- A 5 MW cogeneration facility with an 85% capacity factor
- A 6 MW wind facility with a 33% capacity factor, composed of four 1.5-MW turbines
- For simplification, potential adverse motive force conditions are not taken into account in the minimum delivery obligation. This assumption inflates the potential unrecovered default losses.
- Two events of default are shown. First is a three-month default event that runs from March 2016 to May 2016. This is the type of default event Staff contemplated when making its initial recommendation. The second type of default event is a year-long default event in 2016. ODOE raised this type of event in direct testimony. *See* ODOE Exhibit 6, Keto/9, Lines 16-22.
- The cogeneration QF produces no power during the default period.
- *One* of the wind QF's four 1.5-MW turbines produces no power during the default period.

Because the data are publicly available and recent, the calculations use PacifiCorp's projected forward market prices for the mid-Columbia trading hub, from Figure A.3 of the Company's 2004 IRP Update. For illustrative purposes, these serve as a proxy for the utility's forward market prices at the time of contract execution. For consistency, the calculations use PacifiCorp's filed avoided cost rates.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR EXAMPLE CALCULATIONS FOR A CAP ON DEFAULT LOSSES BASED ON 110% OF FORWARD MARKET PRICES AND A THREE-MONTH DEFAULT EVENT.

A. If market prices turn out 20% higher than forward market prices determined at the time of contract execution, the unrecovered default losses under a 110% cap are about $7,000 for the wind QF and $59,000 for the cogeneration QF. If market prices instead turn out far higher than expected — 70% higher — the unrecovered losses would be about $41,000 for the wind QF and $355,000 for the cogeneration QF. Finally, in the event of a market meltdown in the West similar to the energy crisis of 2000-01, with a FERC price cap of $250 per MWh, the unrecovered losses would be about $197,000 for the wind QF and $1.7 million for the cogeneration QF.

Q. WHAT WOULD BE THE UNRECOVERED DEFAULT LOSSES FOR A THREE-MONTH DEFAULT EVENT UNDER A HIGHER CAP?

A. Staff Exhibit 1503 also shows example calculations of unrecovered default losses if the cap were based on 150% of forward market prices. Staff chose this percentage for the Commission's review based on the percentage cap in the pro forma contract Idaho Power offered in Idaho. However, it is important to note that the Company's cap was based on QF contract prices, not forward market prices at the time of contract execution. Using PacifiCorp's avoided cost rates and the forward market prices in the Company's recent IRP update, the results would be somewhat similar.

Under a cap set at 150% of forward prices, there would be no unrecovered default losses if market prices turn out 20% higher than expected. At market prices 70% higher that forward prices, the unrecovered losses would be some $14,000 for the wind QF and $118,000 for the cogeneration QF. In the market meltdown scenario, those figures would be $170,000 for the wind QF and $1.5 million for the cogeneration QF.

Staff Exhibit 1503 also shows example calculations based on a cap of 125% of forward market prices at the time of contract execution.

Q. WHAT WOULD BE THE UNRECOVERED DEFAULT LOSSES FOR A YEAR-LONG DEFAULT EVENT?

A. Under an extreme case of zero generation from the cogeneration QF, or one wind turbine, lasting an entire year, there are no unrecovered default losses under a cap based on 125% or 150% of forward market prices if actual market prices turn out 20% higher than expected. Under all other cases, the unrecovered default losses are roughly four times the level of a three-month default event.

Q. HAS ODOE RECOMMENDED A SPECIFIC CAP ON DEFAULT LOSSES?

A. Yes. In direct testimony, ODOE recommended that the "contract value" of the minimum delivery obligation during the default period serve as the cap on default losses. *See* ODOE/Exhibit No. 6, Keto/16, Lines 16-21. ODOE clarifies that the contract value is the contract price during the default period, such as the average weighted on-peak/off-peak price during the period. *See* ODOE's response to PacifiCorp Data Request 5; Staff/1502; Schwartz/5.

In other words, ODOE recommends a total dollar cap for default losses that the utility may assess a QF for an event of default equal to 100% of the QF contract price multiplied by the amount of energy the QF failed to deliver the previous year, based on its annual minimum delivery obligation.

Q. PLEASE PROVIDE EXAMPLE CALCULATIONS OF ODOE'S PROPOSED CAP ON DEFAULT LOSSES.

A. Staff Exhibit 1504 shows example calculations of ODOE's proposed cap under the same assumptions about under-deliveries, default periods, QF contract prices and market prices as in Staff Exhibit 1503. Only under the most extreme case, where market prices are set at $250 per MWh, and the cogeneration facility does not produce any generation for one year, would the utility not fully recover default losses from the QF.

Q. WHAT DO YOU RECOMMEND REGARDING A CAP ON DEFAULT LOSSES AS A RESULT OF STAFF'S FURTHER INVESTIGATION INTO ISSUE 36?

A. I recommend the Commission adopt ODOE's proposal to set a cap on default losses for standard contracts for QFs 10 MW and less equal to 100% of the QF contract price multiplied by the amount of energy the QF failed to deliver, based on its minimum delivery obligation for the year in which the event of default occurs. Such a cap poses little risk to the utility or its ratepayers, even when considering an extreme default event such as one year's worth of zero generation. Because ODOE proposes it, such a cap apparently would not hinder QF financing, in tandem with QF payment of default loss damages over a period of time that allows continued QF operation and maintenance and debt service.

Q. DOES STAFF'S RECOMMENDATION ALSO APPLY TO DEFAULT LOSSES FOR CONSTRUCTION DELAY?

A. Yes. Order No. 05-584 (at 47) states that construction default provisions should be consistent with those for default provisions for under-deliveries. The Commission states: "In both situations, the utility may need to replace the contracted for energy at market prices that may exceed the contract price. The only difference with regard to construction default or delay will be that replacement will occur not far in advance of the date of contract implementation."

Q. HOW SHOULD THE UTILITIES IMPLEMENT THE CAP ON DEFAULT LOSSES FOR CONSTRUCTION DELAY?

A. There are two differences in implementation compared to damages for under-deliveries. The first issue is how to address the minimum delivery obligation over which the default amount is calculated. If it is on an annual basis, as in PGE's and PacifiCorp's contracts, and as Staff recommends for Idaho Power as well, the utility would need to pro-rate the annual delivery obligation. For example, if the QF's on-line date is delayed by three months, the under-delivery amount that the utility should use in calculating the default damages is one-fourth of the annual minimum delivery obligation. Second, damages would not apply if, on the date of contract execution, the utility expected to be in a resource-sufficient position on the date the QF was committed to being on-line.

Q. PLEASE EXPLAIN WHY STAFF DOES NOT PROPOSE A SIMILAR CAP ON DAMAGES FOR *TERMINATION* DUE TO THE QF'S BREACH OF CONTRACT.

A. Staff does not propose a similar cap on damages for termination due to the QF's breach of contract because we do not find it necessary to do so to enable QF financing. Further, we want to avoid potential gaming by the QF during periods of high market prices.

ODOE states that in the event it financed a project that is terminated by the utility, it would seek to operate the facility or sell the facility to another operator. *See* ODOE's response to Staff Data Request 2.e.; Staff/1004, Schwartz/3. Thus, Staff assumes that termination damages applied to the original operator would not jeopardize the continued viability of the project.

As I stated in direct testimony, Staff supports damages for termination based on the positive difference between the replacement power price and the QF contract price for a period of 24 months, beginning with the date of termination. *See* Staff/1000, Schwartz/49, Lines 11-16. If replacement power prices are higher than the QF contract prices, the damage provisions make the utility and its ratepayers whole. If replacement power prices are lower than the QF contract prices, the QF pays nothing.

Regarding potential gaming, Idaho Power cites an example of a QF developer that terminated its contract with the Company during the 2000-01 Western energy crisis, paid the liquidated damages, and immediately sought to sell power at high market prices. *See* Idaho Power's response to Staff Data Request 33; Staff/1502, Schwartz/27. A cap on termination damages would exacerbate the potential for such gaming.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

CASE: UM 1129 Phase I Compliance
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1501

Exhibit in Support of Rebuttal Testimony

January 20, 2006

SUMMARY OF STAFF'S FINAL RECOMMENDATIONS

Standard Contract Provisions to Protect Against Breaches

Creditworthiness

- Require PGE to modify Section 7 of its standard contract, requiring default security in the event a QF becomes delinquent during the contract term, to provide an exception for becoming delinquent on its construction loan so long as the lender is working with the borrower to become current on loan payments.

- Require Idaho Power and PacifiCorp to make a similar clarification in their standard contracts.

Security

- Direct PacifiCorp to remove its requirement that a QF choosing the step-in rights or senior lien security option under the standard contract must obtain a letter of credit for potential environmental remediation.

- Direct Idaho Power and PGE to provide specific definitions in their standard contracts for the security options of cash escrow, senior lien, step-in-rights and letter of credit.

- Direct Idaho Power to modify its standard forms of contract to specify how the Company would determine the amount of default security required, in a manner consistent with PGE's or PacifiCorp's standard contract.

- Require PacifiCorp to clarify in its standard contract that Section 11.1.4 applies only to QFs choosing the escrow account or letter of credit option for default security.

Default and Termination

- Require Idaho Power to amend its contract to provide for an annual, rather than monthly, energy delivery commitment for QFs relying on intermittent renewable resources, as well as cogeneration facilities relying on industrial hosts.

- Allow the utilities to amend their standard contracts to use a Mechanical Availability Guarantee based on annual production as the basis for determining default for under-delivery for QFs relying on intermittent resources.

- Require the utilities to modify their standard contracts to exclude delay of commercial operation as an event of default, including as a cause of termination or related damages, if the utility determines at the time of contract execution that it will be resource-sufficient as of the QF on-line date specified in the contract.

- Require the utilities to modify the testing requirement for achieving commercial operation to take into account availability of motive force.

- Require PacifiCorp and Idaho Power to modify their standard contracts to provide that if a QF is terminated due to its default, the utility may require the QF wishing to again sell to the company to do so subject to the terms of the original agreement until its end date.

- Direct PGE to provide for reciprocal default terms in its standard contract.

- Require PGE to modify its standard contract to provide a payment schedule for QF default damages that takes into account sufficient monies to provide for continued QF operations and debt payment, when future utility payments are temporarily reduced as a penalty for under-delivery.

- Require the utilities to modify the standard contracts to eliminate under-delivery damages for QFs 100 kW and smaller. An alternative for the Commission's consideration is requiring the utilities to modify the standard contracts so that under-delivery damages for QFs 100 kW and smaller may be imposed only for failure to deliver the minimum Net Output for two consecutive years.

Damages

- Require Idaho Power to revise the damage provisions in its standard contracts to accommodate an annual, rather than monthly, energy delivery commitment.

- Direct PGE and Idaho Power to specify that if the standard contract is terminated due to the QF's default, the QF must pay the positive difference, if any, obtained by subtracting the contract price from projected forward market prices for 24 months beginning with the date of contract termination, for the minimum annual delivery amount specified in the contract.

- Require PGE to remove from its standard contract the exception for being resource-sufficient for applying damages for under-delivery.

- Establish a cap for the standard contracts for default losses that can be recouped pursuant to future QF contract payment reductions, equal to 100% of the QF contract price multiplied by the amount of energy the QF failed to deliver, based on its minimum delivery obligation for the year in which the event of default occurs.

Other Contract Provisions to Mitigate Risk

- Order PGE to modify Section 3.1.5 of its standard contract to provide an exception for statutory liens.

- Approve PGE's proposal to modify Section 20.2 of its standard contract to read: "By executing this Agreement, Seller releases PGE from any third party claims related to the Facility, known or unknown, that may have arisen prior to the Effective Date."

Detailed List of Procedures in Tariffs

- Direct PGE to provide in its tariff for purchases from QFs up to 10 MW a list of specific project information required to enter into a power purchase agreement.

- Require that all the utilities' tariffs for QFs up to 10 MW include detailed procedures for obtaining draft and final power purchase agreements, with the following timelines:

  a. The Company will provide a draft power purchase agreement to the QF within 15 business days of receipt from the QF of all information required to enter an agreement, as specified in the tariff.

  b. The Company will respond within 14 calendar days to any written comments and proposals the QF provides in response to draft agreements.

  c. The Company will provide a final draft agreement to the QF within 15 business days of the Company's receipt of any additional or clarifying project information needed.

  d. The Company will provide a final executable agreement to the QF within 15 business days of parties' full agreement on the terms and conditions of the draft agreement.

- Direct PGE to specify in its tariff for QF purchases the FERC adjustment factors in 18 C.F.R. § 292.304(e).

Treatment of Additional Generation When QF Increases Output

- Direct the utilities to amend their standard contracts to treat additional generation resulting from efficiency improvements or necessary equipment replacement as follows:

a. The QF will continue to receive the avoided cost rates in place as of the effective date of the current agreement for generating output up to the original nameplate rating specified in the agreement. Payments for generation resulting from any additional capacity installed after the effective date will be based on avoided cost rates as of the date of the improvement or equipment replacement. The contract will be amended at that time to reflect changes in operation or equipment.

b. If the total new capacity rating exceeds 10 MW, the QF and the utility will negotiate a new non-standard contract based on avoided cost rates, terms and conditions at the time of the improvement.

QFs Using Third-Party Transmission Services

- Direct the utilities to modify their standard contract provisions for off-system QFs to provide on-peak avoided cost rates for deliveries during on-peak hours above the nameplate rating to accommodate hourly scheduling in whole megawatts by a third-party transmission provider.

Environmental Attributes

- Direct PGE and PacifiCorp to amend their standard contracts to provide a waiver for non-energy attributes in compliance with Order No. 05-1229.

Revised Protocol for PacifiCorp

- Determine that the Commission's process for calculating avoided costs yields rates for power purchases for new QF contracts that are similar to those for comparable resources under PacifiCorp's Revised Protocol.

Natural Gas Price Forecast

- Require PGE either to provide additional quantitative justification for the use of its filed natural gas forecast, or provide a new forecast consistent in time with the filed natural gas forecast and avoided cost calculations.

Insurance

- Require that the utilities modify their standard contracts to allow QFs to obtain the required insurance from any insurance carrier allowed to write insurance coverage in Oregon. If the Commission instead decides to use the A.M. Best ratings as a benchmark, then the Commission should allow QFs to obtain insurance with companies rated not lower than "B+", which is considered "Very Good (Secure)" by A.M. Best.

Resource Sufficiency Period

- Direct PacifiCorp to include the targeted levels of front office transactions from its 2004 IRP in the load-resource balances used to determine its resource sufficiency period and avoided costs.

- Direct PGE to update the load-resource balances used to determine its resource sufficiency period and avoided costs to: (1) include known and measurable resource additions and changes in expected loads; (2) exclude its 12 percent IRP planning margin from its load requirement; (3) adjust plant availability for forced outages; and (4) include planned front office transactions from its 2002 IRP Final Action Plan.

- Direct PacifiCorp for future avoided cost filings to determine its annual capacity position based on the largest monthly capacity deficit (or smallest capacity surplus) when determining its resource sufficiency period.

CASE: UM 1129 Phase I Compliance
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1502

Exhibit in Support of Rebuttal Testimony

January 20, 2006

January 18, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Doug Kuns
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM-1129/Advice No. 05-10 Phase I
PGE Response to OPUC Data Request
Dated January 4, 2006
Question 071

Request:

Please explain why PGE's standard contract for Qualifying Facilities 10 MW or less provides an exception for default penalties for under-delivery if the company is in a resource sufficient position as defined in the tariff for the contract year.

Response:

Per discussion with Staff on January 12, 2005, PGE will modify its contract to remove the noted exception.

REQUEST STAFF 37:

Please provide a list of QFs that completed a PURPA power purchase agreement with Idaho Power under the standard rate provisions of the Idaho Public Utilities Commission. Include the following information:

a. Resource type (wind, hydro, solar, biomass — specifying type such as mill waste or dairy waste, geothermal, or natural gas cogeneration)
b. Size (in megawatts)
c. On-line date
d. Any Shortfall Energy damages assessed by Idaho Power, including the month and year in which the QF default occurred, the amount of Shortfall Energy by month in kWh and as a percent of the monthly delivery commitment, and the damages assessed per month in dollars.

IDAHO POWER'S RESPONSE TO REQUEST STAFF 37:

a. Please see Exhibit A to Idaho Power's Response to Request Staff 37.

b. Please see Idaho Power's Response to Request Staff 37(a).

c. Please see Idaho Power's Response to Request Staff 37(a).

d. Idaho Power currently has 22 PURPA agreements that contain monthly kWh performance requirements and 1 PURPA agreement that contains an hourly kWh performance requirement. The total nameplate capacity of these 23 projects is approximately 239 MW. These projects include wind, wood waste, landfill gas, hydro, geothermal, and industrial waste projects.

Of these 23 projects, 7 projects are online with the remaining 16 projects scheduled to be online by January, 2007. The total nameplate capacity of the 7 projects currently online is a total of approximately 39 MW, with sizes ranging from 0.13 MW to 12 MW.

For the 7 projects currently online, only one project, in one month has experienced a Shortfall Energy Payment penalty.

This project agreed to deliver approx 2.1 million kWh for the month of October 2005, but only delivered 1.6 million kWh (approx 76% of the contracted amount).

In the same month, the Market Cost of energy was greater than the contract price, therefore a Shortfall Energy Payment was calculated which reduced the project's current month's energy payment by approximately $10,000 out of a total payment of $75,000.

Idaho Power Company
Cogeneration and Small Power Production

	Project Name	Plant Size (Nameplate MW)	Facility Type		First Energy Date	
1	Arrow Rock Wind	19.50	Wind		06/01/2006	QF Estimated
2	Barber Dam	4.14	Hydro		12/31/1988	
3	Birch Creek	0.05	Hydro		03/29/1984	
4	Black Canyon #3	0.14	Hydro		04/16/1984	
5	Blind Canyon	1.50	Hydro		04/09/1992	
6	Box Canyon	0.36	Hydro		12/22/1983	
7	Briggs Creek	0.60	Hydro		09/30/1985	
8	Burley Butte Wind	10.50	Wind		10/01/2006	QF Estimated
9	Bypass	9.96	Hydro		04/20/1988	
10	Canyon Springs	0.13	Hydro		09/20/1984	
11	Cedar Draw	1.55	Hydro		05/02/1984	
12	Clear Springs Trout	0.52	Hydro		11/02/1983	
13	Crystal Springs	2.44	Hydro		11/30/1985	
14	Curry Cattle Company	0.22	Hydro		06/04/1983	
15	Dietrich Drop	4.50	Hydro		08/22/1988	
16	Elk Creek	2.00	Hydro		04/04/1986	
17	Emmett Facility	17.50	Biomass	Wood waste	12/01/2006	QF Estimated
18	Falls River	9.10	Hydro		08/14/1993	
19	Faulkner Ranch	0.87	Hydro		08/15/1987	
20	Fisheries Development Co	0.26	Hydro		07/03/1990	
21	Fossil Gulch Wind	10.50	Wind		12/31/2004	
22	Geo Bon #2	0.93	Hydro		10/10/1986	
23	Golden Valley Wind	10.50	Wind		10/01/2006	QF Estimated
24	Hailey CSPP	0.06	Hydro		02/17/1985	
25	Hazelton A	7.70	Hydro		04/26/1990	
26	Hazelton B	7.60	Hydro		04/30/1993	
27	Hidden Hollow Landfill	3.20	Biomass	Landfill Gas	03/01/2006	QF Estimated
28	Horseshoe Bend Hydroelectric	9.50	Hydro		04/12/1995	
29	Horseshoe Bend Wind Park	9.00	Wind		02/01/2006	QF Estimated
30	Jim Knight	0.34	Hydro		09/14/1984	
31	Kasel and Witherspoon	0.90	Hydro		12/30/1983	
32	Koyle Small Hydro	1.25	Hydro		12/30/1983	
33	Lateral # 10	2.06	Hydro		05/03/1985	
34	Lava Beds	18.00	Wind		01/01/2007	QF Estimated
35	Lemoyne	0.08	Hydro		12/10/1984	
36	Lewandowski Farms	0.40	Wind		10/01/2002	
37	Little Wood Rvr Res	2.85	Hydro		02/23/1985	
38	Littlewood - Arkoosh	0.87	Hydro		08/05/1986	
39	Low Line Midway Hydro	2.50	Hydro		03/01/2007	QF Estimated
40	Lowline #2	2.79	Hydro		04/13/1988	
41	Lowline Canal	7.97	Hydro		12/31/1984	
42	Magic Reservoir	9.07	Hydro		05/16/1989	
43	Magic Valley	10.00	Natural Gas	CHP	11/08/1996	
44	Magic West	10.00	Natural Gas	CHP	11/09/1996	
45	Malad River	0.62	Hydro		11/15/1983	
46	Marco Ranches	1.20	Hydro		07/01/1985	
47	Mile 28	1.50	Hydro		05/26/1994	
48	Milner Dam	18.00	Wind		11/01/2006	QF Estimated
49	Mitchell Butte	2.09	Hydro		05/18/1989	
50	Mud Creek S&S	0.52	Hydro		02/20/1982	
51	Mud Creek White	0.21	Hydro		01/10/1986	
52	Notch Butte	18.00	Wind		12/01/2006	QF Estimated
53	Oregon Trail Wind	10.50	Wind		06/01/2006	QF Estimated
54	Owyhee Dam CSPP	5.00	Hydro		08/08/1985	
55	Pigeon Cove	1.89	Hydro		09/30/1984	
56	Pilgrim Stage Station Wind	10.50	Wind		06/01/2006	QF Estimated
57	Pocatello Waste	0.46	Biomass	Methane gas	12/05/1985	
58	Pristine Springs	0.13	Hydro		03/29/1995	
59	Pristine Springs #3	0.20	Hydro		06/11/2003	
60	Raft River Geothermal #1	10.00	Geothermal		01/01/2007	QF Estimated
61	Reynolds Irrigation	0.26	Hydro		05/19/1986	
62	Rim View	0.20	Hydro		11/01/2000	
63	Rock Creek #1	2.05	Hydro		09/11/1983	
64	Rock Creek #2	1.90	Hydro		12/30/1988	
65	Sagebrush	0.43	Hydro		06/28/1985	
66	Sahko Hydro	0.50	Hydro		03/01/2006	QF Estimated
67	Salmon Falls	21.00	Wind		02/01/2007	QF Estimated
68	Schaffner	0.53	Hydro		08/08/1986	
69	Shingle Creek	0.22	Hydro		07/15/1983	
70	Shoshone #2	0.58	Hydro		04/26/1996	
71	Shoshone CSPP	0.37	Hydro		06/21/1982	
72	Simplot Pocatello	12.00	Cogen	Industrial waste	01/13/1986	
73	Snake River Pottery	0.07	Hydro		11/19/1984	
74	Snedigar	0.54	Hydro		12/31/1984	
75	Sunshine Power #2	0.11	Hydro		12/16/1987	
76	Tamarack CSPP	5.00	Biomass	Wood waste	06/01/1983	
77	TASCO - Nampa	2.00	Natural Gas	CHP	11/01/1998	
78	TASCO - Twin Falls	3.00	Natural Gas	CHP	08/11/2001	
79	Thousand Springs Wind	10.50	Wind		06/01/2006	QF Estimated
80	Tiber Dam	7.50	Hydro		06/01/2004	
81	Trout - Co	0.24	Hydro		11/30/1986	
82	Tuana Gulch Wind	10.50	Wind		06/01/2006	QF Estimated
83	Tunnel #1	7.00	Hydro		06/08/1993	
84	Vaagen Brothers Lumber Inc	4.50	Biomass	Wood waste	09/01/1995	
85	White Water Ranch	0.16	Hydro		07/11/1985	
86	Wilson Lake Hydro	8.40	Hydro		05/11/1993	

HARDY MYERS
Attorney General

COPY

PETER D. SHEPHERD
Deputy Attorney General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

January 12, 2006

VIA EMAIL AND U.S. MAIL

Data Request Response Center
PacifiCorp
825 N.E. Multnomah, Suite 800
Portland, OR 97232
datarequest@pacificorp.com

John M. Eriksson
Stoel Rives LLP
900 S.W. Fifth Avenue, Suite 2600
Portland, OR 97204-1268
jmeriksson@stoel.com

Re: Oregon Department of Energy's Response to PacifiCorp's Data Requests Nos. 2-5
Docket No. UM 1129 – Phase I Compliance
DOJ File No. 330-020-GN0041-04

The Oregon Department of Energy's (ODOE) responses to PacifiCorp's December 29, 2005 Data Requests Nos. 2-5, is included immediately following the questions below.

2. With respect to Mr. Keto's testimony at p.5, lines 22-23, please explain the basis for the belief that a host company would be willing to assume the financial responsibility of the QF for an environmental remediation.

Response: My response was that an option should be given to QF projects at industrial or brownfield sites to allow the host company to accept financial responsibility for environmental remediation in lieu of the QF providing a letter of credit if one was required. I did not imply that a specific host company would be willing to assume this financial responsibility. I recommend the option based on financing industrial energy plants where the host companies were willing to sign their name on loans that included responsibility for any environmental clean up costs.

3. With respect to Mr. Keto's testimony at p.7, lines 19-22, please explain the basis for the recommended annual minimum power delivery percentages.

Response: Our basis for recommending annual minimum power delivery was to avoid the monthly delivery requirements stated in the Idaho Power contract. Our experience with many hydroelectric generating plants has informed us that it is very difficult for many generators to accurately predict delivery of power on a monthly basis. The minimum delivery amounts for each technology were selected so that hypothetical projects could reasonably supply the amount in years with low resource availability and normal outages.

4. With respect to Mr. Keto's testimony at p.9, lines 16-22, please explain what would be "egregious cases."

Response: I would consider an egregious case a willful act of a generator to not operate the facility in a commercially prudent manner for an extended period of time, possibly over one year. For example, lack of motive force or inability to repair a facility because of equipment, material, labor or transportation delays would not be considered egregious if they cause an extended delay in power generation and the generator was making a commercially reasonable effort to correct the problem.

5. With respect to Mr. Keto's testimony at p.16, lines 19-21, please describe how ODOE would propose to determine "contract value."

Response: Contract value was meant to represent the contract price during the default period. This could be the average of the on-peak and off-peak prices weighted by the respective percentage of on-peak and off-peak time during the default period.

Sincerely,

Janet L. Prewitt

Janet L. Prewitt
Assistant Attorney General
Natural Resources Section

c: Sarah J. Adams Lien, Stoel Rives (hard copy and email)
Phil Carver, ODOE (email only)
Carel DeWinkel, ODOE (email only)
Jeff Keto, ODOE, (email only)

JLP:jrs/GENO9005

REQUEST STAFF 36:

Please provide a list of new Qualifying Facilities (QFs) that are in the process of entering into a PURPA contract with Idaho Power. Include the following information:

a. Resource type (wind, hydro, solar, biomass — specifying type such as mill waste or dairy waste, geothermal, or natural gas cogeneration)
b. Size (in megawatts)
c. Location (by state)
d. Projected on-line date
e. The dates the following activities occurred:
   - QF provided initial project information in order to obtain a draft contract
   - Idaho Power provided a draft power purchase agreement
   - QF provided all project information required for a final draft agreement
   - Idaho Power provided a final draft agreement
   - Idaho Power provided a final executable agreement

IDAHO POWER'S RESPONSE TO REQUEST STAFF 36:

Wind Projects
Idaho Power currently has numerous Idaho sitused 10 MW to 25 MW PURPA wind projects (all less than 10 aMW) in various stages of discussions with Idaho Power. No requests for a contract have been received from any Oregon wind projects. Currently Idaho Power, the Idaho Public Utilities Commission Staff, various wind developers, and other interested parties are engaged in settlement discussions that could lift a current temporary reduction in the size of QFs eligible for the standard rates paid to wind projects in Idaho. Under these circumstances, Idaho Power is unable to identify "currently pending" wind contracts and assign realistic times for processing contract requests.

Hydro Projects
Two projects currently under discussion, one Idaho project and one Oregon project.

Idaho Project
Approximate size: 1.7 MW

- On line date: Not yet specified by Developer
- Initial QF Contact – March 2004
- QF requested draft agreement – March 2004
- Idaho Power provided draft agreement – March 2004.
- No response from QF until June 2005.
- QF requested revised draft agreement – June 22, 2005
- Idaho Power provided revised draft agreement – June 30, 2005
- Next contact from QF: Mid September 2005, requested current copy of draft agreement.

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- Idaho Power provided draft agreement –September 30, 2005
- No contact from developer since draft provided.

Oregon Project
Approximate size: 3 MW

- On line date: Not yet specified by Developer
- Initial QF Contact – Various preliminary discussions ongoing since spring of 2005.
- QF has not requested draft agreement.
- Last contact – December 2005. QF was provided information to begin process of reviewing transmission and interconnection issues with Idaho Power Company delivery business unit.

Anaerobic Digester Projects
Three or four projects currently in very general conversations with Idaho Power.

All Idaho Projects
Currently none of these projects are reviewing "active" draft agreements. Two of the projects previously requested draft agreements; agreements were supplied within two weeks of their request. However, no response was received from these projects for approximately 6 months. Response from the projects after 6 months was to advise Idaho Power that they were having issues with the prospective fuel suppliers and would contact Idaho Power at a later date if and when they were able to move forward with these projects.

Approximate size: Each project about 0.5

CHP Project
One Oregon project in active discussions with Idaho Power.

Approximate size: 30 – 130 MW

- On line date: Not yet specified by Developer
- Initial QF Contact – August 24, 2005
- QF provided initial proposal on September 8, 2005
- September 2005 – current
- Various ongoing discussions and proposals have been exchanged between the parties.

QF has never requested a draft agreement.

Geothermal Projects
Idaho Power has engaged in general discussions with several geothermal projects, all located in the state of Idaho. No draft agreements have been requested by the projects.

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UM-1129/PacifiCorp
January 6, 2006
OPUC Data Request 70

OPUC Data Request 70

Please provide a list of new Qualifying Facilities (QFs) that are in the process of entering into a PURPA contract with PacifiCorp. Include the following information:

a. Resource type (wind, hydro, solar, biomass – specifying type such as mill waste or dairy waste, geothermal, or natural gas cogeneration)
b. Size (in megawatts)
c. Location (by state)
d. Projected on-line date
e. The dates the following activities occurred:
   - QF provided initial project information in order to obtain a draft contract
   - PacifiCorp provided a draft power purchase agreement
   - QF provided all project information required for a final draft agreement
   - PacifiCorp provided a final draft agreement

PacifiCorp provided a final executable agreement

Response to OPUC Data Request 70

The requested information is provided as Attachment OPUC 70.

OREGON

ELECTRIC UTILITY PURCHASES FROM QUALIFYING FACILITIES

UM-1129

PACIFICORP

OPUC DATA REQUEST

ATTACHMENT OPUC 70

Attachment OPUC 70

QF Identifier	Resource Type	Size (MW)	State	Date (some are approximate)[2] Projected On-line	Initial Info[1]	Draft PPA	Final Info	Final Draft PPA	Executable PPA
A	Biomass	7.5	CA	2006	08/18/05				
B	Wind	17.5	ID	2006	10/15/03	05/01/04	07/01/05	08/01/05	08/01/05
C	Gas	130.0	OR	2010	11/28/05				
D	Biogas	9.5	OR	2006	05/15/05				
E	Biomass	7.5	OR	2006	02/03/05	09/28/05			
F	Biomass	7.5	OR	2006	10/01/05				
G	Biomass	7.5	OR	2006	09/15/05				
H	Biogas	2.5	OR	2006	11/08/04	09/07/05			
I	Biomass	2.0	OR	2006	10/15/05				
J	Biogas	0.8	OR	06/01/06	05/10/04	10/06/05	10/28/05	11/14/05	11/29/05
K	Wind	40.0	UT	2006	11/07/05				
L	Wind	30.0	UT	2006	05/01/05				
M	Biogas	0.2	UT	03/01/06	02/15/05				09/16/05
N	Wind	80.0	WA	2007	05/15/05				
O	Wind	80.0	WA	2008	12/01/05				
P	Gas	99.0	WY	2007	12/05/05				
Q	Wind	60.0	WY	2007	05/01/05	08/01/05			
TOTAL		581.5							

Note:
1 - Initial Information ranges from initial site visit/meeting for interconnection to specific project information. For the QFs greater than the state's standard contract threshold, the Company uses Schedule 38 or equivalent to as the basis for project information.
2 - Dates may be approximate until the specific project is firmed up.

January 4, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Doug Kuns
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM-1129/Advice No. 05-10
PGE Response to OPUC Data Request
Dated December 19, 2005
Question 065

Request:

Please provide a list of new Qualifying Facilities (QFs) that are in the process of entering into a PURPA contract with PGE. Include the following information:

a. **Resource type (wind, hydro, solar, biomass – specifying type such as mill waste or dairy waste, geothermal, or natural gas cogeneration)**
b. **Size (in megawatts)**
c. **Location (by state)**
d. **Projected on-line date**
e. **The dates the following activities occurred:**
   - **QF provided initial project information in order to obtain a draft contract**
   - **PGE provided a draft power purchase agreement**
   - **QF provided all project information required for a final draft agreement**
   - **PGE provided a final draft agreement**
   - **PGE provided a final executable agreement**

Response:

Currently, there are no QF's that are in the process of entering into a PURPA contract with PGE.

January 4, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Doug Kuns
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM-1129/Advice No. 05-10
PGE Response to OPUC Data Request
Dated December 19, 2005
Question 066

Request:

Please explain how Section 20.2 of PGE's standard power purchase agreement for QFs applies to the following:

a. **Third-party claims related to the facility against the QF. Claims related to the facility by the QF against PGE— for example, any dispute about PGE's interconnection requirements or costs for the facility**

Response:

Section 20.2 is primarily intended to address third party claims. For an issue with interconnection to occur, the QF would need to have constructed and interconnected before signing the standard contract. A reasonable expectation is that the QF would sign the standard contract before construction and interconnection of the facility and thus potential disputes would arise after the execution of the standard contract and would not be subject to Section 20.2.

To more clearly state the intent of Section 20.2 PGE proposes to modify the wording to read, "By executing this Agreement, Seller releases PGE from any third party claims related to the Facility, known or unknown, that may have arisen prior to the Effective Date."

REQUEST STAFF 31:

Pursuant to issue 36 in the Phase I compliance investigation, please explain why Idaho Power did not establish a cap in dollars, or as a percent of projected forward prices, for example on the amount of default losses that can be recouped through future contract payment reductions for QFs 10 MW or less under the standard contract.

IDAHO POWER'S RESPONSE TO REQUEST STAFF 31:

Idaho Power did not propose a limit on the amount of damages that could be recovered from a QF if the QF fails to provide the agreed-upon amount of energy because: (1) Such a limit could shift the cost of QF non-performance from the QF to Idaho Power's customers; and (2) As noted in Idaho Power's Response to Request Staff 34, non-QF purchases in the wholesale market do not limit losses for sellers that default. As such, PURPA's ratepayer neutrality standard could be violated by Idaho Power providing QF sellers more advantageous conditions.

Rather than limit the Company's ability to recover its losses, Idaho Power believes the Commission correctly addressed this issue in Order No. 05-584 by requiring the standard contract to include provisions to allow QF developers to repay the utility losses over time. This allows the QF to continue to operate and maintain its project, pay its debt service, and repay the losses Idaho Power has incurred as a result of the QF's failure to perform in accordance with the terms of its agreement. In its standard contract, Idaho Power included a default 36-month repayment period. In the past, the Company has entered into repayment arrangements with QFs for both shorter and longer time periods keyed to the QF's economics. Idaho Power would make similar arrangements in Oregon.

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REQUEST STAFF 34:

For each Idaho Power contract for power *purchases* signed within the past two years for a term greater than 60 days, please provide:

a. The terms of any cap on default losses

b. The contract term (in months or years)

c. The amount of power under contract (in MW)

IDAHO POWER'S RESPONSE TO REQUEST STAFF 34:

Idaho Power interprets Request Staff 34 as an effort by the Staff to determine if Idaho Power is treating QF purchases differently than other energy purchases it makes in the wholesale market. Idaho Power does not enter into wholesale contracts that limit the Company's ability to recover its actual, direct damages. Consequential damages are limited. Idaho Power believes that such a limit on direct damages would be very unusual in the wholesale market.

With that background, Idaho Power is concerned with the level of effort and potential disclosure of sensitive business information involved in providing the information described in Requests Staff 34 (b) and (c). Idaho Power discussed this concern with Staff counsel, and it was agreed that if, following Staff review of this response, the information requested in Requests Staff 34 (b) and (c) is still desired by Staff, Idaho Power would undertake the considerable effort required to produce the requested information.

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(503) 226-1191

REQUEST STAFF 35:

For each Idaho Power contract for power *sales* signed within the past two years for a term greater than 60 days, please provide:

a. The terms of any cap on default losses

b. The contract term (in months or years)

c. The amount of power under contract (in MW)

IDAHO POWER'S RESPONSE TO REQUEST STAFF 35:

Idaho Power has not entered into any wholesale sale contracts that limit Idaho Power's liability for direct damages if Idaho Power fails to perform. Consequential damages are limited.

With that background, Idaho Power is concerned with the level of effort and potential disclosure of sensitive business information involved in providing the information described in Requests Staff 35 (b) and (c). Idaho Power discussed this concern with Staff counsel, and it was agreed that if, following Staff review of this response, the information requested in Requests Staff 35 (b) and (c) is still desired by Staff, Idaho Power would undertake the considerable effort to produce the requested information.

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PORTLAND, OR 97201-6618
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REQUEST STAFF 32:

If the Commission determines pursuant to issue 36 that a cap is appropriate for the amount of default losses that can be recouped through future contract payment reductions for QFs 10 MW or less under the standard contract, what does Idaho Power believe would be an appropriate cap (in dollars, or as a percent of projected forward prices, for example)? Please explain the basis for the amount.

IDAHO POWER'S RESPONSE TO REQUEST STAFF 32:

Idaho Power believes that it would not be in the customers' interest for the Commission to place a cap on the amount of recoverable losses arising out of a QF developer's failure to deliver the amounts of energy it agreed to provide in the standard agreement. The better approach is to continue the Commission's current requirements contained in Order No. 05-584 and allow utilities to enter into reasonable repayment arrangements with non-performing QFs. This allows QF developers to operate and maintain their projects, make their debt service payments, and repay the utility for the losses the utility has experienced as a result of the QF's default. If the Commission still believes that it is in the public interest to establish a cap on the amount of recoverable losses, then Idaho Power believes that the cap should be equal to that portion of the total amount owed that can be repaid over the remaining term of the contract or fifteen (15) years, whichever is longer.

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January 13, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Doug Kuns
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM-1129/Advice No. 05-10
PGE *First Supplemental* Response to OPUC Data Request
Dated November 18, 2005
Question 051-Modified

Request:

If the Commission determines pursuant to issue 36 that a cap is appropriate for the amount of default losses that can be recouped through future contract payment reductions for QFs 10 MW or less under the standard contract, what does PGE believe would be an appropriate cap (in dollars, or as a percent of *projected forward prices*, for example)? Please explain the basis for the amount.

Response:

We have not evaluated whether and in what form a cap is appropriate. See PGE's response to OPUC Data Request No. 050.

First Supplemental Response (January 13, 2006)

PGE's original responses to OPUC Staff data requests 050, 051, and 052 were based on Commission language in Order No. 05-10 regarding a cap on default damages. The Commission directed that damage caps be investigated in Phase II of this proceeding, and therefore PGE had not considered inclusion of caps in its Phase I standard contract compliance filing. PGE objects to these data requests on damage caps as they require PGE to speculate, do not seek to obtain existing data or evidence and are not for the purpose of clarification of existing evidence or testimony in the record. As Issue 36 was adopted by the ALJ as an official issue in this docket, PGE intended to, and still intends to, present its position on the issue in its testimony. Notwithstanding these concerns, PGE responds as follows:

As the concept has been presented in this proceeding, we do not support a cap on default damages because a cap potentially transfers an unknown amount of replacement power costs to the Company and ratepayers. A cap on default damages effectively transfers the operational risk of a QF to parties who get no financial reward for assuming that risk. However, PGE's standard contract does have limitations on the potential for QF default damages as under-delivery damages are calculated relative to the QF's minimum net output, not their expected net output. In addition, damages are only calculated if the minimum net output is not generated, and the average Mid-C index price is above the avoided cost price.

If the Commission determines that a cap on default damages is appropriate PGE believes that the utility should be able to recover the cost of replacement power. The replacement power cost should be based on 100% of Forward Market Price Curve or the Mid-C index, whichever is applicable to the time of each event of default. Limiting the damage assessment period to no more than two years would be consistent with provisions already in PGE's standard contract that specify a two year period before proceeding with default or contract termination due to under-deliveries.

Request:

2. **Please provide the results and supporting data of any comparative analysis Staff performed, or had performed addressing the existence of, or requirements for default damage caps for QFs under Standard Rate Contracts in other states.**

Supplemental Response:

In reviewing testimony filed in Phase I of this proceeding, Staff found the following discussion of a cap on default losses in Idaho:

> 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. *See* Staff/400, Morgan/20, Lines 20-24, and Morgan/21, Lines 1-8.

In other words, Idaho Power's pro forma contract in Idaho capped default losses for under-deliveries at 150% of the avoided cost rates approved by the Idaho Commission. Please see Attachment PGE DR 2 Supplemental Response for the relevant page from the pro forma contract submitted by Idaho Power in response to Staff Data Request 7 in Phase I of this proceeding.

Attachment PGE DR 2 Supplemental Response

ARTICLE VII: PURCHASE PRICE AND METHOD OF PAYMENT

7.1 Base Energy Purchase Price – For all Base Energy, Idaho Power will pay the non-levelized energy price in accordance with Commission Order XXXX with seasonalization factors applied:

Year	Season 1 - (73.50 %) Mills/kWh	Season 2 - (120.00 %) Mills/kWh	Season 3 - (100.00 %) Mills/kWh
2004	XX.XX	XX.XX	XX.XX
2005	XX.XX	XX.XX	XX.XX
2006	XX.XX	XX.XX	XX.XX
2007	XX.XX	XX.XX	XX.XX
2008	XX.XX	XX.XX	XX.XX
2009	XX.XX	XX.XX	XX.XX
2010	XX.XX	XX.XX	XX.XX

7.2 Surplus Energy Price - For all Surplus Energy, Idaho Power shall pay to the Seller the current month's Market Energy Cost or the Base Energy Purchase Price specified in paragraph 7.1, whichever is lower.

7.3 Shortfall Energy Price – For all Shortfall Energy, if the Market Energy Cost for the month in which the Shortfall Energy occurs is less then the Base Energy Purchase Price for the same month, the Shortfall Energy Price will be 0. If the Market Energy Cost for the month in which the Shortfall Energy occurs is greater then the Base Energy Purchase Price for the same month, the Shortfall Energy Price will be the current month's Market Energy Cost less the Base Energy Purchase Price[redacted]

7.4 Shortfall Energy Payment - The Shortfall Energy Payment amount is the Shortfall Energy amount multiplied by the Shortfall Energy Price. The Shortfall Energy Payment will be withheld from the current month's energy payment. If the current month's energy payment is less than the Shortfall Energy Payment and the Optional Energy Payment, the Seller will make payment to Idaho Power of the unpaid balance within 15 days of being notified of the outstanding balance.

7.5 Optional Energy Price - For all Optional Energy, Idaho Power shall pay to the Seller the current

HARDY MYER;
Attorney General

PETER D. SHEPHERD
ey General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

RECEIVED
DEC 3 0 2005
P U C
Utility Program

December 29, 2005

VIA EMAIL AND U.S. MAIL

Vikie Bailey-Goggins
Oregon Public Utility Commission
550 Capitol Street N.E., Suite 215
PO Box 2148
Salem, OR 97308-2148
vikie.bailey-goggins@state.or.us

Re: Docket No. UM 1129 – Phase I Compliance
ODOE's Responses to Staff Data Requests No. DR 20-21
DOJ File No. 330-020-GN0041-04

The Oregon Department of Energy's (ODOE) responses to Staff's December 19, 2005 data requests No. 20-21 is included immediately following the questions below.

20. Please refer to ODOE's statement in response to Staff Data Request 19 that "there should be a reasonable cap on the total damages" recouped through future contract payment reductions for default by a Qualifying Facility (QF). Based on the experience of the State Energy Loan Program, please explain the importance for financing of such a cap for QFs 10 MW and smaller.

Response: SELP's financing experience includes QF projects that have incurred penalties or repayment of damages to the utility. In two power purchase contracts, where penalties or damages accrued, the repayments to the utility are not capped. In both cases the financial effect of the repayment requires extensive forbearance or loan modification by SELP and raises the possibility of bankruptcy by the project owner. This has taught SELP to more carefully calculate possible damages in power purchase agreements before financing QF projects. If potential damages can exceed the ability of the QF to pay them, it is likely that the project may not qualify for SELP financing. I would likely not recommend SELP finance most of the current QF projects we are reviewing if the power purchase contract's maximum default damages can not be quantified at the time the loan is advanced, usually upon execution of the power purchase agreement. Similarly, I would not recommend financing if projected maximum damages under the power purchase agreement could not be paid from a reduction in future revenue within a reasonable time while keeping expenses and debt service current.

As another example, the current shut down of the PGE Boardman facility that was caused by a faulty rotor that could not be repaired on site and had to be air freighted to a repair facility illustrates how a technical problem can cause a significant disruption in generation. For example, PGE projects that the Boardman facility will be out of service for over ninety days. In financing a QF facility, SELP needs to take into account a possible technical problem with a generator that may also lead to a significant down time. If a similar event were to result in a penalty to the QF, SELP would project the maximum penalty and assess the financial effect of the penalty on the QF's ability to repay its loan before any financing would be recommended.

21. Please refer to ODOE/Exhibit No. 6, Keto/Page 16, Lines 16-21. Mr. Keto states, "ODOE believes a reasonable cap on the amount of losses that can be recouped by the utility for an individual event of default is the contract value of the contracted minimum power delivery during the default period." Please explain the importance for financing of the QF and lender knowing at the time of contract execution the amount of damages (in dollars per megawatt-hour) that will be assessed at the time of default.

Response: Please refer the answer to #20 above. For financing SELP will review financial modeling for a project based on a variety of operating results. The modeling includes all reductions in revenue or payments resulting from the penalty or damage clauses in the power purchase contract. When the amount of the penalty is difficult or impossible to quantify financing becomes much more difficult because SELP would estimate a worst case scenario. As a result, SELP would likely reduce the loan amount and increase project equity, which is usually not available on projects of this size, or decline to finance the project. This would result in fewer projects being approved for financing and likely fewer projects being constructed.

Sincerely,

Janet L. Prewitt

Janet L. Prewitt
Assistant Attorney General
Natural Resources Section

c: Phil Carver, ODOE (email only)
Jeff Keto, ODOE, (email only)
Carel DeWinkel, (email only)

JLP:jrs/GENO8506

HARDY MYERS
Attorney General

PETER D. SHEPHERD
Deputy Attorney General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

January 12, 2006

Rates & Regulatory Affairs
Portland General Electric Company
121 S.W. Salmon Street, 1WTCO702
Portland, OR 97204

Re: Oregon Department of Energy's Response to Portland General Electric's December 29, 2005 Second Data Requests, Nos. 002-004
Docket No. UM 1129
DOJ File No. 330-020-GN0041-04

Please find the attached documents for the following requests:

002. Please provide by hard copy and electronic, complete copies of ODOE's Phase I Compliance Responses to OPUC Data Request Nos. 20-21, along with all associated electronic files.

- Oregon Department of Energy's (ODOE) December 29, 2005 responses to Staff Data Requests Nos. 20-21 are attached.

003. Please provide by hard copy and electronic, complete copies of ODOE's Phase I Compliance Responses to PacifiCorp Data Request Nos. 2-5, along with all associated electronic files.

- ODOE's January 12, 2006 response to PacifiCorp's December 29, 2005 Data Request Nos. 2-5 are attached.

ODOE's response to PGE's data request No. 004 is included immediately following the question below.

004. Please provide by hard copy and electronic, a list of all financial conditions that would cause ODOE to deny QF financing under the SELP program. For each condition provide the rationale for denial of funding.

Response: First, ODOE may decline financing for other than financial reasons so I do not want to imply that meeting a set of financial conditions means a loan will be approved. Other conditions that can affect approval of any individual QF application include, for example: project owners and management, credit history, project location and possible environmental impacts.

In response to Staff Data Request #2, ODOE stated, "The power purchase agreement needs to be reviewed in its entirety for acceptance. The circumstances that make a provision acceptable in one transaction and not in another can't be cited inclusively. In general, the larger the amount of equity capital and the lower the amount of financing needed for a project, the more SELP has the ability to accept higher risk in the power purchase agreement and still finance the project. Loans that are supported by a strong financial balance sheet that includes additional revenue streams may also allow acceptance of more risk in the power purchase agreement while still being acceptable for financing. However, most of the community scale projects SELP has reviewed, have very little financial reserves and thus require a power purchase agreement with limited risk in order to finance their project." This illustrates that there is no specific list of financial conditions that would cause ODOE to deny a QF financing. Loan underwriting is a matter of balancing a large number of conditions that are unique to each loan and assessing the risk of not being repaid on time. A financial condition that may cause ODOE to deny one loan may be present in another loan that we approve.

Having said that it is impossible to list all conditions that might cause denial of a loan, here is a recap of some of the primary financial conditions that would cause SELP to deny a QF financing:

- insufficient verified and available equity and other funds to complete project construction and provide for contingencies;
- reasonable probability of significant construction cost overruns or delay in project completion;
- insufficient favorable history of technology or equipment proposed, contractors, project managers, or inadequate warranties or operating and maintenance plan;
- lack of working capital and reserve funds for project operations and debt service;
- insufficient projected revenue for the term of the loan to meet expenses, debt service and return to owners;
- insufficient assessment or availability of motive force or feedstock to provide adequate assurance of sufficient revenue for the term of the loan;
- risk of power sales agreement or other output contract termination;
- risk of significant revenue reduction because of power sales agreement penalties or damages;
- uncertain project revenue if power sales are tied to a market or variable price;
- uncertain revenue if power sales agreement or other output contract does not exceed maturity of loan;
- legislative risk that could change operating parameters or economics of facility;

- insufficient collateral to provide repayment in the event of foreclosure;
- unacceptable guarantor if required.

Sincerely,

/s/ Janet L. Prewitt

Janet L. Prewitt
Assistant Attorney General
Natural Resources Section

Attachments

c: (Email only)
Doug Kuns, PGE
Richard George, PGE
Ted Drennan, PGE
Phil Carver, ODOE
Carel DeWinkel, ODOE
Jeff Keto, ODOE

JLP:jrs/GENO9079.DOC

REQUEST STAFF 33:

Please explain why Idaho Power did not establish in its standard contract for QFs 10 MW or less a cap in dollars, or as a percent of projected forward prices, for example on the amount of default losses that can be recouped in the event of termination due to Seller's default.

IDAHO POWER'S RESPONSE TO REQUEST STAFF 33:

Staff correctly notes that Idaho Power did not propose to cap the damages to be recovered if the QF contract is terminated early due to the QF's default. The primary reason is the inequitable treatment of the Company's customers under that scenario. A limitation on the Company's ability to recover its damages would only disadvantage Idaho Power's customers.

Idaho Power is also concerned that providing a cap on damages might encourage QF developers to perform a cost-benefit analysis of defaulting on the contract and then subsequently making market sales or requiring a new QF contract if market prices or avoided costs are higher. Such a scenario actually occurred with one QF developer in Idaho in 2000-2001 when market prices spiked. The QF developer terminated its contract with Idaho Power, paid the liquidated damages, and immediately began seeking to sell its generation at market prices that were higher than the prices it was receiving from Idaho Power.

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CASE: UM 1129 Phase I Compliance
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1503

Exhibit in Support of Rebuttal Testimony

January 20, 2006

Staff Exhibit 1503

Note: PacifiCorp figures are used throughout for illustrative purposes.

2016 weighted average market prices 20% higher than forward prices

$75.76

2016 weighted average market prices 70% higher than forward prices

$107.32

Under-delivery of 5 MW cogeneration QF in MWh (Based on 85% capacity factor and zero generation)

March, 2016	April, 2016	May, 2016	**3-month total**	**If no output from QF for year**
3,162.00	3,060.00	3,162.00	**9,384.00**	**37,230.00**

Under-delivery of 6 MW wind QF in MWh (Based on 33% capacity factor and zero generation from one 1.5-MW turbine)

March, 2016	April, 2016	May, 2016	**3-month total**	**If no output from one turbine for year**
368.28	356.40	368.28	**1,092.96**	**4,336.20**

	Mid-C forward prices (2004 IRP Update, Fig. A.3)	**Capped default losses based on forward prices** **110%**	**125%**	**150%**	**Avoided costs** (7/12/05 filing, Table 7)	
2006	$58.41	$64.25	$73.01	$87.62	$58.90	
2007	$57.40	$63.14	$71.75	$86.10	$54.92	
2008	$55.04	$60.54	$68.80	$82.56	$51.73	
2009	$52.68	$57.95	$65.85	$79.02	$48.60	
2010	$50.36	$55.40	$62.95	$75.54	$53.81	
2011	$50.21	$55.23	$62.76	$75.32	$56.82	
2012	$54.75	$60.23	$68.44	$82.13	$62.49	
2013	$59.70	$65.67	$74.63	$89.55	$65.21	
2014	$60.47	$66.52	$75.59	$90.71	$65.82	
2015	$61.84	$68.02	$77.30	$92.76	$66.96	
2016	**$63.13**	**$69.44**	**$78.91**	**$94.70**	**$68.73**	
2017	$64.25	$70.68	$80.31	$96.38	$70.51	
2018	$65.33	$71.86	$81.66	$98.00	$72.22	
2019	$66.48	$73.13	$83.10	$99.72	$74.18	
2020	$67.06	$73.77	$83.83	$100.59	$76.14	
2021	$68.60	$75.46	$85.75	$102.90	$78.21	
2022	$69.75	$76.73	$87.19	$104.63	$80.37	
2023	$70.81	$77.89	$88.51	$106.22	$82.54	
2024	$72.46	$79.71	$90.58	$108.69	$84.74	
2025	$74.35	$81.79	$92.94	$111.53	$87.12	
20-year levelized price	**$59.75**	**$65.73**	**$74.69**	**$89.63**	**$63.88**	**Discount rate** **7.20%** (Table 7)

Unrecouped default losses if market prices are 20% higher than forward prices

		March, 2016	April, 2016	May, 2016	**3-mo. event**	**1 yr event**
110% cap	Cogeneration QF	$19,961.71	$19,317.78	$19,961.71	**$59,241.19**	**$235,032.99**
	Wind QF	$2,324.95	$2,249.95	$2,324.95	**$6,899.86**	**$27,374.43**
125% cap	Cogeneration QF	$0.00	$0.00	$0.00	**$0.00**	**$0.00**
	Wind QF	$0.00	$0.00	$0.00	**$0.00**	**$0.00**
150% cap	Cogeneration QF	$0.00	$0.00	$0.00	**$0.00**	**$0.00**
	Wind QF	$0.00	$0.00	$0.00	**$0.00**	**$0.00**

Unrecouped default losses if market prices are 70% higher than forward prices

		March, 2016	April, 2016	May, 2016	**3-mo. event**	**1 yr event**
110% cap	Cogeneration QF	$119,770.24	$115,906.68	$119,770.24	**$355,447.15**	**$1,410,197.94**
	Wind QF	$13,949.71	$13,499.72	$13,949.71	**$41,399.14**	**$164,246.58**
125% cap	Cogeneration QF	$89,827.68	$86,930.01	$89,827.68	**$266,585.36**	**$1,057,648.46**
	Wind QF	$10,462.28	$10,124.79	$10,462.28	**$31,049.35**	**$123,184.94**
150% cap	Cogeneration QF	$39,923.41	$38,635.56	$39,923.41	**$118,482.38**	**$470,065.98**
	Wind QF	$4,649.90	$4,499.91	$4,649.90	**$13,799.71**	**$54,748.86**

Unrecouped default losses if market prices are at FERC cap ($250/MWh)

		March, 2016	April, 2016	May, 2016	**3-mo. event**	**1 yr event**
110% cap	Cogeneration QF	$570,921.23	$552,504.42	$570,921.23	**$1,694,346.89**	**$6,722,137.11**
	Wind QF	$66,495.53	$64,350.51	$66,495.53	**$197,341.58**	**$782,931.26**
125% cap	Cogeneration QF	$540,978.68	$523,527.75	$540,978.68	**$1,605,485.10**	**$6,369,587.63**
	Wind QF	$63,008.10	$60,975.59	$63,008.10	**$186,991.79**	**$741,869.62**
150% cap	Cogeneration QF	$491,074.41	$475,233.30	$491,074.41	**$1,457,382.12**	**$5,782,005.15**
	Wind QF	$57,195.73	$55,350.70	$57,195.73	**$169,742.15**	**$673,433.54**

CASE: UM 1129 Phase I Compliance
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1504

Exhibit in Support of Rebuttal Testimony

January 20, 2006

Staff Exhibit 1504

Note: PacifiCorp figures are used throughout for illustrative purposes.

2016 weighted average market prices 20% higher than forward prices
$75.76

2016 weighted average market prices 70% higher than forward prices
$107.32

Under-delivery of 5 MW cogeneration QF in MWh (Based on 85% capacity factor and zero generation)

March, 2016	April, 2016	May, 2016	**3-month total**	**If no output from QF for year**
3,162.00	3,060.00	3,162.00	**9,384.00**	**37,230.00**

Under-delivery of 6 MW wind QF in MWh (Based on 33% capacity factor and zero generation from one 1.5-MW turbine)

March, 2016	April, 2016	May, 2016	**3-month total**	**If no output from one turbine for year**
368.28	356.40	368.28	**1,092.96**	**4,336.20**

	Mid-C forward prices (2004 IRP Update, Fig. A.3)	**Avoided costs** (7/12/05 filing, Table 7)
2006	$58.41	$58.90
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2008	$55.04	$51.73
2009	$52.68	$48.60
2010	$50.36	$53.81
2011	$50.21	$56.82
2012	$54.75	$62.49
2013	$59.70	$65.21
2014	$60.47	$65.82
2015	$61.84	$66.96
2016	**$63.13**	**$68.73**
2017	$64.25	$70.51
2018	$65.33	$72.22
2019	$66.48	$74.18
2020	$67.06	$76.14
2021	$68.60	$78.21
2022	$69.75	$80.37
2023	$70.81	$82.54
2024	$72.46	$84.74
2025	$74.35	$87.12
20-year levelized price	**$59.75**	**$63.88**

2016 default cap based on QF contract price (ODOE proposal)

Wind QF	**$1,192,108.10**
Cogen QF	**$2,558,817.90**

Discount rate (Table 7) **7.20%**

Default losses if market prices are higher than forward prices

Market prices	**3-mo. event**	**1 yr event**
20% higher		
Cogeneration	$65,931.98	$261,577.98
Wind	$7,679.14	$30,466.14
70% higher		
Cogeneration	$362,137.94	$1,436,742.93
Wind	$42,178.42	$167,338.29
$250/MWh		
Cogeneration	$1,701,037.68	$6,748,682.10
Wind	$198,120.86	$786,022.97

Unrecouped default losses if market prices are higher than forward prices

Market prices	**3-mo. event**	**1 yr event**
20% higher		
Cogeneration	$0.00	$0.00
Wind	$0.00	$0.00
70% higher		
Cogeneration	$0.00	$0.00
Wind	$0.00	$0.00
$250/MWh		
Cogeneration	$0.00	$4,189,864.20
Wind	$0.00	$0.00

CASE: UM 1129 Phase I Compliance
WITNESS: Steve W. Chriss

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1600

Rebuttal Testimony

January 20, 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 an Economist in the Economic and Policy Analysis Section.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS DOCKET?

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address the positions of Randall Falkenberg (ICNU/200), Dr. Philip Carver (ODOE/Exhibit No. 7), and Don Reading (Sherman/Simplot.)

Q. HAVE YOU PREPARED AN EXHIBIT?

A. Yes. I have prepared Staff/1601, which consists of one page.

RESPONSE TO MR. FALKENBERG'S PROPOSAL

Q. DOES STAFF BELIEVE THE COMMISSION INTENDED TO ESTABLISH THE NATURAL GAS INDEX PRICING OPTIONS ONLY FOR QFS 10 MW AND LESS AT THIS TIME?

A. Yes. Page 34 of Order No. 05-584 states: "We conclude that the adoption of more pricing options for QF *standard contracts* is consistent with our goal, in this proceeding, to more accurately value avoided costs." [Emphasis added.] Clearly, the Commission did not intend in its decision for the natural gas index pricing options to be available to QFs larger than 10 MW that are not eligible for standard contracts. The Commission will further explore market pricing options in Phase II.

Q. DOES STAFF BELIEVE THE COMMISSION INTENDED TO RELY SOLELY ON THE USE OF MONTHLY FORWARD MARKET PRICES FOR THE SUFFICIENCY PERIOD? (SEE ICNU/200, FALKENBERG/9, LINES 20-24)?

A. Yes. Order No. 05-584 states, "When the utility is in a resource surplus position, Staff asserts that capacity should be valued, using one of two methodologies that would establish a 'market-based' value for avoided capacity costs."[1] Using the Deadband and Gas Market pricing methods during the resource sufficiency period would pose the problem of calculating the market value of Qualifying Facility (QF) capacity. The use of forward market prices

[1] *See* Order No. 05-584 at 23.

negates that problem and was approved by the Commission in Order No. 05-584.[2]

Q. MR. FALKENBERG STATES THAT IT WOULD BE APPROPRIATE TO OFFER A GAS MARKET INDEXED RATE DURING THE SUFFICIENCY PERIOD (SEE ICNU/200, FALKENBERG/9, LINES 15-17). DO YOU AGREE?

A. Conceptually, yes. However, determining the value of the capacity portion of the avoided cost rates continues to be a challenge.

Q. DO YOU AGREE WITH MR. FALKENBERG THAT THE DIFFERENCE IN ON-PEAK AND OFF-PEAK PRICES IS REPRESENTATIVE OF THE MARKET VALUE OF CAPACITY DURING THE SUFFICIENCY PERIOD (SEE ICNU/200, FALKENBERG/13, LINES 8-10)?

A. No. The market value of capacity is likely embedded in the difference between on-peak and off-peak prices. However, this approach sells short the impact of local and regional supply and demand on the difference in on-peak and off-peak prices. The market-clearing wholesale price of power is the intersection of supply and demand in the market, not necessarily a combination of the underlying market value of capacity and the price of natural gas, though those two factors will play a role, especially on the supply side.

[2] *Ibid* at 28.

Q. DOES STAFF HAVE A PROPOSAL REGARDING THE MARKET VALUE OF CAPACITY IF A GAS MARKET INDEXED RATE WERE AVAILABLE DURING THE UTILITY'S RESOURCE SUFFICIENCY PERIOD?

A. No. Staff continues to find that the Commission's approval of the use of forward market prices for the sufficiency period is the best solution. However, staff does not oppose working with parties towards the creation of a workable market value of capacity.

RESPONSE TO DR. CARVER's PROPOSAL

Q. WHAT METHODOLOGY DOES DR. CARVER SUGGEST TO SET THE NATURAL GAS PRICES FOR CALCULATING AVOIDED COSTS?

A. Dr. Carver proposes the use of New York Mercantile Exchange (NYMEX) forwards. *See* ODOE/7, Carver/4, Lines 11-20. Dr. Carver suggests that these prices would then be adjusted by the basis values for Henry Hub and Sumas, Henry Hub and Opal, and Henry Hub and AECO. *See* ODOE/7, Carver/5, Lines 1-3. Dr. Carver proposes that the basis values be escalated at "normal" inflation.

Q. WHAT DOES DR. CARVER MEAN BY "BASIS?"

A. Basis, defined simply for the context of this docket, is the difference between two prices. For instance, in commodity trading, basis is calculated by the following formula:

Basis = Cash Price – Futures Price

Q. FOR HOW LONG DOES DR. CARVER SUGGEST THIS METHODOLOGY BE USED?

A. This methodology would be in place through the end of 2011. *See* ODOE/7, Carver/4, Line 20.

Q. WHAT METHODOLOGY FOR CALCULATING FORWARD COSTS DOES DR. CARVER PROPOSE AFTER 2011?

A. Dr. Carver proposes that after 2011, a flat real price of $7/MMBtu be used as a base for long-term fixed cost QF contracts.

Q. DOES STAFF SUPPORT DR. CARVER'S PROPOSAL?

A. No. In this docket the Commission has adopted market prices as the basis for avoided costs during the resource sufficiency period and as the basis for the avoided energy costs for the Deadband and Gas Market pricing options.[3] Dr. Carver's use of market prices in his proposal can be viewed as another step toward further adoption of market-based pricing. However, several facets of the proposal make it an unreasonable answer to the question of the validity and usefulness of the natural gas forecasts provided by the utilities.

Q. PLEASE EXPLAIN THE FIRST PROBLEM WITH THE PROPOSAL.

A. The first problem with the proposal is the use of NYMEX natural gas forwards to set the monthly natural gas prices through 2011. While this suggestion is workable in the very short-term, the NYMEX futures will not provide natural gas prices that are more reliable than the utility forecasts for the long-term.

Q. WHAT IS THE LIMITATION OF USING NYMEX FUTURES FOR CALCULATING AVOIDED COSTS BEYOND THE SHORT-TERM?

A. The limitation is that, beyond a certain point in the near future, which as of January 2006 is around May 2007, the level of activity on the NYMEX exchange drops off significantly. This suggests that the NYMEX futures market from that point on is not sufficiently liquid to produce reliable price data.

Q. PLEASE DEFINE WHAT YOU MEAN BY "LIQUID."

A. Whether a market is liquid can be defined several ways, but in the context of this docket a market can be considered liquid if the instruments it trades can

[3] *See* Order 05-584 at 34-35.

easily be bought or sold in quantity with little impact on market prices. A related feature then of liquid markets would be the presence of a significant number of willing buyers and sellers and the exchange of significant volumes of natural gas.

Q. WHAT METRICS CAN BE USED TO DETERMINE THE LIQUIDITY OF THE NYMEX FUTURES MARKET?

A. The two most useful and accessible metrics are open interest and volume. Open interest is defined simply as the total number of futures or options on futures contracts that have not yet been offset or fulfilled for delivery. A number of publications publish these numbers on a daily basis.

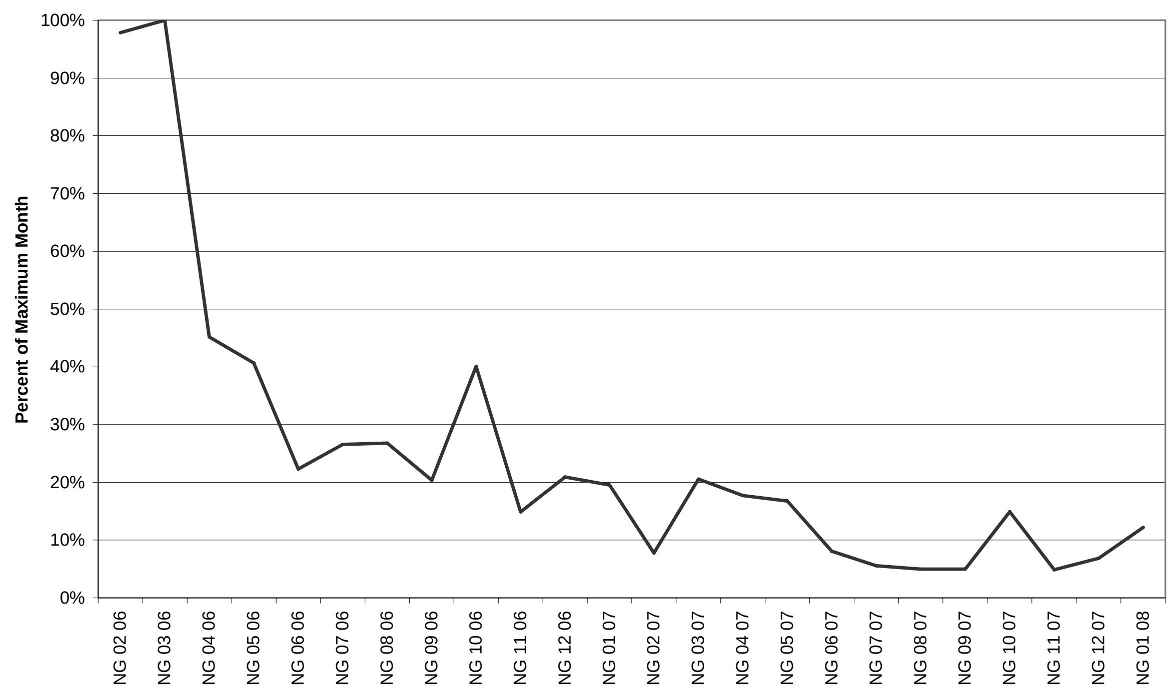
Q. PLEASE DESCRIBE THE CURRENT OPEN INTEREST DATA.

A. In general, the prompt month will have the highest number of open interests. For January 10, 2006, the date used in my analysis, February and March 2006 have the highest number of open interests. It is reasonable to consider, then, that these months represent a hypothetical "maximum market." As soon as June 2006, the number of open interests is only 22 percent of the maximum market. (*See* Table 1.) With the exception of a spike in October 2006, the number of open interests, as a percent of the maximum market, declines to around ten percent by January 2008. This reduction in active contracts suggests a lack of sufficient market liquidity.

Q. PLEASE DESCRIBE THE CURRENT VOLUME DATA.

A. As was the case with the open interest data, the largest amount of market activity is in the prompt month, which in this case is February 2006. For this

Table 1. NYMEX Futures Contract Open Interests, Percent of Maximum Month (NG 03 06). Source: Enerfax report, 1/10/2006

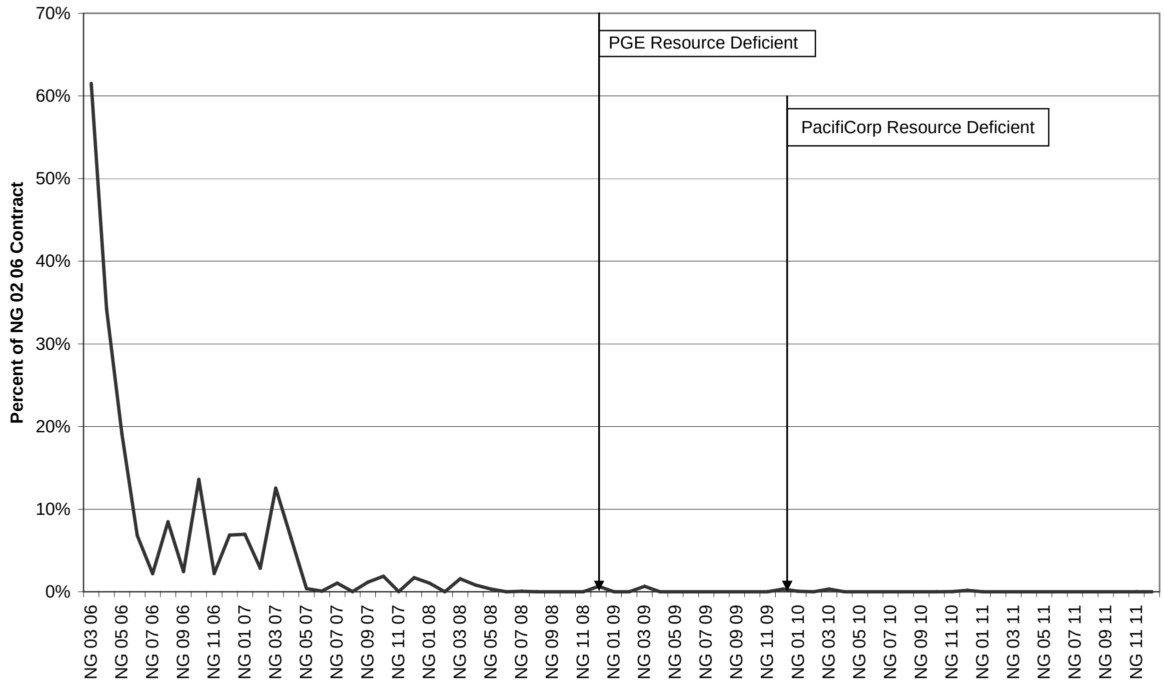


analysis, February 2006 is the hypothetical “maximum market.” Traded volumes for contracts that expire after February 2006 quickly decline to five percent to ten percent of the maximum market. (*See* Table 2.) Beginning with the May 2007 contract, traded volumes for contracts are either zero percent of maximum or very close to zero percent of maximum.

Q. HOW DO THE OPEN INTEREST AND VOLUME DATA CORRELATE WITH THE DEFINITION OF LIQUIDITY?

A. With such little market activity, any trades made for a contract with few open interests or little traded volume may have a large impact on that contract’s price of natural gas. This opens the door for any party that trades on the NYMEX to potentially affect reported prices for future contracts.

Table 2. NYMEX Futures Contract Volumes as a Percentage of February 2006 Contract Volumes. Source: NYMEX report, 1/10/2006.



However, this is only a problem in the mid- to long-term of Dr. Carver's model. In the short-term, the number of open interests and amount of traded volume is much higher. Buyers and sellers have much better information in the short-term and are more likely to participate in the market.

Q. WOULD THE USE OF NYMEX FUTURES WORK WITH THE COMMISSION'S RULING REGARDING AVOIDED COST RATES DURING THE UTILITY SUFFICIENCY PERIOD?

A. No. By the time PGE and PacifiCorp are resource deficient and Dr. Carver's pricing proposal would take effect, the NYMEX futures market is well into the non-liquid time period. (*See* Table 2.)

Q. PLEASE EXPLAIN THE SECOND PROBLEM WITH THE PROPOSAL.

A. The second problem with the proposal is the use of the basis values from the Northwest Power and Conservation Council's (Council) 5th Power Plan, escalated at nominal inflation. Essentially, Dr. Carver suggests that the difference between NYMEX and the Intercontinental Exchange (ICE) cash prices will increase with inflation.

Q. PLEASE EXPLAIN.

A. The basis for Henry Hub and Sumas would use settlement data from the NYMEX for Henry Hub prices and spot prices from ICE, Platt's, or another publication for the Sumas cash price. The basis for Henry Hub and Sumas generally would be calculated as follows:

Basis = Sumas Cash Price – Henry Hub NYMEX Settlement Price

The basis for Henry Hub and AECO and the basis for Henry Hub and Opal would be calculated in a similar fashion.

Q. DID YOU PERFORM BASIS CALCULATIONS IN SUPPORT OF YOUR TESTIMONY?

A. Yes. For each hub's relationship with Henry Hub, I calculated an average monthly basis for the NYMEX contract months of January 2002 through December 2005.

Q. HOW IS EACH MONTHLY BASIS VALUE CALCULATED?

A. The calculation of the average monthly basis value was a three-step process.

First, daily data were collected for the NYMEX settlements for each month's contract at Henry Hub. Corresponding daily spot price data were collected for

Sumas or Opal. For example, for April 2005, daily NYMEX settlement data began on December 17, 2001, when that month's contract became available. The final trading date for the contract was March 29, 2005. Spot price data for December 17, 2001, through March 29, 2005 were collected from the ICE website.

Q. WHAT WAS THE SECOND STEP IN THE PROCESS?

A. The second step in the process was the calculation of a basis value for each day of the contract's life. For the April 2005 contract, a basis value was calculated for each trading day from December 17, 2001, through March 29, 2005.

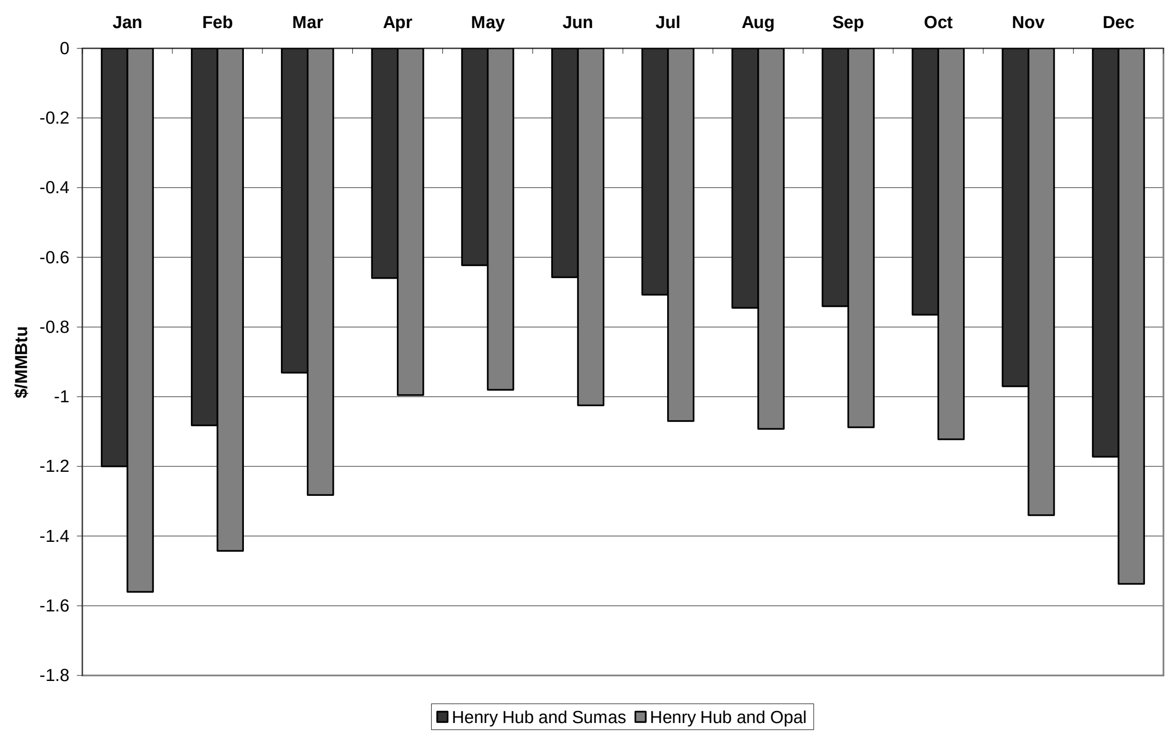
Q. WHAT WAS THE THIRD STEP IN THE PROCESS?

A. The third, and final, step was averaging all of the daily basis values. This averaged value is represented in the following analyses as the monthly basis for the hub combination. For example, the monthly basis for Henry Hub and Sumas for April 2005 is -0.54.

Q. WERE THERE ANY LIMITATIONS TO THE CALCULATIONS?

A. Yes. Spot market data were available only as far back as April 1, 2001. Early months in the analysis may not have the benefit of the full contract trading period.

Table 3. Average of Calculated Basis Values for Each Calendar Month, 2002 Through 2005.



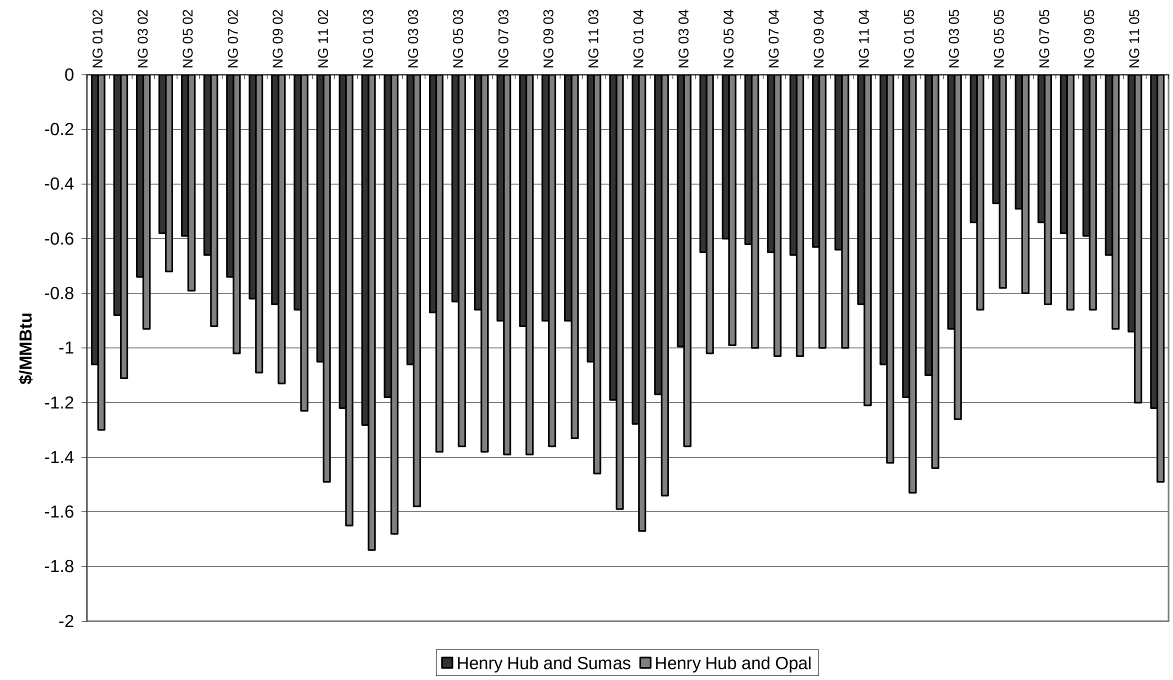
Q. WHAT IS THE FIRST REASON WHY DR. CARVER'S USE OF THE BASIS VALUES FROM THE 5TH POWER PLAN IS AN ISSUE?

A. The first reason is the use of a fixed basis. The use of a fixed basis ignores the fact that a basis is not constant over the course of a year, nor is it constant from year to year.

Q. PLEASE EXPLAIN WHY YOU CONCLUDE A BASIS IS NOT CONSTANT OVER THE COURSE OF A YEAR.

A. Staff's analysis of the basis values for Henry Hub and Sumas and those for Henry Hub and Opal shows that there is seasonal variation in the basis for both hubs. The basis for each combination is largest in the winter months and tightens during the summer months. (*See* Table 3.) The use of a fixed value

Table 4. Basis Values for Henry Hub and Sumas and Henry Hub and Opal for NYMEX Contracts Dated January 2002 Through December 2005. Sources: NYMEX.com and theice.com.



ignores the seasonal variation of the basis for each hub combination, which exacerbates the price reliability issues with Dr. Carver's proposal.

Q. PLEASE EXPLAIN WHY YOU BELIEVE A BASIS IS NOT CONSTANT FROM YEAR TO YEAR.

A. Staff's analysis of the basis values for Henry Hub and Sumas and those for Henry Hub and Opal shows that basis values do not remain constant from year to year. *See* Table 4. The use of a fixed value ignores the movement of basis values from year to year, which further exacerbates the price reliability issues with Dr. Carver's proposal.

Q. DOES THE USE OF ESCALATION AT NOMINAL INFLATION ADDRESS THE ISSUE OF BASIS VARIABILITY?

A. No. Dr. Carver has presented no evidence to suggest that the basis values for either combination of hubs moves with inflation or trends in another significant fashion. Dr. Carver also did not explain in which direction the basis values would be escalated.

Q. PLEASE EXPLAIN.

A. I believe that Dr. Carver intended for the “escalation” of the basis values to represent a widening in the spread between the Henry Hub price and the price of the Northwest hubs. However, this widening would create basis values that are lower than the forecast values from the Council. A positive increase in the basis values, which could also be implied by the use of the term “escalation,” would actually result in a narrowing of the spread between Henry Hub and the Northwest hubs.

Q. DOES YOUR ANALYSIS INDICATE ANY TRENDING OF THE BASIS VALUES FOR HENRY HUB AND SUMAS?

A. Yes. When the basis values in Table 4 for Henry Hub and Sumas are regressed against a trend and monthly dummy variables, there is a small statistically significant positive increase each month. *See* Staff/1601. This indicates that the Sumas cash price is slowly approaching the Henry Hub futures price over the time period analyzed.

Q. DOES YOUR ANALYSIS INDICATE A SIMILAR TRENDING OF THE BASIS VALUES FOR HENRY HUB AND OPAL?

A. No. The trend variable is not significant when the basis values for Henry Hub and Opal are analyzed.

Q. WHAT IS THE SECOND ISSUE WITH THE USE OF THE BASIS VALUES?

A. The second problem with the use of the Council basis values is that, like the forecasts provided by the utilities, the numbers grow stale. Additionally, neither the Commission nor any party in this docket has any control over when or if the Council will decide to update its forecasts. Providing current numbers for filings could prove to be a challenge.

Q. WHAT IS THE FINAL ISSUE WITH DR. CARVER'S PROPOSAL?

A. The final issue is the use of a flat real price of $7/MMBtu after 2011. Dr. Carver provides no basis other than a brief narrative regarding liquefied natural gas and peak oil to defend his choice of natural gas price. *See* ODOE/Exhibit No. 7, Carver/6. Also, a flat real price of $7/MMBtu assumes that the price of natural gas will increase with inflation for the duration of its use, which may or may not be realistic.

Q. WHAT IS THE CORRESPONDING PRICE OF NATURAL GAS TO DR. CARVER'S PROPOSAL AT THE UTILITIES' TIME OF FILING?

A. The corresponding price of natural gas at the utilities' time of filing is about $8/MMBtu, assuming 3.1 percent inflation. This is about $1.00/MMBtu to $2.00/MMBtu higher than actual natural gas prices at the time of filing.

RESPONSE TO DR. READING'S PROPOSAL

Q. HAS THE NATURAL GAS PRICE LANDSCAPE CHANGED SINCE THE UTILITIES FILED THEIR AVOIDED COSTS?

A. Yes. The wake of Hurricanes Katrina and Rita has included natural gas prices consistently well above $10/MMBtu and, currently, an expectation of a return of similarly high prices next winter.

Q. GIVEN THIS CHANGE IN NATURAL GAS PRICES, DO YOU AGREE WITH DR. READING THAT THE COMMISSION SHOULD REQUIRE THE UTILITIES TO REFILE THEIR COMPLIANCE FILINGS WITH UPDATED NATURAL GAS PRICES BASED ON CURRENT MARKET CONDITIONS (SEE SHERMAN/SIMPLOT, READING/11)?

A. No. Implementing Dr. Reading's proposal could potentially create a series of moving targets in the analysis of the utilities' avoided cost filings.

Q. PLEASE EXPLAIN.

A. If, at any time during an avoided cost docket, a substantial change that is beneficial to one or more parties occurs, the proposal would open the door for asymmetrical rent-seeking. Staff does not believe that a later change in the opposite direction would lead the requesting party to give back any potential gains.

For example, updating avoided costs in-between filings to reflect an increase in natural gas prices, which would benefit QF developers. If, before UM 1129 concludes, there is a substantial downward shift in natural gas prices, staff would not expect the parties that benefit from the implemented higher prices to ask for a reduction to better reflect market conditions current to that time. Staff or the utilities could ask for a reduction, but this does not mean that the developers would accept the reduction.

Another example of a moving target that could be generated by Dr. Reading's proposal is that of the avoided resource chosen by the utility. There is a possibility that the increase in natural gas prices may make it economical for a utility to forgo the use of a natural gas plant as the avoided resource and utilize a coal plant in its place.[4]

Q. WHAT IS THE APPROPRIATE RESPONSE TO DR. READING'S PROPOSAL?

A. Staff proposes that the Commission examine the merits of the utility's avoided cost filing at the initial time of filing. Analysis of the natural gas forecasts should be done in the context of the markets at the time of filing, and any substantial shifts in the marketplace or other factors should be dealt with in the following avoided cost filing. Staff does not believe this is unreasonable, given that avoided cost filings occur every two years.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[4] The shift in avoided resource could potentially reduce avoided cost rates quite significantly. Coal plants are more expensive to build than natural gas plants but have a significantly lower variable cost, especially during periods of high natural gas prices. While the capacity payment to QFs would theoretically increase, it would likely be offset by the reduction in the energy payment. This is also significant because QFs only receive capacity payments during on-peak hours.

CASE: UM 1129 Phase I Compliance
WITNESS: Steve W. Chriss

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1601

Exhibit in Support of Rebuttal Testimony

January 20, 2006

SUMMARY OUTPUT HH/SUMAS

Regression Statistics	
Multiple R	0.880488576
R Square	0.775260132
Adjusted R Square	0.698206463
Standard Error	0.128505614
Observations	48

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	12	1.993790733	0.166149228	10.06130067	4.08086E-08
Residual	35	0.577979246	0.016513693		
Total	47	2.571769979			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-1.260021528	0.069414732	-18.15207653	2.18281E-19	-1.400940925	-1.119102131	-1.400940925	-1.119102131
Trend	0.003159028	0.0013825	2.285010585	0.028485122	0.000352403	0.005965653	0.000352403	0.005965653
February	0.114340972	0.090877707	1.258185045	0.216653925	-0.070150581	0.298832525	-0.070150581	0.298832525
March	0.262431944	0.090909249	2.886746361	0.00662857	0.077876358	0.446987531	0.077876358	0.446987531
April	0.530522917	0.090961795	5.832370802	1.28402E-06	0.345860657	0.715185177	0.345860657	0.715185177
May	0.564863889	0.091035308	6.204887994	4.15144E-07	0.38005239	0.749675388	0.38005239	0.749675388
June	0.526704861	0.091129737	5.779725433	1.50661E-06	0.34170166	0.711708062	0.34170166	0.711708062
July	0.473545833	0.091245019	5.189826694	9.03346E-06	0.288308599	0.658783068	0.288308599	0.658783068
August	0.432886806	0.091381073	4.737160483	3.53979E-05	0.247373367	0.618400244	0.247373367	0.618400244
September	0.434727778	0.091537807	4.749160969	3.41459E-05	0.248896152	0.620559403	0.248896152	0.620559403
October	0.40656875	0.091715115	4.43295254	8.77382E-05	0.22037717	0.59276033	0.22037717	0.59276033
November	0.198409722	0.091912878	2.15867164	0.037815228	0.011816662	0.385002783	0.011816662	0.385002783
December	-0.007249306	0.092130964	-0.07868479	0.937731494	-0.194285105	0.179786494	-0.194285105	0.179786494

SUMMARY OUTPUT HH/OPAL

Regression Statistics	
Multiple R	0.741065837
R Square	0.549178575
Adjusted R Square	0.394611229
Standard Error	0.221084556
Observations	48

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	12	2.083981667	0.173665139	3.553005143	0.001658892
Residual	35	1.710743333	0.048878381		
Total	47	3.794725			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-1.625444444	0.119422995	-13.61081631	1.52126E-15	-1.867886011	-1.383002878	-1.867886011	-1.383002878
Trend	0.003444444	0.002378491	1.448163675	0.156470981	-0.001384149	0.008273038	-0.001384149	0.008273038
February	0.114055556	0.156348482	0.729495767	0.470552638	-0.203348734	0.431459846	-0.203348734	0.431459846
March	0.270611111	0.156402747	1.730219678	0.092401158	-0.046903344	0.588125566	-0.046903344	0.588125566
April	0.554666667	0.156493148	3.544351128	0.001139472	0.236968688	0.872364646	0.236968688	0.872364646
May	0.566222222	0.156619622	3.615270009	0.00093469	0.248267488	0.884176957	0.248267488	0.884176957
June	0.517777778	0.156782081	3.302531603	0.002214542	0.199493234	0.836062322	0.199493234	0.836062322
July	0.469333333	0.156980414	2.989757265	0.00508243	0.150646152	0.788020514	0.150646152	0.788020514
August	0.443388889	0.157214485	2.820280137	0.007849733	0.124226519	0.762551259	0.124226519	0.762551259
September	0.444944444	0.157484134	2.8253287	0.007750059	0.125234657	0.764654232	0.125234657	0.764654232
October	0.4065	0.15778918	2.576222275	0.014367333	0.086170937	0.726829063	0.086170937	0.726829063
November	0.185555556	0.158129417	1.173441092	0.248542828	-0.135464225	0.506575336	-0.135464225	0.506575336
December	-0.015388889	0.158504619	-0.097087953	0.923210391	-0.33717037	0.306392592	-0.33717037	0.306392592

CASE: UM 1129 Phase I Compliance
WITNESS: Maury Galbraith

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1700

Rebuttal Testimony

January 20, 2006

Q. PLEASE STATE YOUR NAME.

A. My name is Maury Galbraith.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS PROCEEDING?

A. Yes. I sponsored Staff/1200. My witness qualifications were provided at Staff/1201.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to respond to the recommendations put forward by Sherman County Court and J.R. Simplot Company (Sherman/Simplot) witnesses Paul Woodin and Don Reading, and Industrial Customers of Northwest Utilities (ICNU) witness Randall Falkenberg, regarding the determination of the resource sufficiency/deficiency period for the calculation of avoided costs in PacifiCorp Advice No. 05-006 and Portland General Electric (PGE) Advice No. 05-10. I also provide supplemental testimony regarding PGE's determination of its resource sufficiency/deficiency period in its compliance filing.

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS OF THE SHERMAN/SIMPLOT AND ICNU WITNESSES.

A. The recommendations for determining the utility resource sufficiency/deficiency period include the following:

- Sherman/Simplot witness Woodin recommends determining the utility resource sufficiency/deficiency period based on the forecasted trajectory of utility load. If the forecast is for increasing load, then the utility is deemed to be resource deficient. If the forecast is for decreasing load, then the utility is deemed to be resource sufficient. In the alternative, Mr. Woodin recommends eliminating “planned resources” from the load-resource balance used to determine the resource sufficiency/deficiency periods. Sherman/Simplot, Woodin/4-6.

- Sherman/Simplot witness Reading recommends determining the utility resource sufficiency/deficiency periods based on whether the utility is currently (or actively) acquiring resources. If the utility is currently acquiring resources, then the utility is deemed to be resource deficient, and the use of a resource sufficiency period is not warranted. Sherman/Simplot, Reading/7.

- ICNU witness Falkenberg recommends determining PacifiCorp’s resource sufficiency/deficiency periods based on the company’s forecasted load and resource balance during the summer peak period. If PacifiCorp’s available resources exceed its load requirement during the summer peak period, then PacifiCorp is deemed to be resource sufficient. If PacifiCorp’s available resources are less than its load requirement during the summer peak period, then PacifiCorp is deemed to be resource deficient. ICNU/200, Falkenberg/8.

Q. IS MR. WOODIN’S PRIMARY RECOMMENDATION WELL FOUNDED?

A. No. Mr. Woodin’s recommendation to focus solely on the forecasted trajectory of utility load is one-sided. Increasing load is not a necessary or sufficient condition for utility resource deficiency. Consider two examples where increasing load and utility resource sufficiency are not mutually exclusive. First, consider a case where the utility’s existing resources are able to cover the forecasted increase in load over the entire forecast period. Second, consider a case where the utility’s existing resources are not able to cover the forecasted increase in load over the entire forecast period; nevertheless the utility is able to fill the emerging resource gap with a reasonable amount of short-term market purchases. In both of these cases the utility should be considered resource sufficient over the entire forecast period. It is also easy to think of counter-examples where decreasing load and utility resource deficiency occur simultaneously, as may be the case with expiration of contracts or retirement of owned resources.

Q. IS MR. WOODIN'S ALTERNATIVE RECOMMENDATION WELL FOUNDED?

A. Yes, with one exception. Mr. Woodin's recommendation to exclude planned resources from the load-resource balances used to determine the utility resource sufficiency/deficiency periods for avoided costs is consistent with Staff's recommendation in this case. Staff/1200, Galbraith/8 and Galbraith/13. The one exception is that it is appropriate to include the planned level of front office transactions in these load-resource balances. Staff/1200, Galbraith/6-8.

Q. IS MR. READING'S RECOMMENDATION WELL FOUNDED?

A. No. Mr. Reading's recommendation to focus solely on whether the utility is currently acquiring resources fails to give appropriate weight to the chronology of resource additions. Current acquisition activity is not necessarily indicative of current resource deficiency. For example, current acquisition activity may be directed at adding resources at a particular date in the future. As the Commission emphasized in Order No. 05-584, the change from resource sufficiency to resource deficiency occurs at a point in time. Staff/1200, Galbraith/7.

Q. IS MR. FALKENBERG'S RECOMMENDATION WELL FOUNDED?

A. No. Mr. Falkenberg even recognizes that it is inappropriate to determine PacifiCorp's resource sufficiency/deficiency periods based solely on the company's forecasted load and resource balance during the summer peak. According to Mr. Falkenberg, a major part of the problem with PacifiCorp's approach to determining its resource sufficiency/deficiency period is "…that the Company really considers it irrelevant whether it can meet the summer peak, so long as it can meet the winter peak and annual energy requirements." ICNU/200, Falkenberg/5. The determination of PacifiCorp's resource sufficiency/deficiency periods for avoided costs should be based on consideration of both annual energy and capacity positions. Staff/1200, Galbraith/4.

Q. WHAT ADDITIONAL INFORMATION HAVE YOU RECEIVED REGARDING PGE'S DETERMINATION OF ITS RESOURCE SUFFICIENCY/DEFICIENCY PERIODS IN ADVICE NO. 05-10.

A. Exhibit Staff/1701 includes:

- PGE's response to OPUC Data Request No. 70. Staff/1701, Galbraith/1;
- PGE's response to OPUC Data Request No. 59. Staff/1701, Galbraith/2-4;
- PGE's response to OPUC Data Request No. 68. Staff/1701, Galbraith/5-7 (Galbraith/6-7 are CONFIDENTIAL).

Q. WHY DID YOU INCLUDE PGE'S RESPONSE TO OPUC DATA REQUEST NO. 70?

A. I included this response for two reasons. First, PGE appears to agree with Staff that the resource sufficiency period for avoided costs should end with the occurrence of both energy and capacity deficits in a particular year. Staff/1701, Galbraith/1. Second, Staff agrees with PGE that there may be additional factors to consider when establishing the utility resource sufficiency/deficiency periods. The Commission should adopt Staff's general guidelines for determining the utility resource sufficiency/deficiency periods for avoided costs, but at the same time retain enough flexibility to make case-by-case determinations at the time of the utility's avoided cost filings.

Q. WHY DID YOU INCLUDE PGE'S RESPONSE TO OPUC DATA REQUEST NO. 59?

A. I included this response because it provides the specific load-resource balance calculations used by PGE to establish its resource sufficiency period in Advice No. 05-10.

Q. WHY DID YOU INCLUDE PGE'S RESPONSE TO OPUC DATA REQUEST NO. 68?

A. I included this response because it provides a more detailed view of PGE's load-resource calculations. Specifically, these detailed load-resource balances show the effect of: (1) including Port Westward in both the capacity and energy balances beginning in 2007; (2) including the 12 percent planning margin in the capacity balance; (3) using theoretical availability in the energy balance (e.g., note the output of the Beaver plant under theoretical availability compared to the output included in PGE's final 2006 RVM filing); and (4) including planned front office transactions in the capacity and energy balances.

Q. DID YOU IDENTIFY THESE SPECIFIC ISSUES IN YOUR DIRECT TESTIMONY?

A. Yes. I recommended that the Commission:

> Direct PGE to update the load-resource balances used to determine its resource sufficiency period and avoided costs to: (1) include known and measurable resource additions and changes in expected loads; (2) exclude its 12 percent IRP planning margin from its load requirement; (3) adjust plant availability for forced outages; and (4) include planned front office transactions from its 2002 IRP Final Action Plan.

Staff/1200, Galbraith/2.

Q. HAS PGE RESPONDED TO YOUR DIRECT TESTIMONY REGARDING THESE ISSUES?

A. No, not yet. The schedule in this phase of UM 1129 calls for simultaneous rebuttal testimony; therefore PGE's response is concurrent with this testimony. In particular, Staff is interested in PGE's rationale for including Port Westward in the load-resource balances used to establish avoided costs in Advice No. 05-10. Staff recognizes, that at the time of PGE's filing, Port Westward was under construction and therefore may have been more 'known and measurable' than other generic planned resources. Staff may conduct further discovery after it has reviewed PGE's arguments regarding Port Westward and the other issues.

Q. DO YOU WISH TO REVISE ANY OF THE RECOMMENDATIONS YOU MADE IN YOUR DIRECT TESTIMONY REGARDING THE DETERMINATION OF THE RESOURCE SUFFICIENCY/DEFICIENCY PERIODS FOR SETTING AVOIDED COSTS?

A. No, not at this time.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UM 1129 Phase I Compliance
WITNESS: Maury Galbraith

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1701

Exhibit in Support of Rebuttal Testimony

<u>REDACTED VERSION</u>

January 20, 2006

CERTAIN INFORMATION CONTAINED IN STAFF EXHIBIT 1701 IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 04-378. YOU MUST HAVE SIGNED THE PROTECTIVE ORDER IN DOCKET UM 1129 TO RECEIVE THE CONFIDENTIAL PORTION OF THIS EXHIBIT.

January 18, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Doug Kuns
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM-1129/Advice No. 05-10 Phase I
PGE Response to OPUC Data Request
Dated January 4, 2006
Question 070

Request:

In PGE Response to OPUC Data Request No. 59, PGE provided two tables to support PGE's resource sufficiency period in PGE Advice No. 05-10 (see Attachment 59-A). The first table shows a capacity deficit of 58 MW in 2009. The second table shows an energy deficit of 62 MWa in 2009. Calendar Year 2009 is the first year in which PGE is deficit on both a capacity and energy basis. Does PGE support a resource sufficiency period standard (or definition) based on the first year of combined capacity and annual energy deficits?

Response:

Generally, we assume that a resource sufficiency period that ends with the occurrence of both energy and capacity deficits in a particular year to be a reasonable definition of the resource sufficiency period for avoided cost purposes. This appears to be the appropriate point in time to begin using the costs of the proxy plant (combined cycle combustion turbine for PGE) in the avoided cost calculation.

There may also be additional factors to consider in establishing the point where resource sufficiency ends. For example, the availability of economic market purchases compared to the costs of the proxy plant will influence the selection of resources used to supply load. The objective of the resource sufficiency period, as explained in Commission Order 05-584, is to recognize that avoided costs may be based on market purchases or the variable costs of existing resources for a period of time. Ideally, the integrated resource plan will define the economic supply path to determine avoided costs. This process will maintain the correct price signals to potential QFs and appropriate costs to customers.

December 8, 2005

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Doug Kuns
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM-1129/Advice No. 05-10
PGE Response to OPUC Data Request
Dated November 25, 2005
Question 059

Request:

Please provide electronic spreadsheet copies of all workpapers related to the determination of PGE's resource sufficiency period for calculation of avoided cost rates in Advice No. 05-10.

Response:

The calculations used to establish PGE's resource sufficiency[1] period are provided in Attachment 059-A. Two tables set out energy and capacity sufficiency based on the Company's IRP Final Action Plan with adjustments for updated load forecasts. Based on this analysis and the general trend toward lower load forecasts, 2009 was set as the year to use the proxy CCCT plant as the avoided resource.

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[1] OPUC Order 05-584 did not specifically define "resource sufficiency." As a proxy, PGE used the notion of resource adequacy contained in our IRP. Resource adequacy calls for capacity and energy to meet our 1-2 peak load probability plus a twelve percent reserve margin.

PGE UM-1129 Sufficiency Period Calculation

Values in MW

			2006	2007	2008	2009	2010	2011	2012
(1)		IRP Final Action Plan 1 in 2 Probability Load (graph p. 53)	4,336	4,449	4,492	4,663	4,756	4,851	4,947
(2) =	(1) - (6)	Resources & Load difference	1,382	1,917	1,974	2,139	2,340	2,437	2,755
(3)		Updated March 2005 Indicative RVM Load Forecast		3,867	3,949	4,015	4,084		
(4)		IRP Reserve Margin Calc	0.12	464	474	482	490		
(5)		1 in 2 Prob Load based on 2005 RVM Forecast		4331	4423	4497	4574		
(6)		IRP Final Action Plan Long Term Resources MW (graph p. 53)	2,954	2,532	2,518	2,524	2,416	2,414	2,193
		Table 4 - IRP Final Action Plan, page 12							
(7)		Incremental Resource Mix, 2007		960	960	960	960		
(8)		2007 Additional Capacity Actions		955	955	955	955		
(9)				1,915	1,915	1,915	1,915		
(10) =	(6) + (9)	Total IRP Final Action Plan Resources		4,447	4,433	4,439	4,331		
(11) =	(9) - (5)	Sufficiency based on March 2005 Indicative RVM Load Forecast		116	10	-58	-244		
(12) =	(9) - (1)	Sufficiency based on IRP Final Action Plan		-2	-59	-224	-425		

PGE UM-1129 Sufficiency Period Calculation

Values in MWa

			2006	2007	2008	2009	2010	2011	2012
(1)		IRP Final Action Plan MWa (graph p. 53)	2,426	2,492	2,514	2,603	2,656	2,710	2,766
(2) =	(1) - (4)	Resources & Load difference	443	773	807	904	1,016	1,078	1,251
(3)		Updated March 2005 Indicative RVM Load Forecast		2,454	2,505	2,551	2,601		
(4)		IRP Final Action Plan Long Term Resources MWa (graph p. 53)	1,983	1,719	1,707	1,699	1,640	1,632	1,515
		Table 4 - IRP Final Action Plan, page 12							
(5)		Incremental Resource Mix, 2007		790	790	790	790		
(6)		2007 Additional Capacity Actions		0	0	0	0		
(7)				790	790	790	790		
(8) =	(7) + (4)	Total IRP Resources		2,509	2,497	2,489	2,430		
(9) =	(8) - (3)	Sufficiency based on March 2005 Indicative RVM Load Forecast		54	-8	-62	-171		
(10) =	(8) - (1)	Sufficiency based on IRP Final Action Plan		17	-17	-114	-226		

January 18, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Doug Kuns
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM-1129/Advice No. 05-10
PGE Response to OPUC Data Request
Dated January 4, 2006
Question 068

Request:

Please update the load-resource balance tables provided in response to Staff Data Request No. 67 to reflect: (1) the load forecast used in PGE Advice No. 05-10; and (2) known and measurable additions and changes to PGE's existing resources as of January 2005. Please provide the response in both hard copy and electronic spreadsheet format.

Response:

The hard copies and electronic spreadsheets of the load balance tables in PGE's IRP Final Action Plan updated for the specified actions in Table 4, page 12, are included in Attachment 068-A. Attachment 068-A is Confidential and Subject to Protective Order No. 04-378 and provided under separate cover. Actions included below the Tables are 125 MW of short-term acquisitions and 500 MW of market purchases. An estimate of ESS load has not been included which would further reduce the system load. PGE will also be providing an IRP Action Plan update by March 31, 2006, as requested in Commission Order No. 05-1138.

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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 20th day of January, 2006.

Mike Weirich

Mike Weirich
Assistant Attorney General
Of Attorneys for Public Utility Commission's Staff
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UM 1129
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