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December 9, 2005

Via Electronic Filing and U.S. Mail

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 2148
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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 Direct Testimony. This document is being filed by electronic mail with the PUC Filing Center. A confidential version is being sent via first-class mail to all parties that have signed the protective order.

/s/ Kay Barnes

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cc: UM 1129 Service List - parties

CASE: UM 1129 - Phase I Compliance
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1000

Direct Testimony

December 9, 2005

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

A. My name is Lisa Schwartz. I am employed by the Public Utility Commission of Oregon as a senior analyst in the Resource and Market Analysis Section. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. HAVE YOU FILED TESTIMONY PREVIOUSLY IN THIS CASE?

A. Yes. I filed Staff/200, Exhibit Staff/201, Exhibit Staff/202 and Staff/600.

Q. HAVE YOU PREPARED AN EXHIBIT?

A. Yes. I prepared Exhibit Staff/1001, a summary of Staff's recommendations. I also prepared Exhibits Staff/1002-1005, selected responses to Staff's data requests.

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. First, I provide an overview of Staff's direct testimony and a summary of Staff's recommendations. Next, I address provisions in the standard form contracts filed by the electric utilities — for purchases from Qualifying Facilities (QFs) 10 MW or less — that are intended to protect the utility and its ratepayers against breaches of the contract. The specific provisions I address are related to creditworthiness, security, default and termination, damages and indemnity. I then address other items in the standard contracts intended to mitigate risk, related to force majeure, liens and encumbrances, project maintenance, and release for claims against the facility prior to contract execution. Next, I address procedures set forth in the tariffs for entering a PURPA contract. I then address a variety of other issues related to the standard contracts. Finally, I discuss issues related to the application of the Revised Protocol for PacifiCorp.

Q. HAVE OTHER STAFF WITNESSES PREVIOUSLY FILED TESTIMONY IN THIS CASE ON THESE ISSUES?

A. Yes, for many of these items. I adopt and will sponsor for the remainder of this proceeding the testimony of Staff witness Jack Breen, consisting of Staff/100 and Staff/500 and supporting exhibits, with the exception of his testimony on insurance issues. Staff witness Michael Dougherty will adopt and sponsor Mr. Breen's testimony on those issues. I also adopt and will sponsor the testimony of Staff witness Thomas Morgan, consisting of Staff/400 and Staff/800.

Through the filings made in compliance with Order No. 05-584, the Commission is approving standard contracts for QFs for the first time. The Commission and parties first saw these contracts at the time the compliance filings were made. Therefore, some issues were not vetted in Phase I of this proceeding. The Commission is now investigating whether the provisions in the standard contracts comply with the order and are reasonable.

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

A. In Staff/1100 and supporting exhibits, Staff witness Steve Chriss addresses issues related to forecasted natural gas and power market prices, natural gas trading hubs, and certain proxy plant assumptions that Portland General Electric (PGE) and PacifiCorp use for determining avoided costs. In Staff/1200 and supporting exhibits, Staff witness Maury Galbraith addresses issues related to how PGE and PacifiCorp determine their resource sufficiency period. In Staff/1300 and supporting exhibits, Staff witness Michael Dougherty provides testimony related to insurance provisions in the standard contracts. Finally, in Staff/1400 and supporting exhibits, Staff witness J.R. Gonzalez provides testimony on three issues: correction for meter reading errors, land rights, and interconnection cost assumptions for the utility proxy plant.

Q. PLEASE SUMMARIZE STAFF'S RECOMMENDATIONS.

A. A summary of Staff's recommendations is provided in Staff/1001.

Settlement negotiations are proceeding on Issue 4. That issue addresses whether the Commission should adopt criteria for determining if multiple energy projects are in fact a single QF, in order to protect the intent of Order No. 05-584 which provides standard avoided cost rates and a standard contract only for projects 10 MW and smaller. Staff reserves its testimony on this issue either for a stipulated settlement or rebuttal testimony.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

STANDARD CONTRACT PROVISIONS TO PROTECT AGAINST BREACHES

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

A. Issue 5 addresses whether provisions in the standard forms of contract related to creditworthiness, security, damages and termination reasonably comply with the letter and intent of Order No. 05-584.

Q. WHAT IS YOUR APPROACH TO EVALUATING THESE PROVISIONS?

A. I first review what the Order states related to the provision. Next, I review the utilities' standard forms of contract, as well as responses to Staff data requests, to determine whether the provision complies with the letter and intent of the Order. To the extent that the Order provides insufficient direction, I provide testimony on whether the provision is standard business practice or otherwise reasonable. For example, the utilities typically purchase power in the short-term market using the Edison Electric Institute (EEI) or Western System Power Pool (WSPP) master agreements. If the provisions in the standard contracts for QFs are consistent with these master agreements, that is an indication that the provisions are standard business practice.

At the same time, Staff recognizes that these master agreements are typically used for power traded in blocks of 25 MW, rather than 10 MW – the limit for standard avoided cost rates and standard contracts, and they are typically used for terms shorter than 20 years. Further, PURPA is designed to encourage QFs. Therefore, to the extent a provision in one utility's standard contract may preclude QF financing, and an alternative provision in another utility's standard contract reasonably protects the utility and its ratepayers, I recommend in some cases that the Commission direct the utilities to adopt the alternative provision.

Creditworthiness

Q. PLEASE SUMMARIZE THE ISSUE.

A. This issue addresses requirements for a QF to establish creditworthiness. The issues list states Issue 5d as follows:

> Are the creditworthiness terms reasonable? For example:
> i. Is it reasonable for PacifiCorp and Idaho Power to impose security and creditworthiness requirements in addition to representations that the Qualifying Facility has good credit, is current on existing debt obligations and has not been a debtor in the last two years?
> ii. Is it reasonable for PacifiCorp to require Qualifying Facilities larger than 3 MW to have a long-term debt credit rating by a credit agency in order to meet credit requirements?
> iii. Is it reasonable that PGE requires a Qualifying Facility to warrant that it will remain current on financial obligations to others throughout the contract term, or post default security?
> iv. Is it clear in the utilities' contracts that security measures only come into play if a Qualifying Facility is unable to make these creditworthiness representations?
> v. Is the definition of Credit Requirements in § 1.8 of PacifiCorp's contract consistent with Order No. 05-584 at 45?

Q. WHAT REQUIREMENTS DOES ORDER NO. 05-584 ESTABLISH FOR CREDITWORTHINESS?

A. The Order states at 45:

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

Q. IS IT REASONABLE FOR THE UTILITIES TO INCLUDE CREDITWORTHINESS REQUIREMENTS IN ADDITION TO REPRESENTATIONS THAT THE QF IS CURRENT ON EXISTING DEBT OBLIGATIONS AND HAS NOT BEEN A DEBTOR IN THE LAST TWO YEARS?

A. Yes. Staff believes that the Commission's use of the term "including" in the quotation above allows the utilities to require additional documentation to establish that the QF has good credit, so long as the additional requirements are reasonable. Further support is provided at page 45 of the Order: "[I]n the event that a QF cannot demonstrate creditworthiness, the QF should be required, regardless of its size, to provide some default security."

Q. ARE THE UTILITIES' CREDITWORTHINESS TERMS REASONABLE?

A. Yes, with one exception stated below, the requirements for establishing – and maintaining – creditworthiness in each of the utility's standard contract forms are reasonable.

Q. PLEASE COMMENT ON IDAHO POWER'S REQUIREMENTS FOR ESTABLISHING CREDITWORTHINESS.

A. Section 4.1.6 of Idaho Power's standard contract requires QFs to provide commercially reasonable documentation of creditworthiness. The utility requires "at a minimum" that the QF is current on existing debt obligations and has not been a debtor in a bankruptcy proceeding within the preceding two years.

The Company states:

> Idaho Power intends to take a flexible approach that allows QFs to demonstrate creditworthiness by providing different types of credit documentation appropriate for the QF's situation. Such documentation could include independent third-party credit rating information, financial information for the QF or a parent entity, as well as the warranties and representations described in Section 4.1.6. The intention of Section 4.1.6 is not to limit the types of documentation that could be provided and accepted.

Idaho Power goes on to say that most QF developers form a new single-purpose legal entity to facilitate project financing. Thus, in the Company's opinion, the minimum representations and warranties required by the Commission have "very limited" value. *See* Idaho Power's response to Staff Data Request 8; Staff/1002, Schwartz/3.

Given the Company's stated intention to provide flexibility for the QF in establishing creditworthiness, and the Commission's allowance for a utility to require additional documentation of creditworthiness, Staff finds Idaho Power's approach complies with Order No. 05-584 and is reasonable.

Q. ARE PGE'S REQUIREMENTS FOR ESTABLISHING CREDITWORTHINESS REASONABLE?

A. Yes, in part. Besides requiring the QF to represent or warrant that it has not been a debtor in any bankruptcy proceeding within the past two years and that it is current on all its financial obligations, Section 7 of PGE's standard contract requires the QF to maintain this status throughout the term of the contract. If at any time the QF can no longer do so, it must provide default security at that time.

PGE states that in the event the seller is no longer current on its payment obligations to others, the WSPP and EEI master power trading agreements require either termination of the agreement or provision of collateral. Further, PGE states that default in making payments to others is a good indication that the QF will fail to deliver power to PGE.

At the same time, in deciding whether to terminate the contract (presumably in the event the QF cannot provide collateral at the time), the Company says it could take into account whether the QF's financial difficulty is being resolved and whether PGE's customers would be best served by not terminating the contract. *See* PGE's response to Staff Data Request 41; Staff/1003, Schwartz/12-13.

Q. HAVE PARTIES EXPRESSED CONCERNS ABOUT THIS ADDITIONAL REQUIREMENT?

A. Yes. For example, the Oregon Department of Energy (ODOE) states that if PGE is able to require default security at a time a QF becomes delinquent on its State Energy Loan Program (SELP) loan — even if an agreement were in place to make the borrower current on its loan payments — SELP would be unable to finance the project. ODOE estimates that it has financed about half of Oregon's QFs 10 MW or smaller through its loan program. *See* ODOE's responses to Staff Data Requests 1 and 2.L.; Staff/1004, Schwartz/1, 4-5.

ODOE explains that at a time when the QF has reduced revenue, it would be unlikely to have resources to provide default security. Typically an escrow account would be the only form of security a small QF could provide.

Staff recommends that the Commission 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. This is an indication that the lender finds the financial difficulty of the QF to be temporary and that the QF project remains viable.

Q. DO THE OTHER UTILITIES' STANDARD CONTRACTS RAISE THE SAME CONCERN?

A. It is unclear in Idaho Power's and PacifiCorp's standard contracts whether they, too, would require a QF to post security at a later date if the QF falls behind on any of its financial obligations to others. Therefore, Staff recommends that the Commission require Idaho Power and PacifiCorp to make a similar clarification in their standard contracts.

Q. PLEASE COMMENT ON PACIFICORP'S REQUIREMENTS FOR ESTABLISHING CREDITWORTHINESS.

A. Under Section 3.2.7 of PacifiCorp's standard contract, QFs 3 MW or smaller would only be required to meet the minimum representations and warranties for creditworthiness in the Commission's order. QFs larger than 3 MW also must meet the Company's credit requirements in Section 1.8. These require a minimum rating by a major credit rating agency ("Baa3" or greater by Moody's or "BBB-" or greater by Standard & Poor's) or "other indicia of creditworthiness acceptable to PacifiCorp in its reasonable judgment."

PacifiCorp states that in lieu of meeting a published credit rating level, the Company would accept an equivalent rating as determined by reviewing the QF's financial statements and using a proprietary credit scoring model developed with Standard & Poor's. *See* PacifiCorp's response to Staff Data Request 42; Staff/1005, Schwartz/7.

Staff finds these requirements for establishing creditworthiness, in lieu of posting default security, reasonable and consistent with Order No. 05-584.

ODOE states:

> In SELP's experience it is highly unlikely that a QF of 10 MW or smaller has a senior unsecured debt rating. This rating is usually limited to large corporations and generally requires the consistent issuance of unsecured debt and a payment to the rating agencies. *See* ODOE's response to Staff Data Request 6; Staff/1004, Schwartz/6.

The utilities must be able to use other documentation and methods to determine a QF's creditworthiness if they find that the minimum warranties and representations in the Order are insufficient and if the QF does not have a long-term rating by a major credit rating agency.

Q. DO THE STANDARD CONTRACTS MAKE IT CLEAR THAT DEFAULT SECURITY IS REQUIRED ONLY IF THE QF DOES NOT MEET THE UTILITY'S CREDITWORTHINESS REQUIREMENTS?

A. Yes. Section 4.1.6 of Idaho Power's contract states that security will be required "[i]n lieu of providing evidence of acceptable creditworthiness." Section 7 of PGE's contract states that the QF must provide default security "[i]n the event the Seller" is unable or becomes unable to make the creditworthiness representations and warranties. Section 3.2.7 of PacifiCorp's contract states that "Seller need not post security … for PacifiCorp's benefit in the event of Seller default, provided that Seller warrants all of the following…."

Security

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

A. Issue 5a is stated generally as, "Are the security provisions reasonable?" I address individually below the specific items raised for standard contracts for QFs 10 MW and smaller.

Q. FIRST, PLEASE CITE THE SECURITY REQUIREMENTS THAT ORDER NO. 05-584 ESTABLISHES.

A. The Order states at 45:

> [I]n the event that a QF cannot demonstrate creditworthiness, the QF should be required, regardless of its size, to provide some default security…. [W]e adopt Staff's proposal that requires a QF unable to satisfy credit rating requirements to provide a reasonable amount of default security by one of the following means, selected at the QF's discretion: senior lien, step-in rights, a cash escrow or a line of credit….

> Should a QF demonstrate creditworthiness, we conclude that some provision for default security in the event that it is needed is appropriate…. Consequently, we adopt Staff's recommendation that standard contracts include a clause providing that, in the event that a QF defaults and the market prices to replace the contracted for energy exceed the contract price, future payments after the default period ends shall be commensurately reduced over a reasonable period of time to recoup the costs incurred by the utilities.

Q. PLEASE ADDRESS ISSUE 5.a.i: "IS IT CONSISTENT WITH ORDER NO. 05-584 THAT THE SECURITY REQUIREMENTS IN § 4.1.6 OF IDAHO POWER'S CONTRACT ARE 'AT A MINIMUM,' ALLOWING FOR UNSPECIFIED CONDITIONS AT THE SOLE DISCRETION OF IDAHO POWER?"

A. Section 4.1.6 of Idaho Power's standard contract states:

> In lieu of providing evidence of acceptable creditworthiness, the Seller may provide Idaho Power with commercially reasonable security instruments such as letter of credit, senior lien rights, step-in rights, escrow accounts or other forms of liquid financial security that would provide readily available cash to Idaho Power in the Event of a Default under this Agreement.

The statement of the issue indicates confusion about what Section 4.1.6 states. Idaho Power is simply providing a QF additional flexibility by allowing it to provide other types of liquid financial security, in addition to the four options provided for in the Order. As explained earlier in my testimony, the Company's standard contract uses the phrase "at a minimum" when referring to the type of documentation that would be reviewed to determine the QF's creditworthiness.

If the Company did not deem the QF to be creditworthy, then the security provisions would apply.

Q. PLEASE EXPLAIN ISSUE 5.a.ii., REGARDING A LETTER OF CREDIT FOR POTENTIAL ENVIRONMENTAL REMEDIATION FOR A QF THAT SELECTS THE SENIOR LIEN OR STEP-IN RIGHTS SECURITY OPTION.

A. Section 10.5 of PacifiCorp's standard contract requires a letter of credit in favor of the Company during the term of the agreement for potential environmental remediation if a QF selects the senior lien or step-in rights security option. PacifiCorp would draw on the letter of credit in the event the QF defaults, the Company steps in to own or operate the facility, and the site requires environmental remediation.

In response to Staff Data Request 5, PacifiCorp states:

> [I]f it took over the facility as an owner/operator under its lien rights, or if PacifiCorp only became the operator under its step-in rights, the Company would potentially be exposed to joint and several liability for environmental remediation costs under CERCLA (the federal Superfund laws).

According to the contract, PacifiCorp would determine the required amount of credit based on what the Company might reasonably incur to satisfy remediation requirements. The Company states that the determination would be based on an evaluation of the project site. Further, the Company states there would be less likelihood of existing contamination at a greenfield site than an industrial site. *See* PacifiCorp's responses to Staff Data Requests 5-6; Staff/1005, Schwartz/1.

Q. DO PARTIES EXPRESS A CONCERN REGARDING THIS PROVISION?

A. Yes. For example, ODOE states that small QFs either would not be able to obtain a letter of credit, or that the issuer of the letter of credit may require collateral. Because the QF also would need collateral to secure a loan, this provision in PacifiCorp's contract may make it impossible to finance the project. *See* ODOE's response to Staff Data Request 2.b., Staff/1004, Schwartz/2.

Q. WHAT ARE ODOE'S CONSIDERATIONS AND RECOMMENDATIONS ON THIS ISSUE?

A. In addition to administering SELP, ODOE also serves as staff for the state Energy Facility Siting Council. ODOE explains that in order to receive a site certificate for a large power plant in Oregon, the applicant must provide either a letter of credit or a bond for the estimated cost to the state of restoring a site to a "useful, non-hazardous condition." This requirement addresses the risk that the plant will fail to restore the site after it shuts down.

ODOE states that at most renewable generation sites, typically greenfield sites, the risk that environmental remediation would be required should be minimal. While stating that QFs at industrial sites would pose more of a risk, ODOE notes that the Siting Council has not had experience with these facilities. However, in SELP's single foreclosure on a loan for an industrial cogeneration facility, there were no significant costs for environmental remediation.

ODOE points out that the senior lien option would not be available to QFs that finance their project with SELP. SELP requires that it have a first or senior security position in the facility.

Focusing then on QFs that choose step-in rights, ODOE states that the utility would simply decide not to step in as the facility operator if its assessment of probable environmental remediation determined that it should not do so. Therefore, in order for QFs choosing the step-in rights option to pose a risk to the utility and its ratepayers for environmental remediation, three things would have to occur:

First, the QF would have to default on the power purchase agreement with the utility. Second, the remediation required would have to be substantial. And third, market prices would have to exceed contract prices. ODOE states that it would be rare for all these conditions to occur. However, if they did, the utility would not exercise its step-in rights, and instead could seek damages from the QF through litigation.

ODOE argues that requiring all QFs that choose step-in rights to provide a letter of credit for potential environmental remediation would be unduly burdensome, would provide only minimal reduction in risk to ratepayers, and would reduce QF development. Without a letter of credit, however, ODOE concedes that it would be more difficult for the utility to collect damages.

For QFs at industrial sites that choose the senior lien or step-in rights security option, ODOE suggests as an alternative having the host company assume the financial responsibility of potential environmental remediation.

Finally, ODOE states that if the Commission determines that PacifiCorp is allowed to require a letter of credit for potential environmental remediation, the Company should be allowed to do so only where there is a “clear documented risk," and the risks should be specified. Further, there should be a cap on the amount of the letter of credit the utility can require based on project type and location. *See* ODOE's Responses to Staff Data Requests 13-16; Staff/1004, Schwartz/7-8.

Q. WHAT DOES STAFF RECOMMEND REGARDING A LETTER OF CREDIT FOR ENVIRONMENTAL REMEDIATION?

A. ODOE and Staff have commented throughout this proceeding on the unlikelihood of a small QF obtaining a letter of credit. Further, ODOE makes a reasonable case that environmental remediation poses a minimal risk to the utility and customers. Therefore, Staff recommends that the Commission direct PacifiCorp to remove its requirement that a small QF must obtain a letter of credit for potential environmental remediation in the event the QF chooses the step-in rights or senior lien security option under the standard contract.

Q. PLEASE ADDRESS ITEM 5.a.iii.: "SHOULD PGE § 7 AND IDAHO POWER § 4.1 DEFINE THE SECURITY OPTIONS OF CASH ESCROW, SENIOR LIEN, STEP-IN-RIGHTS AND LETTER OF CREDIT?"

A. PacifiCorp appropriately provides these definitions in Sections 1 and 10 of its standard contract. However, Idaho Power and PGE do not define these terms in their standard contracts. The Commission should direct the companies to do so.

Idaho Power provides definitions for these security options in response to Staff Data Request 9. *See* Idaho Power's response to Staff Data Request 9; Staff/1002, Schwartz/4. PGE provides definitions in response to Staff

Data Request 56. *See* PGE's response to Staff Data Request 56; Staff/1003, Schwartz/22-23.

Q. PLEASE ADDRESS ITEM 5.a.iv.: IS THE DEFINITION OF DEFAULT SECURITY IN § 1.9 OF PACIFICORP'S CONTRACT CONSISTENT WITH ORDER NO. 05-584 AT 45?

A. PacifiCorp defines Default Security in Section 1.9 as follows:

> "**Default Security**", unless otherwise agreed to by the Parties in writing, means the amount of either a Letter of Credit or cash placed in an escrow account sufficient to replace twelve (12) average months of replacement power costs over the term of this Agreement, and shall be calculated by taking the average, over the term of this Agreement, of the positive difference between (a) the monthly forward power prices at **[specify POD]** (as determined by PacifiCorp in good faith using information from a commercially reasonable independent source), multiplied by 110%, minus (b) the average of the Fixed Avoided Cost Prices specified in Schedule 37, and multiplying such difference by (c) the Minimum Annual Delivery; provided, however, the amount of Default Security shall in no event be less than the amount equal to the payments PacifiCorp would make for three (3) average months based on Seller's average monthly volume over the term of this Agreement and utilizing the average Fixed Avoided Cost Prices specified in Schedule 37. Such amount shall be fixed at the Effective Date of this Agreement.

In Order No. 05-584 (at 45), the Commission declined to impose any requirements regarding the proper amount of default security, leaving it to the discretion of each utility, subject to Commission review of the standard contracts. The Commission directed the parties to further address the appropriate amount of default security in Phase II of Docket UM 1129.

However, Staff proposed that the issue be taken up in the Phase I Compliance investigation as it relates to standard contracts for QFs 10 MW and less. The issue was adopted in this investigation as Issue 35. I address this later in my testimony.

Q. PLEASE ADDRESS ITEM 5.a.v.: IS THE DEFINITION OF LETTER OF CREDIT IN § 1.17 OF PACIFICORP'S CONTRACT CONSISTENT WITH ORDER NO. 05-584 AT 45?

A. The Order did not impose any requirements regarding the definition of letter of credit, leaving it to the discretion of each utility subject to Commission review of the standard contracts. PacifiCorp defines Letter of Credit in Section 1.17 as follows:

> **"Letter of Credit"** means an irrevocable standby letter of credit, from an institution that has a long-term senior unsecured debt rating of "A" or greater from S&P or "A2" or greater from Moody's, in a form reasonably acceptable to PacifiCorp, naming PacifiCorp as the party entitled to demand payment and present draw requests thereunder.

PacifiCorp states that it has not executed contracts for projects between 3 MW and 10 MW in recent years, and contracts executed with projects 3 MW and less have not included a definition of Letter of Credit. The Company further states that its definition in the standard QF contract is commercially reasonable because it sets forth the credit requirements for the issuing institution and the form of the letter of credit, and it is consistent with definitions for agreements used in the wholesale power market such as WSPP and EEI. *See* PacifiCorp's response to Staff Data Request 31; Staff/1005, Schwartz/3.

While PacifiCorp requires a higher credit rating for the issuer than EEI, staff finds the Company's definition of Letter of Credit to be reasonable and consistent with definitions used in the wholesale power market.

Q. ARE THE AMOUNTS OF DEFAULT SECURITY THAT EACH OF THE UTILITIES FOR THE STANDARD CONTRACTS REQUIRE REASONABLE?

A. The amount of default security that PacifiCorp and PGE require is reasonable. Idaho Power does not specify how it determines the amount of security required.

ODOE recommended in Phase I of this proceeding that default security be limited to around 2% of project capital costs. *See* ODOE/Exhibit No. 3, Keto/5-6. Based on a phone conversation with SELP Loan Manager Jeff Keto on December 2, 2005, my understanding is that ODOE based this rough estimate on economic models of sample projects, including availability of funds for an escrow account, the only avenue available for most small QFs.

To the extent that the utility determines that a QF has a lower risk of default relative to other QFs, PacifiCorp and Idaho Power state that they may reduce the level of default security required. The percent of project capital costs that the default security amount represents also could be considered at that time.

Q. PLEASE DESCRIBE THE AMOUNT OF DEFAULT SECURITY PACIFICORP REQUIRES FOR QFS THAT DO NOT ESTABLISH CREDITWORTHINESS.

A. PacifiCorp determines the amount of default security it requires based on the positive difference, for 12 average months over the term of the agreement, between:

1) 110% of monthly forward power prices, and
2) the estimated payments to the QF.

The estimated payments are based on the Fixed Avoided Cost prices in Schedule 37 and the QF's Minimum Annual Delivery commitment.

There is a minimum default security requirement equal to three average months of estimated payments to the QF.

PacifiCorp states that the definition is a reasonable, transparent and verifiable measurement of potential replacement power costs. The definition also allows parties to negotiate an alternative agreement. The Company used 110% rather than 100% of forward market prices, as well as a minimum of three months of payments to the QF, to protect ratepayers from movement in the market.

The Company explains that it based its default security amount on the QF's energy commitment, rather than capacity payments to the QF (embedded in on-peak prices), because the QF does not have a minimum capacity obligation. In addition, avoided cost prices are "energy only" prices – in other words, they do not include fixed capacity payments. The Company further states that if the QF fails to perform, the Company will look to replace energy, not capacity. *See* PacifiCorp's response to Staff Data Requests 30 and 62; Staff/1005, Schwartz/2, 18.

Staff finds PacifiCorp's approach reasonable. The Company requires default security in an amount that reflects potential harm to the Company and ratepayers in the event the QF defaults and market prices for replacement power exceed the cost of the QF contract.

Q. PLEASE DESCRIBE THE AMOUNT OF DEFAULT SECURITY PGE REQUIRES FOR QFs THAT DO NOT ESTABLISH CREDITWORTHINESS.

A. PGE bases its required default security on one year's worth of capacity payments to the QF. The calculation is as follows:

> Annual number of on-peak hours X (Minimum net output/
> 8,760 hours) X (On-peak price - Off-peak price)

PGE explains that the intent is to limit the collateral required to the damages from a default, which are tied to the value of the power. PGE states that the amount required is similar to the amount specified in other agreements. For example, firm power purchases under the EEI agreement — typically for a term much less than 20 years — require companies that are not rated investment grade by S&P and Moody's to provide collateral equal to the amount the prospective market price exceeds the contract price. PGE states that it also has longer-term contracts that require collateral to protect against at least a portion of the risk that the Company would have to pay higher market prices for power not delivered under the contract.

PGE explains that it used capacity payments as the basis for determining the amount of default security, instead of forward market prices at the time of contract execution, because it is a simple, straightforward calculation that is easy to administer. In addition, PGE believes it is difficult to quantify an appropriate risk premium to apply to projected market prices for a 20-year contract. *See* PGE's responses to Staff Data Requests 28 and 54; Staff/1003, Schwartz/6-7, 21.

While this approach differs from PacifiCorp's, staff finds it reasonable. Avoided costs are based on a firm proxy resource. PGE's default security amount reflects the lost capacity value of the QF contract in the event the QF defaults. The amount is transparent and measurable.

Q. PLEASE DESCRIBE THE AMOUNT OF DEFAULT SECURITY IDAHO POWER REQUIRES FOR QFs THAT DO NOT ESTABLISH CREDITWORTHINESS.

A. Idaho Power's contract does not specify how the Company would determine the amount of security it would require for a QF that does not establish creditworthiness.

In response to Staff Data Request 1, Idaho Power simply states that the security amount required is:

> …100% of a reasonable estimated amount of potential damages for failure to provide the expected energy amounts under the Agreement. The estimate would be based on an analysis of the project's capacity to perform both financial and non-financial obligations. For example, if a QF maintains adequate business interruption/mechanical breakdown insurance, the likelihood of an extended default period is diminished and the estimated amount of potential damages could be reduced. *See* Idaho Power's response to Staff Data Request 1; Staff/1002, Schwartz/1.

The Commission ordered the utilities to file standard forms of contract for its approval in order to remove transaction costs and overcome economic impediments created by market barriers such as asymmetric information and a non-level playing field. *See* Order No. 05-584 at 16. Further, the Commission stated (at 45) that it would review the amount of security required when reviewing the standard contract filings.

From this, Staff concludes the Commission intended that each standard contract form plainly state how the utility would calculate the amount of default security required for QFs that do not demonstrate creditworthiness. Therefore, the Commission should 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. Both PacifiCorp and Idaho Power indicate they may reduce the amount of default security required in particular situations. Staff's recommendation is not intended to preclude such consideration by Idaho Power.

<u>Default and Termination</u>

Q. PLEASE SUMMARIZE ISSUE 5B, REASONABLENESS OF DEFAULT AND TERMINATION PROVISIONS IN THE STANDARD CONTRACTS.

A. Issue 5b addresses the QF's breach of the contract — for delays in commercial operation, under-deliveries or other events of default. It also addresses opportunities to cure such events, damage provisions, and the conditions under which the utility may terminate the agreement due to the QF's default.

Q. PLEASE SUMMARIZE YOUR POSITION ON THE FIRST FOUR ITEMS UNDER ISSUE 5b.

A. Items b.i. through b.iv. relate to how to determine the amount of QF energy under contract to the utility. The QF is in default when deliveries fall below that amount.

In Order No. 05-584 (at 28), the Commission stated:

> [W]e conclude that intermittent and firm resources should be valued equally, and direct utilities to pay full avoided costs pursuant to the appropriate methodology for all energy delivered under a QF standard contract, but only up to the nameplate rating of the facility.

The Commission ordered that a second phase of Docket UM 1129 further explore how the calculation of avoided costs should reflect the nature and quality of QF energy.

Given that avoided costs are based on a firm proxy resource, the utilities must be able to rely on some reasonable amount of QF energy. Staff stated in Phase I of this proceeding that we do not believe weather-related events should trigger default provisions for QFs that rely on natural motive force, including wind and hydro projects. *See* Staff/400, Morgan/7. Instead, Staff recommended use of a Mechanical Availability Guarantee (MAG) for determining whether a QF eligible for standard rates should receive capacity payments. *See* Staff/100, Breen/18-19; Staff/500, Breen/13-14.

The Commission has ordered parties to explore this issue further in Phase II. However, because Staff believes that a MAG is the ultimate solution to issues related to under-deliveries for intermittent resources, I comment briefly on the MAG here.

Q. HAVE ANY OF THE UTILITIES RECOMMENDED USE OF A MAG FOR QF CONTRACTS?

A. Yes. PacifiCorp proposed a MAG for its QF contract with the proposed 17.5 MW Schwendiman Wind project in Idaho, with the QF's concurrence.

PacifiCorp states:

> PacifiCorp's MAG approach recognizes that a wind QF cannot accurately predict monthly generation six months in advance…and therefore grades the QF's performance by what it can control: mechanical availability. The Agreement's MAG provisions require that [the] QF's average availability equal or exceed the following: 75% for Contract Year 1; 85% for Contract Years 2-10; and 80% for Contract years 11-20. With each passing year, PacifiCorp and the QF expect to gain more confidence in the dependable annual energy production of the facility — a number critical to PacifiCorp's long range resource planning. Without the MAG provision, PacifiCorp would have less confidence in the facility's minimum annual output because the QF would have less incentive to invest in reliability…. *See* Reply Comments of PacifiCorp at 4, Idaho Public Utilities Commission, Case No. PAC-E-05-9.

> PacifiCorp defines availability as...

> …the percentage of time that the Facility is actually producing Net Energy compared to the total amount of time that the Facility could have produced Net Energy. The total amount of time that the facility could have produced Net Energy is determined by taking the total hours in the measurement period and deducting the total number of hours of non-generation due to lack of sufficient wind, force

> majeure, and scheduled maintenance. *See* Application, Section 1.2, Case No. PAC-E-05-9.

The MAG measures performance annually, rather than using monthly delivery requirements. PacifiCorp explains:

> Generally speaking, monthly wind resource at a site can vary greatly from year to year, but the annual wind supply tends to be much more stable. Accordingly, once the annual wind resource at a facility has been established, the annual output from that facility should be predictable so long as the availability of the facility remains the same. *See* Reply Comments of PacifiCorp at 4, Case No. PAC-E-05-9.

PacifiCorp further states (at 6) that the MAG approach for determining whether non-performance should be excused is straightforward, less likely to give rise to contract disputes, rewards reliability, and does not create incentives for low-balling performance targets.

Q. DID THE IDAHO COMMISSION APPROVE USE OF A MAG?

A. No. The Idaho Commission rejected the use of a MAG in Order No. 29880 (with Commissioner Smith dissenting). The decision was in large part the result of previous decisions to measure generation on a monthly basis and use a 90/110 performance band. Staff is not aware of PacifiCorp raising the MAG approach until it brought forth for Idaho Commission approval its proposed contract with Schwendiman. Further, the Commission wanted to have similar PURPA contract provisions for all of its electric utilities.

Q. PLEASE EXPLAIN HOW EACH UTILITY'S COMPLIANCE FILING IN OREGON SETS MINIMUM DELIVERY REQUIREMENTS.

A. Idaho Power requires the QF to specify minimum *monthly* net energy amounts. At any time, the QF may revise the monthly amounts for the next calendar year. Failure to meet any monthly minimum is an event of default, unless excused by an event of force majeure. The difference between these monthly amounts and the amounts actually delivered to Idaho Power are subject to Shortfall Energy damages.

PacifiCorp uses a minimum *annual* delivery amount as the basis for default for under-delivery.

PGE also uses a minimum *annual* delivery amount as the basis for default for under-delivery. The QF can choose either: a) 75% of the average annual Net Output (all energy produced by the QF, less station and other on-site use, transformation and transmission losses, and other adjustments) or b) an "alternative" minimum amount based on supporting documentation. The QF is not in default for under-delivery unless it falls below this level for two consecutive contract years.

Q. PLEASE EXPLAIN HOW THESE DELIVERY AMOUNTS ARE DETERMINED.

A. Each utility allows the QF to designate the amounts, provided there is sufficient documentation. Idaho Power explains:

> [I]f the Monthly Net Energy Amounts submitted by the QF project do not appear to be consistent with the nameplate rating of the facility or the routine operations and industrial standards for the specific type of generation resource, Idaho Power may request additional information from the project to confirm that the project-specific Monthly Net Energy Amounts are reasonable for the specific project. If the QF

> sets its Monthly Net Energy Amounts at zero or some extreme minimum, the net result will likely be that the Company will not avoid or defer the correct amount of firm resources or firm energy purchases and customers will pay more than Idaho Power's true avoided cost. *See* Idaho Power's Response to Staff Data Request 5; Staff/1002, Schwartz/2.

Idaho Power describes the types of documentation it would require in accepting a QF's designation of Monthly Net Energy Amounts:

> Idaho Power would expect to review any data the QF developer has compiled that would support the QF developer's estimate of the firm energy production of the project. In many instances, this would be the same data that the QF's lender would require that the QF produce in order to accommodate the lender's due diligence review of the ability of the project to generate sufficient energy to support the debt financing of the project….
>
> Idaho Power will review the provided information and either accept the values as presented by the QF or will work cooperatively with the QF developer to determine an equitable monthly energy amount for inclusion in the contract. *See* Idaho Power's response to Staff Data Request 12; Staff/1002, Schwartz/5.

The Company provided examples of such documentation, such as water flow and head data for a hydroelectric project, wind velocity and duration data for a wind project, fuel source information on biomass facilities, and turbine and generator efficiency data.

Further, Idaho Power states that for wind and hydro projects, "[t]he monthly amount would not be set equal to the long-term average production, but at a lesser level to accommodate reasonably anticipated reductions in natural motive force." For cogeneration projects at industrial plants, Idaho Power stated that it would be reasonable that the QF would make allowances in its long-term average energy production estimates for market and price conditions that may impact the ability of the QF to deliver energy to the utility. *See* Idaho Power's response to Staff Data Request 13; Staff/1002, Schwartz/6.

As explained above, PGE requires the QF to designate 75% of its Net Output, or an Alternative Minimum Amount:

> Such Alternative Minimum Amount, if provided, shall exceed zero, and shall be established in accordance with Prudent Electrical Practices and documentation supporting such a determination shall be provided to PGE upon execution of the Agreement. Such documentation shall be commercially reasonable, and may include, but is not limited to, documents used in financing the project, and data on output of similar projects operated by seller, PGE or others. *See* PGE's Response to Staff Data Request 22; Staff/1003, Schwartz/4.

PacifiCorp's contract states:

> Seller shall specify the Minimum Annual Delivery of the Facility, and explain the basis for the estimate. NOTE: The Minimum Annual Delivery should be based on the most adverse natural motive force conditions reasonably expected and should take into account maintenance and Seller's load (if any). (See Exhibit D-1B.)

Q. DO YOU HAVE CONCERNS ABOUT ANY OF THESE MINIMUM DELIVERY REQUIREMENTS?

A. Yes. I am concerned about Idaho Power's requirement that QFs specify minimum monthly net energy amounts below which the Company assesses damages for under-delivery.

I agree with PacifiCorp that monthly wind generation can vary widely from year to year and cannot be accurately predicted far in advance. Generation from hydro resources also can vary widely, including the potential for drought years. Weather is beyond the QF's control.

It also may be difficult to predict monthly power production levels for a cogeneration project at an industrial site because of potential market disruptions for the host facility – falling paper prices for a mill, for example.

Further, I am concerned that a small wind project may have only a year's worth of anemometer data on the wind resource at the site, and a hydro project may have only a few years of flow data. Neither of these may be representative of the most adverse natural motive force conditions that may occur over the 20-year contract period.

ODOE states that SELP generally would not fund a QF if there is more than an incidental risk of default due to under-delivery related to minimum delivery requirements, assuming the consequences include significant financial harm to the QF. ODOE states that for projects relying on natural motive force, the minimum delivery requirements must be "very low" to allow for adverse years, or weather-caused shortfalls in generation must not cause default. *See* ODOE's response to Staff Data Request 2.c.; Staff/1004, Schwartz/2-3.

Q. WHAT ARE STAFF'S RECOMMENDATIONS REGARDING MINIMUM DELIVERY COMMITMENTS?

A. Staff recommends that delivery requirements for QFs relying on intermittent renewable resources, as well as cogeneration facilities relying on industrial hosts, be set on an annual, rather than monthly, basis, and account for the resource and production variations outlined above.

Staff believes that PacifiCorp's and PGE's contracts allow for these situations to be addressed. PacifiCorp's contract states that delivery obligations should be based on the most adverse natural motive force conditions. Further, the Company states that the "Seller's load variation" should be taken into account in designating Minimum Annual Delivery. *See* PacifiCorp's response to Staff Data Request 33; Staff/1005, Schwartz/4.

Similarly, PGE states:

> The Minimum Net Output is expected to be based on data available for roughly a worst year for wind, or water conditions, factors such as production variations, or data on output from other units with a longer history if the QF lacks data. The requirement to establish a Minimum Net Output recognizes that no default occurs unless the QF has not met the output levels for 2 consecutive years (Section 10.1.4). We expect that the Minimum Net Output will be less than the QF's expected output by an amount that recognizes expected variations in conditions. *See* PGE's response to Staff Data Request 23; Staff/1003, Schwartz/5.

Staff recommends that the Commission require Idaho Power amend its contract to allow for an annual delivery commitment for QFs relying on intermittent renewable resources, as well as cogeneration facilities relying on industrial hosts.

Q. DOES STAFF HAVE ANY RECOMMENDATIONS AT THIS TIME REGARDING THE MAG?

A. Pending the completion of Phase II of this proceeding, Staff recommends that for contracts with QFs relying on intermittent resources, the Commission *allow*, but not require, the utilities to use a MAG based on annual production as the basis for determining default for under-delivery. I further recommend that the utilities be allowed to submit revised standard contracts with such provisions in their compliance filings for the Phase I Compliance investigation.

Q. PLEASE MOVE ONTO YOUR NEXT ISSUE. DOES STAFF BELIEVE THE QF HAS BREACHED THE AGREEMENT IF COMMERCIAL PRODUCTION IS DELAYED OR IF IT UNDER-DELIVERS DURING THE UTILITY'S RESOURCE SUFFICIENCY PERIOD?

A. This is the question raised by Issues 5.b.vi. and 5b.ix.

I first address a delay in QF construction. In Order No. 05-584 (at 47), the Commission stated that security should be provided in the event a QF project is delayed coming on line. The Commission explained that "…the utility may need to replace the contracted for energy at market prices that exceed the [QF] contract price." However, the Commission provided the following caveat:

> At the time the contract is signed, we would expect parties to be aware of whether the contracting utility is in a resource deficient or sufficient position. We observe that if a utility is in a resource sufficient position, the contracted-for energy will likely not need to be immediately replaced. Consequently, we do not discern any reason to require additional security requirements in such a situation.

This passage refers specifically to whether security should be provided for construction delay when a utility is resource-sufficient, rather than whether a delay should constitute an event of default. However, Staff believes that the citation indicates that the Commission found the utility and its customers likely would not be harmed by a delay in QF commercial operation if a utility was resource-sufficient. While the Order makes clear that the determination of whether the utility is resource sufficient is made at the time of contract execution, it is unclear whether the Commission intended that the designation would be based on the utility's resource position at the time of contract execution or as of the specified on-line date for the QF. If Staff correctly understands the Commission's order on this point, a delay in commercial operations should not be an event of default 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.

In fact, if a utility is resource-sufficient, there may be an *advantage* to the utility and its ratepayers if the QF project is delayed, particularly if market prices are low.

Further, ODOE states that some small QFs may not be approved for financing if SELP perceives the risk of default for delays in commercial operation is too great and beyond the control of the developer. ODOE states that in today's project development environment, there is an increased risk of delays beyond the developer's control in procuring project equipment, construction material, specialized labor and transportation to get materials to the site. *See* ODOE's response to Staff Data Request 2.d.; Staff/1004, Schwartz/3.

Therefore, I recommend the Commission order the utilities to modify their standard forms of contract to clarify that a delay in QF commercial operation is not an event of default 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.

Regarding under-deliveries, staff finds no explicit statement in the Commission's order that makes a distinction as to whether the utility is resource-sufficient or resource-deficient. Once a QF project is on line, the utility depends on it for its operations, including meeting retail load requirements and making market sales. Further, the project is being paid based on a firm proxy resource. Therefore, there should not be an exception for under-delivery as an event of default for the sole reason that the utility is in a resource-sufficient position.

Q. WHAT IS STAFF'S POSITION REGARDING TERMINATION DUE TO WEATHER-RELATED UNDER-DELIVERIES OR DELAYS IN PRODUCING POWER?

A. Issue 5.b.v. asks whether the utility should be able to terminate the QF contract under the following conditions:

First, should the utility be able to terminate the contract due to weather-related under-deliveries? Staff believes that annual minimum delivery requirements for intermittent renewable resources should be set through a MAG. However, pending the outcome of the Phase II proceeding, Staff recommends an annual delivery requirement with adverse motive force conditions taken into account. In either case, weather should not be a cause of termination.

Second, should the utility be able to terminate the contract due to delays in producing power? For the same reasons stated above, Staff believes that Order No. 05-584 does not allow the utility to do so if it is resource-sufficient.

However, the QF should be required to provide an updated on-line date for utility planning.

ODOE states that SELP would not finance a project subject to termination for delays in commercial operation, or under-delivery of power, unless termination is limited to the most egregious cases. In addition, SELP would want the right to cure the default within a commercially reasonable time, operate the facility, or sell the facility to another operator under a continuation of the power purchase agreement. Further, in order for SELP to finance the QF, any testing requirement to achieve commercial operation would have to take into account availability of motive force. *See* ODOE's response to Staff Data Requests 2.e. and f.; Staff/1004, Schwartz/3.

Staff recommends that the Commission require the utilities to modify their standard contracts to exclude delay of commercial operation as an event that allows termination 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. Staff further recommends that the standard contracts be modified to take into account availability of motive force in the testing requirement for achieving commercial operation.

Q. REGARDING TERMINATION, ISSUE 5.b.xii ASKS WHETHER SECTION 11.3.2 OF PACIFICORP'S STANDARD CONTRACT IS CONSISTENT WITH PURPA. PLEASE DESCRIBE PACIFICORP'S APPROACH.

A. Section 11.3.2 of PacifiCorp's contract reads as follows:

> <u>Seller Disqualification</u>. If this Agreement is terminated because of Seller's default, Seller may not require PacifiCorp to purchase energy or capacity from the Facility prior to the Termination Date, and Seller hereby waives its rights to require PacifiCorp to do so. This subsection shall survive the termination of this Agreement.

Staff agrees with the general concept that a utility may, for good cause, terminate a QF agreement. However, Staff is concerned that PacifiCorp's additional provision, that the QF may not again contract with the utility for a set period of time, may conflict with a QF's general right to enter into agreements under PURPA. Staff notes that PGE's approach to this issue, discussed immediately below, sidesteps the potential legal flaw inherent with PacifiCorp's language.

Q. PLEASE EXPLAIN PGE'S APPROACH TO THIS ISSUE.

A. Section 10.4 of PGE's contract provides that if a QF is terminated due to its default, PGE 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. This provision is reasonable. It prevents a QF from intentionally defaulting on the original agreement in order to obtain more favorable avoided cost rates or other terms and conditions that may be available to QFs at a later date.

Q. HOW DOES IDAHO POWER'S CONTRACT ADDRESS THIS ISSUE?

A. Idaho Power's contract does not state how it would treat a QF's request to again sell power to the Company under PURPA, after the Company terminates the standard contract due to the QF's default.

Q. WHAT ARE STAFF'S RECOMMENDATIONS ON THIS ISSUE?

A. Staff recommends that the Commission require that PacifiCorp and Idaho Power adopt PGE's approach. The approach is transparent, and it recognizes that so long as the project remains a QF, and the federal PURPA mandate exists, the utility is required to purchase all energy from the QF at avoided costs*.* It also prevents gaming by the QF to obtain more favorable terms and conditions at a later date.

Q. MOVING ONTO ISSUE 5.b.xiii, PLEASE DESCRIBE IDAHO POWER'S TERMINATION PROVISION FOR UNDER-DELIVERY.

A. Section 6.3 of Idaho Power's contract states that the Company may terminate the contract if the QF fails to deliver at least 10% of the sum of the monthly Net Energy Amounts in any contract year. I find the under-delivery level at which termination would be contemplated reasonable.

ODOE has stated that some hydroelectric projects may not produce for a period longer than a year due to prolonged drought. Idaho Power states that it would not terminate a QF contract due to reduced resource availability resulting from adverse natural motive force conditions or production curtailments at the host industrial facility, unless the project appears to have permanently curtailed its generation to very low levels and the developer is not making reasonable efforts to cure the problem. The Company also would consider the value of the contract relative to then-current avoided costs. *See* Idaho Power's response to Staff Data Request 14; Staff/1002, Schwartz/7.

So long as the replacement power provisions of the contract keep the Company whole in the event market prices at the time of under-delivery exceed the QF contract price, there may be no harm to the utility or ratepayers in allowing the QF contract to continue.

Q. DOES STAFF FIND IDAHO POWER'S TERMINATION PROVISION FOR UNDER-DELIVERY REASONABLE?

A. Yes, except that Idaho Power should add language to the contract that explains the conditions under which it would again purchase energy from the QF, as I described earlier.

Q. PLEASE EXPLAIN ISSUE 5.b.xi., OPPORTUNITY TO CURE FOR EVENTS OF DEFAULT.

A. For certain events of default, the QF is allowed a period of time to fix the breach of contract. Some events cannot be cured – for example, if the project no longer meets the PURPA criteria. For other breaches, the contract provides the QF either a time certain, or a "commercially reasonable time," after the event of default to cure.

Q. IS IT REASONABLE FOR PACIFICORP TO LIMIT THE OPPORTUNITY TO CURE FOR A BREACH OF MATERIAL TERM TO A TIME CERTAIN AFTER THE DEFAULT?

A. Yes. Staff finds either time-certain deadlines, or a cure within a "commercially reasonable time," to be reasonable. PacifiCorp believes fixed time periods are preferable because they reduce the risk of disagreement over how long the cure period should be for a particular event. Further, PacifiCorp states that time-certain cure periods are standard business practice and commercially reasonable, citing such provisions in the WSPP agreement. *See* PacifiCorp's response to Staff Data Request 39; Staff/1005, Schwartz/6.

Q. ARE THE OPPORTUNITIES TO CURE FOR EVENTS OF DEFAULT IN PACIFICORP'S CONTRACT REASONABLE?

A. Yes. Section 11.2.2 of PacifiCorp's contract provides for a cure period up to 120 days for a default under Section 11.1.1, breach of material term, as well as Section 11.1.5, delayed commercial operations. Section 11.1.2 provides an opportunity to cure for defaults on other agreements, commercial or financing, within the time allowed for a cure under those agreements.

Regarding Section 11.1.3, default due to insolvency, PacifiCorp states that insolvency increases the risk of the QF's default on its contract with PacifiCorp.

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.

Regarding Section 11.1.6, under-delivery, PacifiCorp explains that because the minimum delivery obligation exists for a time period which will have passed, failure to satisfy that obligation is not capable of being cured. *See* PacifiCorp's response to Staff Data Request 38; Staff/1005, Schwartz/5.

Q. ARE THE OPPORTUNITIES TO CURE REASONABLE IN PGE'S CONTRACT?

A. Yes. PGE does not provide an opportunity to cure for the QF's breach of Section 10.1.1. There also is no opportunity to cure for breach of a representation or warranty (Section 10.1.2) or for failure to provide default security (Section 10.1.3). PGE states that the utility and its customers are subjected to additional risk or costs when the QF is in breach of those sections.

There is a built-in cure period for Section 10.1.4, seller's initial failure to deliver Minimum Net Output, because the Company will not terminate the contract until there are two consecutive years of under-delivery. Thus, the QF can cure the initial year of performance failure. Sections 10.1.5 (facility is modified to exceed a 10 MW nameplate rating) and 10.1.6 (seller no longer qualifies as a QF) do not provide an opportunity to cure because a breach of these provisions would make the seller ineligible for a standard PURPA contract. *See* PGE's response to Staff Data Request 8; Staff/1003, Schwartz/2-3.

Q. DO YOU FIND IDAHO POWER'S CURE PROVISIONS REASONABLE?

A. Yes. Section 19.2.1 of Idaho Power's contract states:

> If the defaulting Party shall fail to cure such Default within the sixty (60) days after service of such notice, or if the defaulting Party reasonably demonstrates to the other Party that the Default can be cured within a commercially reasonable time but not within such sixty (60) day period and then fails to diligently pursue such cure, then, the nondefaulting Party may, at its option, terminate this Agreement and/or pursue its legal or equitable remedies.

Section 19.2.2 of the contract states that these cure provisions do not apply to Material Breaches, which must be cured as expeditiously as possible following occurrence of the breach.

I find these provisions and timelines reasonable.

Q. ISSUE 5.b.xi. ALSO ASKS WHETHER PGE'S CONTRACT SHOULD PROVIDE FOR RECIPROCAL DEFAULT TERMS AS IN THE OTHER UTILITIES' CONTRACTS. PLEASE SUMMARIZE STAFF'S POSITION.

A. Staff recommends that the Commission direct PGE to provide for reciprocal default terms as in the other utilities' contracts. *See* Section 18.2 of Idaho Power's contract and Section 11 of PacifiCorp's contract.

In explaining why the Company does not provide for reciprocal default terms, PGE states that the QF would have recourse through the Commission in the event of PGE's non-performance under the agreement or the Commission's orders. Further, PGE states that as a regulated utility, the likelihood of a PGE default is low. *See* PGE's response to Staff Data Request 39; Staff/1003, Schwartz/11.

Nothing in PGE's response explains why it should not provide reciprocal default terms in the contract or why it is not standard business practice to do so.

Q. THERE ARE TWO REMAINING ITEMS UNDER ISSUE 5.b. FIRST, PLEASE SUMMARIZE ISSUE 5.b.vii.

A. Item 5.b.vii. addresses damages for termination due to the QF's default under PacifiCorp's contract when the utility is resource-sufficient. Again, Staff believes that Order No. 05-584 intended that there be no event of default, and therefore no damages, related to a QF's delay in commercial operation 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.

Q. DO THE OTHER UTILITIES' CONTRACTS RAISE SIMILAR CONCERNS?

A. Yes. Section 10.2 of PGE's contract regarding termination, and Section 10.4 regarding damages for termination, do not provide an exception for the Company's resource sufficiency period for a delay in QF commercial operation. Section 5.4 of Idaho Power's contract specifies that the QF is in default if it fails to achieve commercial operation within 10 months of the scheduled operation date.

Q. WHAT IS STAFF'S POSITION ON ISSUE 5.b.vii?

A. Staff recommends the Commission direct the utilities to modify their standard contracts to provide an exception for termination-related damages due to delay in commercial operation 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.

Q. PLEASE SUMMARIZE STAFF'S POSITION ON ITEM 5.b.x.

A. The issue is stated as follows:

> Should PGE's and Idaho Power's default provisions take into account sufficient monies to provide for continued facility operations and debt payment in the event future payments are temporarily reduced as a penalty for under-delivery, as in PacifiCorp's contract (§ 11.4.2)?

Both PacifiCorp's and Idaho Power's approaches are reasonable. However, PGE's repayment period does not take into account that the QF may be unable to remain a going concern during the repayment period. The Commission should order PGE to modify its standard contract to provide repayment schedule provisions similar to either of the other two utilities.

Q. PLEASE EXPLAIN HOW PACIFICORP ADJUSTS THE REPAYMENT SCHEDULE FOR DAMAGES TO AVOID THE QF'S DEFAULT ON FINANCING AND OTHER COMMERCIAL AGREEMENTS SO THAT IT MAY CONTINUE TO OPERATE.

A. Under Section 11.4.2 of PacifiCorp's contract, if the QF met creditworthiness requirements and did not have to post default security, or if the default security is exhausted, the Company will collect any remaining damages by partially withholding future payments to the QF, pursuant to Commission Order No. 05-584 (at 45). To meet the Commission's requirement that the period of time over which payments are reduced is "reasonable," PacifiCorp's contract states:

> PacifiCorp and Seller shall work together in good faith to establish the period, and monthly amounts, of such withholding so as to avoid Seller's default on its commercial or financing agreements necessary for its continued operation of the Facility.

It is important to note that the total amount of damages recouped is not affected by this provision, only the time period over which the damages are collected, and the monthly amounts. This provision is reasonable.

Q. OVER WHAT TIME PERIOD DOES IDAHO POWER RECOUP DAMAGES?

A. Under Section 7.5 of Idaho Power's contract, the Company recoups damages for under-deliveries beginning January 31 of the following calendar year. The accumulated Shortfall Energy Repayment Amount is deducted from the next 36 monthly QF payments, in equal amounts.

The extended QF repayment period accommodates the QF's temporary financial difficulties. It also meets the Commission's intent to make standard contract provisions transparent.

Q. PLEASE EXPLAIN THE DEFICIENCIES IN PGE'S RECOUPMENT PERIOD FOR DAMAGES.

A. Under Section 4.3, PGE recoups damages for under-deliveries in the following contract year by reducing the QF's purchase price to the off-peak price for all energy deliveries until such time as the recoupment value equals the Lost Energy Value. (The Lost Energy Value represents the amount that average market prices exceeded the average QF contract price for the energy not delivered.) PGE does not apply damages if it is in a resource sufficient position as defined in the tariff for the contract year.

A QF may not be able to meet its operation and maintenance expenses and its financial obligations if it receives only off-peak energy prices for all energy deliveries during the repayment period.

ODOE states that in SELP's experience, it is important to have flexibility to work through low production periods. SELP typically would enter into a forbearance agreement with the QF in that situation to adjust loan repayment terms until improved generation enables the borrower to return to the original payment schedule. The agreement would allow payment of operating and maintenance expenses prior to debt service. ODOE states that such an agreement may be in place for several years before a borrower can catch up financially. See ODOE's response to Staff Data Request 10; Staff/1004, Schwartz/6-7.

Therefore, Staff recommends that the Commission order PGE to modify the repayment schedule in its standard contract to adopt repayment schedule provisions similar to those in PacifiCorp's or Idaho Power's standard contracts for QFs up to 10 MW.

Damages

Q. ISSUE 5.C. ADDRESSES THE *LEVEL* OF DAMAGES ASSESSED, BOTH FOR AN EVENT OF DEFAULT AND FOR TERMINATION RESULTING FROM QF'S DEFAULT. FIRST, PLEASE SUMMARIZE THE LEVEL OF DAMAGES SPECIFIED IN EACH UTILITY'S STANDARD CONTRACT FOR DEFAULT DUE TO UNDER-DELIVERY.

A. Under PacifiCorp's standard contract, the QF pays the difference between the replacement price and the contract price for any energy the QF was obligated to provide during the year, based on the minimum annual delivery amount specified in the contract. The replacement price is the price at which PacifiCorp buys replacement power at the QF's point of delivery, plus administrative costs and any additional transmission costs reasonably incurred for replacement power purchases. If the Company does not make such a purchase, the replacement price is the market price at the Mid-Columbia (Mid-C) trading hub, plus any additional cost or expense incurred as a result of the QF's failure to deliver the minimum annual delivery amount.

Similarly, PGE bases its "Lost Energy Value" on an annual delivery commitment specified in the contract. Any portion of that amount which the QF failed to deliver for the contract year is multipled by the amount that average market prices for the year exceeded the average QF contract price. However, PGE does not apply damages if it is in a resource sufficient position as defined in the tariff for the contract year.

In contrast, Idaho Power bases its "Shortfall Energy" on the difference between actual monthly deliveries from the QF and monthly minimum delivery commitments specified in the QF contract. If 85% of the current month's Mid-C market price, using a weighted average of daily on- and off-peak prices, exceeds the QF's current month's contract price, the Company will charge damages for the under-deliveries based on that "Shortfall Energy Repayment Price."

Q. IS THE BASIS FOR CALCULATING DAMAGES REASONABLE?

A. Yes, with two exceptions. First, as I stated previously, QFs using intermittent renewable resources cannot accurately forecast production levels for the year by month. I have similar concerns for cogeneration facilities at industrial plants, where market disruptions can affect power production. I recommended that default for under-deliveries for these types of resources be based on an annual delivery commitment. It follows that damages should not be assessed based on monthly commitment levels.

Therefore, Staff recommends that the Commission direct Idaho Power to revise the damages provisions in its standard contract to accommodate an annual delivery commitment. I recognize that Idaho Power attempted to provide some leeway for fluctuating monthly market prices by basing the replacement power price on 85%, rather than 100%, of the current month's market price. I would expect that in moving from monthly market prices to annual prices, the Company would base replacement power costs on 100% of market prices.

Second, the Commission should direct PGE to remove from its standard contract the exception for being resource-sufficient for applying damages for under-delivery, unless the Company demonstrates that this provision is appropriate. As I stated earlier, Staff finds nothing in the Commission's order that states default for under-deliveries are inapplicable for the sole reason that a utility is resource-sufficient.

Q. NEXT, PLEASE SUMMARIZE THE DAMAGES SPECIFIED IN EACH UTILITY'S STANDARD CONTRACT FOR TERMINATION RESULTING FROM THE QF'S DEFAULT.

A. PacifiCorp assesses as damages for termination the positive difference, if any, between the replacement price and the QF contract price for a period of 24 months from the date of termination. That is, PacifiCorp will charge the QF for any higher cost for the energy the QF would have provided for 24 months, based on the minimum annual delivery commitment in the contract. The

Company states that it would take approximately 24 months for a third party to design and build a like resource and the Company to secure a purchase contract with that party. *See* PacifiCorp's response to Staff Data Request 61; Staff/1005, Schwartz/17.

Section 18.2.1 of Idaho Power's standard contract simply states that "...the nondefaulting Party may, at its option, terminate this Agreement and/or pursue its legal or equitable remedies." No damages are specified.

Section 10.2 of PGE's standard contract states that PGE "…may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement including damages related to the need to procure replacement power." Again, damages are not specified.

Q. DO YOU HAVE ANY RECOMMENDATIONS ON DAMAGES PROVISIONS FOR TERMINATION DUE TO QF'S DEFAULT?

A. Yes. While damages are appropriate for termination due to the QF's default under the contract, the amount of damages should be transparent and verifiable. PacifiCorp's provisions meet this test. Further, PacifiCorp bases the damages on the difference between the QF contract price and forward market prices at the time of contract termination. Forward market prices appropriately reflect the estimated cost of replacement power or the value of lost energy sales.

While Staff disagrees with the *basis* for PacifiCorp's 24-month replacement period, we still find the period reasonable. In the event the utility terminates a QF up to 10 MW due to the QF's default, the utility would not likely replace the small lost resource with a comparable new long-term resource, as PacifiCorp states. However, if the utility did so, it may be able to replace a lost wind resource within a year through the addition of turbines at an existing wind site, often designed for such expansion. Staff finds it more likely that the lost resource would be reflected immediately in the Company's balancing requirements, followed by adjustments to its Front Office Transactions in the power market. In its 2004 Integrated Resource Plan (at 52) filed in LC 39, PacifiCorp stated that Front Office Transactions can be made years, quarters or months in advance of delivery. Today, 24 months in advance of delivery is within the range of such transactions.

Therefore, I recommend the Commission direct PGE and Idaho Power to specify in their standard contracts as follows: If the 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.

Q. ISSUE 5.c. CONTAINS SPECIFIC ITEMS FOR THE COMMISSION'S RESOLUTION. PLEASE SUMMARIZE YOUR POSITION ON EACH ITEM.

A. Item 5.c.i. asks whether the definition of Net Replacement Power Costs in Section 1.25 of PacifiCorp's contract is consistent with Order No. 05-584 at 45. Section 1.25 refers to the definition of Net Replacement Power Costs in Section 11.3.1. Staff understands that the reference to Section 11.3.1 is a typographic error, and that the correct reference is Section 11.4.1.

As I explained earlier, the basis for calculating default damages in PacifiCorp's contract is reasonable and consistent with the Commission's order which states (at 45): "[I]n the event that a QF defaults and the market prices to replace the contracted for energy exceed the contract price, future payments after the default period ends shall be commensurately reduced over a reasonable period of time to recoup the costs incurred by the utilities."

Q. WHAT IS YOUR POSITION ON THE NEXT ITEM UNDER ISSUE 5.c.?

A. Items 5.c.ii. asks whether the Shortfall Energy Repayment Price in Section 7.3 of Idaho Power's contract should be zero if the utility is "energy surplus" as defined in its Integrated Resource Plan. The answer is no for two reasons. First, as I explained earlier, once a QF is on line, the utility counts on the resource for meeting retail load and making market sales. Therefore, there is potential risk or cost to the utility and ratepayers if a QF under-delivers. Second, for calculation of avoided costs, the determination of the utility's resource sufficiency period is made at the time of utility filing, not at the time the utility locks in its resource position for its Integrated Resource Plan.

Q. WHAT IS YOUR POSITION ON ISSUE 5.c.iii.?

A. Issue 5.c.iii. asks whether it is reasonable for Idaho Power to impose interest expenses on recoupment power costs. Section 7.5 of Idaho Power's contract states that the Company will apply an annual interest rate of 7.8% to the unamortized balance of the accumulated repayment amount for Shortfall Energy at the end of each month. The provision allows the QF to pay the outstanding balance at any time, which would avoid further interest.

Idaho Power applies Shortfall Energy repayments against the next 36 months of QF payments. With such a long repayment schedule, it makes sense to take account of the time value of money. Therefore, notwithstanding my objection to assessing damages on a monthly basis for certain types of QF resources, I find it reasonable for Idaho Power to apply interest to the outstanding balance.

As to the interest rate of 7.8%, Staff considers this reasonable. It is approximately equal to Idaho Power's current authorized Oregon rate of return, 7.83% (UE 167, Commission Order No. 05-871), and it is less than 1% above the November 2005 prime rate.[1]

Q. THE FINAL ITEM, ISSUE 5.c.iv., RELATES TO IDAHO POWER'S USE OF MONTHLY PRODUCTION LEVELS FOR APPLYING DAMAGES. PLEASE REITERATE YOUR POSITION ON THIS.

A. As I stated earlier, I recommend that monthly production levels not be used for assessing damages for QFs that rely on intermittent renewable resources or cogeneration at industrial host sites.

Q. REGARDING ISSUE 36, WHAT DO THE UTILITIES RECOMMEND REGARDING A CAP ON THE AMOUNT OF DEFAULT LOSSES THAT CAN BE RECOUPED, PURSUANT TO FUTURE QF CONTRACT PAYMENT REDUCTIONS?

[1] The prime rate is defined by The Wall Street Journal as "[t]he base rate on corporate loans posted by at least 75% of the nation's 30 largest banks." It is the interest rate that commercial banks charge their most creditworthy customers.

A. PacifiCorp states that a cap of any type could subject the Company and ratepayers to additional cost exposure if replacement power costs exceed the cap. However, if the Commission orders a cap, the Company states that it should be based on 100% of projected forward market prices for the default period. In other words, the dollar amount represented by the cap would not be set at the time of contract execution.

Only one power purchase agreement that PacifiCorp signed within the last two years for a term greater than 60 days includes a cap on default losses. The agreement is for a 100 MW resource with a term of about 19 years. The cap was for default damages for termination, rather than an event of default that does not lead to termination. The terms of the cap are as follows:

> If the Agreement is terminated as a result of the Seller's default, the Seller shall pay PacifiCorp the positive difference, if any, obtained by subtracting the contract price from the replacement price for any energy and capacity that Seller was otherwise obligated to provide for thirty-six months following the termination date of the Agreement.

No power *sales* contract that PacifiCorp signed within the past two years for a term greater than 60 days has a cap on default losses. *See* PacifiCorp's response to Staff Data Requests 57, 58, 63 and 64; Staff/1005, Schwartz/15-16, 19-22.

PGE did not provide responsive answers to several of Staff's data requests on this subject. *See* PGE's responses to Staff Data Requests 50, 51 and 52; Staff/1003, Schwartz/18-20. Staff is considering its legal options to require PGE to provide this information. Only one power purchase agreement that PGE signed within the last two years includes a cap on default losses. The cap on damages was $6,750,000 for a contract for 7 million MWh over 30 years. All of PGE's power *sales* contracts in the past two years call for uncapped liquidated damages for non-delivery. *See* PGE's responses to Staff Data Requests 57 and 58; Staff/1003, Schwartz/24-25.

Staff sent Idaho Power data requests regarding a cap on default losses on December 7, 2005.

We reserve the right to further address this issue in rebuttal testimony, after we receive additional utility responses.

Q. WHAT ARE YOUR RECOMMENDATIONS AT THIS TIME REGARDING A CAP ON DEFAULT LOSSES?

A. It is important for QF financing and for transparency that there be a cap specified in the standard contracts for default losses that can be recouped. To provide certainty, a cap should be based on forward market prices *at the time of contract execution*. Forward market prices reflect the estimated cost of replacement power or the value of lost energy sales, and they serve as the basis for damages for default.

I recommend that the Commission direct the utilities to modify their standard contracts to include a cap on default losses that may be recouped pursuant to future QF contract payment reductions. The amount of the cap should be based on 110% of the utility's forward market prices at the time of contract execution, on average, over the term of the contract. The risk premium addresses potential upward movement in the market. The result will be a cost per megawatt-hour against which replacement power costs will be capped for the period of default.

Indemnity

Q. ISSUE 5.e. ASKS WHETHER PACIFICORP SHOULD BE REQUIRED TO INDEMNIFY THE QF "AT THE POINT OF DELIVERY" RATHER THAN "AFTER THE POINT OF DELIVERY," CONSISTENT WITH INDEMNITY TERMS FOR THE QF. WHAT IS STAFF'S POSITION ON THIS ISSUE?

A. PacifiCorp's standard contract provides reciprocal indemnification provisions. That is, the Seller indemnifies PacifiCorp from actions taken against the Company that are the result of the Seller delivering energy "to and at the Point of Delivery," and PacifiCorp indemnifies the Seller from any actions taken against PacifiCorp "after the Point of Delivery." It does not make sense that both parties would be responsible for actions at the Point of Delivery.

Section 1.28 of PacifiCorp's contract, defining Point of Delivery, appropriately indicates that the Seller or the third-party transmission provider is responsible at that point:

> **"Point of Delivery"** means the high side of the Seller's step-up transformer(s) located at the point of interconnection between the Facility and PacifiCorp's distribution/ transmission system, as specified in the Generation Interconnection Agreement, or, if the Facility is not interconnected directly with PacifiCorp, the point at which another utility will deliver the Net Output to PacifiCorp as specified in **Exhibit B**.

OTHER CONTRACT PROVISIONS TO MITIGATE RISK

Force Majeure

Q. SHOULD LACK OF WATER AND WIND BE INCLUDED AS EVENTS OF FORCE MAJEURE FOR WIND AND RUN-OF-RIVER HYDRO PROJECTS?

A. No. The utilities explain that lack of water or wind is not an event of force majeure in their standard contracts because the QF's minimum delivery obligation should reflect expected adverse wind or water conditions.

Idaho Power further states that in most instances, reduced streamflow and reduced wind are events that are reasonably anticipated and modeled. Citing Staff's Opening Comments in UM 1147, Idaho Power notes that hydro variability and weather are examples of such stochastic risks. Conversely, force majeure events are limited to those that neither party could have anticipated and therefore are more akin to scenario risk. PacifiCorp adds that none of its commercial wind transactions allow for lack of wind as a force majeure. *See* PGE's response to Staff Data Request 33; Staff/1003, Schwartz/10. *See* PacifiCorp's response to Staff Data Request 46; Staff/1005, Schwartz/11. *See* Idaho Power's response to Staff Data Request 20; Staff/1002, Schwartz/11.

Liens and Encumbrances

Q. PLEASE EXPLAIN ISSUE 30, LIENS AND ENCUMBRANCES ON THE PROJECT OTHER THAN FOR THIRD-PARTY FINANCING, RELATED TO PGE'S STANDARD CONTRACT.

A. Section 3.1.5 of PGE's standard contract states:

> During the Term of this Agreement, all of Seller's right, title and interest in and to the Facility shall be free and clear of all liens and encumbrances other than liens and encumbrances arising from third-party financing of the Facility.

PGE asserts that it is not a common business practice for contractors performing maintenance work to impose a lien on the property of the owner. PGE views a lien against a QF as an indication that it may have financial difficulty or is having problems with a contractor. PGE believes that either of these circumstances reflects negatively on the QF's financial or operational stability. PGE further states that liens reduce the value of the step-in rights security option. *See* PGE's response to Staff Data Request 42; Staff/1003, Schwartz/14.

ODOE states that the provision may prohibit or reduce availability of financing. ODOE states that by law, contractors, material suppliers and others can file a lien during construction, maintenance or upgrading of a generating facility. ODOE further notes that it may take significant time to contest and clear a lien. *See* ODOE's supplemental response to Staff Data Request 2.m.; Staff/1004, Schwartz/10.

Q. WHAT IS STAFF'S POSITION ON PGE'S PROHIBITION ON LIENS OR ENCUMBRANCES OTHER THAN FOR FINANCING?

A. Staff recommends that the Commission order PGE to modify Section 3.1.5 of its standard contract to provide an exception for statutory liens. Statutory liens are those allowed by law. They include, for example, labor or material provided by third parties for construction or repair of a facility. If a QF paid a contractor, but the contractor defaults with a subcontractor, the subcontractor could file a lien against the QF. Therefore, the filing of a lien allowed by statute is not necessarily an indication that the QF is likely to default on its power purchase agreement with the utility.

Project Maintenance

Q. ISSUE 31 ASKS, "IS IT APPROPRIATE TO PROVIDE FLEXIBILITY IN THE SELLER'S NOTICE REQUIREMENTS FOR MAINTENANCE IN § 6.2 OF PGE'S CONTRACT BY ADDING THE WORDS "WHEN PRACTICABLE" AFTER "OFF-PEAK HOURS"? WHAT IS STAFF'S POSITION?

A. Section 6.2 of PGE's standard contract states in part:

> Seller shall take all reasonable measures and exercise its best efforts to avoid unscheduled maintenance, to limit the duration of such unscheduled maintenance, and to perform unscheduled maintenance during Off-Peak hours.

Staff finds this provision reasonable as written. It only asks the QF to take all reasonable measures and exercise its best efforts to perform unscheduled maintenance during off-peak hours. Further, PGE states there are no penalties associated with the provision. *See* PGE's response to Staff Data Request 43; Staff/1003, Schwartz/15.

Release for Claims Against Facility

Q. PLEASE RESPOND TO ISSUE 32, REGARDING CLAIMS AGAINST THE QF PRIOR TO CONTRACT EXECUTION.

A. Staff finds Section 20.2 of PGE's contract to be reasonable. It states in its entirety:

> By executing this Agreement, Seller releases PGE from any claims related to the Facility, known or unknown, that may have arisen prior to the Effective Date.

PGE explains that this contract provision mitigates exposure of PGE and its customers to risk. *See* PGE's response to Staff Data Request 44; Staff/1003, Schwartz/16. This provision makes sense. PGE had no business relationship with the QF prior to the effective date of the contract. Therefore, the Company should be released from any claims that arose before this date.

DETAILED LIST OF PROCEDURES IN TARIFFS

Q. ISSUE 6 ADDRESSES WHETHER TARIFFS FOR QFs SHOULD INCLUDE A DETAILED LIST OF PROCEDURES, INCLUDING TIMELINES, FOR ENTERING INTO A CONTRACT WITH THE UTILITY. PLEASE SUMMARIZE STAFF'S POSITION.

A. The Commission's Order states (at 59):

> We expect tariffs to contain information including the following: (1) full details about the process to enter into a standard contract or a negotiated contract, including

> instructions to contact a utility for further information…; (3) details about how non-standard contracts are negotiated, including a statement that the starting point for negotiation of price is standard avoided costs and that standard avoided costs may be modified to address specific factors mandated by federal and state law; (4) delineation of these factors.…

Phase II of the UM 1129 proceeding will address item (3) and the process to enter into a negotiated contract under item (1), cited above. My comments here are focused on item (1) as it relates to standard contracts, and item (4).

Regarding item (1), I recommend the Commission direct PGE to provide in its tariff for purchases from QFs up to 10 MW a list of specific project information required to enter a power purchase agreement, and direct all utilities to provide in their tariffs detailed procedures for obtaining draft and final power purchase agreements. Such detailed procedures should include specific timelines for the following events:

a. The number of days by which the Company will provide a draft power purchase agreement to the QF after receipt of all required QF information as specified in the tariff
b. The number of days by which the Company will respond to any written comments and proposals the QF provides in response to draft agreements
c. The number of days, after the Company's receipt of any additional or clarifying project information needed, by which the Company will provide a final draft agreement to the QF

d. The number of days by which the QF will receive a final executable agreement from the Company after parties are in full agreement on the terms and conditions of the draft agreement

Regarding item (4), delineation of adjustment factors for negotiated contracts mandated by federal or state law, Staff believes that the Commission intended that the FERC adjustment factors in 18 C.F.R. § 292.304(e) – or the adjustments required by Oregon PURPA law, if applicable – should be spelled out in the tariff.

Q. DOES EACH OF THE UTILITY'S TARIFFS DEVIATE FROM THESE RECOMMENDATIONS?

A. Yes, in part. Regarding item (1), PacifiCorp Schedule 37 specifies how to contact the utility for further information and provides detailed procedures for entering a standard contract. Those procedures include a list of specific QF information required at a minimum to enter a power agreement, as well as specific timelines related to Staff recommendations a. and b., above. However, the Company does not provide specific timelines for Staff recommendations c. and d.

PGE Schedule 201 provides information on how to contact the Company for further information. However, there is no information that would constitute detailed procedures for entering a standard contract.

Idaho Power Schedule 85 provides information on how to contact the Company for further information and outlines the minimum information required for a QF to request a power purchase agreement with the Company. There is no other information that would constitute detailed procedures for entering a standard contract.

Both PacifiCorp and Idaho Power comply with item (4). PGE does not. The Company simply provides the citation and a Web site link for the applicable federal regulation. Staff recommends that the Commission direct PGE, which has not done so, to spell out the FERC adjustment factors in 18 C.F.R. § 292.304(e).

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE APPROPRIATE TIMELINES FOR EVENTS a. THROUGH d. ABOVE?

A. Yes. PacifiCorp's Schedule 37 sets a timeline for event a., QF receipt of draft power purchase agreement, of 15 business days following receipt of all information required to enter an agreement, as specified in the tariff. This timeline is reasonable.

Schedule 37 also sets a timeline for event b., QF receipt of the Company's responses to written comments and proposals from the QF related to the *final* draft agreement. The specified timeline is 14 calendar days, which I find reasonable. However, the timeline does not appear to apply to a QF's written comments or proposals on the *initial* draft agreement. I believe it should.

PacifiCorp does not provide a specified timeline in its tariff for event c., QF receipt of a final draft agreement after the Company has received any additional or clarifying project information it needed to prepare the agreement. Nor does the Company provide a specified timeline for event d., QF receipt of a final executable agreement from the Company after parties are in full agreement on the terms and conditions of the draft agreement. A 15-business day timeline would be reasonable for each of these events.

INDEPENDENT ENGINEERING REVIEW

Q. REGARDING ISSUE 7, WHAT IS STAFF'S POSITION ON WHETHER QFs SHOULD BE REQUIRED TO HIRE AN UNAFFILIATED LICENSED PROFESSIONAL ENGINEER TO VERIFY THAT THE FACILITY OPERATES AS SPECIFIED?

A. All of the utilities require that a licensed professional engineer unaffiliated with the QF verify that the facility operates as specified in the contract. Staff believes this is a reasonable requirement at this time.

However, for very small packaged systems, Staff anticipates exploring similar issues in the Commission's forthcoming investigation into interconnection requirements, procedures and agreements. In that proceeding, the Commission should explore a precertification process for preengineered small systems that do not require an engineering study and are considered safe to connect to the grid because they already incorporate technology to address safety, reliability and power quality concerns. The Commission may wish to revisit its engineering review requirements for standard QF contracts for such systems at that time.

Q. PLEASE EXPLAIN THE BASIS FOR AN INDEPENDENT ENGINEERING REVIEW.

A. Idaho Power explains that engineering certificates provide assurance that the project is adequately designed and will be adequately operated and maintained. Both are necessary to allow the utility to avoid or defer the construction or purchase of a firm dispatchable resource, which serves as the basis for avoided cost rates. Idaho Power adds that in most cases lenders will require an independent engineering review as part of their due diligence. Therefore, such a requirement in the standard contract may impose no additional effort or expense on the part of the QF. *See* Idaho Power's responses to Staff Data Requests 17-18; Staff/1002, Schwartz/8-9.

PacifiCorp explains that its requirement provides an unbiased determination that the resource will deliver what the QF proposes in order to minimize disputes regarding performance. *See* PacifiCorp's responses to Staff Data Requests 43-44; Staff/1005, Schwartz/8-9.

PGE states that it requires the engineer be unaffiliated with the QF to avoid a conflict of interest to ensure that ratepayers do not bear inappropriate risks. *See* PGE's responses to Staff Data Requests 30-31; Staff/1003, Schwartz/8-9.

ODOE states that while most projects SELP evaluates for financing include use of a licensed professional engineer, SELP does not require it. Instead, SELP evaluates the technical merits of a project, including the experience of the design team and contractors, reliability of the proposed equipment, and any production or performance guarantees offered. *See* ODOE's response to Staff Data Request 7; Staff/1004, Schwartz/6.

<u>TREATMENT OF ADDITIONAL GENERATION WHEN QF INCREASES OUTPUT</u>

Q. REGARDING ISSUE 8, WHAT IS YOUR POSITION ON TREATMENT OF INCREASED QF OUTPUT RESULTING FROM EFFICIENCY IMPROVEMENTS OR REPLACEMENT OF GENERATING EQUIPMENT.

A. The appropriate resolution of the issue is as follows:

1) The QF would 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 should be based on avoided cost rates as of the date of the improvement or equipment replacement. The contract should be amended at that time to reflect changes in operation or equipment.

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

The Commission should direct the utilities to amend their standard contracts to spell out this treatment of additional generation resulting from efficiency improvements or necessary equipment replacement.

Q. PLEASE EXPLAIN THE BASIS FOR YOUR POSITION.

A. The QF cannot control necessary equipment replacement, and available turbine and generator sizes change over time. Also, the QF should not be penalized for efficiency improvements, whether through operational changes or upgraded equipment. That would run counter to the Commission's objective to encourage utilities and customers to meet energy needs at the lowest possible cost and risk.

PacifiCorp states that it would accept the additional generation associated with efficiency improvements or necessary equipment replacement at the avoided cost rates listed in the original contract, including generation due to increases in manufacturer nameplate capacity. *See* PacifiCorp's responses to Staff Data Requests 45, 54, 55 and 56; Staff/1005, Schwartz/10, 12-14.

Idaho Power states that so long as the QF discloses the equipment replacement, it is a necessary replacement, and the new project size does not exceed 10 MW, the Company would modify the existing contract to reflect the new generation levels. *See* Idaho Power's response to Staff Data Request 19; Staff/1002, Schwartz/10.

PGE believes that a new contract would be required if the QF increases its nameplate capacity, even if the increase is the result of efficiency improvements or necessary equipment replacement. The new contract would be based on avoided cost rates and other terms and conditions at the time capacity is increased. If instead the Commission resolves the issue as Staff recommends, PGE expresses concern related to a QF having access to more than one avoided cost rate for a single project, including administrative impacts on the utility and potential contractual disputes. *See* PGE's responses to Staff Data Requests 6 and 49; Staff/1003, Schwartz/1, 17.

The QF should continue to receive the avoided costs on which it based its original investment decision only for the portion of the revised project that matches the nameplate capacity of the original project. The QF should be subject to updated avoided cost pricing for the increase in installed capacity. That would put the increased capacity on par with new QFs coming on line that receive payments based on the utility's up-to-date avoided costs. I believe that the utility and the QF should be able to come to agreement during the contract amendment process about the amount of additional generation resulting from the addition in nameplate capacity.

Finally, the Commission requires that standard avoided cost rates and standard contracts be made available only to QFs up to 10 MW. If the QF later increases its size beyond that level, it should no longer be eligible for standard avoided cost rates and the standard contract.

QFs USING THIRD-PARTY TRANSMISSION SERVICES

Q. ISSUE 12 RELATES TO STANDARD CONTRACTS FOR QFs THAT DO NOT DIRECTLY INTERCONNECT WITH THE COMPANY'S ELECTRIC SYSTEM. DO YOU BELIEVE THE UTILITIES SHOULD FILE A STANDARD FORM OF CONTRACT FOR BUYING QF POWER WHEELED OVER A THIRD-PARTY TRANSMISSION SYSTEM?

A. The utilities should either file a standard form QF contract specifically for this purpose, or include provisions in a generic form of standard contract that would be applicable only for QFs that do not interconnect directly with the utility's electric system. In addition, certain provisions in a generic standard contract would be inapplicable for these "off-system" QFs, including provisions related to interconnection to the utility's system.

Order No. 05-584 directed the utilities "to draft and file *one or more* standard contract forms as necessary to comply with … decisions in this order." [Emphasis added.] Therefore, the utilities are free to request Commission approval of additional standard contracts that address a circumstance likely to be encountered by more than one particular QF, such as off-system facilities.

Q. WHAT PROVISIONS SHOULD BE MODIFIED OR ADDED TO ADDRESS THIRD-PARTY WHEELING?

A. In Idaho Power Advice No. 05-20, the Company filed for Commission approval an additional standard form of contract to address off-system QFs. The Company modified or added provisions to its original standard QF contract related to point of delivery, transmission arrangements, metering and telemetry equipment, and reliability requirements of the Western Electricity Coordinating Council (WECC).

The Company explained that except for very small projects, off-system QFs located within its control area will require telemetry to Idaho Power so it can comply with its obligations as control area operator. Further, because the projects are not interconnected to Idaho Power's system, the WECC Reliability Management System Criteria that otherwise would be part of the Company's interconnection agreement must instead be included in the power purchase agreement.

Staff finds such modifications to the standard form of contract reasonable. In its forthcoming interconnection investigation, the Commission may determine a project size below which telemetry is not required. The Commission can direct the utilities to modify telemetry requirements in their standard off-system QF contracts at that time.

Q. SHOULD STANDARD CONTRACTS FOR QFS REQUIRING THIRD-PARTY TRANSMISSION STATE THAT THE PURCHASING UTILITY BUYS THE QF'S SCHEDULE OFF THE TRANSMITTING UTILITY'S SYSTEM?

A. My understanding is that the primary issue here under the Commission's jurisdiction is as follows:

The third-party transmission provider schedules only whole increments of power to the utility. If an off-system hydroelectric QF has a nameplate rating specified in the utility's standard contract that is not a whole number – 4.5 MW, for example – the QF delivers roughly 4.5 MW every hour to the transmission provider. The transmission provider schedules 4 MW to the utility most hours, and 5 MW other hours to make up for the difference in QF deliveries.

Order No. 05-584 (at 28) requires the utility to accept delivery of energy in excess of the nameplate rating of the QF, but to compensate the QF only for the energy itself and not capacity. Thus, the QF gets only the off-peak price for excess energy, regardless of whether the delivery is during peak hours.

In the example above, the QF is eligible for the on-peak price only up to 4.5 MW. When the transmission provider schedules 5 MW of its generation to the utility during *on*-peak hours, the QF gets the *off*-peak price for 0.5 MW of the delivery (5 MW delivered by transmission provider – 4.5 MW nameplate rating in standard contract = 0.5 MW of “excess energy”).

I recommend the Commission 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.

NET OUTPUT

Q. PLEASE SUMMARIZE YOUR POSITION ON ISSUE 13.

A. Issue 13 seeks clarification on treatment of the host’s on-site load in determining net output. FERC defines net output of a QF as the gross output of the generator, less power for running equipment necessary for power generation and other essential electricity uses. Phase II of this proceeding will further explore negotiation of net output sales for non-standard contracts. My comments therefore focus on standard contracts.

PURPA requires the utility to purchase *up to* the QF’s net output. However, the QF may choose to use some of its generating output to service the host’s on-site load. At staff’s request, the utilities indicated in their standard contracts that a QF may deduct from net output any on-site load the QF will serve. I believe the standard contracts as filed appropriately address this issue.

CHANGING STANDARD CONTRACT TERMS

Q. REGARDING ISSUE 14, IF THE QF AND UTILITY AGREE TO CHANGE A FEW TERMS OF THE STANDARD CONTRACT FOR A FACILITY, BUT THE UTILITY APPLIES ITS TARIFF FOR PURCHASES FROM QFs UP TO 10 MW, IS THE ARRANGEMENT CONSIDERED A PURPA CONTRACT IN A FUTURE RATEMAKING PROCEEDING?

A. Yes. QFs 10 MW and smaller are *eligible* to receive a standard contract. Staff finds nothing in Order No. 05-584 that prohibits such small QFs to instead negotiate a PURPA agreement with the utility.

So long as the utility applies its tariff for QF purchases up to 10 MW, the negotiated agreement would be considered a PURPA contract. In a prudence review, the Commission would review whether the negotiated contract terms provided reasonably similar protection for ratepayers compared to the standard contract terms.

ENVIRONMENTAL ATTRIBUTES

Q. SHOULD STANDARD CONTRACTS CONTAIN A WAIVER OF CLAIM TO OWNERSHIP OF ENVIRONMENTAL ATTRIBUTES?

A. Yes. Order No. 05-1229 in AR 495 (entered November 28, 2005) clarifies that the owner of a renewable energy facility owns the non-energy attributes associated with the generation of electricity. Further, a sale of power to an electric company, including purchases under a PURPA contract, would not convey title to these “green tags” without an express clause doing so.

The rulemaking defined the term “non-energy attributes” as “the environmental, economic, and social benefits of generation from renewable energy facilities. These attributes are normally transacted in the form of Tradable Renewable Certificates.” Avoided cost rates do not compensate the QF for non-energy attributes.

To comply with the Commission’s order in AR 495, standard QF contracts should include a waiver of the non-energy attributes of power delivered to the utility. Section 8.1 of Idaho Power’s standard contract includes such a waiver. The Commission should direct PGE and PacifiCorp to amend their standard contracts to provide a waiver for non-energy attributes in compliance with Order No. 05-1229.

For negotiated QF contracts, including all those for projects larger than 10 MW, the utilities can negotiate ownership of the green tags so long as the total contract cost remains at or below market cost, considering both cost as well as risk. Consideration of risk should include compliance with a potential Renewable Portfolio Standard.

FERC HYDROELECTRIC LICENSE

Q. REGARDING ISSUE 33, DO YOU FIND IT REASONABLE FOR IDAHO POWER TO REQUIRE THAT A PROPOSED HYDROELECTRIC QF WARRANT THAT IT HAS A FERC LICENSE AT THE TIME IT EXECUTES A STANDARD CONTRACT WITH THE UTILITY?

A. Yes. Idaho Power states that because a QF contract is a legally enforceable obligation, there should not be “a free option for the QF to acquire a contract, lock in a rate, and then go see if it can create a project." The Company further states that in most instances, small hydro projects can qualify for either an exemption from licensing or a short-form minor license from FERC, and therefore the requirement is not onerous. *See* Idaho Power's response to Staff Data Request 29; Staff/1002, Schwartz/12.

ODOE states that while it has not financed a QF hydro project in recent years, a review of older hydro projects found that SELP normally required a FERC license at the time of loan closing and first loan disbursement. In a current application, SELP would determine whether there was any risk the hydro facility would not receive a FERC license in considering any request for advancing funds prior to issuance of the license. *See* ODOE's response to Staff Data Request 12; Staff/1004, Schwartz/7.

For all these reasons, Staff finds Idaho Power's requirement reasonable.

ISSUES RELATED TO APPLICATION OF REVISED PROTOCOL FOR PACIFICORP

Q. PLEASE DISCUSS YOUR FINAL ISSUE, NUMBER 25. WHAT IS THE PACIFICORP REVISED PROTOCOL?

A. The PacifiCorp Revised Protocol is the allocation methodology that the Commission adopted for purposes of allocating PacifiCorp costs to Oregon. *See* Order No. 05-021. The Revised Protocol focuses mainly on generation and transmission costs. Idaho, Wyoming and Utah have adopted the same Revised Protocol as Oregon.

Q. HOW DOES THE REVISED PROTOCOL TREAT QF COSTS?

A. Section IV.C. of the Revised Protocol addresses QFs. The text is provided below.

> 3. Qualifying Facilities (QF) Contracts:
>
> a. Existing QF Contracts Embedded Cost Differential Adjustment: The Existing QF Contracts Cost Differential Adjustment is calculated as the Annual Existing QF Contracts Costs for each State, less the Annual Embedded Costs – All Other, multiplied by the normalized MWh's of output from the respective State's Existing QF Contracts (State QF less All Other). The Existing QF Contract Embedded Cost Differential Adjustment will be allocated on a situs basis and the inverse amount will be allocated on the SG factor.
>
> b. New QF Contracts: Costs associated with any New QF Contract, which exceed the costs PacifiCorp would have otherwise incurred acquiring Comparable Resources, will be assigned on a situs basis to the State approving such contract.

Q. DOES THIS TESTIMONY ADDRESS THE TREATMENT OF EXISTING QF CONTRACTS?

A. No. This testimony focuses on the treatment of new QF contracts. As can be seen from the text above regarding new QFs, the Revised Protocol establishes a comparable resource benchmark for QFs. That is, to the extent that the power purchase costs of QFs are equal to, or less than, the cost of comparable resources, QF power purchase costs are assigned system-wide. The costs of QFs above that for comparable resources will be assigned by the Revised Protocol situs to the state that approved the contract.

Q. WHAT METHOD OR PROCESS DOES THE OPUC USE TO ESTABLISH RATES FOR PACIFICORP'S PURCHASES THROUGH NEW QF CONTRACTS?

A. The Commission requires PacifiCorp to use monthly on- and off-peak forward market prices, as of the utility's avoided cost filing, to calculate standard avoided costs for the period the utility is resource-sufficient. For the period of resource deficiency, the Commission requires the Company to calculate standard avoided costs based on the variable and fixed costs of a natural gas-fired combined-cycle combustion turbine.

Only QFs up to 10 MW are entitled to standard avoided cost rates and a standard form of contract. For QFs larger than 10 MW, the standard avoided costs provide a basis for negotiations between the utility and the QF. FERC identifies adjustment factors in 18 C.F.R. § 292.304(e), such as dispatch, reliability, scheduling outages and line losses, that also must be taken into account when a utility determines its avoided costs for a non-standard contract.

The standard contract is not pre-approval of a utility's recovery of costs that are incurred under a particular standard contract. The utility remains responsible for prudently administering each contract. For QFs larger than 10 MW, the utilities maintain the obligation to negotiate and administer non-standard contracts in compliance with federal and state mandates.

Regardless of project size, the Commission does not approve contracts for individual QF projects. *See* Order No. 05-584 at 56.

Q. DOES STAFF CONSIDER THIS PROCESS TO BE CONSISTENT WITH REPRESENTING THE COSTS OF COMPARABLE RESOURCES?

A. Yes. The Commission's process yields rates for power purchases for new QF contracts that are similar to those for comparable resources. That is, the process yields a result from which Oregon should not be exposed to any situs-assigned new QF contract costs as contemplated in the Revised Protocol.

Q. DOES PACIFICORP AGREE WITH THIS VIEWPOINT?

A. Staff believes so. However, if PacifiCorp disagrees, it would be helpful for PacifiCorp to alert the Commission to that opinion. That way, the Commission would know that PacifiCorp views the process the Commission uses as inconsistent with the "comparable resource" standard contained in the Revised Protocol.

Q. IF ANOTHER STATE DETERMINED THE COMMISSION-APPROVED AVOIDED COST RATES ARE ABOVE THE COMPARABLE RESOURCE BENCHMARK, WOULD OREGON BE REQUIRED TO ALLOW RECOVERY OF THE EXCESS COSTS FROM OREGON CUSTOMERS?

A. No, not if the method Oregon uses to establish avoided costs is consistent with, and expected to provide results not different from, those of comparable resources. Therefore, the Commission would benefit from knowing whether PacifiCorp holds the view that Oregon's method of establishing avoided costs likely yields results inconsistent with those for comparable resources.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UM 1129 – Phase I Compliance
WITNESS: Lisa Schwartz

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STAFF EXHIBIT 1001

Exhibits in Support of Direct Testimony

December 9, 2005

SUMMARY OF STAFF'S 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.

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.

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, based on 110% of the utility's forward market prices at the time of contract execution, on average, over the term of the contract. The cap would result in a cost per megawatt-hour against which recoupment of replacement power costs would be limited for the period of default.

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.

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).

<u>Treatment of Additional Generation When QF Increases Output</u>

- 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.

<u>QFs Using Third-Party Transmission Services</u>

- 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
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STAFF EXHIBIT 1002

Exhibit in Support of Testimony

December 9, 2005

DATA REQUEST NO. 1:

Please specify the security amount Idaho Power would require under Section 4.1.6 of the proposed standard Energy Sales Agreement in lieu of a demonstration of acceptable creditworthiness, including any cap, and explain the basis for these amounts.

RESPONSE TO DATA REQUEST NO. 1:

The amount of security that Idaho Power would request under the proposed standard Energy Sales Agreement in lieu of creditworthiness demonstrations would be 100% of a reasonable estimated amount of potential damages for failure to provide the expected energy amounts under the Agreement. The estimate would be based on an analysis of the project's capacity to perform both financial and non-financial obligations. For example, if a QF maintains adequate business interruption/mechanical breakdown insurance, the likelihood of an extended default period is diminished and the estimated amount of potential damages could be reduced.

DATA REQUEST NO. 5:

Please explain all of the criteria Idaho Power will use to determine whether the Monthly Net Energy Amounts designated by the Qualifying Facility (QF) in Section 6.2.1 of the proposed standard Energy Sales Agreement are acceptable, including:

a. Whether a wind, hydro or solar QF can designate Monthly Net Energy Amounts based on the most adverse natural motive force conditions.

b. Whether a QF can designate Monthly Net Energy Amounts based on the self-generating customer's highest projected on-site load requirements.

c. Explain any other criteria Idaho Power will use.

RESPONSE TO DATA REQUEST NO. 5:

Idaho Power's avoided cost rates offered QF projects are determined on the assumption that the QF purchase will allow the Company to avoid or defer the construction or purchase of a firm disbatchable resource. For matching its load requirements with available resources, the Company must have a realistic measure of the generation quantities produced by its various resources. Thus, it is of value to the Company that QF developers provide their best estimates of the long-term energy production of their projects. Because the Company requests Monthly Net Energy Amounts instead of daily or hourly amounts, there is a certain amount of flexibility designed in the contract to accommodate the unique operating conditions encountered by a particular project. Furthermore, if the Monthly Net Energy Amounts submitted by the QF project do not appear to be consistent with the nameplate rating of the facility or the routine operations and industrial standards for the specific type of generation resource, Idaho Power may request additional information from the project to confirm that the project-provided Monthly Net Energy Amounts are reasonable for the specific project. If the QF sets its Monthly Net Energy Amounts at zero or some extreme minimum, the net result will likely be that the Company will not avoid or defer the correct amount of firm resources or firm energy purchases and customers will pay more than Idaho Power's true avoided cost.

REQUEST STAFF 8:

Please list all types of documentation Idaho Power will require or consider for determining the Seller's creditworthiness, pursuant to § 4.1.6 of the Company's standard contract for Qualifying Facilities (QFs) 10 MW and less.

IDAHO POWER'S RESPONSE TO REQUEST STAFF 8:

Section 4.1.6 of the Company's standard contract provides that QFs will provide Idaho Power with commercially-reasonable documentation of Seller's creditworthiness. Idaho Power intends to take a flexible approach that allows QFs to demonstrate creditworthiness by providing different types of credit documentation appropriate for the QF's situation. Such documentation could include independent third-party credit rating information, financial information for the QF or a parent entity, as well as the warranties and representations described in Section 4.1.6. The intention of Section 4.1.6 is not to limit the types of documentation that could be provided and accepted.

In considering this response, it is important to remember that to facilitate project financing, QF developers almost always form a new legal entity for the single purpose of owning the QF project and entering into a contract with the utility. As a result, this new single-purpose entity will very easily be able to represent that it has never filed bankruptcy and that it is current in all of its obligations. As a result, the value of these warranties and representations for determining creditworthiness is very limited. In addition, in most cases the only assets that will be owned by the new entity will usually be subject to a first priority lien by the project lender and thereby be unavailable to Idaho Power for satisfying claims if the QF fails to perform its contract.

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REQUEST STAFF 9:

Please provide definitions for the security options identified in § 4.1.6 of the standard contract: letter of credit, senior lien rights, step-in rights, escrow accounts, and other forms of liquid financial security.

IDAHO POWER'S RESPONSE TO REQUEST STAFF 9:

Letter of Credit: The form of letter of credit Idaho Power has used in other QF security situations is a standard irrevocable standby letter of credit. This financial instrument is essentially a commitment by a bank or other financial institution to pay the utility a liquidated amount if the QF fails to perform as required by the agreement or pay an amount due the utility as required by the agreement.

Senior Lien Rights: Senior lien rights would include a first-priority mortgage or deed of trust in real property and a first priority perfected security interest in the project's personal property and fixtures.

Step-In Rights: Usually contained in a contingent assignment for security purposes. It would allow Idaho Power to step into the shoes of the QF to own, operate and maintain the generating facilities subject to any senior lender's rights.

Escrow Accounts: Account established in a commercial bank or at other financial institutions in which the QF deposits cash, which can be accessed by Idaho Power in the event of specific events of default or by the QF project with Idaho Power's consent to fund extraordinary operations or maintenance expense.

Other Forms of Liquid Financial Security Idaho Power has taken from QFs in the past include a third-party guarantee from a creditworthy institution or corporate parent and a jointly held certificate of deposit.

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REQUEST STAFF 12:

Please describe the documentation Idaho Power requires under the standard contract for accepting a QF's designation of Monthly Net Energy Amounts per § 6.2.1 of the standard contract.

IDAHO POWER'S RESPONSE TO REQUEST STAFF 12:

As noted in Idaho Power's response to Staff Data Request No. 5, Idaho Power's avoided cost rates offered to QF projects are determined on the assumption that the QF purchase will allow the Company to avoid or defer the construction or purchase of a firm dispatchable resource. For matching its load requirements with available resources, the Company must have a realistic measure of the generation quantities produced by its various resources. Thus, it is reasonable for the Company to require that QF developers provide their best estimates of the monthly energy production from their projects. Idaho Power would expect to review any data the QF developer has compiled that would support the QF developer's estimate of the firm energy production of the project. In many instances, this would be the same data that the QF's lender would require that the QF produce in order to accommodate the lender's due diligence review of the ability of the project to generate sufficient energy to support the debt financing for the project. Examples of this data would be:

- Water flow and head data for a hydroelectric project
- Wind velocity and duration data for a wind project
- Well flow and temperature records for a geothermal QF
- Fuel source information on biomass facilities
- Turbine and generator efficiency data
- Engineering performance analysis
- Historical generation data
- and any other similar information.

It would be expected that the QF would provide Idaho Power the monthly estimated kWh production and supporting documentation. Idaho Power will review the provided information and either accept the values as presented by the QF or will work cooperatively with the QF developer to determine an equitable monthly energy amount for inclusion in the contract.

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REQUEST STAFF 13:

In accepting a QF's designation of Monthly Net Energy Amounts under § 6.2.1 of the standard contract, how would the Company take into account the following issues regarding resource data and QF operations:

a. A wind QF with only one year of anemometer data, or a hydroelectric project with only a few years of flow data, neither of which may be representative of the most adverse natural motive force conditions that may occur over the 20-year contract period

b. A QF at an industrial plant that shuts down periodically due to product prices, labor strikes or other market conditions.

IDAHO POWER'S RESPONSE TO REQUEST STAFF 13:

a. If the QF projects have developed data to support a loan application for project financing, Idaho Power would expect to have an opportunity to review the same data that was provided to the project lender. Idaho Power would review all of the available data and, in conjunction with the QF developer, establish a reasonable level of monthly generation that would be representative of reasonably anticipated long-term motive force conditions. The monthly amount would not be set equal to the long-term average production, but at a lesser level to accommodate reasonably anticipated reductions in natural motive force. Each project is different and needs to be assessed individually.

b. Idaho Power would expect to be provided for supporting documentation that would provide a reasonable estimate of the long-term average energy production of the facility, which would include periodic downtime periods. Some events such as labor strikes may be considered an event of Force Majuere and may relieve the QF of its performance requirements. Typically a QF at an industrial plant is a large sophisticated operation that has at its disposal significant data and analytical tools to access market and price conditions that may impact the ability of the QF to deliver energy to the Utility. Therefore it would be reasonable that the QF would make allowances in its long-term average energy production estimates for these conditions.

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REQUEST STAFF 14:

Would the Company terminate the QF contract due to reduced resource availability under conditions cited in 13 a. or b., above? Please explain.

IDAHO POWER'S RESPONSE TO REQUEST STAFF 14:

No. Contract termination would only be appropriate if the project appears to have permanently curtailed its generation to very low levels and the developer is not making reasonable efforts to cure the problem. Under those circumstances, the Company would also consider whether current avoided costs are less than the purchase price contained in this agreement in making a final decision to seek contract termination.

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REQUEST STAFF 17:

Please explain why Idaho Power requires a licensed professional engineer to verify that the QF operates as specified, per § 4.1.3 of the standard contract, regardless of project size or whether the project is a standard packaged system. For example, would the Company impose such a requirement on a project that consists of a single wind turbine or microturbine?

IDAHO POWER'S RESPONSE TO REQUEST STAFF 17:

As previously noted, Idaho Power's avoided cost rates are set at a level that assumes the QF purchase will allow the Company to avoid or defer the construction or purchase of a firm dispatchable resource. To the extent the QF facility is poorly designed or inadequately maintained, it is less likely that the project will provide a resource whose value is commensurate with the purchase price. Requiring that the QF provide the engineering certificates described in § 4.1.3 provides assurance the project is adequately designed and will be adequately operated and maintained.

It is important to remember that a single 2.5 MW wind turbine will cost approximately $3 million. The cost of providing engineering certificates is an extremely small component of a total development cost and provides Idaho Power's customers with tangible benefits in the form of increased reliability. In most instances, project lenders require similar independent engineering reviews as a part of their due diligence for lending. In those instances, Idaho Power works with the lenders to ensure that there is no duplication of effort and expense to the QF project. Idaho Power has included these provisions in approximately 40 existing QF contracts ranging in size from 100 kW to 17.5 MW. Idaho Power is not aware of any instance where inclusion of the provision for an engineer's certificate has adversely affected the development of a QF project.

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REQUEST STAFF 18:

Please explain why Idaho Power requires that the licensed professional engineer for this purpose be unaffiliated with the QF project, per Appendix C.

IDAHO POWER'S RESPONSE TO REQUEST STAFF 18:

See 17 above. In Idaho Power's experience, most project lenders require an unaffiliated professional engineer to perform a similar analysis. In those instances Idaho Power works with the lender to ensure there is no duplication of effort or expense for the QF.

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REQUEST STAFF 19:

Please explain how Idaho Power would treat additional QF power sales to the Company under the standard contract given the following circumstances, explain the basis for such treatment, and state how the Company would take into account whether any increase in generating output or manufacturer nameplate capacity is material:

a. When the manufacturer's nameplate capacity of the QF changes because of necessary equipment replacement, but remains at or below 10 MW

b. When the QF increases generating output due to efficiency improvements, but the manufacturer's nameplate capacity remains the same

c. When efficiency upgrades for a portion of the original equipment increase the manufacturer's nameplate capacity, but capacity remains at or below 10 MW

IDAHO POWER'S RESPONSE TO REQUEST STAFF 19:

a. If the QF discloses the replacement and the replacement is in fact a necessary replacement of existing equipment and not an equipment change with the sole intention of substantially increasing the size of the facility, Idaho Power will consult with the QF developer to confirm that the replaced equipment will not cause the project to generate at levels in excess of the maximum capacity amount. This is to protect the integrity of the interconnection with the Company's system. During the consultation process, the Company also works with the QF developer to amend the contract to modify the monthly net energy amounts to correspond to the capabilities of the modified generating equipment. As provided in Order No. 05-584, generation in excess of 10 MW is purchased at off-peak prices. So long as the modified equipment does not exceed the maximum capacity amount, the change would not be an issue.

b. See response to No. 19(a). To the extent the purchase price for energy generated in excess of 10 MW remains at the off-peak price, the changes described would not be material.

c. See response to No. 19(a).

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REQUEST STAFF 20:

Please explain why lack of water and lack of wind are not included as events of Force Majeure for wind and run-of-river hydro projects.

IDAHO POWER'S RESPONSE TO REQUEST STAFF 20:

Force majeure events are limited to events that neither party could have anticipated and included in the monthly energy production estimates. In most instances, reduced streamflow and reduced wind are events that are reasonably anticipated and even modeled. QF lenders will certainly do this analysis. Commission Staff's discussion regarding stochastic v. scenario risk that took place in the UM-1147 docket provides a good analogy of the difference between force majeure events and normal variations in stream flow and wind. As noted in Staff's Opening Comments in UM-1147, stochastic risk is defined as "risk that can be predicted as a part of the normal course of events, it is quantifiable and can be represented by a known statistical distribution. Examples of stochastic risk are hydro variability, normal plant outages, employee compensation and weather." Scenario risk is defined as a risk that is not susceptible to prediction and quantification; often represented by abrupt changes in business factors or practices. (Commission Order No. 04-108). Idaho Power believes that scenario risk as discussed in Order No. 04-108 is akin to force majeure events.

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REQUEST STAFF 29:

Please explain why § 3.3 of the standard contract requires that a hydroelectric QF warrant that it has a FERC license at the time of execution of the agreement, rather than warrant it will have a FERC license prior to the first operation date.

IDAHO POWER'S RESPONSE TO REQUEST STAFF 29:

Section 3.3 of the standard contract is consistent with an Idaho Public Utilities Commission requirement that a QF seeking a PURPA contract demonstrate that it has obtained a FERC license at the time of the execution of the agreement. The underlying rationale is that for a QF contract to qualify as a legally-enforceable obligation, there should be a reciprocal obligation on the part of both the QF and the utility, and not simply a free option for the QF to acquire a contract, lock in a rate, and then go see if it can create a project. In most instances, small hydro projects can quality for either an exemption from licensing or for a short-form minor license from the FERC. Requiring that the QF either have a FERC license or exemption from licensing is not an onerous requirement. Idaho Power currently has approximately 61 contracts with hydro QFs that contain this requirement and it has not proved to be a disincentive to QF development.

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CASE: UM 1129 - Phase I Compliance
WITNESS: Lisa Schwartz

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STAFF EXHIBIT 1003

Exhibits in Support of Direct Testimony

December 9, 2005

July 28, 2005

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Doug Kuns
Manager, Pricing and Offer Development

PORTLAND GENERAL ELECTRIC
UM-1129/Advice No. 05-10
PGE Response to OPUC Data Request
Dated July 14, 2005
Question 006

Request:

Please refer to Section 4.4 of the proposed standard Power Purchase Agreement. Explain why any increased Qualifying Facility (QF) output resulting from changes in operation of generating equipment — for example, improving its efficiency or operating at a higher power factor — should not receive the full avoided cost prices in the Tariff as of the effective date of the agreement. In addition, explain how this provision would comply with the requirement "to pay full avoided costs pursuant to the appropriate methodology for all energy delivered under a QF standard contract, but only up to the nameplate rating of the facility." ***See*** **Order No. 05-584 at 28.**

Response:

Section 4.4 requires, "Seller shall not increase the Nameplate Capacity Rating above that specified in Exhibit B or increase the ability of the Facility to deliver Net Output in quantities in excess of the Net Dependable Capacity, or the Maximum Net Output as described in Section 3.1.10." As the Seller specifies both the Net Dependable Capacity, and Maximum Net Output, there are no inconsistencies with OPUC Order No. 05-584. That is, QF's will be paid for generation, up to their nameplate capacity at full avoided costs.

If a Seller decided to modify their facilities to increase the nameplate capacity - there would be the need for a new contract for additional generation. Without some ceiling on output, the QF would be able to choose either the current avoided cost rates, or those in effect at the time the original contract was signed. In essence, all QFs would have a free "put option" (opportunity to sell at a specified price) for generation up to 10 MW by virtue of having a signed contract with PGE.

July 28, 2005

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Doug Kuns
Manager, Pricing and Offer Development

PORTLAND GENERAL ELECTRIC
UM-1129/Advice No. 05-10
PGE Response to OPUC Data Request
Dated July 14, 2005
Question 008

Request:

For each event constituting default in Section 10 of the proposed standard Power Purchase Agreement, please explain why PGE does not provide an opportunity to cure prior to termination.

Response:

Section 10.1 of the Standard Contract Power Purchase Agreement ("Agreement") sets forth a list of events that PGE considers, pursuant to Order 05-584 and prudent utility practices, to be events of default under the Agreement. If an event under Section 10.1 occurs, PGE has the discretion to exercise termination rights, but the contract does not automatically terminate as Data Request 8 implies. PGE may, for any default set forth in Section 10.1, choose not to terminate the Agreement and provide the Seller with an opportunity to cure the breach. Even if PGE does terminate the Agreement, PGE is still obligated to comply with Order 05-584 and PGE's obligations under PURPA. Therefore, assuming the Seller meets applicable requirements, it may require PGE to enter into a new Power Purchase Agreement.

Notwithstanding that Order 05-584 does not require PGE to offer any cure period for Seller defaults, PGE does not provide an explicit opportunity to cure events of default under Section 10.1 for various reasons. Sections 10.1.1, 10.1.2 and 10.1.3 do not contain cure periods because during the time period when Seller is in breach of those sections, PGE, and ultimately its customers, are subjected to either additional risk or costs. For example, if Seller does not meet the deadlines for establishing the Commercial Operation Date (deadlines which Seller unilaterally selects), PGE may incur costs as planning decisions are based on the availability of Seller's resource on a particular date. See also PGE's response to OPUC DR 007. Similarly, a breach by Seller of a representation it made under the contract will impose planning costs on PGE, and will substantially raise the risk of Seller's nonperformance. If Seller fails to provide the creditworthiness security set forth in Order 05-584, PGE faces risk associated with a Seller default, that Order 05-584 intended to mitigate, for any period that such security is not in place.

Effectively there is a cure period provided for Seller's initial failure to deliver Minimum Net Output. Section 10.1.4 calls for two consecutive Contract Years of under delivery before termination is permitted. Thus the QF can cure the initial year of performance failure.

Lastly, Sections 10.1.5 and 10.1.6 contain events that under Order 05-584, make the Seller ineligible for a Standard Contract. In the event a Seller is no longer qualified to require PGE to purchase power from it under the Standard Contract, PGE should not be required to purchase power pursuant to the terms of such a contract while awaiting a Seller to regain eligibility.

November 17, 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 2, 2005
Question 022

Request:

Please describe the documentation PGE requires under the standard contract for accepting a QF's designation of average annual Net Output or the Alternative Minimum Amount per § 4.2.

Response:

PGE expects that the particulars of how to document Net Output or Alternative Minimum Amount (also referred to as the Minimum Net Output) will vary from case to case. Exhibit A, Minimum Net Output, to the Standard Contract Power Purchase Agreement states:

Seller may designate an alternative Minimum Net Output to seventy-five (75%) percent of annual Net Output in this exhibit ("Alternative Minimum Amount"). Such Alternative Minimum Amount, if provided, shall exceed zero, and shall be established in accordance with Prudent Electrical Practices and documentation supporting such a determination shall be provided to PGE upon execution of the Agreement. Such documentation shall be commercially reasonable, and may include, but is not limited to, documents used in financing the project, and data on output of similar projects operated by seller, PGE or others.

This provides Sellers with a range of options to establish levels of output consistent with project expectations. Specific analysis used in support of financing requests for the initial investment will likely be sufficient to document Net Output and Alternative Minimum Amounts for a QF Facility.

November 17, 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 2, 2005
Question 023

Request:

In accepting a QF's designation of Minimum Net Output per § 4.2 under the standard contract, how would the Company take into account the following issues regarding resource data and QF operations:

a. A wind QF with only one year of anemometer data, or a hydroelectric project with only a few years of flow data, neither of which may be representative of the most adverse natural motive force conditions that may occur over the 20-year contract period

b. A QF at an industrial plant that shuts down periodically due to product prices, labor strikes or other market conditions

Response:

a & b. Please refer to the response to OPUC Data Request No. 022. The Minimum Net Output is expected to be based on data available for roughly a worst year for wind, or water conditions, factors such as production variations, or data on output from other units with a longer history if the QF lacks data. The requirement to establish a Minimum Net Output recognizes that no default occurs unless the QF has not met the output levels for 2 consecutive years (Section 10.1.4). We expect that the Minimum Net Output will be less than the QF's expected output by an amount that recognizes expected variations in conditions.

November 17, 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 2, 2005
Question 028

Request:

Regarding the amount of default security in § 7 of PGE's standard contract for QFs, please explain:

- **a. How the amount compares to other contracts the Company enters into for power of similar amounts (10 MW or less) and durations (up to 20 years)**
- **b. How the amount is standard business practice**
- **c. How the amount is commercially reasonable**

Response:

a. PGE purchases firm power under the EEI agreement in 25 MW blocks. Under this agreement companies which are not rated investment grade by S & P and Moody's service are required to provide collateral equal to the value by which the prospective market value of energy to be delivered exceeds the amounts to be paid for it. Transactions under the EEI agreement are normally for a term well under 20 years. PGE has recent contracts for longer terms that also require collateral to protect PGE's customers against at least part of the risk of non-delivery of power that if not delivered will have to be replaced at a higher cost than the contract price.

The WSPP agreement limits collateral "to a reasonable estimate of the damages to the First Party (consistent with Section 22.3 of this Agreement) if the Second Party were to fail to perform its obligations."

b & c. The intent of the default security clauses in these agreements is to make collateral limited to the damages from a default. When calculating the default security requirement in the standard contract, the provision approximates the potential damages to the company by requiring a single year of capacity payments as collateral which would be lost in the event of a default. The capacity to be provided would be at least the average minimum MW. The average minimum MW is multiplied by the difference in peak and off peak price to calculate the capacity value, which is then multiplied by the number of on peak hours. The value of lost energy is compounded when the term of the contract is for much more than one year. The collateral limits in the standard contract are intended to provide for collateral amounts that are tied to the value of the power, which is similar to the amounts specified in other agreements.

November 17, 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 2, 2005
Question 030

Request:

Please explain why PGE requires a licensed professional engineer to verify that the QF operates as specified, regardless of project size or whether the project is a standard packaged system. For example, would the Company impose such a requirement on a project that consists of a single wind turbine or microturbine

Response:

Verification of the operational capabilities of a QF requires the expertise of a licensed professional engineer, regardless of project size, because the engineering principles involved are the same whether the project is small or large, packaged or an original design. This will also avoid any biased conclusions because the principles used for analysis are uniformly applied to all projects. Further, we anticipate that verification should cost much less for packaged systems.

November 17, 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 2, 2005
Question 031

Request:

Please explain why PGE requires that the licensed professional engineer for this purpose be unaffiliated with the QF project, per § 1.10 of the standard contract.

Response:

This requirement is to avoid a conflict of interest in an engineer being affiliated with the Facility also providing the evaluation of Facility. Ultimately, conflicts of interest should be avoided to ensure that PGE's ratepayers do not bear inappropriate risks.

November 17, 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 2, 2005
Question 033

Request:

Please explain why lack of water and lack of wind are not included as events of Force Majeure for wind and run-of-river hydro projects.

Response:

Lack of wind or water, are not events of force majeure because the Minimum Net Output should reflect adverse wind or rainfall conditions.

November 17, 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 2, 2005
Question 039

Request:

Please explain why the standard contract does not include reciprocal default terms for PGE and the QF, and how this is standard business practice and otherwise commercially reasonable.

Response:

PGE believes that Sellers under the Standard Agreement would have recourse to the OPUC in the event of non-performance under the agreement or non-compliance with the Commission's order. In addition, as a regulated utility the likelihood of a PGE default is low.

November 17, 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 2, 2005
Question 041

Request:

Regarding PGE's requirement that a QF warrant it will remain current on financial obligations to others throughout the contract term or post default security, please explain:

a. How it is standard business practice
b. How it is commercially reasonable
c. Whether PGE would terminate the QF contract if the Seller makes this warranty at the time it signs the standard contract, but at some point during the contract period falls behind in financial obligations to others — for example, if the Seller becomes delinquent on debt payments for QF construction and the lender is working with the QF to meet its loan obligations
d. Whether PGE would require a QF to post default security in the future if the Seller makes this warranty at the time it signs the contract, but at some point during the contract period falls behind in financial obligations to others — for example, if the Seller becomes delinquent on debt payments for QF construction and the lender is working with the QF to meet its loan obligations

Response:

a. & b. PGE's other master power trading agreements require either termination of the agreement or providing collateral in the event of not being current on payment to others. These agreements include:

WSPP Agreement
The agreement states that if, "The First Party has knowledge that the Second Party (or its Guarantor if applicable) are failing to perform or defaulting under other contracts," the first party may request collateral and failure to do so shall be an event of default leading to termination of all transactions and a termination payment".

EEI Master Power Purchase and Sales Agreement
This agreement states that if "a default by such Party or any other party specified in the Cover Sheet for such Party in making on the due date therefore one or more payments, individually or collectively, in an aggregate amount of not less than the applicable Cross Default Amount (as specified in the Cover Sheet)" occurs, PGE or the other party may "liquidate and terminate all, but not less than all, Transactions (each referred to as a "Terminated Transaction") between the Parties"

c. Default in making payments with parties other than PGE is a good indication of likely future failure to perform and deliver on the part of the Seller. In the event the Seller fails to make payments for delivery of fuel, this would most likely make power deliveries to PGE impossible.

d. Consistent with b. above, PGE would exercise its rights as necessary to protect the interest of its customers. This does not preclude recognition of particular circumstances that suggest financial difficulty by the Seller is being resolved and PGE's customers would be best served by not exercising the right to terminate a Standard Contract.

November 17, 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 2, 2005
Question 042

Request:

Regarding § 3.1.5 of the standard contract, please explain how it is standard business practice and otherwise commercially reasonable that PGE prohibits any liens and encumbrances other than for third party financing of the QF. For example, please explain how it is standard business practice and otherwise commercially reasonable to prohibit a short-term lien for labor and material for maintenance work performed on the QF.

Response:

It is not a common business practice for contractors performing maintenance work to lien the property of the owner. PGE views a lien (and not project financing-related obligations) as a breakdown in the financial and business relationships of a QF. A lien to cover labor and material for maintenance might be used if the contractor had limited knowledge about the financial status of the owner, but in the case of a QF, the financial status should be discoverable. A Contractor may place a lien on the property if the QF does not pay bills within a reasonable time. A lien against a QF is an indication that the QF may have financial difficulty or is having problems with a Contractor, both of which reflect negatively on the QF's financial or operational stability. In addition, liens also reduce the value of the step in rights included in Order No. 05-584 and subsequently in the Standard Contract Power Purchase Agreement.

November 17, 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 2, 2005
Question 043

Request:

Please explain why § 6.2 of the standard contract requires the Seller to take all reasonable measures and exercise its best efforts to perform unscheduled maintenance during off-peak hours, and how such a requirement is standard business practice and otherwise commercially reasonable. Also, please explain why the company does not believe it is appropriate to impose such a requirement on a QF only "when practicable."

Response:

Section 6.2 is consistent with and supports the standard contract incentives to maintain on-peak production through receiving higher prices (energy and capacity). In addition, PGE has a higher need for on-peak energy. This section is also limited to unscheduled maintenance, and only requests that the QF "exercise its best efforts." Further, there are no penalties associated with the provision.

November 17, 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 2, 2005
Question 044

Request:

Please explain why § 20.2 of the standard contract, requiring the Seller to release PGE from any claims related to the QF that may have arisen prior to the Effective Date, is standard business practice and otherwise commercially reasonable.

Response:

In any business relationship, particularly when signing a new contract, both parties need to go forward with resolution of any and all outstanding issues or conflicts. If outstanding claims are not resolved it is detrimental to an ongoing contractual relationship. In addition, the release of claims provision at Section 20.2 of the standard contract is included to mitigate exposure risk for PGE and PGE's customers.

December 5, 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 18, 2005
Question 049

Request:

Please refer to staff data requests 6 and 32. Explain whether PGE would continue to believe a QF "would have a free put option" if payments to the Seller for generating output specified in the original contract continue to be based on avoided cost pricing as of the date of the original contract, and payments for generating output above that amount (due to circumstances outlined in 32a., 32b. and 32c.) are based on the avoided cost pricing at the time the QF increased its generating output due to necessary equipment replacement or efficiency upgrades.

Response:

PGE objects to this request on the grounds it is speculative and requires new analysis. Notwithstanding this objection, PGE responds as follows:

This question implies that a QF may have access to more than one avoided cost rate. Generally, in this situation PGE would consider factors such as whether the applicable avoided costs are consistent with the definitions in the standard contract, administrative impacts on the utility and the potential impacts on QF development from contractual disputes or the appearance of gaming.

December 5, 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 18, 2005
Question 050 - Modified

Request:

Pursuant to issue 36 in the Phase I compliance investigation, please explain why PGE 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.

Response:

Commission Order No. 05-584 did not call for a cap on default losses but required further investigation of the appropriate cap in the second phase of this proceeding. Specifically, see Order No. 05-584 at 3-4 under the heading, "The issues identified for the second phase include:"

> Cap on amount of default losses that can be recouped, pursuant to future QF contract payment reductions.

Also see Order No. 05-584 at 45:

> Although PacifiCorp proposed a reasonable cap on the amount that can be recouped, PacifiCorp provided no further detail. As no evidence was presented regarding the appropriate size of such a cap, nor any evidence about alternate provisions, we decline to impose any requirements. Instead, we encourage PacifiCorp to raise this issue in the second phase of this proceeding.

December 5, 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 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.

December 5, 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 18, 2005
Question 052-Modified

Request:

Please explain why PGE 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.

Response:

Please see PGE's Response to OPUC Data Request No. 050.

December 5, 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 18, 2005
Question 054

Request:

Please explain why PGE used as the basis for determining the amount of default security one year of capacity payments (based on the minimum expected capacity from the project), instead of the difference on average over the term of the agreement between a) forward power prices with a risk premium and b) the estimated payments to the QF.

Response:

PGE used one year of capacity payments based on the minimum expected capacity from the project because it is a simple straightforward calculation that is easy to administer. The amount of default security required is a fixed amount and can be determined before the QF begins operation. We assumed that certainty in the standard form contract for default security would be beneficial.

Using other approaches such as forward power prices to calculate a default security amount adds uncertainty and complexity. Depending on current market conditions, a risk premium for a twenty year contract would most likely be substantial and also difficult to quantify. Finally, the forward power price method would need to be applied to MWh output which requires another variable that is difficult to define.

December 5, 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 18, 2005
Question 056

Request:

Please provide the complete "standard commercial definitions" PGE refers to in its response to staff data request 21 for the following security options:

a. Senior lien
b. Step-in rights
c. Cash escrow
d. Letter of credit

Response:

PGE's market-based trading agreements employ more restricted security options for risk mitigation. The company recognizes the unique risk associated with Qualifying Facilities. Therefore, for purposes of PGE's standard contract for Qualifying Facilities, the "standard commercial definitions" for the four mandated security options identified in Section 7 are as follows:

a. "Senior lien" means a prior lien which has precedence as to the property under the lien over another lien or encumbrance.

b. "Step-in rights" means the right of one party to assume an intervening position to satisfy all terms of an agreement in the event the other party fails to perform its obligations under the agreement.

c. "Cash escrow" means an agreement by two firms to place money into the custody of a third party for delivery to a grantee only after the fulfillment of the conditions specified.

d. "Letter of Credit" means an engagement by a bank or other person made at the request of a customer that the issuer will honor drafts or other demands for payment upon compliance with the conditions specified in the letter of credit.

December 6, 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 21, 2005
Question 057

Request:

For each PGE 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)**

Response:

PGE objects to this request on the grounds that it is overly broad and unduly burdensome. Notwithstanding the objection, PGE responds as follows:

In the past two years PGE has entered into approximately 440 transactions for energy with thirty counterparties. These transactions have ranged from 60 days to 30 years, with quantities ranging from 2 MWh to 7 million MWh. All of PGE's contracts call for uncapped liquidated damages in the event of non-delivery, with the exception of one.

The single contract with a provision capping damages recoverable by PGE calls for 7 million MWh over 30 years. The damages were capped at $6,750,000.

December 6, 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 21, 2005
Question 058

Request:

For each PGE 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)**

Response:

PGE objects to this request on the grounds that it is overly broad and unduly burdensome. Notwithstanding the objection, PGE responds as follows:

In the past two years PGE has entered into approximately 250 transactions for energy with 27 counterparties. The deliveries associated with these contracts have ranged from 28 to 152 days, with quantities ranging from 625 to 31,200 MWh. All of PGE's power sales contracts call for uncapped liquidated damages in the event of non-delivery.

CASE: UM 1129 - Phase I Compliance
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1004

Exhibits in Support of Direct Testimony

December 9, 2005

HARDY MYERS
Attorney General

PETER D. SHEPHERD
Deputy Attorney General

Staff/1004
Schwartz/1

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

November 4, 2005

VIA EMAIL AND U.S. MAIL

Vikie Bailey-Goggins
Oregon Public Utility Commission
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Re: Docket No. UM 1129 – Phase I Compliance
ODOE Responses to Staff Data Requests No. DR 1-19
DOJ File No. 330-020-GN0041-04

The Oregon Department of Energy's (ODOE) responses to Staff's October 21, 2005 data requests No. 1-19 are included immediately following the questions below.

1. Based on the State Energy Loan Program's (SELP's) knowledge of the lending industry and renewable resource and cogeneration projects in Oregon, what percentage of QFs 10 MW or smaller does SELP estimate it provides financing for? Is SELP aware of other financial institutions that have financed QFs 10 MW or smaller in Oregon, or Oregon QFs of that size that did not need external financing? Please explain.

Response: Based on the information provided in response to Staff data requests in Phase 1 of UM 1129 proceedings, I estimate SELP financed 21 QF facilities or between 50 and 60% of Oregon QF projects 10MW or smaller. We are not aware of the financing by other parties.

2. Please refer to the standard power purchase contracts for Qualifying Facilities (QFs) 10 MW or less filed by Portland General Electric (PGE), PacifiCorp and Idaho Power pursuant to Order No. 05-584. For each of the contract provisions cited below, please state whether SELP would be able to provide a loan to a QF selling to a utility under a contract with such a provision and, if so, under what circumstance(s). In providing your answers, assume that the borrower is acceptable, the project design is acceptable, the development and management team is acceptable, and the project has adequate equity. Explain the basis for your answers.

Response: In responding to the question, the assumption is that all underwriting criteria of the project and transaction, excluding the power purchase agreement, meet SELP criteria for underwriting. In addition, I am answering these questions as the loan manager of the Small Scale Energy Loan Program from an underwriting perspective relating to making recommendation on the approval or denial of a loan. I have not consulted with counsel as to any legal requirements of specific contract language.

The purpose of the power purchase agreement and its assignment to SELP is to provide a source of revenue sufficient to cover projected operating and maintenance expenses, debt service and a reserve, with minimal risk of disruption of that revenue stream. This income stream acts as the primary security for the loan. 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. The proposed decreasing power rates over the first five years delivers sufficient risk in the financing that the probability of default and payment of damages must be very small in order to accommodate financing.

a. § 4.1.6 of Idaho Power's contract, stating that the specified security requirements are "at a minimum"

Response: SELP would want to know from Idaho Power what specifically was required to meet the creditworthiness requirement in the loan underwriting stage so we could determine if any additional costs or time delays would be incurred for the project. SELP funding would not occur until after the creditworthy determination was made by the utility.

b. § 10.5 of PacifiCorp's contract, requiring a letter of credit for potential environmental remediation requirements the company might incur if a QF selects the senior lien or step-in rights security option and defaults

Response: This is also an issue during loan underwriting. SELP would need to know the amount of the letter of credit, the cost to the borrower and the conditions under which the borrower is able to obtain a letter of credit. SELP is concerned that a community owned project or other small projects would not be able to obtain a letter of credit or the bank (issuer of the letter of credit) may require collateral that is also needed to secure the SELP loan and thus financing would not be available.

c. Default provisions triggered by under-deliveries, such as weather-related events causing reduced resource availability for QFs that rely on natural motive force

Response: SELP would generally not be able to fund a generation project if there was more than an incidental risk of default because of under delivery of minimum delivery requirements in the power purchase agreement. This assumes that the consequences of default could include significant financial harm to the QF. For generation projects that rely upon a natural motive force, either the minimum generation required must be very low to allow for adverse years or weather-caused shortfalls in generation should not cause default. Any minimum delivery requirement that is acceptable for financing could vary significantly by resource type, technology used and specifics of an individual project.

d. Default provisions triggered by delays in commercial operation

Response: The ability for SELP to finance a project that has the potential of default caused by a delay in commercial operation depends on the project and timing. In the current project development environment there is an increased risk of delays in procuring such key resources as: project equipment as well as other construction material, specialized labor, and transportation to get materials to the site. Some possible delays are beyond the control of a developer. In addition, some generating equipment has a long manufacturing lead time and some types of projects have a much longer construction time. This requires SELP to reasonably ensure that the project can be constructed within the time required as well as determine if the developer has sufficient resources to pay any default penalty if there is a delay. This may mean that some community owned project or other small QF project may not be approved for financing if SELP perceives this risk to be too great and beyond the control of the QF developer.

e. Termination due to under-deliveries, including those caused by weather-related events

Termination for under-delivery of power would not be acceptable for financing unless the termination was limited to the most egregious cases. In any event SELP would want the right to cure within a commercially reasonable time and operate the facility or sell the facility to another operator under a continuation of the power purchase agreement.. Commercially reasonable time would have to take into account the lack of availability of a motive force that may exceed one year as has been the case with some hydro generation.

f. Termination due to delays in commercial operation

Response: As stated above, termination for delay in commercial operation of project would not be acceptable for financing unless the termination was limited to the most egregious cases. In any event SELP would want the right to work with the project developers to complete the project in a commercially reasonable time. Any testing requirement to reach commercial operation would need to take availability of motive force into account.

g. Opportunity to cure provisions

Response: SELP's need for an opportunity to cure is linked with any default penalties and termination provisions as indicated in our answer to (f) above. SELP wants time to work with a borrower to resolve any default in the power purchase agreement. If resolution with the borrower is not possible we want the right to foreclose on the project and take over control, operate and/or sell the project and sell power under the existing power purchase agreement. Without legal review I do not know how our rights are impaired by the specific proposed language.

h. PGE's and Idaho Power's default provisions which do not take into account sufficient monies to provide for continued facility operations and debt payment, in the event future utility payments to the QF are reduced temporarily as a penalty for under-delivery

Response: SELP would calculate the possible default penalty under several power market rate assumptions and determine the possible net affect on project revenue. The lower the projected revenue is to pay operating expenses and debt service the more likely SELP would decline to finance the project. SELP typically requires a debt service reserve to cover seasonality of generation, but this reserve may be insufficient to cover a sever reduction in revenue caused by a contract penalty.

i. § 11.3.2 of PacifiCorp's contract, which prohibits the Seller from requiring that the utility purchase energy or capacity from the QF until after the expiration date in the contract, if the contract has been terminated due to the QF's default

Response: SELP needs to be able to foreclose on a project, sell the power under the existing power purchase agreement and ultimately to sell the project including the power purchase agreement. To the extent these rights are reduced by this provision we would not be able to finance the transaction.

j. § 6.2.1 of Idaho Power's contract, establishing default for failure to achieve the specified net energy amount each month

Response: Establishing the Monthly Net Energy Amount in 6.2.1 does not preclude SELP project financing if this information is used for utility planning purposes. Use of Monthly Net Energy Amounts in calculating the Shortfall Energy (1.19), the Shortfall Energy Repayment Amount (7.4) and the damages due under the Shortfall Energy Repayment Schedule (7.5) creates financing difficulties because it creates a significant financial risk that the project may owe penalties. This would reduce project net revenues below what would be prudent for loan underwriting. Section 6.2 defines the amounts shown in 6.2.1 as those the seller intends to produce, which are generally far greater than what might be produced in adverse conditions. If SELP projects, through due diligence of a specific project, that the risk of not meeting the contracted Monthly Net Energy Amount is material, in calculating potential revenue we will estimate any damages that might be owed. I estimate that for most QFs the projected damages would reduce their projected revenue to where they would not be eligible for financing.

k. § 6.3 of Idaho Power's contract, which allows for termination for failure to deliver at least 10% of the sum of the monthly Net Energy amounts in any contract year

Response: Based on SELP's experience, our ability to finance a project that allows for termination for failure to deliver at least 10% of the Net Energy amount as in Idaho Power proposed contract or other minimum power contracted amount may not be financeable. Our experience is that in a severe draught some hydro projects have suffered periods beyond one year with no generation. The ability to accept this type of contract provision depends on the type of resource used by a QF and its specific resource assessment.

l. § 3.1.4 of PGE's contract, requiring a QF to warrant that it will remain current on all its financial obligations to others throughout the contract term or post default security

Response: SELP interprets this to mean that if the seller was delinquent on its loan to SELP, even if we had a structured workout to bring the borrower current, PGE could require default security. It is unlikely the seller would have resources to meet the default security so SELP would be unable to finance such a transaction as it could place too great a financial burden on a QF when they already operating with reduced revenue. SELP assumes that the only viable security option a QF has under such a situation is to establish an escrow account. They would most likely not qualify for a letter of credit and a senior lien on the project could not be given.

m. § 3.1.5 of PGE's contract, prohibiting any liens or encumbrances on the project other than for third-party financing

Response: This condition does not prohibit financing.

n. § 20.2 of PGE's contract, providing a release for all claims related to the facility, whether known or unknown, that arose before the contract effective date

Response: I do not believe this affects SELP ability to finance a project.

3. In SELP's experience, is the utility sufficiently protected from under-deliveries through damage provisions and the QF's natural incentive to maintain revenues from generation, such that termination for under-deliveries may be unnecessary? Conversely, are there any circumstances under which SELP believes it would be reasonable for the utility to terminate the QF contract for under-deliveries? Please explain.

Response: If SELP is financing a project, we believe the utility and ratepayers receive some protection from our due diligence, our loan conditions and covenants and the fact that the financing exists. SELP requires that any QF has an investment in their project. Our experience is that QFs try to maximize their generation and project revenue. If there is a reduction in generation SELP has historically worked with QFs to help improve their generation where possible. This can include upgrading controls, transmission or operating characteristics of the project. In the event a borrower does not have the resources or capability to get sufficient generation to meet contracted minimums, they are likely to be delinquent on their loan. In such a case SELP has foreclosed on a project and sold it to an operator who was able to renew generation and operate the facility effectively. SELP believes its involvement in projects helps reduce the risk to utilities and ratepayers.

In SELP's experience, for financed projects, termination for under-delivery is not needed. Because of severe or unusual weather events that can affect a QF's ability to generate power, and because these events have exceeded one year as in the case of droughts, SELP believes it is unreasonable to allow termination that involves lack of motive resource. Conversely, termination for egregious under delivery (e.g. several years with no delivery but with current sufficient motive resource) would allow sufficient time for a lender to foreclose on a project and re-establish good generation. Thus termination would not be needed. Sufficient time needs to be given for SELP to act and re-establish generation, which may include new equipment, before termination could be triggered.

4. In SELP's experience, are the opportunity to cure provisions in the standard contracts standard industry practice and commercially reasonable? For example, are the extent to which these provisions apply to various events of default, and the opportunity to cure periods, standard industry practice and commercially reasonable? Please explain.

Response: Because there has not been a QF market in recent years, SELP is not aware of current industry practices pertaining to right to cure provisions.

5. Is it SELP's experience that reciprocal default terms are standard industry practice and commercially reasonable? Please explain.

Response: I am not aware of what standard industry practice is regarding reciprocal default terms.

6. In SELP's experience, do QFs 10 MW or smaller typically have a credit rating by a credit rating agency? Please explain.

Response: In SELP's experience it is highly unlikely that a QF of 10MW or smaller has a senior unsecured debt rating. This rating is usually limited to large corporations and generally requires the consistent issuance of unsecured debt and a payment to the rating agencies.

7. Does SELP require that a licensed professional engineer verify that the QF for which it provided financing operates as specified? Does any such SELP requirement vary by size, type and design of project? Please explain.

Response: No. In underwriting the financing SELP evaluates the technical merits of a project including the experience of the design team and contractors, reliability of the proposed technology and equipment, and any production or performance guarantees offered. Most projects include the use of a licensed PE but SELP does not include this as a requirement in its loan documentation.

8. If SELP requires that a licensed professional engineer verify that the QF it is financing operates as specified, is the licensed professional engineer required to be unaffiliated with the project?

Response: N/A

9. In Oregon Department of Energy's (ODOE's) experience, through SELP and other programs, are small wind and hydroelectric projects able to accurately establish minimum monthly production levels, below which they would be in default? For example, how many years of historical data for the local wind or hydro resource do such projects typically have prior to operation? Are such data likely to uncover the most adverse natural motive force conditions? Please explain.

Response: SELP loan underwriting is based on available resource data. The amount of historical resource data varies greatly among projects. This data can vary from 30 years of water flow to only a few years of water flow, a year or two of wind data, or the assumed availability of biomass from forest lands. In SELP's experience it is difficult for a generator to accurately predict minimum production over the long run for a specific month. In our experience actual available resources do vary below those estimated in for a given month or year. SELP's analysis is meant to estimate a long term average that can be used for financing and then structure the loan to accommodate adverse periods that are unpredictable. Because of this, SELP does not include a specific level of production as an event of default.

10. What actions does SELP take in the event of reduced power generation and revenue due to a lack of natural motive force for a wind or run-of-the-river hydro project?

Response: If a generating project does not produce sufficient revenue because of lack of resource and the borrower becomes delinquent on their loan, SELP's usual course of action would be to enter into a forbearance agreement that adjusts the repayment terms until improved generation enables the borrower to return to the original payment schedule. The forbearance agreement would allow the payment of operating and maintenance expenses prior to debt service. The forbearance agreement may be in existence for several years before a borrower can financially catch up and resume the original payment schedule. SELP's experience tells us that it is important to have the flexibility to work through low production periods with renewable generation projects.

11. When SELP underwrites loans, how does it address the issue of determining net generating output available for electricity sales in the case of a QF that uses part of the output to service on-site load and sells the remainder of the output to an electric utility under a power purchase agreement?

Response: In underwriting a loan for a generating facility, SELP will review the project business plan that includes reviewing the historic and projected energy load of the host facility and any plant parasitic load. SELP will estimate the net delivered power for sale to determine the anticipated power revenue. In underwriting, we anticipate that there may be times when the host load or the generation is more or less than anticipated. We project that the cash flow will vary from the baseline case and require that projected revenue contains sufficient cushion to provide funds for operation, maintenance and pay debt service under varying conditions of operations and revenue.

12. Does SELP require that a hydroelectric QF warrant that it has a FERC license at the time of execution of the loan agreement, or prior to the first operation date? Please explain.

Response: SELP has not financed a QF hydro project in recent years. A limited review of older hydro projects, found that SELP normally required a FERC license at the time of loan closing and first loan disbursement. SELP staff believe that loan advances were made on a least one hydro project prior to the facility receiving its FERC license. In a current application, if we were asked to advance funds prior to the issuance of the FERC license, SELP would determine if there was any risk the hydro facility would not receive the license.

13. Will a QF be able to choose the senior lien security option in the standard utility contract if it receives SELP financing? Please explain.

Response: It is SELP's understanding that the senior lien security option will not be available to generators if they finance their project with SELP. This is because SELP requires that it have a first or senior security position in the facility and as a result it would not be available to the utility.

14. In ODOE's experience as staff to the state Energy Facility Siting Council, please describe how § 10.5 of PacifiCorp's contract, requiring a letter of credit for environmental remediation when a QF chooses the senior lien or step-in rights security option in the standard contract, compares to what the Council requires for a site certificate for a power plant.

Response: The Energy Facility Siting Council (EFSC) requires either a letter of credit or a bond for the estimated cost to the state of restoring the site to a "useful, non-hazardous condition" in the event that the power plant shuts down and the certificate holder fails to restore the site. This is different from environmental remediation that usually pertains to chemicals at industrial sites or development on brownfield sites. There should be minimal environmental risk at most renewable generation sites. EFSC has not had experience with QFs at industrial sites that would be more prone to environmental remediation but SELP has financed generation projects at such sites. SELP has an experienced a foreclosure of an industrial cogeneration facility but no significant environmental remediation costs resulted.

15. Regarding utility and ratepayer concerns related to potential environmental remediation of a QF site, in the case where a QF chooses the senior lien or step-in rights security option and defaults, what alternatives does SELP in its experience believe the utility may have to address these concerns, in lieu of a letter of credit? What are the pros and cons of these alternatives for the QF, the lender, and the utility and its ratepayers?

Response: The most important alternative is to first assess probable environmental remediation to see what the potential risk is and decide whether to step-in as the facility operator. Many renewable generation projects have little environmental remediation potential and asking all those who choose step-in rights to provide a letter of credit would unduly burden them at minimal reduction in risk to ratepayers. To pose a risk to the utility and ratepayers, a QF would need to default, there would need to be significant environmental remediation needed, and market energy prices would need to be above contract prices. In the rare event all these condition happen and a utility chooses not to step-in they can always litigate against a QF to seek damages. The pros of not requiring a letter of credit would be more potential renewable generation projects and not posing a cost on projects were no risk exists. The cons would be a more difficult path for a utility to collect damages with the possibility of uncollectability. An alternative for a generation project at an industrial site is to have the host company assume this financial responsibility as an option for a letter of credit. This would offer resources for environmental remediation if needed without the burden of the letter of credit.

16. If the requirement for a letter of credit for environmental remediation in PacifiCorp's standard contract is upheld by the Commission, what does SELP believe would be an appropriate cap on the amount a utility should require? Should such a cap vary by type of project — a greenfield wind project vs. a cogeneration project at an industrial site? Please explain.

Response: Yes, any cap should vary by project type and location. The Commission should qualify that a letter of credit should only be needed in circumstances where environmental remediation is a clear documented risk. It would be best to specify what these risks could be. SELP has not analyzed appropriate caps at this time.

17. When SELP underwrites loans for QFs 10 MW or smaller, what representations, warranties and other requirements do you require from the QF to demonstrate that it is a creditworthy borrower?

Response: For loan underwriting, creditworthiness is determined by reviewing the complete project and not just the borrower. The review includes technical feasibility, resource assessment, equipment used, resource assessment, experience and strength of project manager, developer and contractors, maintenance and operations plan, warranties or guarantees, available equity or other funds including reserves, siting in addition to project financial feasibility including projections of revenue and expenses. Creditworthiness is ultimately tied to the projected ability of the borrower or project to repay the loan using all the above avenues of analysis. SELP wants to ensure it is financing a good project that will both be able to repay its loan but also be a regional generating asset after the loan is paid off.

18. In the event a QF 10 MW or smaller is unable to establish creditworthiness with a utility as defined in Order No. 05-584, what in SELP's estimation would be an appropriate amount of default security for the utility to require? Please explain the basis for your response.

Response: In earlier testimony (ODOE/Exhibit No.3/Keto/Page 5and 6) SELP proposed that the amount of default security may be specific to project type, but should be limited to around 2% of project capital costs. SELP does not make any additional recommendation at this time.

19. In SELP's estimation, what would be an appropriate cap on the amount of damages that a utility can recoup through future contract payment reductions for default by QFs 10 MW and smaller? Please explain the basis for your response.

Response: SELP firmly believes that any reduction in future payments to recoup damages should be limited such that the reduction does not result in project revenues being insufficient to fund operations, maintenance and debt service. In addition, there should be a reasonable cap on the total damages. The purpose of the penalty should be to dissuade any generators from mismanaging their project but not cause a project to stop operating. SELP is not able at this time to recommend a specific cap.

If you have questions about these responses, please call me.

Sincerely,

Janet L. Prewitt

Janet L. Prewitt
Assistant Attorney General
Natural Resources Section

Enclosure

c: Phil Carver, ODOE (email only)
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DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

December 7, 2005

VIA EMAIL AND U.S. MAIL

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Re: Docket No. UM 1129 – Phase I Compliance
ODOE Supplemental Responses to Staff Data Requests No. DR 2.m.
DOJ File No. 330-020-GN0041-04

The Oregon Department of Energy's (ODOE) supplemental responses to Staff's October 21, 2005 data requests No. 2.m. is included immediately following the questions below.

2. Please refer to the standard power purchase contracts for Qualifying Facilities (QFs) 10 MW or less filed by Portland General Electric (PGE), PacifiCorp and Idaho Power pursuant to Order No. 05-584. For each of the contract provisions cited below, please state whether SELP would be able to provide a loan to a QF selling to a utility under a contract with such a provision and, if so, under what circumstance(s). In providing your answers, assume that the borrower is acceptable, the project design is acceptable, the development and management team is acceptable, and the project has adequate equity. Explain the basis for your answers.

   m. § 3.1.5 of PGE's contract, prohibiting any liens or encumbrances on the project other than for third-party financing

Response: This provision may prohibit or reduce the availability of financing. As a lender, we would ask that an exception be included in the contract to allow for statutory liens. Contractors, material suppliers and others have the authority under law to file liens, which may occur during construction, maintenance or upgrade of a generating facility. The filing of this type of lien can't be prohibited and we would not want the filing to automatically cause a default in the contract and subsequent penalties or termination. An exception for statutory liens should also recognize that the project owner has the right to contest a lien in good faith, which may involve significant time to clear the lien.

Sincerely,

/s/ 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)
Lisa Schwartz, OPUC, (email only)

JLP:jrs/GENO5985.DOC

CASE: UM 1129 - Phase I Compliance
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1005

Exhibits in Support of Direct Testimony

December 9, 2005

UM-1129/PacifiCorp
July 25, 2005
OPUC Data Request 5

OPUC Data Request 5

Please describe PacifiCorp's potential liability under state and federal law for environmental remediation of a Qualifying Facility site in cases where the facility owner has selected the Senior Lien or Step-in Rights security option and is in default.

Response to OPUC Data Request 5

PacifiCorp objects to this request in that it does not seek factual information, but rather a legal conclusion. Without waiving this objection, PacifiCorp notes that if it took over the facility as an owner/operator under its lien rights, or if PacifiCorp only became the operator under its step-in rights, the Company would potentially be exposed to joint and several liability for environmental remediation costs under CERCLA (the federal Superfund laws).

UM-1129/PacifiCorp
July 25, 2005
OPUC Data Request 6

OPUC Data Request 6

If a Qualifying Facility owner selects the Senior Lien or Step-in Rights security option:

a. How will PacifiCorp determine the appropriate amount for the proposed Letter of Credit for environmental remediation?

b. Does PacifiCorp anticipate requiring a different credit amount for a greenfield wind project vs. a cogeneration project at an industrial site? Please explain your response.

Response to OPUC Data Request 6

a. The amount will be determined based upon an evaluation of the project site.

b. The amount will be determined based upon an evaluation of the project site, regardless of the type of the project. In general, it could be expected that there would be less likelihood of existing contamination at a greenfield site than an industrial site.

UM-1129/PacifiCorp
November 15, 2005
OPUC Data Request 30

OPUC Data Request 30

Regarding the definition of Default Security, § 1.9 in PacifiCorp's standard contract for Qualifying Facilities (QFs):

a. Please explain how the definition compares to other contracts the Company enters into for power of similar amounts (10 MW or less) and durations (up to 20 years).
b. Please explain whether the definition is standard business practice.

Please explain why the definition is commercially reasonable.

Response to OPUC Data Request 30

a. For those contracts that are 3MW or less, and that have been executed in recent years, the Company does not have a definition of Default Security. However, the Seller has satisfied the credit requirements by making a series of representations and warranties.

In most instances, the definition of Default Security will apply to those contracts that are larger than 3MW and below 10MW. The Company has not entered into any contracts in this category in recent years and therefore there is no basis of comparison for the definition.

b. It is standard business practice for PacifiCorp to require a certain amount of Default Security from counterparties that are not creditworthy. The definition in Sec.1.9 is a reasonable measurement of replacement power costs, and it also allows for negotiation between the parties, since the definition is prefaced with "unless otherwise agreed to by the Parties in writing". While it is consistent with the Company's standard business practice, Sec. 1.9 was drafted in response to OPUC Order No. 05-584.

c. The definition is a commercially reasonable one as it provides a reasonable, transparent, and verifiable measurement of replacement power costs, which would mitigate the exposure of these costs to PacifiCorp's ratepayers should the Seller fail to perform.

UM-1129/PacifiCorp
November 15, 2005
OPUC Data Request 31

OPUC Data Request 31

Regarding the definition of Letter of Credit, § 1.17 in the standard contract:

a. Please explain how the definition compares to other contracts the Company enters into for power of similar amounts (10 MW or less) and durations (up to 20 years).
b. Please explain whether the definition is standard business practice.
c. Please explain why the definition is commercially reasonable.

Response to OPUC Data Request 31

a. For those contracts that are 3MW or less, and that have been executed in recent years, the Company does not have a definition of Letter of Credit. However, the Seller has satisfied the credit requirements by making a series of representations and warranties.

In most instances, the definition of Letter of Credit will apply to those contracts that are larger than 3MW and below 10MW. The Company has not entered into any contracts in this category in recent years and therefore there is no basis of comparison for the definition.

However as examples from other power purchase agreements, the Western Systems Power Pool Agreement (effective 2/1/2005) has this definition for Letter of Credit: "An irrevocable, transferable, standby letter of credit, issued by an issuer acceptable to the Party requiring the Letter of Credit." The Edison Electric Institute's Master Power Purchase & Sale Agreement (modified 4/25/00) defines Letter of Credit as follows: ""Letter(s) of Credit" means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a foreign bank with a U.S. branch with such bank having a credit rating of at least A- from S&P or A3 from Moody's, in a form acceptable to the Party in whose favor the letter of credit is issued. Costs of a letter of credit shall be borne by the applicant for such Letter of Credit."

b. Requiring a Letter of Credit as defined in Sec. 1.17, or similarly, is standard business practice in other trading agreements which PacifiCorp uses.

c. The definition is commercially reasonable because it sets forth the credit requirements for the issuing institution and the form of the letter of credit, thus protecting PacifiCorp and its ratepayers, and is consistent with what PacifiCorp sees in the wholesale power market.

UM-1129/PacifiCorp
November 15, 2005
OPUC Data Request 33

OPUC Data Request 33

In accepting a QF's designation of Minimum Annual Delivery per § 4.3 under the standard contract, how would the Company take into account the following issues regarding resource data and QF operations:

a. A wind QF with only one year of anemometer data, or a hydroelectric project with only a few years of flow data, neither of which may be representative of the most adverse natural motive force conditions that may occur over the 20-year contract period

b. A QF at an industrial plant that shuts down periodically due to wood product prices, labor strikes or other market conditions

Response to OPUC Data Request 33

a. In either case, per Exhibit D-1B, the Company is requesting Minimum Annual Delivery based on the most adverse natural motive force conditions reasonably expected taking into account QF maintenance and Seller's load variation. This is not unreasonable and most likely the QF has included it in its business case. That is all that is requested. In the case of wind or hydro, the Company understands that the QF may have limited data on weather conditions but expects the QF to supply a reasonable estimate of a minimum delivery. Specifically a minimum of zero kWh would be deemed unacceptable since it is highly unlikely and suspect that a wind project would have no wind over a period of a year or a hydro project would see no water. In the case of the industrial plant, it is important to note that the labor strike is a Force Majeure condition but market conditions or wood products prices are not allowed Force Majeure events. QFs per PURPA are paid based on the Company's avoided cost not the economics of the QF's generation or its thermal load / plant.

b. See the response to OPUC 33 a.

UM-1129/PacifiCorp
November 15, 2005
OPUC Data Request 38

OPUC Data Request 38

Please explain in each case why the opportunity to cure provisions in § 11.2 do not apply to § 11.1.2, 11.1.3, 11.1.4 and 11.1.6, and the potential harm to the Company and its ratepayers if the Company provided an opportunity to cure for these events of default.

Response to OPUC Data Request 38

(a) With respect to § 11.1.2: The opportunity to cure, governed by the terms of the particular agreement or instrument, is provided by § 11.1.2 itself. The PPA cannot effectuate an extension of the cure periods allowed by those other agreements or instruments. It cannot be determined at this time what all the potential harms to the Company and its customers could be if further opportunity to cure were provided, but it could include increased risk of higher replacement power costs.

(b) With respect to § 11.1.3: The listed events or circumstances for which a cure period is not already provided are not particularly conducive to cure. Regarding potential harm, PacifiCorp believes there would be increased risk of default; also, see response (a).

(c) With respect to § 11.1.4: The provision itself contains an effective cure period. See responses (a) and (b) regarding potential harm.

(d) With respect to § 11.1.6: Since the minimum delivery obligation exists for a time period which will have passed, failure to satisfy that obligation is not capable of being cured.

UM-1129/PacifiCorp
November 15, 2005
OPUC Data Request 39

OPUC Data Request 39

Please explain why § 11.2.2 limits the opportunity to cure period to a time certain after the default, rather than a "commercially reasonable time." Also, please explain how the opportunity to cure periods in § 11.2.2 compare to other contracts the Company enters into for power of similar amounts (10 MW or less) and durations (up to 20 years), and is otherwise standard business practice and commercially reasonable.

Response to OPUC Data Request 39

Use of fixed time periods rather than the term "commercially reasonable time" is preferable because it reduces the risk of disagreement as to just how long the cure period should be for a particular event. The cure periods in the PPA are generally similar to those in recent UM-1129 PPAs (less than 10 MW/20 yrs). Specifying cure periods is a standard business practice, and is commercially reasonable, as reflected by specific cure periods in the WSPP agreement (effective 2-1-2005), providing a 2 business day cure period for failure to pay, and a 5 business day cure period for failure to provide good title and failure to meet representations and warranties.

UM-1129/PacifiCorp
November 15, 2005
OPUC Data Request 42

OPUC Data Request 42

In the likely case that the QF 10 MW or smaller does not have a credit rating from a major credit rating agency, please describe the "indicia of creditworthiness" that will be "acceptable to PacifiCorp" under § 1.8.

Response to OPUC Data Request 42

The "indicia of creditworthiness" in Section 1.8 for those QFs without a published credit rating would be an equivalent rating as determined by PacifiCorp after performing a review of the QF's financial statements and utilizing a proprietary credit scoring model developed in conjunction with Standard & Poor's.

UM-1129/PacifiCorp
November 15, 2005
OPUC Data Request 43

OPUC Data Request 43

Please explain why PacifiCorp requires a licensed professional engineer to verify that the QF operates as specified, regardless of project size or whether the project is a standard packaged system. For example, would the Company impose such a requirement on a QF that consists of a single wind turbine or microturbine?

Response to OPUC Data Request 43

The requirement provides the Company with an un-biased determination that the resource will deliver what has been proposed by the QF in order to minimize disputes regarding performance.

UM-1129/PacifiCorp
November 15, 2005
OPUC Data Request 44

OPUC Data Request 44

Please explain why PacifiCorp requires that the licensed professional engineer for this purpose be unaffiliated with the QF project, per § 1.18 of the standard contract.

Response to OPUC Data Request 44

The requirement provides the Company with an un-biased determination that the resource will deliver what has been proposed by the QF in order to minimize disputes regarding performance.

UM-1129/PacifiCorp
November 15, 2005
OPUC Data Request 45

OPUC Data Request 45

Please explain how PacifiCorp would treat additional QF power sales to the Company under the standard contract given the following circumstances, explain the basis for such treatment, and state how the Company would take into account whether any increase in generating output or manufacturer nameplate capacity is material:

a. When the manufacturer's nameplate capacity of the QF changes because of necessary equipment replacement, but remains at or below 10 MW

b. When the QF increases generating output due to efficiency improvements, but the manufacturer's nameplate capacity remains the same

c. When efficiency upgrades for a portion of the original equipment increase the manufacturer's nameplate capacity, but capacity remains at or below 10 MW

Response to OPUC Data Request 45

a. So long as the QFs nameplate capacity remains below the 10 MW cap, the Company would amend the contract.

b. See the Company's response to a. above.

c. See the Company's response to a. above.

UM-1129/PacifiCorp
November 15, 2005
OPUC Data Request 46

OPUC Data Request 46

Please explain why lack of water and lack of wind are not included as events of Force Majeure for wind and run-of-river hydro projects.

Response to OPUC Data Request 46

The Company expects a resource developer to provide a reasonable estimate of the minimum annual delivery level based on their knowledge of lack of wind or water. This estimate should include expected lack of water or lack of wind conditions. If the QF developer has performed their responsibility related to securing adequate and accurate data on wind or water then their confidence level should be sufficient to meet minimum levels. The Company is also concerned that other thermal resources would claim the same reason – no fuel and therefore be let out of their obligation. None of our commercial wind transactions allow for lack of wind as a Force Majeure.

OPUC Data Request 54

Please refer to staff data request 45a:

a. Specify the types of contract amendments that would be made to § 4.2 and § 4.3.
b. Specify the types of amendments that would be made to Exhibit A.
c. Specify the types of amendments that would be made to Exhibits D-1 and D-2.
d. Specify the types of amendments that would be made pursuant to § 1.9 and § 10.
e. For the portion of generating output above that expected under the manufacturer's nameplate capacity specified in the original contract, would payments to the Seller be based on the avoided cost pricing at the time of the contract amendment or the date of the original contract? Please explain your answer.

Response to OPUC Data Request 54

a. PacifiCorp anticipates that sections 4.2 and 4.3 would be amended to state the increased estimated average kWh (4.2) and minimum and estimated maximum deliveries (4.3), if such amounts were expected to change due to the increase in nameplate capacity.
b. PacifiCorp anticipates that the increased nameplate capacity would be reflected by revising the Rated Output (kW and kVA), Maximum kW Output (kW and kVA), Power Factor Requirements, Facility Capacity Rating, and the description of the maximum output and any differences between that output and the Nameplate Capacity Rating.
c. PacifiCorp anticipates that parts A, B and C would be amended to state the increased estimated monthly kWh and minimum and estimated maximum deliveries, if such amounts were expected to change due to the increase in nameplate capacity.
d. PacifiCorp does not anticipate that any amendments would be made to either section 1.9 or section 10.
e. The Company would amend the contract to allow the additional generation at the prices listed in the contract.

UM-1129/PacifiCorp
December 5, 2005
OPUC Data Request 55

OPUC Data Request 55

Please refer to staff data request 45b:

a. Specify the types of contract amendments that would be made to § 4.2 and § 4.3.
b. Specify the types of amendments that would be made to Exhibit A.
c. Specify the types of amendments that would be made to Exhibits D-1 and D-2.
d. Specify the types of amendments that would be made pursuant to § 1.9 and § 10.
e. For the portion of generating output above that expected under the original contract, would payments to the Seller be based on the avoided cost pricing at the time of the contract amendment or the date of the original contract? Please explain your answer.

Response to OPUC Data Request 55

a. PacifiCorp anticipates that sections 4.2 and 4.3 would be amended to state the increased estimated average kWh (4.2) and minimum and estimated maximun deliveries (4.3).
b. PacifiCorp anticipates that the increased nameplate capacity would be reflected by revising the Rated Output (kW and kVA), Maximum kW Output (kW and kVA), Power Factor Requirements, Facility Capacity Rating, and the description of the maximum output and any differences between that output and the Nameplate Capacity Rating
c. PacifiCorp anticipates that parts A, B and C would be amended to state the increased estimated monthly kWh and minimum and estimated maximum deliveries.
d. PacifiCorp does not anticipate that any amendments would be made to either section 1.9 or section 10.
e. The Company would amend the contract to allow the additional generation at the prices listed in the contract.

UM-1129/PacifiCorp
December 5, 2005
OPUC Data Request 56

OPUC Data Request 56

Please refer to staff data request 45c:

a. Specify the types of contract amendments that would be made to § 4.2 and § 4.3.
b. Specify the types of amendments that would be made to Exhibit A.
c. Specify the types of amendments that would be made to Exhibits D-1 and D-2.
d. Specify the types of amendments that would be made pursuant to § 1.9 and § 10.
e. For the portion of generating output above that expected under the manufacturer's nameplate capacity specified in the original contract, would payments to the Seller be based on the avoided cost pricing at the time of the contract amendment or the date of the original contract? Please explain your answer.

Response to OPUC Data Request 56

a. Please see responses to Request 54(a).
b. Please see responses to Request 54(b).
c. Please see responses to Request 54(c).
d. Please see responses to Request 54(d).
e. The Company would amend the contract to allow the additional generation at the prices listed in the contract.

UM-1129/PacifiCorp
December 5, 2005
OPUC Data Request 57

OPUC Data Request 57

Pursuant to issue 36 in the Phase I compliance investigation, please explain why PacifiCorp 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.

Response to OPUC Data Request 57

A default by a QF may occur at any time within their contract. The cost of replacement power will vary over the term of the contract and including a cap of any type could subject the Company and ratepayers to additional cost exposure should the replacement power cost exceed some established cap. In the event a cap was ordered by the Commissioners then it should be based on 100% of the forward market prices for the default period.

UM-1129/PacifiCorp
December 5, 2005
OPUC Data Request 58

OPUC Data Request 58

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 PacifiCorp 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 to OPUC Data Request 58

Although the Company is opposed to a default cap, the Company would prefer a cap using replacement costs based on 100% of projected forward prices over the term of the contract. This reflects the current best estimate of the costs the Company would have to incur to replace the power not delivered by the defaulting QF.

UM-1129/PacifiCorp
December 5, 2005
OPUC Data Request 61

OPUC Data Request 61

Please explain the basis for selecting 24 months as the appropriate period for which replacement power costs should be assessed as damages for termination as a result of Seller's default, per § 11.3.3.

Response to OPUC Data Request 61

The Company believes that a 24 month period is the approximate time required for a 3rd party to design and build a like resource and the Company to secure a purchase contract with the party.

OPUC Data Request 62

Please explain why PacifiCorp used as the basis for determining the amount of default security the positive difference on average over the term of the agreement between a) 110% of the monthly forward power prices and b) the estimated payments to the QF (based on Fixed Avoided Cost prices and Minimum Annual Delivery) — but not less than three average months of estimated payments to the QF — instead of a year of capacity payments based on the minimum expected capacity from the project.

Response to OPUC Data Request 62

The amount of default security is established with reference to the energy to be delivered by the QF, rather than capacity payments paid to the QF, because the QF will not have a minimum capacity obligation, and the avoided cost prices are "energy only" prices. Further, if the QF fails to perform, the Company will be looking to replace energy, not capacity. The basis for determining the amount of default security was that 12 average months of replacement power for the minimum energy obligation was considered to be a reasonable limitation to the Seller's obligation for default security purposes should the Seller fail to perform. The multiplication of the forward market prices by 110%, as well as the three-month minimum provision, was to protect PacifiCorp's ratepayers in the event of a movement in the forward market prices.

UM-1129/PacifiCorp
December 6, 2005
OPUC Data Request 63

OPUC Data Request 63

For each PacifiCorp 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)

Response to OPUC Data Request 63

a. There is one contract for a power purchase signed within the past two years for a term of greater than 60 days that has a cap on default losses. (Contract #24 in Attachment 63 b.) The terms of this cap are as follows:

> If the Agreement is terminated as a result of the Seller's default, the Seller shall pay PacifiCorp the positive difference, if any, obtained by subtracting the contract price from the replacement price for any energy and capacity that Seller was otherwise obligated to provide for thirty-six months following the termination date of the Agreement.

b. Please see Attachment OPUC 63 b

c. Please see Attachment OPUC 63 b

OREGON

ELECTRIC UTILITY PURCHASES FROM QUALIFYING FACILITIES

UM-1129

PACIFICORP

OPUC DATA REQUEST

ATTACHMENT OPUC 63 b

Attachment OPUC 63 b

Contract ID #	Agreement Description	Effective Date	Expiration Date	Capacity	Purchase / Sale
23	Power Purchase Agreement (QF)	1/1/2004	12/31/2005	75 kW	Purchase
24	Power Purchase Agreement	6/1/2005	9/30/2024	100 MW	Purchase
25	QF Power Purchase Agreement	1/1/2006	12/31/2025	95 MW	Purchase
28	Power Purchase Agreement (QF)	10/14/2004	10/14/2006	511 kW	Purchase
29	Power Purchase Agreement (QF) up to 80 MW's	2/1/2005	12/31/2005	80 MW	Purchase
30	Power Purchase Agreement (QF) up to 1074 MW's	1/1/2006	12/31/2006	107.4 MW	Purchase
33	Purchase of 6% Piece of Priest Rapids (Meaningful Priority)	11/1/2005	12/31/2006	Varies	Purchase
34	Conversion Amendment #2/Conversion of non-firm energy to firm Priest Rapids	11/1/2005	12/31/2025	2 MW	Purchase
35	Power Purchase Agreement (QF) 1,400 kW	1/10/2005	1/9/2025	1.4 MW	Purchase
45	Power Purchase Agreement 95 MW's Reserves	1/1/2005	12/31/2009	95 MW	Purchase
71	QF Photovoltaic Purchase	12/15/2004	12/14/2009	100 kW	Purchase
72	Power Purchase Agreement (QF)	1/1/2004	12/31/2008	75 kW	Purchase
77	QF Purchase	11/30/2005	9/22/2010	150 kW	Purchase
80	Power Purchase Agreement (QF)	9/15/2004	12/31/2005	12 MW	Purchase
108	QF-Biomass Purchase 125 kW	12/14/2004	12/13/2009	125 kW	Purchase
112	Forward Purchase Wind Test Energy 64.5 MW	12/2/2005	12/31/2005	64.5 MW	Purchase
113	Power Purchase Agreement QF	1/1/2006	12/31/2008	1.4 MW	Purchase
114	Power Purchase Agreement QF	1/1/2006	12/31/2008	1.5 MW	Purchase
118	Sales for Re-Sale Agreement	11/1/2004	10/31/2009	37 MW	Sale

UM-1129/PacifiCorp
December 6, 2005
OPUC Data Request 64

OPUC Data Request 64

For each PacifiCorp 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)

Response to OPUC Data Request 64

a. There are no contracts for power sales signed within the past two years for a term of greater than 60 days that have a cap on default losses.

b. Please see Attachment OPUC 63 b

c. Please see Attachment OPUC 63 b

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

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1100

Direct Testimony

<u>Redacted Version</u>

December 9, 2005

CERTAIN INFORMATION CONTAINED IN STAFF EXHIBIT 1100 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.

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. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My updated Witness Qualification Statement is found in Exhibit Staff/1101.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS DOCKET?

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address issues 15, 16, 17, 19 A through C and 20 in the compliance portion of Phase One of this docket.

Q. DID YOU PREPARE EXHIBITS FOR THIS DOCKET?

A. Yes. I prepared Exhibits Staff/1101, consisting of one page, Staff/1102, consisting of four pages, Staff/1103, consisting of four pages, Staff/1104, consisting of three pages, Staff/1105, consisting of eight pages, Staff/1106, consisting of 17 pages, Staff/1107, consisting of one page, Staff/1108, consisting of five pages, and Staff/1109, consisting of two pages.

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Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

1. Determine the reasonableness of Portland General Electric's (PGE) and PacifiCorp's natural gas price forecasts;
2. Determine the appropriate natural gas hubs for PGE and PacifiCorp;
3. Determine the reasonableness of PGE and PacifiCorp on-peak and off-peak avoided costs during their projected resource sufficiency period; and
4. Issues related to the PGE and PacifiCorp proxy units in the avoided cost calculations.

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Findings and Recommendations

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. My findings and recommendations are as follows:

- PGE should either 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.
- PacifiCorp's natural gas forecast is reasonable.
- The forward electricity prices to be used in the resource sufficiency period, for both PacifiCorp and PGE, are reasonable.
- PGE's use of an average of the natural gas hubs Sumas and AECO in avoided cost calculations is appropriate.
- PacifiCorp's use of Currant Creek burner-tip price in avoided cost calculations is appropriate.
- The assumptions regarding PGE and PacifiCorp’s capacity factors for CCCTs are reasonable.
- The assumptions regarding PGE and PacifiCorp’s costs of CCCTs are reasonable.
- Altitude should be factored into avoided costs if altitude causes a utility to incur a cost during plant development or operations.

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<u>Determination of the Reasonableness of PGE and PacifiCorp Natural Gas Price Forecasts</u>

Background for Technical Analyses

Q. ARE THE FILED NATURAL GAS FORECAST PRICES AND SUPPORTING MATERIALS FOR PGE AND PACIFICORP SUITABLE FOR ECONOMETRIC ANALYSIS?

A. No. As I will discuss later in my testimony, neither company provided much more than the forecast price series and, in PGE's case, some narrative explaining the basis for the forecast values.

Q. IN LIEU OF ECONOMETRIC ANALYSIS, HOW DID YOU DETERMINE IF THE NATURAL GAS FORECASTS ARE REASONABLE?

A. I developed three analyses which focus on three aspects of the natural gas forecast price series: 1) how the price for natural gas changes over time; 2) how the forecast prices compare with the natural gas market at the time of the forecast; and 3) how the forecast prices compare with the natural gas market in the years before the time of the forecast.

Q. ARE PRICES FROM ONE PERIOD OF TIME DIRECTLY COMPARABLE TO PRICES FROM ANOTHER PERIOD OF TIME?

A. No. Prices need to be measured relative to the overall price level, which changes over time.

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Q. PLEASE EXPLAIN.

A. For example, in absolute terms, the price of gasoline today is much higher now than it was 15 years ago. In nominal terms, which is the price consumers see, the price of regular gas in the United States was $2.48/gallon in October 2005 compared to $1.33/gallon in October 1990.[1] Relative to the overall price level, however, the increase is much smaller. The U.S. price of regular gasoline for October 1990, relative to the overall price level at that time, was $1.00/gallon. For October 2005, the U.S. Price of regular gasoline, relative to the overall price level of October 2005, was $1.24 a gallon.

Q. HOW IS THE OVERALL PRICE LEVEL DETERMINED?

A. A common method of determining the overall price level is the use of the Consumer Price Index (CPI).[2] The CPI is calculated by the U.S. Bureau of Labor Statistics and is published monthly. The CPI records how the cost of a large market basket of goods purchased by a “typical” consumer in a base year. Percentage changes in the CPI measure the rate of inflation in the economy.[3]

Q. ARE PRICES DIRECTLY COMPARABLE ONCE THEY ARE ADJUSTED BY THE CPI OR ANOTHER MEASURE OF THE OVERALL PRICE LEVEL?

A. Yes. Once a nominal price is adjusted by the CPI or another measure of the overall price level, it is called a “real” price. Real prices from different periods of time are directly comparable to one another.

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[1] Source: Energy Information Administration.
[2] All Consumer Price Index data sourced at www.economagic.com.
[3] Pindyck, R. and D. Rubinfeld (2001). *Microeconomics*, 5th edition.

Q. WHAT PRICES DO THE THREE TECHNICAL ANALYSES USE?

A. The three technical analyses use three prices in order for prices in different periods to be directly comparable.

Q. ARE THE PROCEDURES USED FOR THE TECHNICAL ANALYSIS OF THE NATURAL GAS FORECAST PRICES FOR PGE AND PACIFICORP SIMILAR?

A. Yes. I performed the same technical analysis for both companies.

Q. PLEASE DESCRIBE THE FIRST ANALYSIS.

A. The first analysis performed was the deflation of the monthly forecast values to analyze the level of future prices in March 2005, dollars. This is important, because due to the effects of inflation over time, the nominal, or stated, prices may not represent the actual magnitude of the price in later periods. A "real" price, which has been deflated by an index calculated using the rate of inflation, allows for the comparison of prices over time on a single base period.

Q. WHAT BASE PERIOD WAS SELECTED FOR THE ANALYSIS?

A. For both companies, I selected a base period of March 2005. I chose this base period because it represents the last month of actual data used in the analysis for both companies; all of the data from April 2005, onward is forecast data.

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Q. HOW ARE REAL PRICES CALCULATED IN THIS ANALYSIS?

A. Real prices for each month in the analysis are calculated using the following equation:

$$\text{Real Price} = (\text{Nominal Price}/\text{Index Value}) \times 100$$

Q. HOW IS THE INDEX VALUE CALCULATED?

A. The first step in calculating an index is selecting a base period. As I stated before, the base period for this analysis is March 2005. Numerically, the value 100 is assigned to the base period. The second step is choosing the rate of inflation. Once the rate of inflation is chosen, the following equation is used for each month in sequence:

$$\text{Index}_t = \text{Index}_{t-1} + (\text{Index}_{t-1} \times (\text{Rate of Inflation}/12))$$

Q. WHAT RATES OF INFLATION DID YOU USE IN THE ANALYSIS?

A. I selected the following three annual rates of inflation: base, low, and high.

The base case is represented by the percentage change in the CPI, All Urban Consumers, All Items (Base = 1982 – 84, not seasonally adjusted), from March 2004 to March 2005. This time period corresponds both with the base period for the study and the publication times of PacifiCorp's official forecast and PGE's forecast from CERA that are used in this docket. The resulting rate of inflation used for the base case was 3.1 percent.

The rate of inflation used for the low case is two percent. This number was chosen because it was high enough to be realistically attainable while being significantly lower than the rate used in the base case. In the analysis, the application of the low case (2.0 percent inflation) results in the highest price levels.

The rate of inflation used for the high case is six percent. In the analysis, the application of the high case (6.0 percent inflation) results in the lowest price levels.

Q. PLEASE DESCRIBE THE SECOND ANALYSIS.

A. The purpose of the second analysis was to compare the change in the level of the forecast prices from the beginning to the end of the base period to determine the real price gains or losses over time. This was done through a comparison of the deflated monthly forecast price values to the spot market price for March 31, 2005, for each company's applicable hub, adjusted for monthly seasonality and deflated for the study period.

Monthly seasonality factors for each company's respective hub were calculated using historical data from the Intercontinental Exchange's website[4] for the time period of April 2001 through March 2005.

Q. PLEASE DESCRIBE THE THIRD ANALYSIS.

A. The purpose of the third analysis is to look at the longer-term movements in the magnitude of the forecast natural gas prices through a comparison of the deflated forecast data with deflated historical data available to staff. For each company, the historical comparison period is April 2001 through March 2005.

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[4] www.theice.com.

Q. DOES THE THIRD ANALYSIS HAVE ANY LIMITATIONS?

A. Yes. The third analysis has limited value because of the lack of available historical data prior to April 2001. It would be preferable to have a more symmetrical data set on both sides of March 2005. Unfortunately, the data required in order to accomplish this was not available to staff.

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PGE

General Discussion

Q. PLEASE DESCRIBE THE SOURCE OF PGE'S NATURAL GAS PRICE FORECAST.

A. The source of PGE's natural gas price forecast is CERA, a Cambridge-based energy industry consulting firm.

Q. IS CERA A REASONABLE SOURCE FOR THE FORECAST?

A. Yes. The firm is well-known for its work in the oil and natural gas industries. It is safe to assume that they have put a great deal of thought and work into their forecast product.

Q. WHAT IS THE THEORETICAL BASIS FOR THE FORECAST?

A. The theoretical basis for the forecast is a March 2005 CERA report entitled "Review Mirror." *See* Staff/1106. "Review Mirror" is a narrative that describes CERA's predictions for North American and world energy markets through 2020.

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Q. DOES CERA PROVIDE THE NATURAL GAS FORECAST PRICES FOR PGE?

A. Yes. CERA bases the natural gas forecast prices on the theoretical backdrop of the “Rearview Mirror.”

Q. DOES PGE, THROUGH THE “REARVIEW MIRROR” AND ASSOCIATED PRICE SERIES, INCLUDE MODEL INPUT DATA VALUES, ECONOMETRIC ANALYSES, RESULTS, SENSITIVITY ANALYSES, OR ALTERNATIVE SCENARIOS?

A. No. PGE has only provided staff with the narrative and forecast price streams.

Q, DID STAFF ASK PGE TO SUPPLY ADDITIONAL INFORMATION?

A. Yes. However, because PGE did not create the forecast model, it was unable to provide specific inputs and assumptions.

Q. DOES STAFF HAVE THE DATA NECESSARY TO CONDUCT A ROBUST ECONOMETRIC ANALYSIS ON THE FORECAST MODEL?

A. No. For that reason, staff has developed the three technical analyses in order to determine the reasonableness of PGE’s forecast.

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Technical Analyses

Q. PLEASE DESCRIBE THE APPLICATION OF THE TECHNICAL ANALYSES TO PGE'S NATURAL GAS PRICE FORECAST.

A. I analyzed PGE's natural gas forecast data for the years 2009 through 2020. The current price level was defined as the average of the ICE March 31, 2005, spot prices for Sumas and AECO (March 30, 2005, trading date). The results for each rate of inflation are graphed on Staff/1102, Chriss/1.

Base Inflation Case

Q. PLEASE DESCRIBE THE PRICE RANGE IN THE BASE CASE RESULTS FOR THE FIRST TECHNICAL ANALYSIS.

A. For the base case (3.1 percent annual inflation), prices rise from near $3.00/MMBtu, in real terms, in 2010, to just over $4.00/MMBtu in 2015 before they fall back to $3.00/MMBtu due to an exogenous shock. The prices then rise, this time toward $5.00/MMBtu over the next five years.

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Q. PLEASE COMPARE THE AVERAGED REAL FORECAST PRICE TO THE DEFLATED CURRENT PRICE LEVEL.

A. When the second technical analysis is performed on the base case, it becomes apparent that, even though the real prices of the forecast are increasing, they are considerably lower than the deflated current price level. *See* Staff/1102, Chriss/2. The averaged real price of natural gas for the PGE forecast under the base case is $3.84/MMBtu, while the averaged real price of the trended current price level is $4.82/MMBtu. This price differential occurs when the forecast real price is increasing over the time period, as it indicates that the forecast is too low and does not match the natural gas price in March 2005.

Q. PLEASE COMPARE THE AVERAGED REAL FORECAST PRICE TO THE AVERAGED REAL PRICE FOR APRIL 2001 THROUGH MARCH 2005.

A. The averaged real price for April 2001 through March 2005 was $4.32, while the averaged real price for the forecast is $3.84/MMBtu. It is questionable whether the actual real price of natural gas would decrease between the periods before and after March 2005.

Low Inflation Case

Q. PLEASE DESCRIBE THE PRICE RANGE IN THE LOW CASE (2.0 PERCENT) RESULTS.

A. For the low inflation case (2.0 percent annual inflation), prices rise from near $3.00/MMBtu, in real terms, in 2010, to just over $5.00/MMBtu in 2015 before returning back to $3.00/MMBtu once again. After the shock, prices again rise, this time to $6.00/MMBtu.

Q. PLEASE COMPARE THE AVERAGED REAL FORECAST PRICE TO THE DEFLATED CURRENT PRICE LEVEL.

A. The real forecast prices fail to match a fixing of the March 2005 price. *See* Staff/1102, Chriss/3. The averaged real price of natural gas for the PGE forecast under the low case is $4.32/MMBtu, while the averaged real price of the trended current price level is $5.37/MMBtu.

Q. PLEASE COMPARE THE AVERAGED REAL FORECAST PRICE TO THE AVERAGED REAL PRICE FOR APRIL 2001 THROUGH MARCH 2005.

A. The averaged real price for April 2001 through March 2005 was $4.24, while the averaged real price for the forecast is $4.32/MMBtu.

High Inflation Case

Q. PLEASE DESCRIBE THE PRICE RANGE IN THE HIGH CASE RESULTS.

A. For the high inflation case (6.0 percent annual inflation), the real price of natural gas remains relatively steady around $3.00/MMBtu until 2015. After 2015, the real price drops to around $2.00/MMBtu before slowly returning to $3.00/MMBtu.

Q. PLEASE COMPARE THE AVERAGED REAL FORECAST PRICE TO THE DEFLATED CURRENT PRICE LEVEL.

A. Again, the real forecast prices fail to match a fixing of the March 2005 price. The averaged real price of natural gas for the PGE forecast under the high case is $2.91/MMBtu, while the averaged real price of the trended current price level is $3.71/MMBtu. *See* Staff/1102, Chriss/4.

Q. PLEASE COMPARE THE AVERAGED REAL FORECAST PRICE TO THE AVERAGED REAL PRICE FOR APRIL 2001 THROUGH MARCH 2005.

A. The averaged real price for April 2001 through March 2005 was $4.54/MMBtu, while the averaged real price for the forecast is $2.91/MMBtu.

Conclusion

Q. BASED ON YOUR TECHNICAL ANALYSES, IS PGE'S NATURAL GAS PRICE FORECAST REASONABLE?

A. No. When compared to real prices before the base period as well as the current price for the base period, PGE's natural gas price forecast is not reasonable.

Q. PLEASE EXPLAIN.

While staff does not advocate a parity standard, a long-term equivalence between the real forecast prices and a price fixed in March 2005 appears to be more reasonable than a particularly low forecast.

Utility customers would benefit under a particularly low forecast, but it is important to remember that low or high, avoided cost rates need to be calculated correctly and accurately represent the cost being avoided. Using PGE's submitted forecast is questionable at best.

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Q. WAS STAFF ABLE TO FULLY EVALUATE WHAT FACTORS ARE AFFECTING THE FORECAST'S PERFORMANCE AND SUGGEST CHANGES OR IMPROVEMENTS?

A. No. Staff did not have access to quantitative model inputs and assumptions and cannot provide any analysis or recommendations as to factors that could improve the forecast's performance. PGE was not able to furnish this data at staff's request, because PGE does not have this data, as the model was created by CERA.

Q. WHAT COURSE OF ACTION DOES STAFF RECOMMEND?

A. Staff recommends that PGE either 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.

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PacifiCorp

General Discussion

Q. WHAT IS THE SOURCE OF THE NATURAL GAS FORECAST CHOSEN BY PACIFICORP FOR ITS AVOIDED COST RATES?

A. PacifiCorp uses a long-term natural gas forecast provided by PIRA, a New York City-based energy industry consulting firm.

Q. IS PIRA A REASONABLE SOURCE FOR THE FORECAST?

A. Yes. The firm is well-known for its work in the energy industry. It is safe to assume that they have put a great deal of thought and work into their forecast product.

Q. DID PACIFICORP PROVIDE ANY SPECIFIC INPUTS AND ASSUMPTIONS FOR THE FORECASTS?

A. No. PacifiCorp, in response to a staff data request, stated that because the Company does not produce the forecast, it has no specific inputs or assumptions for the forecast. Additionally, the Company has no specific methodology used to prepare the forecasts. *See* Staff/1109, Chriss/1-2.

Q. DOES STAFF HAVE THE DATA NECESSARY TO CONDUCT A ROBUST ECONOMETRIC ANALYSIS ON THE FORECAST MODEL?

A. No. For that reason, staff has developed the three technical analyses in order to determine the reasonableness of PacifiCorp's forecast.

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Technical Analyses

Q. PLEASE DESCRIBE THE APPLICATION OF THE TECHNICAL ANALYSES TO PACIFICORP'S NATURAL GAS PRICE FORECAST.

A. PacifiCorp's natural gas forecast data was analyzed for the years 2010 through 2028. The current price level was defined as the ICE March 31, 2005, spot price for Opal (March 30, 2005, trading date). The results for each rate of inflation are graphed on Staff/1103, Chriss/1.

Base Inflation Case

Q. PLEASE DESCRIBE THE PRICE RANGE IN THE BASE CASE RESULTS FOR THE FIRST TECHNICAL ANALYSIS.

A. For the base case (3.1 percent annual inflation), after an initial upswing in prices through 2013, the real price of natural gas declines over time, however, the rate of decline is very slow. For the majority of the time period, annual peak natural gas prices are either just above or just below $5.00/MMBtu in March 2005 dollars, and non-peak prices range between $4.00/MMBtu and $5.00/MMBtu.

Q. PLEASE COMPARE THE AVERAGED REAL FORECAST PRICE TO THE DEFLATED CURRENT PRICE LEVEL.

A. When the second technical analysis is performed on the base case, it becomes apparent that, even though the real prices of the forecast are declining, they are considerably higher than the deflated current price level. This is especially evident towards the end of the study period. *See*

Staff/1103, Chriss/2. For instance, for January 2028 there is a $1.50/MMBtu difference in the real forecast price and the deflated current price. The averaged real price of natural gas for the PacifiCorp forecast under the base case is $4.63/MMBtu, while the real averaged price of the trended current price level is $4.24/MMBtu.

Q. PLEASE COMPARE THE AVERAGED REAL FORECAST PRICE TO THE AVERAGED REAL PRICE FOR APRIL 2001 THROUGH MARCH 2005.

A. No. The averaged real price for April 2001 through March 2005 was $3.93/MMBtu, while the averaged real price for the forecast is $4.63/MMBtu.

Low Inflation Case

Q. PLEASE DESCRIBE THE PRICE RANGE IN THE LOW CASE RESULTS.

A. For the low inflation case (2.0 percent annual inflation), after an initial price upswing in prices through 2013, the real price of natural gas declines slightly before slowly rising for the rest of the study period. For the majority of the study period, the real annual peak price is at or above $6.00/MMBtu, and the non-peak price starts near $5.00/MMBtu and rises towards $5.50/MMBtu over time.

Q. WHY DOES THE PRICE RISE OVER TIME IN THE LOW CASE?

A. The price rises over time because increases in the nominal price outpace the rate of inflation.

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Q. PLEASE COMPARE THE AVERAGED REAL FORECAST PRICE TO THE DEFLATED CURRENT PRICE LEVEL.

A. The real forecast prices are lower than the trended prices for the first few years of the time period, but by 2015, the real forecast prices are rising while the trended prices continue downward. *See* Staff/1103, Chriss/3. The averaged real price of natural gas for the PacifiCorp forecast under the low case is $5.46/MMBtu, while the averaged real price of the trended current price level is $4.95/MMBtu.

Q. PLEASE COMPARE THE AVERAGED REAL FORECAST PRICE TO THE AVERAGED REAL PRICE FOR APRIL 2001 THROUGH MARCH 2005.

A. The average real price for April 2001 through March 2005 was $3.86/MMbtu, while the average real price for the forecast is $5.46/MMBtu.

High Inflation Case

Q. PLEASE DESCRIBE THE PRICE RANGE IN THE HIGH CASE RESULTS.

A. For the high inflation case (6.0 percent annual inflation), the real price of natural gas shows a brief increase in the first few years of the time period, but declines over the remainder of the study period. The real price begins the time period near $4.00/MMBtu and ends the time period near $2.00/MMBtu.

Q. PLEASE COMPARE THE AVERAGED REAL FORECAST PRICE TO THE DEFLATED CURRENT PRICE LEVEL.

A. The trended current price level begins the time period above the real forecast prices. However, by 2018 the real forecast prices begin to decline at a slower rate than the trended current price. *See* Staff/1103, Chriss/4. The averaged real price of natural gas for the PacifiCorp forecast is $3.13/MMBtu, while the averaged real price of the trended current price level is $2.94/MMBtu.

Q. PLEASE COMPARE THE AVERAGED REAL FORECAST PRICE TO THE AVERAGED REAL PRICE FOR APRIL 2001 THROUGH MARCH 2005.

A. The averaged real price for April 2001 through March 2005 was $3.13/MMBtu, while the averaged real price for the forecast is $4.11/MMBtu.

Conclusion

Q. BASED ON THE RESULTS OF YOUR TECHNICAL ANALYSES, WHAT DO YOU CONCLUDE ABOUT PACIFICORP'S NATURAL GAS PRICE FORECAST?

A. When compared to real prices before the base period as well as the current price for the base period, I conclude PacifiCorp's natural gas price forecast is reasonable.

Q. PLEASE EXPLAIN.

A. The forecast provides a conservative long term appraisal of where natural gas prices may or may not be headed. When comparing a price current as of the time of filing to a future price, the forecast seems fairly realistic. Events in late 2005, such as Hurricanes Katrina and Rita, showed that the United States' natural gas market is susceptible to large shocks. However, we do not yet know if these shocks will result in a large sustained price increase over time. A good example is the price trough that occurred after the high prices of

2000-2001, when nominal prices dropped from upwards of $4.00/MMBtu to almost $1.00/MMBtu.

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Determination of the Appropriate Natural Gas Hubs for PGE and PacifiCorp

PGE

Q. WHAT RESOURCE SERVES AS PGE'S AVOIDED RESOURCE?

A. PGE does not currently have a designated avoided resource.[5]

Q. GIVEN THAT PGE DOES NOT CURRENTLY HAVE A DESIGNATED AVOIDED RESOURCE, WHAT IS THE APPROPRIATE NATURAL GAS HUB FOR USE IN THIS DOCKET?

A. PGE's choices appear reasonable. PGE uses the average of Sumas, which would be the applicable hub if PGE were to build the avoided resource west of the Cascades, and AECO, which would be the applicable hub if PGE were to build the avoided resource east of the Cascades. The averaged price represents a reasonable compromise because the location of the avoided resource is unknown.

PacifiCorp

Q. WHAT RESOURCE SERVES AS PACIFICORP'S AVOIDED RESOURCE?

A. The second unit at the Current Creek plant serves as PacifiCorp's avoided resource.

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[5] Telephone conversation with Ted Drennan, PGE, December 1, 2005.

Q. WHAT IS THE APPROPRIATE NATURAL GAS HUB FOR USE IN THIS DOCKET?

A. The appropriate natural gas hub for use in this docket is the burner tip price at Currant Creek. As I will discuss later in my testimony, PacifiCorp has submitted revisions to its calculation of the natural gas forecast prices to be used in its filing. These revisions reflect a change to prices that represent the burner tip price at Current Creek.

Q. IS CURRANT CREEK A TRANSPARENT MARKET HUB WITH DATA AVAILABLE TO ALL PARTIES FOR ANALYSIS?

A. No. Instead, PacifiCorp has defined the burner tip price for Currant Creek as the sum of the Opal commodity price plus the average of the bid and offer price differential. Essentially, the Currant Creek price is the Opal price plus the basis differential between Opal and Currant Creek. An example calculation is included in Staff/1108.

Q. IS THE METHODOLOGY FOR CALCULATING THE CURRANT CREEK BURNER-TIP PRICE REASONABLE?

A. Yes.

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<u>Determination of the Reasonableness of PGE and PacifiCorp On-peak and Off-peak Avoided Costs During Their Projected Resource Sufficiency Period</u>

Q. HOW HAS THE COMMISSION DETERMINED THAT AVOIDED COSTS SHOULD BE VALUED DURING PERIODS OF RESOURCE SUFFICIENCY?

A. The Commission has determined that avoided costs, during periods of resource sufficiency, should be valued at the monthly on-peak and off-peak forward market prices as of the utility's avoided cost filing.[6]

PGE

Q. WHAT IS THE DATE OF THE FORWARD PRICES USED FOR PGE'S FILED ON-PEAK AND OFF-PEAK PRICES?

A. PGE used the on-peak and off-peak forecasts for Mid-C from July 6, 2005. The forecasts are included in Staff/1104.

Q. DO THE FORWARD PRICES DIFFER FROM THE PRICES LISTED IN THE TARIFF?

A. Yes. This difference is that the tariff prices include the wheeling adjustment to get Mid-C energy to PGE's service territory.

Q. HOW DID STAFF ANALYZE PGE'S FORWARD PRICES?

A. Staff utilized two analyses to determine the reasonableness of on-peak and off-peak forward prices.

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[6] See Order No. 05-584 at 28.

Q. PLEASE DESCRIBE THE FIRST ANALYSIS.

A. The forward prices submitted in the filing were compared to forward price curves from two weeks before and two weeks after the date of the submitted prices. The curves for comparison were submitted by PGE at Staff's request. The source of the curves was the same as the submitted forward price curve. This analysis was done to check the internal validity of the forward prices, thus ensuring that the company did not pick a particular date in order to ensure disproportionately high or low prices.

Q. PLEASE DESCRIBE THE RANGE AGAINST WHICH THE FORWARD PRICES WILL BE COMPARED.

A. The range was constructed around the average of the two weeks before and after the date of the forward price curve PGE used in its avoided cost filing. Once the average was calculated for each month in the analysis, the standard deviation was calculated. The upper and lower bounds of the range were calculated as the average plus two standard deviations, and the average minus two standard deviations, respectively.

Q. WHAT IS YOUR CONCLUSION FROM THIS ANALYSIS?

A. For the on-peak period, I found that the submitted forward prices all fell within the range used in the analysis, and most values were in the upper half of the range. *See* Staff/1104, Chriss/1.

For the off-peak period, I found that the submitted forward prices all fell within the range used in the analysis, and most values were close to the average. *See* Staff/1104, Chriss/2.

Q. PLEASE DESCRIBE THE SECOND ANALYSIS.

A. The second analysis compared the submitted forward prices to a forward price curve constructed from the Energy Market Report (EMR) of the same day as PGE's data. This analysis was done to check the external validity of PGE's forward prices, ensuring that the submitted prices are consistent with available market price reports.

The results of the analysis for the on-peak period show that if a QF were to sell one aMW from August 2005 through December 2009, there would only be a $40 difference between PGE's forward prices and the EMR for the entire time period. *See* Staff/1104, Chriss/3. On a per MWh basis for the time period, this is less than one dollar per MWh.

The difference is slightly larger when the off-peak period is considered, but the difference is still quite small. *See* Staff/1104, Chriss/3.

Q. BASED ON THE ABOVE EVIDENCE, DOES STAFF BELIEVE THAT PGE'S FORWARD PRICES ARE REASONABLE?

A. Yes.

PacifiCorp

Q. WHAT IS THE DATE OF THE FORWARD PRICES USED FOR PACIFICORP'S FILED ON-PEAK AND OFF-PEAK PRICES?

A. PacifiCorp used prices dated March 31, 2005, which is the date of its most recent official forecast prior to the Company's avoided cost filing. PacifiCorp provided forward price curves for the Mid-C, California-Oregon Border (COB), and Palo Verde (PV) hubs.

Q. WHAT DOES THE FILED FORWARD PRICE CURVE REPRESENT?

A. The filed forward price curve represents a mix of the three hubs that PacifiCorp uses in their forecast. There are no additional charges or price components included in the filed forward prices.

Q. HOW DID STAFF ANALYZE PACIFICORP'S FORWARD PRICES?

A. Staff used the same two analyses as were used for the PGE forward prices.

Q. PLEASE DESCRIBE THE FIRST ANALYSIS.

A. The forward prices submitted in PacifiCorp's filing were compared to PacifiCorp's forward price curves from two weeks before and two weeks after the date of the submitted prices. PacifiCorp submitted the averages of the four weeks in question in lieu of individual daily curves. The analysis was performed on each individual hub used by the company. This analysis was done to check the internal validity of the forward prices, thus ensuring that the company did not pick a particular date in order to ensure disproportionately high or low prices.

Q. PLEASE DESCRIBE THE RANGE AGAINST WHICH THE FORWARD PRICES WILL BE COMPARED.

A. The range was constructed around the average of the two weeks before and after PacifiCorp's filed forward price curve. In addition to submitting the average for each month in the analysis, PacifiCorp also submitted the standard deviation. The upper and lower bounds of the range are the average plus two standard deviations, and the average minus two standard deviations, respectively.

Q. WHAT IS YOUR CONCLUSION FROM THIS ANALYSIS?

A. For the on-peak period, I found that the submitted forward prices for COB all fell within the range used in the analysis. In the earlier years, the submitted forward prices tend to be towards the upper end of the range, and in the later years the prices more closely follow the average. *See* Staff/1105, Chriss/1. The result was similar for PacifiCorp's submitted on-peak Mid-C forward prices. *See* Staff/1105, Chriss/3. For Palo Verde, the submitted on-peak forward prices all fell within the range used in the analysis, but all values were above the average. *See* Staff/1105, Chriss/5.

For the off-peak period, I found that the submitted forward prices for COB all fell within the range used in the analysis, and the values fell both above and below the average. *See* Staff/1105, Chriss/2. The result was similar for the submitted Palo Verde off-peak forward prices. *See* Staff/1105, Chriss/6. For the submitted Mid-C off-peak forward prices, all of the prices fell within the range used in the analysis, but most values were above the average. *See* Staff/1105, Chriss/4.

Q. PLEASE DESCRIBE THE SECOND ANALYSIS.

A. The second analysis compared the submitted forward prices to a forward price curve constructed from the Energy Market Report (EMR) as of the same day as PacifiCorp's projection. In PacifiCorp's case, the EMR data used was from March 31, 2005 (trading date March 30, 2005), in order to have April

2005 data available. This analysis was done to check the external validity of PacifiCorp's forward prices, ensuring that they are consistent with other available market price reports.

The results of the analysis for Mid-C during the on-peak period show that if a QF were to sell one aMW from August 2005 through December 2009, there would only be a $28.61 difference between PacifiCorp's forward prices and the EMR. *See* Staff/1105, Chriss/7, columns (1) and (2). On a per MWh basis for the time period, this is only fifty cents per MWh.

The difference is larger when the off-peak period is considered, but the difference is still small. *See* Staff/1105, Chriss/7, columns (3) and (4).

The results of the analysis for Palo Verde during the on-peak period () show that if a QF were to sell one aMW from August 2005 through December 2009, there would only be a $67.58 difference between PacifiCorp's forward prices and the EMR. *See* Staff/1105, Chriss/8, columns (1) and (2). On a per MW basis for the time period, this is slightly over one dollar per MW.

The difference is smaller when the off-peak period is considered, and the difference is minimal given the amount of money and length of time involved in the analysis. *See* Staff/1105, Chriss/8, columns (3) and (4).

Q. BASED ON THE ABOVE EVIDENCE, DOES STAFF BELIEVE THAT PACIFICORP'S FORWARD PRICES ARE REASONABLE?

A. Yes.

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Issues Related to the PGE and PacifiCorp Proxy Units in the Avoided Cost Calculations

Q. ARE THE ASSUMPTIONS REGARDING THE CAPACITY FACTORS FOR COMBINED CYCLE COMBUSTION TURBINES (CCCTS) REASONABLE?

A. Yes. The assumptions regarding the capacity factors for CCCTs for PGE are drawn from its Commission-acknowledged Integrated Resource Plan (IRP). The assumptions regarding the capacity factors for CCCTs for PacifiCorp are drawn from its 2004 IRP,[7] which has not yet been acknowledged by the Commission. However, in its recommendations, staff did not oppose PacifiCorp's estimated CCCT capacity factors.

Q. ARE THE ASSUMPTIONS FOR THE COSTS OF CCCTS REASONABLE AND CONSISTENT WITH OTHER PLANNING ASSUMPTIONS?

A. Yes. The assumptions regarding the costs of CCCTs for PGE are drawn from its Commission-acknowledged IRP.[8] The assumptions regarding the capacity factors for CCCTs for PacifiCorp are drawn from its 2004 IRP,[9] which has not yet been acknowledged by the Commission. However, in its recommendations, staff did not oppose PacifiCorp's proposed CCCT costs.

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[7] See PacifiCorp's Technical Appendix for the 2004 Integrated Resource Plan, Appendix C, page 67.
[8] See PGE's 2002 IRP, Appendix O, page 212.

Q. SHOULD THE ALTITUDE OF NEW RESOURCE LOCATIONS BE CONSIDERED IN DEVELOPING AVOIDED COSTS?

A. Yes. If altitude causes a utility to incur a cost during plant development or operations, then altitude should be factored in to avoided costs.

Q. HAS STAFF IDENTIFIED ANY OTHER ISSUES IN THE CALCULATION OF AVOIDED COST RATES FOR EITHER PACIFICORP OR PGE?

A. Yes. The transportation and distribution cost adjustments built into PacifiCorp's natural gas prices are outdated. *See* Staff/1107 and Staff/1108, Chriss/1-4. Investigation into the transportation and distribution costs revealed that PacifiCorp had no work papers or other documentation in support of the transportation and distribution adjustments.

Q. HAS PACIFICORP PROPOSED NEW TRANSPORTATION AND DISTRIBUTION ADJUSTMENTS?

A. Yes. Going forward, PacifiCorp will use the Current Creek burner-tip gas price. The March 2005 Official Market Price Projection does not include prices at Currant Creek, so PacifiCorp submitted an updated natural gas forecast which reflects the change in methodology. *See* Staff/1108, Chriss/5.

Q. HOW HAVE THE FORECAST RESULTS CHANGED?

A. The forecast prices now represent the Opal forecast plus the differential between Opal and Current Creek. The Opal forecast itself has not changed.

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[9] See PacifiCorp's Technical Appendix for the 2004 Integrated Resource Plan, Appendix C, pages 65

Q. IS THIS CHANGE APPROPRIATE?

A. Yes. If PacifiCorp, because they know the location of the avoided resource, is able to more accurately calculate the costs that they will avoid, it is appropriate to implement the change. Additionally, staff supports the change because PacifiCorp has documentation available supporting the new calculations, whereas no documentation exists for the previous transportation and documentation costs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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and 67.

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

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 1101

Witness Qualification Statement

December 9, 2005

WITNESS QUALIFICATIONS STATEMENT

NAME:	STEVE W. CHRISS
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	ECONOMIST
ADDRESS:	550 CAPITOL ST. NE, SUITE 215, SALEM, OR 97310-1380
EDUCATION:	Masters of Science degree, Agricultural Economics, from Louisiana State University (2001). Bachelor of Science degree, Agricultural Development, from Texas A&M University (1997). Bachelor of Science degree, Horticulture, from Texas A&M University (1997).
EXPERIENCE:	Employed with the Oregon Public Utility Commission as Economist in the Economic Research and Financial Analysis Division since June, 2003. Previously submitted testimony as the lead witness in Oregon docket UX 29 and as a supporting witness in Oregon docket UM 1129. Employed as an Analyst and Senior Analyst at the Houston office of Econ One Research, Inc., a Los Angeles-based economic and regulatory consulting firm, between 2001 and 2003. Worked on regulatory and market issues in electricity, natural gas, and oil in both domestic and international markets. Employed by North Harris College in Houston as an adjunct microeconomics instructor from January through May 2003.

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

PUBLIC UTILITY COMMISSION
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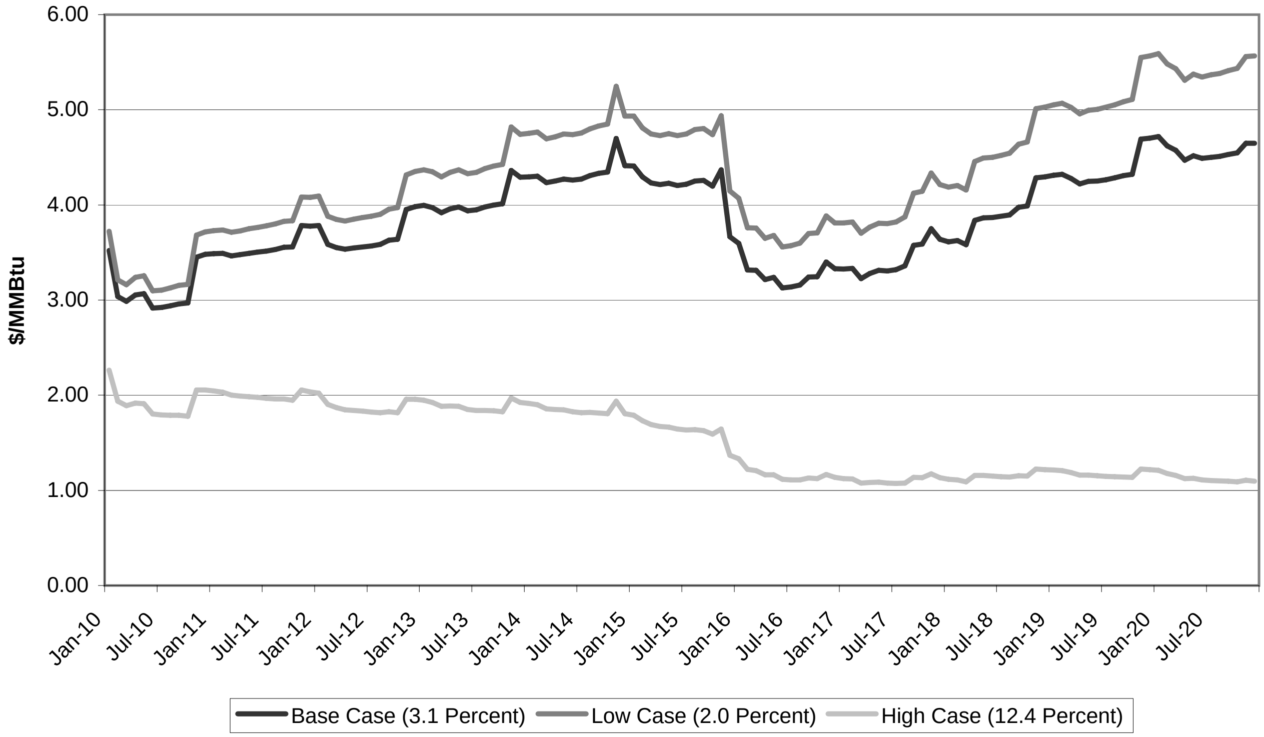
STAFF EXHIBIT 1102

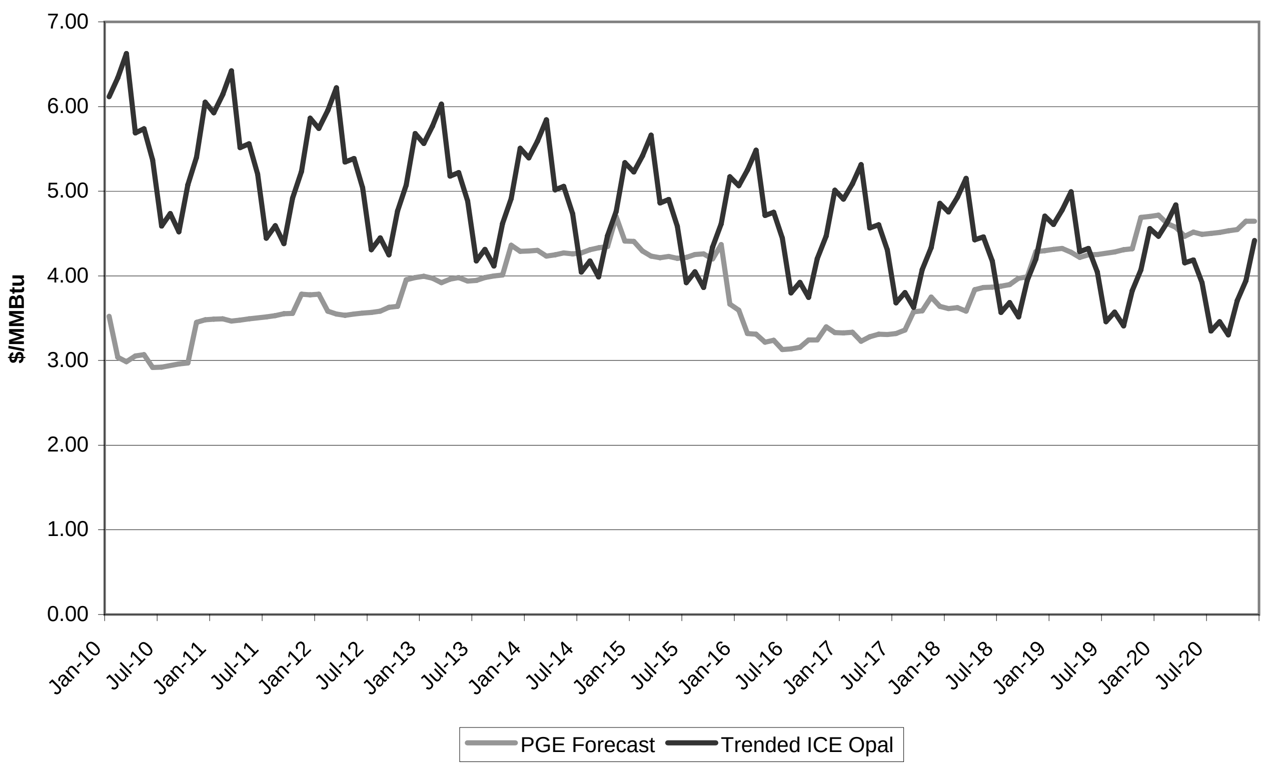
Exhibits in Support of Direct Testimony

December 9, 2005

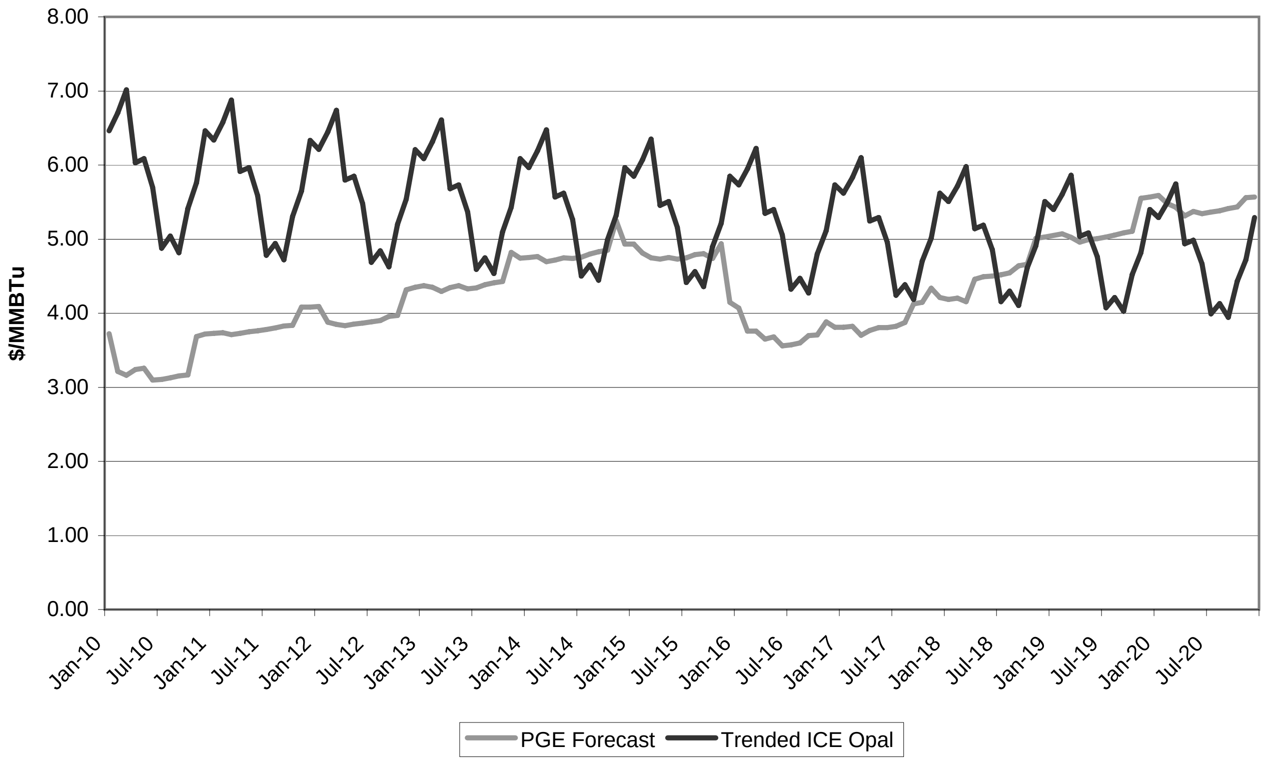
PGE AECO/Sumas Forecast Average in March, 2005, Dollars For Three Levels of Inflation, January 2010 through December 2028.



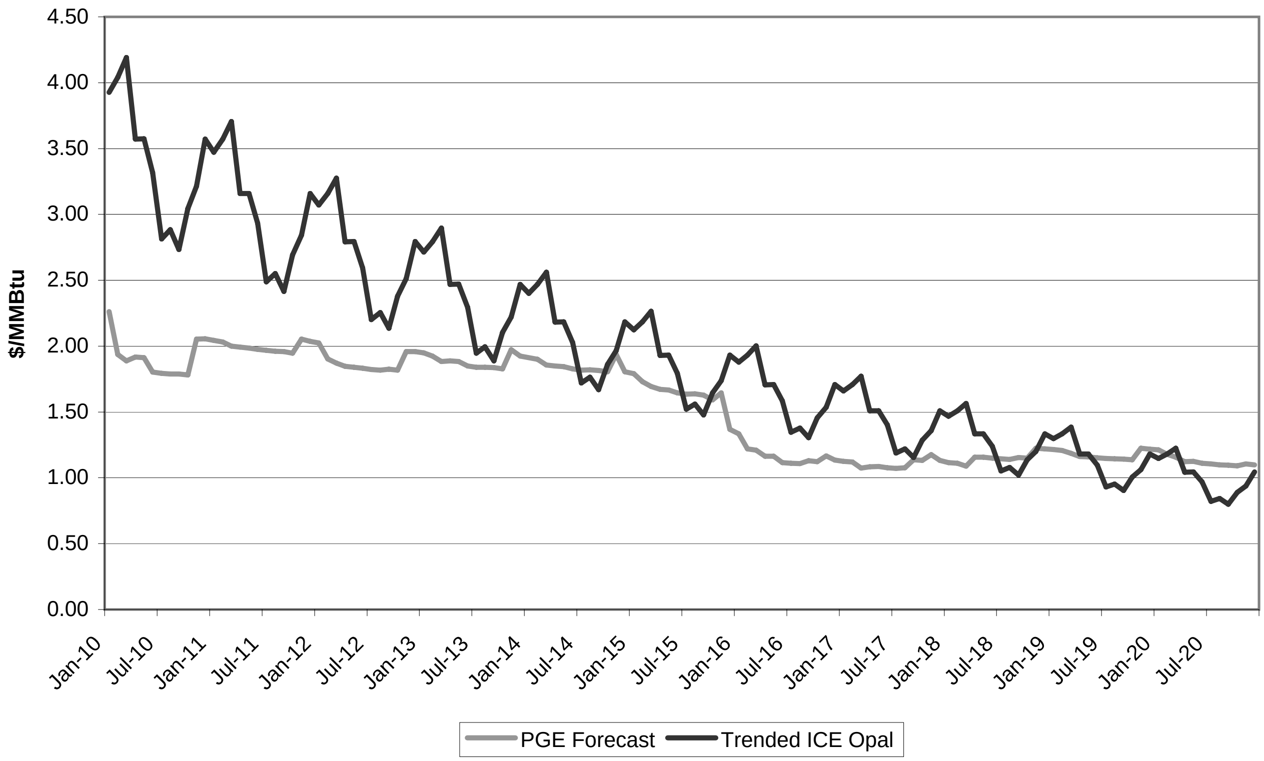
PGE Forecast vs. Trended ICE AECO/Sumas Average Spot Price for March 31, 2005, Base Case, $/MMBtu in March 2005 Dollars.



PGE Forecast vs. Trended ICE AECO/Sumas Average Spot Price for March 31, 2005, Low Case, $/MMBtu in March 2005 Dollars.



PGE Forecast vs. Trended ICE AECO/Sumas Average Spot Price for March 31, 2005, High Case, $/MMBtu in March 2005 Dollars.



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

PUBLIC UTILITY COMMISSION
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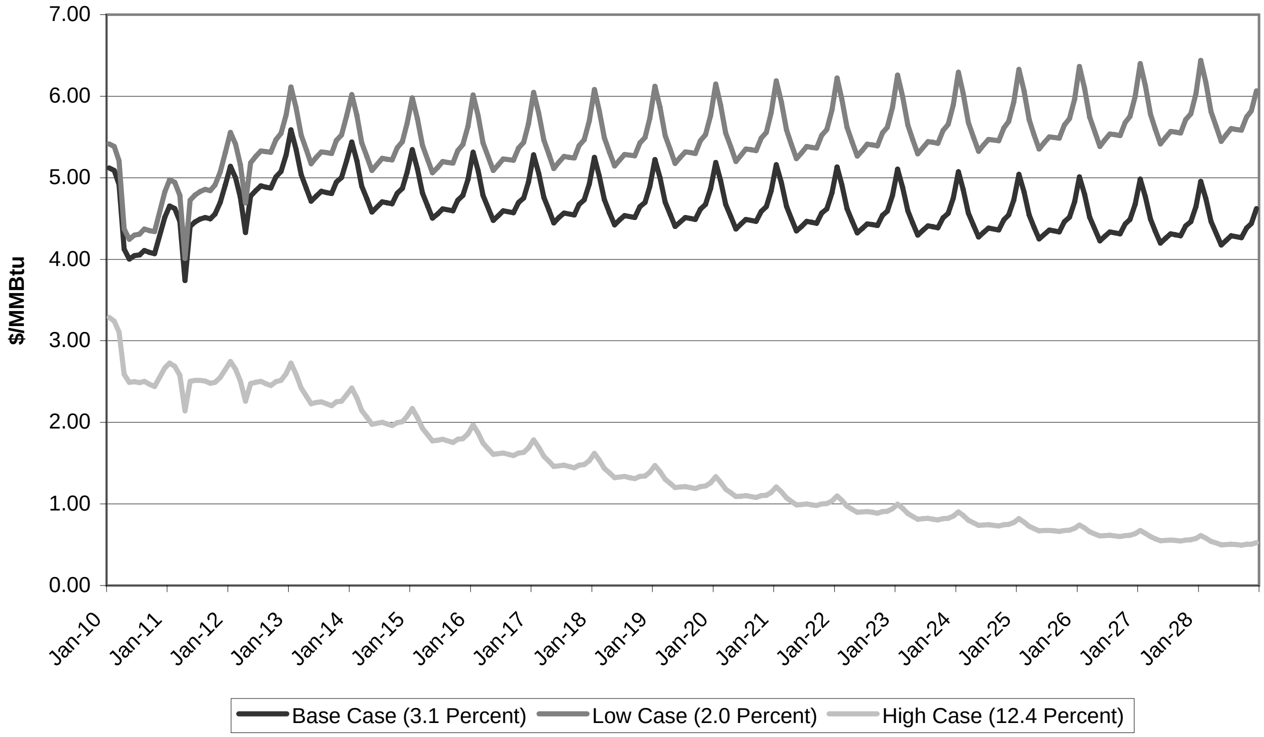
STAFF EXHIBIT 1103

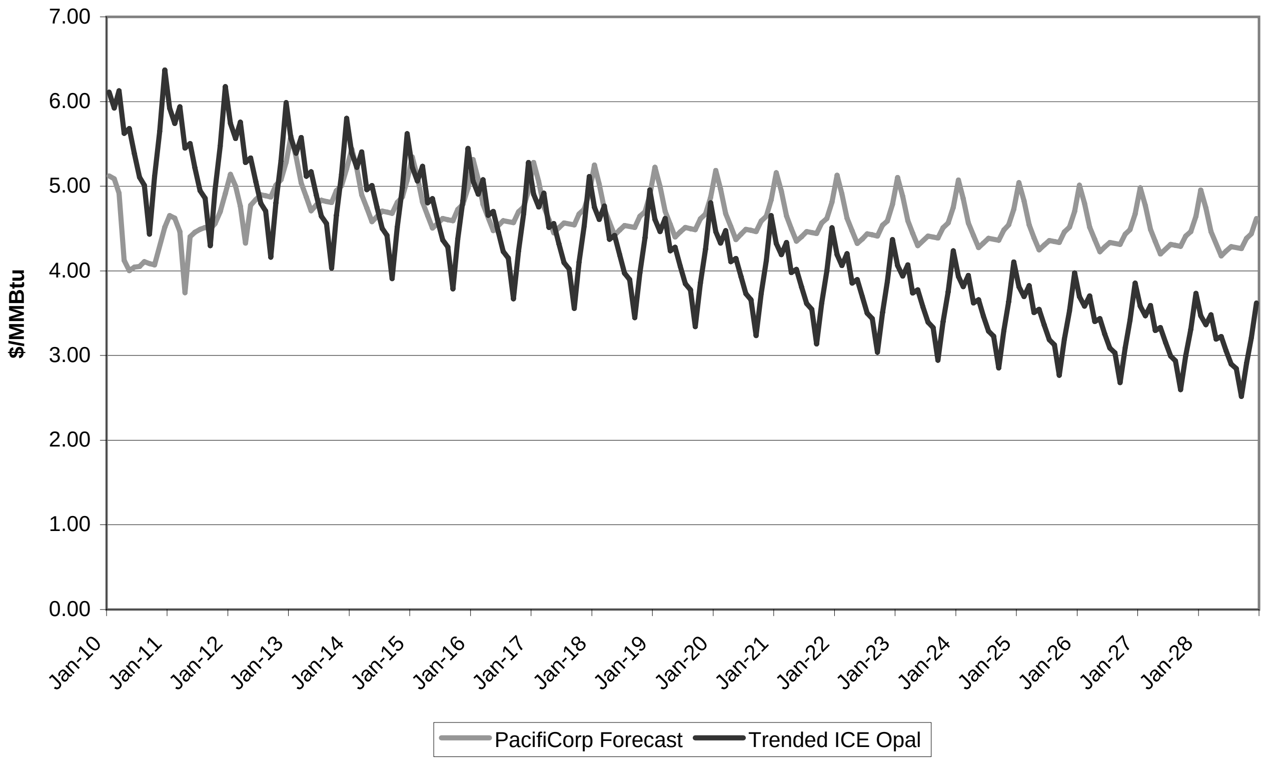
Exhibits in Support of Direct Testimony

December 9, 2005

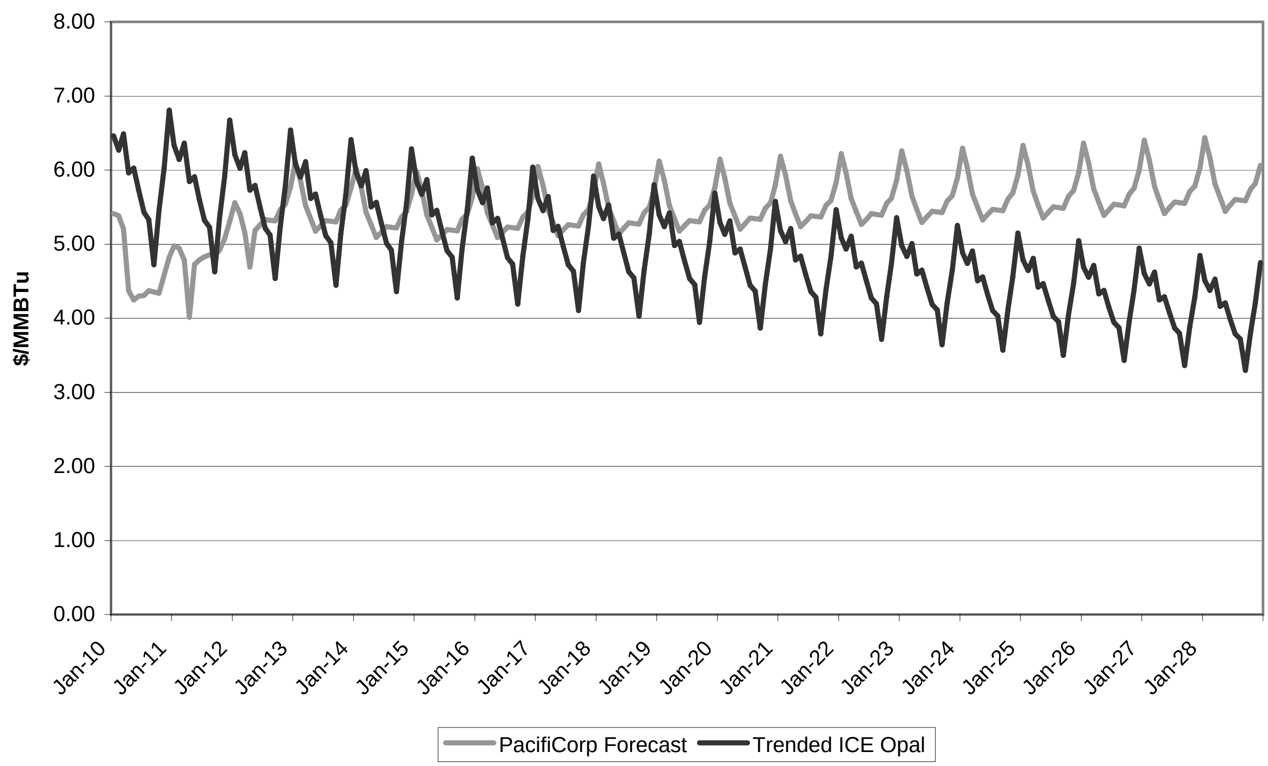
PacifiCorp Opal Forecast in March, 2005, Dollars For Three Levels of Inflation, January 2010 through December 2028.



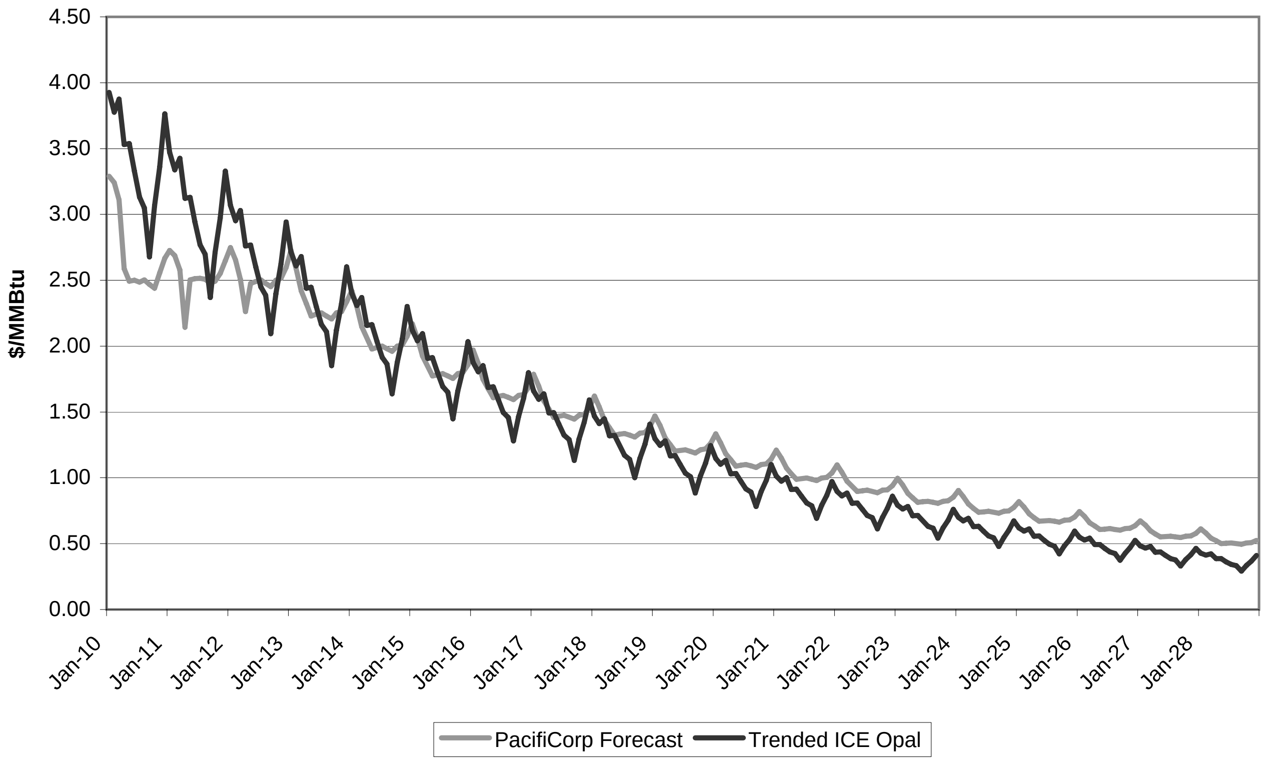
PacifiCorp Forecast vs. Trended ICE Opal Spot Price for March 31, 2005, Base Case, $/MMBtu in March 2005 Dollars.



PacifiCorp Forecast vs. Trended ICE Opal Spot Price for March 31, 2005, Low Case, $/MMBtu in March 2005 Dollars.



PacifiCorp Forecast vs. Trended ICE Opal Spot Price for March 31, 2005, High Case, $/MMBtu in March 2005 Dollars.



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

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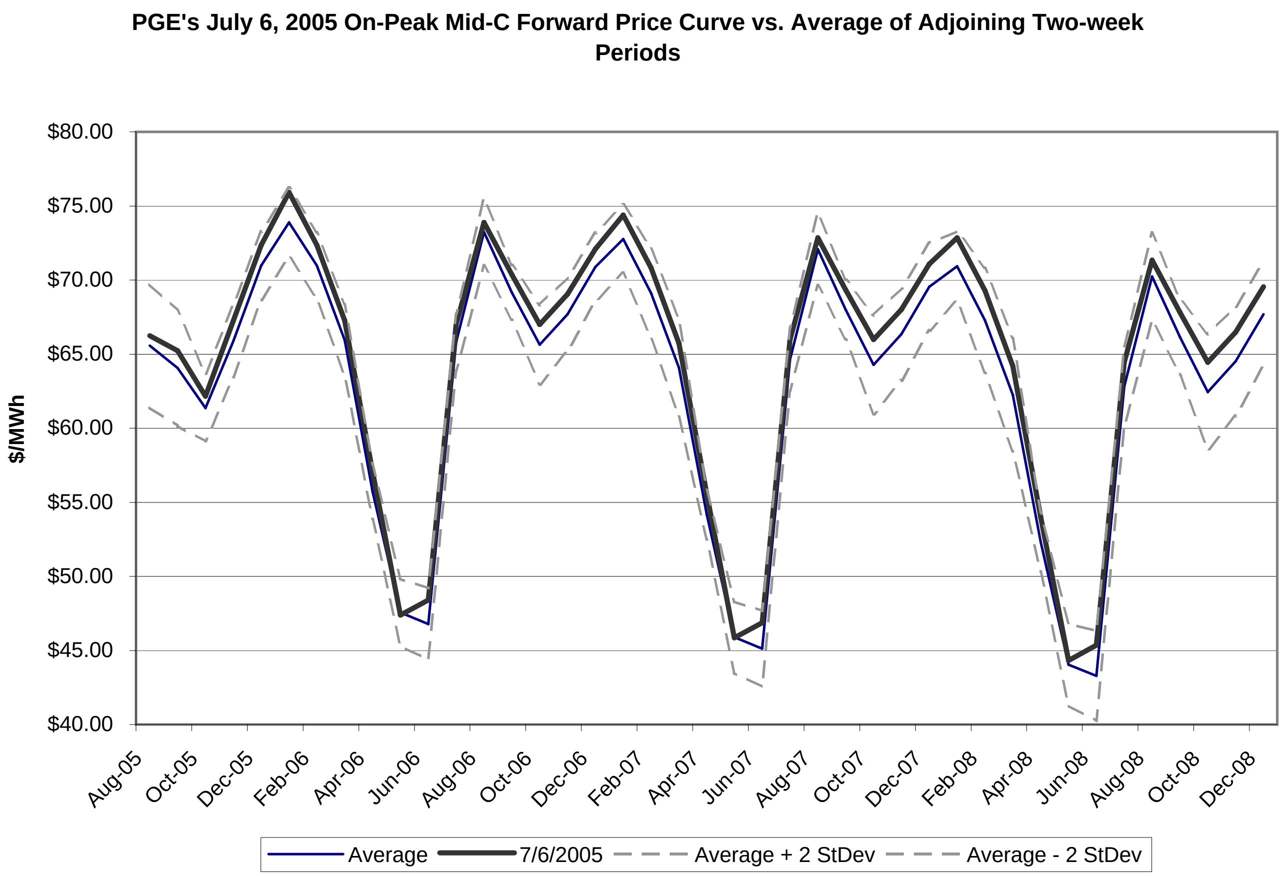
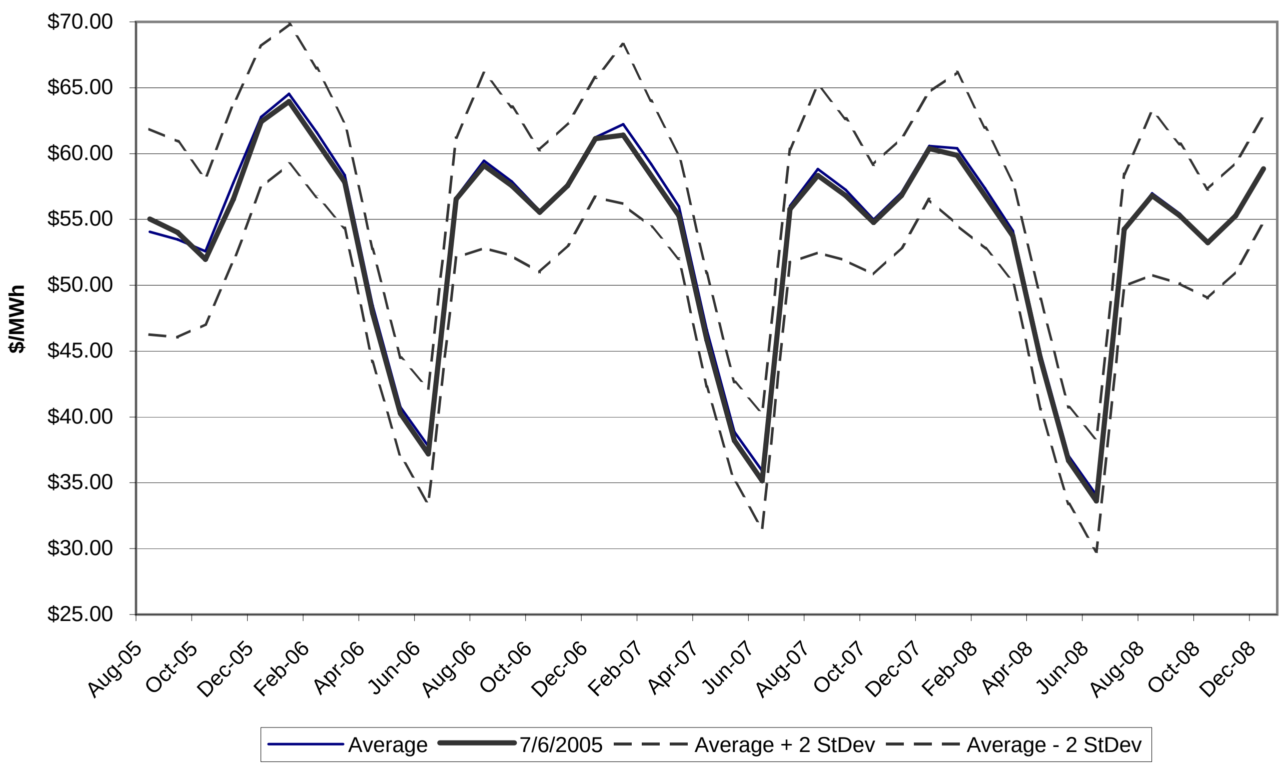
STAFF EXHIBIT 1104

Exhibits in Support of Direct Testimony

December 9, 2005


PGE's July 6, 2005 On-Peak Mid-C Forward Price Curve vs. Average of Adjoining Two-week Periods
$/MWh
$80.00
$75.00
$70.00
$65.00
$60.00
$55.00
$50.00
$45.00
$40.00
Aug-05
Oct-05
Dec-05
Feb-06
Apr-06
Jun-06
Aug-06
Oct-06
Dec-06
Feb-07
Apr-07
Jun-07
Aug-07
Oct-07
Dec-07
Feb-08
Apr-08
Jun-08
Aug-08
Oct-08
Dec-08
Average
7/6/2005
Average + 2 StDev
Average - 2 StDev

PGE's July 6, 2005 Off-Peak Mid-C Forward Price Curve vs. Average of Adjoining Two-week Periods



PGE's Submitted Forward Prices Vs. 7/6/2005 Energy Market Report (EMR)

	On-Peak		Off-Peak	
Date	PGE's Submitted Forward Prices	7/6/2005 EMR	PGE's Submitted Forward Prices	7/6/2005 EMR
	($/MWh)	($/MWh)	($/MWh)	($/MWh)
	(1)	(2)	(3)	(4)
Aug-05	$66.24	$65.00	$55.03	$62.00
Sep-05	65.22	63.25	54.01	62.00
Oct-05	62.16	66.75	51.97	62.00
Nov-05	67.25	66.75	56.55	62.00
Dec-05	72.35	66.75	62.41	62.00
Jan-06	75.92	70.75	63.94	62.50
Feb-06	72.35	70.75	60.89	62.50
Mar-06	67.25	70.75	57.83	62.50
Apr-06	57.06	50.50	47.89	55.75
May-06	47.38	50.50	40.25	55.75
Jun-06	48.40	50.50	37.19	55.75
Jul-06	67.00	69.75	56.55	55.75
Aug-06	73.88	69.75	59.10	55.75
Sep-06	70.36	69.75	57.57	55.75
Oct-06	67.00	68.50	55.54	55.75
Nov-06	69.04	68.50	57.57	55.75
Dec-06	72.09	68.50	61.14	55.75
Jan-07	74.39	63.50	61.39	53.75
Feb-07	70.82	63.50	58.34	53.75
Mar-07	65.73	63.50	55.28	53.75
Apr-07	55.54	63.50	45.86	53.75
May-07	45.86	63.50	38.21	53.75
Jun-07	46.87	63.50	35.16	53.75
Jul-07	65.98	63.50	55.79	53.75
Aug-07	72.86	63.50	58.34	53.75
Sep-07	69.34	63.50	56.81	53.75
Oct-07	65.98	63.50	54.77	53.75
Nov-07	68.02	63.50	56.81	53.75
Dec-07	71.08	63.50	60.38	53.75
Jan-08	72.86	61.50	59.87	51.50
Feb-08	69.29	61.50	56.81	51.50
Mar-08	64.20	61.50	53.75	51.50
Apr-08	54.01	61.50	44.33	51.50
May-08	44.33	61.50	36.68	51.50
Jun-08	45.35	61.50	33.63	51.50
Jul-08	64.45	61.50	54.26	51.50
Aug-08	71.33	61.50	56.81	51.50
Sep-08	67.81	61.50	55.28	51.50
Oct-08	64.45	61.50	53.24	51.50
Nov-08	66.49	61.50	55.28	51.50
Dec-08	69.55	61.50	58.85	51.50
Total (Selling 1 aMW/Month) ($)	**$ 2,647.54**	**$ 2,607.00**	**$ 2,191.36**	**$ 2,262.25**
Difference Between Submitted and EMR ($)	**$ 40.54**		**$ (70.89)**	
Difference in $/MWh	**$ 0.99**		**$ (1.73)**	

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

PUBLIC UTILITY COMMISSION
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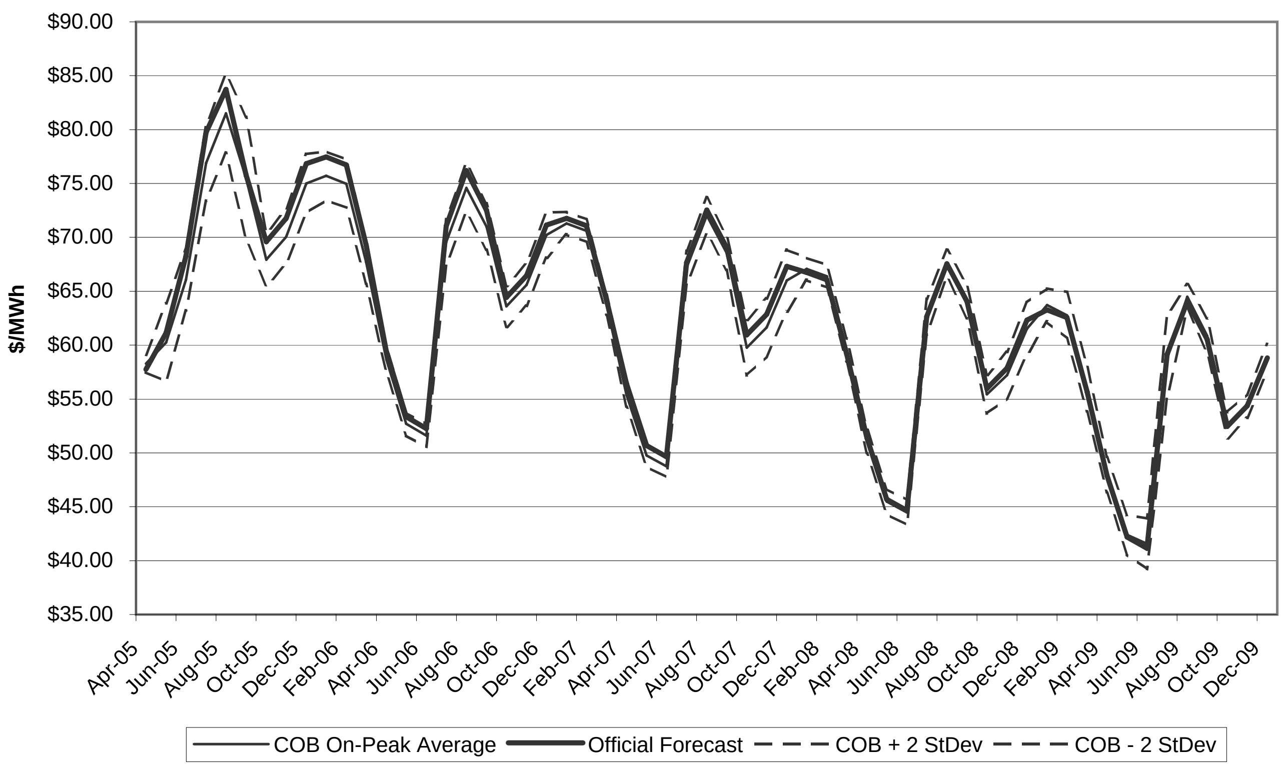
OREGON

STAFF EXHIBIT 1105

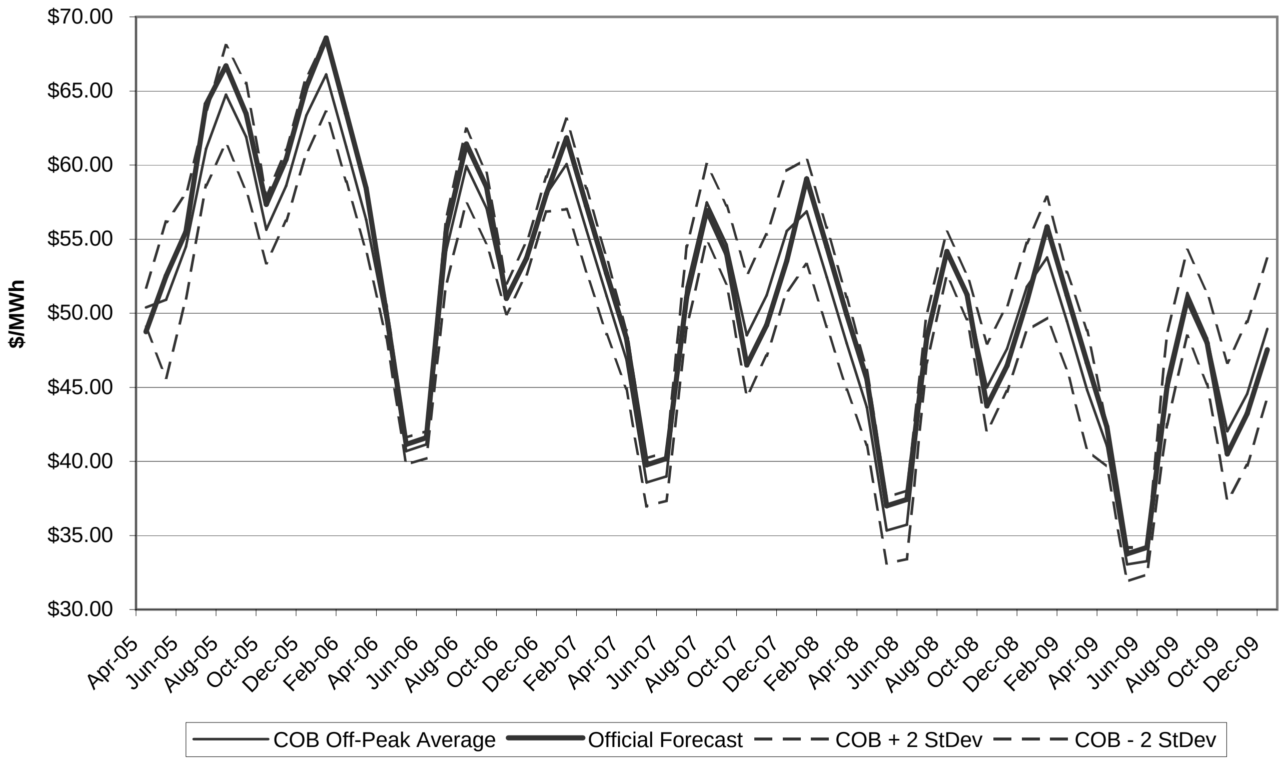
Exhibits in Support of Direct Testimony

December 9, 2005

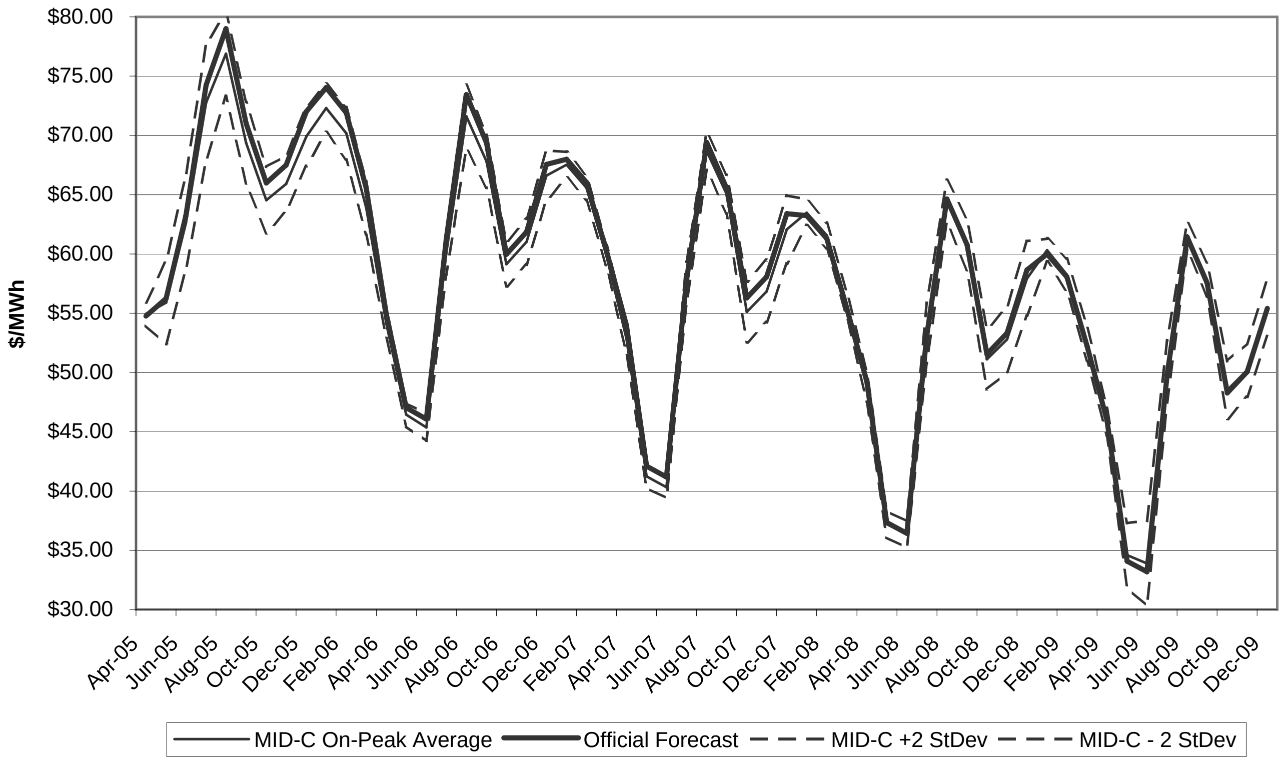
PacifiCorp's March 31, 2005 On-Peak COB Forward Price Curve vs. Average of Adjoining Two-week Periods



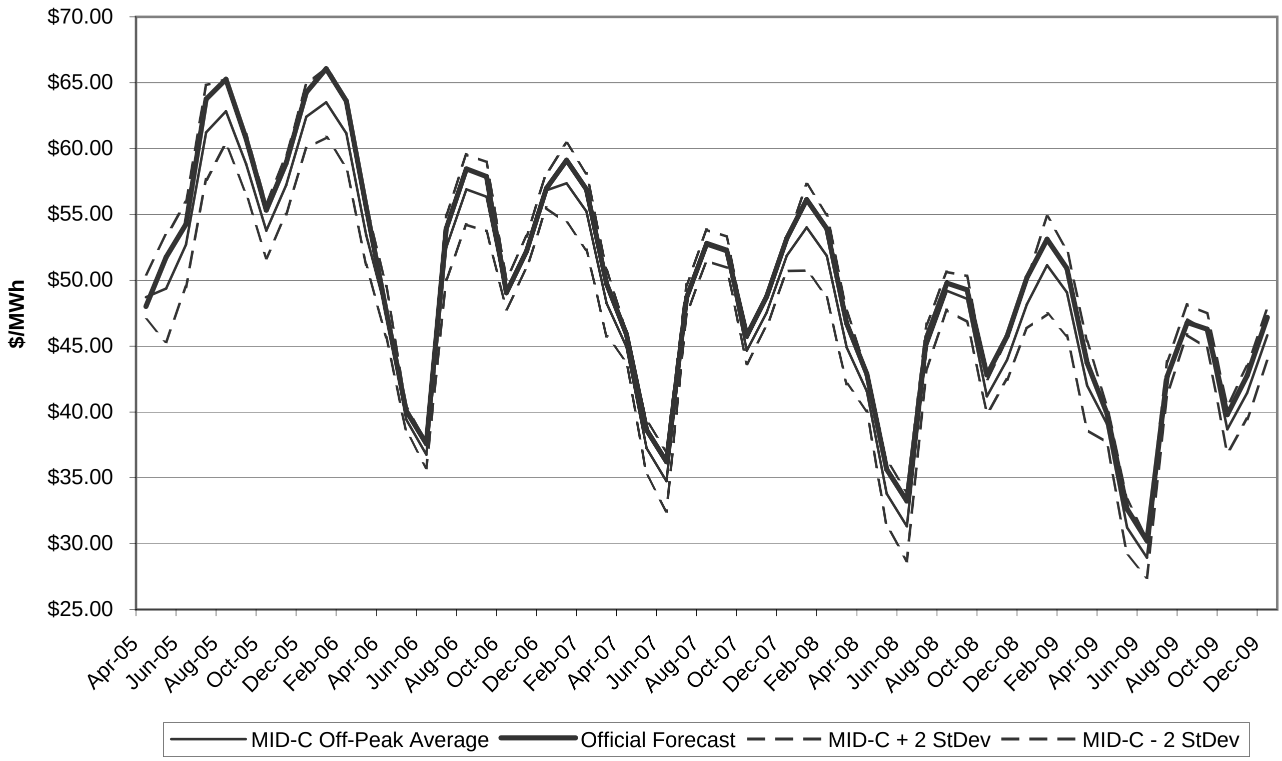
PacifiCorp's March 31, 2005 Off-Peak COB Forward Price Curve vs. Average of Adjoining Two-week Periods



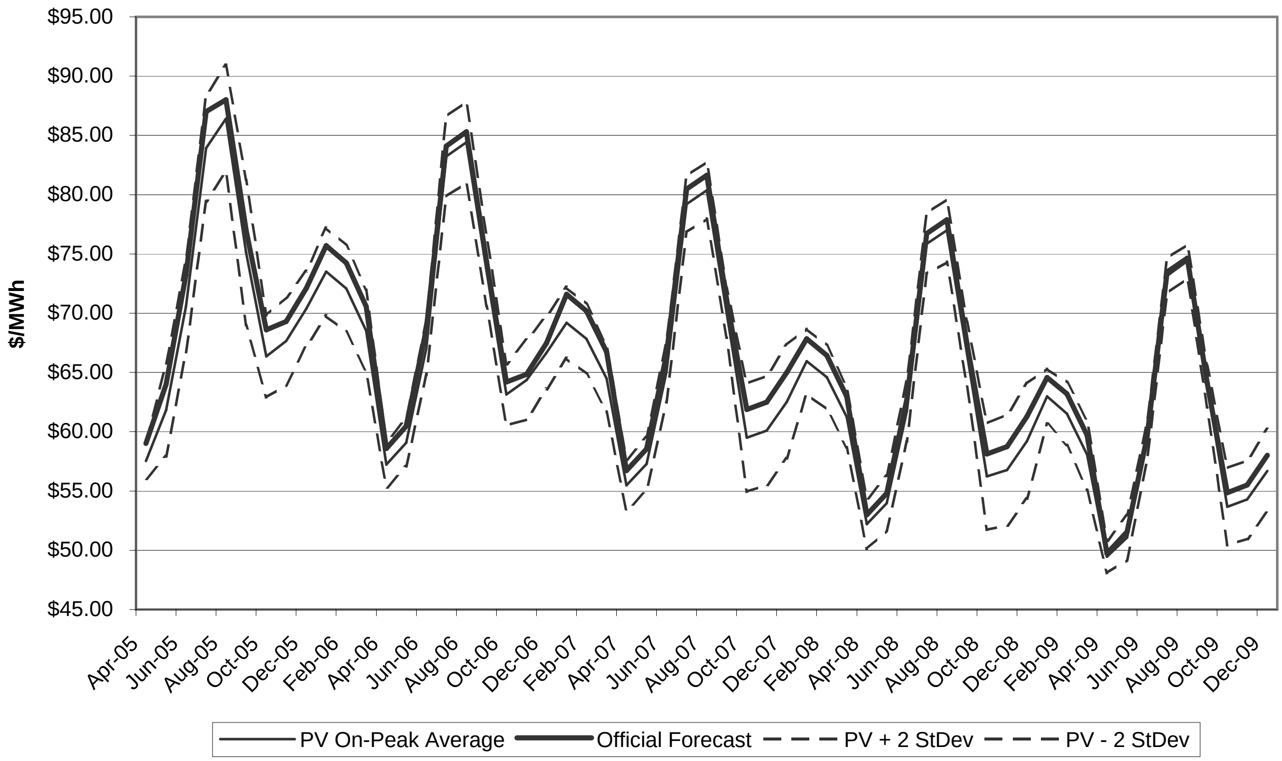
PacifiCorp's March 31, 2005 On-Peak MID-C Forward Price Curve vs. Average of Adjoining Two-week Periods



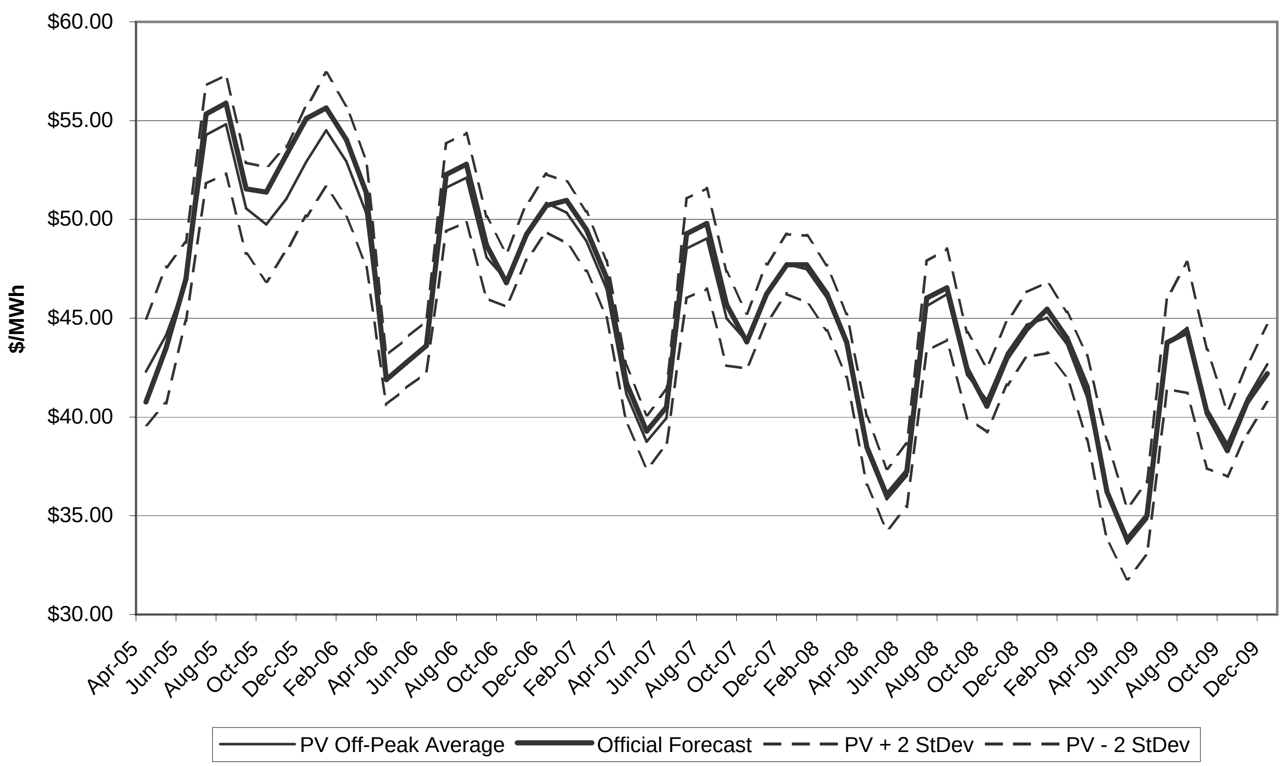
PacifiCorp's March 31, 2005 Off-Peak MID-C Forward Price Curve vs. Average of Adjoining Two-week Periods



PacifiCorp's March 31, 2005 On-Peak Palo Verde Forward Price Curve vs. Average of Adjoining Two-week Periods



PacifiCorp's March 31, 2005 Off-Peak Palo Verde Forward Price Curve vs. Average of Adjoining Two-week Periods



PacifiCorp's Submitted Mid-C Forward Prices Vs. 3/30/2005 Energy Market Report (EMR)

	On-Peak		Off-Peak	
Date	PacifiCorp's Official Forecast	3/30/2005 EMR	PacifiCorp's Official Forecast	3/30/2005 EMR
	($/MWh)	($/MWh)	($/MWh)	($/MWh)
	(1)	(2)	(3)	(4)
Apr-05	$54.75	$54.50	$48.00	$47.25
May-05	56.25	56.50	51.75	51.50
Jun-05	63.25	58.50	54.25	51.50
Jul-05	74.25	74.25	63.75	62.00
Aug-05	79.00	74.25	65.25	62.00
Sep-05	71.00	74.25	60.75	62.00
Oct-05	66.00	66.50	55.34	58.00
Nov-05	67.50	66.50	58.91	58.00
Dec-05	72.00	66.50	64.26	58.00
Jan-06	74.03	68.50	66.07	52.50
Feb-06	71.91	68.50	63.60	52.50
Mar-06	65.57	68.50	55.58	52.50
Apr-06	54.88	62.00	47.60	52.50
May-06	47.04	62.00	40.08	52.50
Jun-06	46.06	62.00	37.58	52.50
Jul-06	61.20	62.00	53.91	52.50
Aug-06	73.44	62.00	58.45	52.50
Sep-06	69.36	62.00	57.89	52.50
Oct-06	59.97	62.00	49.06	52.50
Nov-06	61.86	62.00	52.22	52.50
Dec-06	67.54	62.00	56.97	52.50
Jan-07	67.99	57.75	59.12	47.75
Feb-07	66.05	57.75	56.91	47.75
Mar-07	60.22	57.75	49.73	47.75
Apr-07	53.99	57.75	45.89	47.75
May-07	42.09	57.75	38.64	47.75
Jun-07	41.18	57.75	36.23	47.75
Jul-07	57.83	57.75	48.69	47.75
Aug-07	69.39	57.75	52.79	47.75
Sep-07	65.54	57.75	52.28	47.75
Oct-07	56.29	57.75	45.80	47.75
Nov-07	58.07	57.75	48.76	47.75
Dec-07	63.40	57.75	53.19	47.75
Jan-08	63.24	53.00	56.12	44.75
Feb-08	61.30	53.00	53.91	44.75
Mar-08	55.47	53.00	46.73	44.75
Apr-08	49.24	53.00	42.89	44.75
May-08	37.34	53.00	35.64	44.75
Jun-08	36.43	53.00	33.23	44.75
Jul-08	53.08	53.00	45.69	44.75
Aug-08	64.64	53.00	49.79	44.75
Sep-08	60.79	53.00	49.28	44.75
Oct-08	51.54	53.00	42.80	44.75
Nov-08	53.32	53.00	45.76	44.75
Dec-08	58.65	53.00	50.19	44.75
Jan-09	59.99	49.75	53.12	40.00
Feb-09	58.05	49.75	50.91	40.00
Mar-09	52.22	49.75	43.73	40.00
Apr-09	45.99	49.75	39.89	40.00
May-09	34.09	49.75	32.64	40.00
Jun-09	33.18	49.75	30.23	40.00
Jul-09	49.83	49.75	42.69	40.00
Aug-09	61.39	49.75	46.79	40.00
Sep-09	57.54	49.75	46.28	40.00
Oct-09	48.29	49.75	39.80	40.00
Nov-09	50.07	49.75	42.76	40.00
Dec-09	55.40	49.75	47.19	40.00
Total (Selling 1 aMW/Month) ($)	**$3,309.86**	**$3,281.25**	**$2,817.25**	**$2,730.25**
Difference Between Submitted and EMR ($)	**$28.61**		**$87.00**	
Difference in $/MWh	**$0.50**		**$1.53**	

PacifiCorp's Submitted Palo Verde Forward Prices Vs. 3/30/2005 Energy Market Report (EMR)

	On-Peak		Off-Peak	
Date	PacifiCorp's Official Forecast ($/MWh)	3/30/2005 EMR ($/MWh)	PacifiCorp's Official Forecast ($/MWh)	3/30/2005 EMR ($/MWh)
	(1)	(2)	(3)	(4)
Apr-05	$59.00	$58.13	$40.75	$51.75
May-05	$64.00	$62.75	$43.50	$51.75
Jun-05	$73.25	$64.00	$47.00	$51.75
Jul-05	$87.00	$82.75	$55.34	$51.75
Aug-05	$88.00	$82.75	$55.88	$51.75
Sep-05	$77.00	$82.75	$51.54	$51.75
Oct-05	$68.60	$68.25	$51.39	$52.00
Nov-05	$69.30	$68.25	$53.25	$52.00
Dec-05	$72.10	$68.25	$55.11	$52.00
Jan-06	$75.71	$71.75	$55.64	$47.75
Feb-06	$74.24	$71.75	$54.04	$47.75
Mar-06	$70.56	$71.75	$51.36	$47.75
Apr-06	$58.59	$69.75	$41.90	$47.75
May-06	$60.48	$69.75	$42.75	$47.75
Jun-06	$68.67	$69.75	$43.61	$47.75
Jul-06	$84.09	$69.75	$52.28	$47.75
Aug-06	$85.31	$69.75	$52.79	$47.75
Sep-06	$74.34	$69.75	$48.69	$47.75
Oct-06	$64.19	$69.75	$46.80	$47.75
Nov-06	$64.85	$69.75	$49.24	$47.75
Dec-06	$67.47	$69.75	$50.70	$47.75
Jan-07	$71.59	$66.00	$50.96	$45.00
Feb-07	$70.20	$66.00	$49.49	$45.00
Mar-07	$66.72	$66.00	$47.04	$45.00
Apr-07	$56.73	$66.00	$41.72	$45.00
May-07	$58.56	$66.00	$39.29	$45.00
Jun-07	$66.49	$66.00	$40.50	$45.00
Jul-07	$80.47	$66.00	$49.28	$45.00
Aug-07	$81.64	$66.00	$49.79	$45.00
Sep-07	$71.14	$66.00	$45.69	$45.00
Oct-07	$61.86	$66.00	$43.80	$45.00
Nov-07	$62.49	$66.00	$46.24	$45.00
Dec-07	$65.02	$66.00	$47.70	$45.00
Jan-08	$67.84	$63.00	$47.71	$41.75
Feb-08	$66.45	$63.00	$46.24	$41.75
Mar-08	$62.97	$63.00	$43.79	$41.75
Apr-08	$52.98	$63.00	$38.47	$41.75
May-08	$54.81	$63.00	$36.04	$41.75
Jun-08	$62.74	$63.00	$37.25	$41.75
Jul-08	$76.72	$63.00	$46.03	$41.75
Aug-08	$77.89	$63.00	$46.54	$41.75
Sep-08	$67.39	$63.00	$42.44	$41.75
Oct-08	$58.11	$63.00	$40.55	$41.75
Nov-08	$58.74	$63.00	$42.99	$41.75
Dec-08	$61.27	$63.00	$44.45	$41.75
Jan-09	$64.59	$60.00	$45.46	$40.50
Feb-09	$63.20	$60.00	$43.99	$40.50
Mar-09	$59.72	$60.00	$41.54	$40.50
Apr-09	$49.73	$60.00	$36.22	$40.50
May-09	$51.56	$60.00	$33.79	$40.50
Jun-09	$59.49	$60.00	$35.00	$40.50
Jul-09	$73.47	$60.00	$43.78	$40.50
Aug-09	$74.64	$60.00	$44.29	$40.50
Sep-09	$64.14	$60.00	$40.19	$40.50
Oct-09	$54.86	$60.00	$38.30	$40.50
Nov-09	$55.49	$60.00	$40.74	$40.50
Dec-09	$58.02	$60.00	$42.20	$40.50
Total (Selling 1 aMW/Month) ($)	**$3,816.46**	**$3,748.88**	**$2,592.96**	**$2,566.50**
Difference Between Submitted and EMR ($)	**$67.58**		**$26.45**	
Difference in $/MWh	**$1.19**		**$0.46**	

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

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1107

Exhibits in Support of Direct Testimony

December 9, 2005

Table 9
Natural Gas Price Forecast ($/MMBtu)

Year	PacifiCorp			
	Opal Raw Fuel	Transport Cost	Distribution Cost	Combined Cycle CT Fuel Cost
	(a)	(b)	(c)	(d)
		(a) x .016 + 0.13	((a)+(b))x.015+0.09	(a) + (b) + (c)
2005	$7.18	$0.24	$0.20	$7.62
2006	$6.96	$0.24	$0.20	$7.40
2007	$6.38	$0.23	$0.19	$6.80
2008	$5.90	$0.22	$0.18	$6.30
2009	$5.51	$0.22	$0.18	$5.91
2010	$5.16	$0.21	$0.17	$5.54
2011	$5.49	$0.22	$0.18	$5.89
2012	$6.17	$0.23	$0.19	$6.59
2013	$6.48	$0.23	$0.19	$6.90
2014	$6.51	$0.23	$0.19	$6.93
2015	$6.60	$0.24	$0.19	$7.03
2016	$6.77	$0.24	$0.20	$7.21
2017	$6.95	$0.24	$0.20	$7.39
2018	$7.12	$0.24	$0.20	$7.56
2019	$7.31	$0.25	$0.20	$7.76
2020	$7.50	$0.25	$0.21	$7.96
2021	$7.70	$0.25	$0.21	$8.16
2022	$7.90	$0.26	$0.21	$8.37
2023	$8.10	$0.26	$0.22	$8.58
2024	$8.31	$0.26	$0.22	$8.79
2025	$8.53	$0.27	$0.22	$9.02
2026	$8.75	$0.27	$0.23	$9.25
2027	$8.98	$0.27	$0.23	$9.48
2028	$9.21	$0.28	$0.23	$9.72

Columns

(a) Official Price Forecast March 31, 2005 - Opal Index

		Shrinkage	Fees
(b)	Transport Cost	0.016	0.13
(c)	Distribution Cost	0.015	0.09

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

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1108

Exhibits in Support of Direct Testimony

December 9, 2005

UM-1129/PacifiCorp
August 16, 2005
OPUC Data Request 13

OPUC Data Request 13

Please provide all workpapers and supporting documentation for the transport costs provided in the table.

Response to OPUC Data Request 13

The current avoided cost study uses Opal index gas prices from the Company's Official Market Price Projection and converts the gas prices to proxy resource (Currant Creek) burner-tip prices using transportation and distribution cost adjustment factors. The adjustment factors were developed in November 2002, based upon tariff fuel losses and average commodity charges being experienced at the time. The Company does not have detailed work papers.

UM-1129/PacifiCorp
August 16, 2005
OPUC Data Request 14

OPUC Data Request 14

Please indicate if the workpapers and documentation in your answer to Data Request 13 have been updated or superseded. If yes, then:

a. Please provide the updated or superseded workpapers and documentation.

b. Please provide a calculation of the transport costs using the updated or superseded data.

Response to OPUC Data Request 14

a. Going forward, the Company will use proxy resource (Currant Creek) burner-tip gas prices, which are now included in the Company's Official Market Price Projection. Attachment OPUC 14, on the enclosed CD, provides the Company's June 30, 2005 Official Market Price Projection, which includes burner-tip prices.

b. A burner-tip price for the proxy resource is the sum of the Rock/Opal commodity price plus the average of the Bid and Offer price differential. Shown below is an example of how the burner-tip prices were calculated for March 2006. All other months are calculated the same way.

<u>Bid</u>

Basis Rock/Opal to Goshen bid (1)	$0.040 /MMBtu

<u>Offer</u>

The offer side is calculated as follows.

Basis Rock/Opal to Goshen offer (1)	$0.060
Questar variable transportation	$0.010
Commodity gas offer price x pipeline loss, as calculated by Questar $7.768 x (.021/.979)	<u>$0.167</u>
Total offer	$0.237

Average of Bid and Offer ($.040+$0.237)/2	$0.138/MMBtu
Rock/Opal commodity price (2)	$7.680
Transportation cost	<u>$0.138</u>
Proxy resource (Currant Creek) burner-tip price	$7.818 /MMBtu

UM-1129/PacifiCorp
August 16, 2005
OPUC Data Request 14

(1) Assumes scenario where suppliers could divert deliveries from Goshen to Currant Creek at no incremental cost.

(2) The Rock/Opal commodity price is the average of the bid and offer commodity price.

UM-1129/PacifiCorp
November 18, 2005
Supplemental OPUC Data Request 14

OPUC Data Request 14

Please indicate if the workpapers and documentation in your answer to Data Request 13 have been updated or superseded. If yes, then:

a. Please provide the updated or superseded workpapers and documentation.

b. Please provide a calculation of the transport costs using the updated or superseded data.

Supplemental Response to OPUC Data Request 14

As discussed in the Company's original response to OPUC Data Request 14, the adjustment for Transportation and Distribution included in Table 9 are outdated.

Attachment OPUC 14 1st Supplemental on the enclosed CD provides updated March 30, 2005 prices using the adjustment factors provided in response to OPUC Data Request 14.

Supplemental Attachment OPUC 14
Revised Natural Gas Price Forecast ($/MMBtu)

Year	Opal Raw Fuel	Revised Transport Distribution	Revised CCCT Fuel Cost
	(a)	(b)	(c)
			(a) + (b)
2005	$7.35	$0.18	$7.53
2006	$6.96	$0.13	$7.09
2007	$6.38	$0.13	$6.51
2008	$5.90	$0.13	$6.03
2009	$5.51	$0.12	$5.63
2010	$5.16	$0.12	$5.28
2011	$5.49	$0.12	$5.60
2012	$6.17	$0.12	$6.29
2013	$6.48	$0.12	$6.60
2014	$6.51	$0.12	$6.63
2015	$6.60	$0.12	$6.71
2016	$6.77	$0.12	$6.88
2017	$6.95	$0.12	$7.06
2018	$7.12	$0.12	$7.24
2019	$7.31	$0.12	$7.43
2020	$7.50	$0.12	$7.62
2021	$7.70	$0.12	$7.81
2022	$7.90	$0.12	$8.01
2023	$8.10	$0.12	$8.22
2024	$8.31	$0.12	$8.43
2025	$8.53	$0.12	$8.64
2026	$8.75	$0.12	$8.87
2027	$8.98	$0.12	$9.09
2028	$9.21	$0.12	$9.33

Columns

(a) Official Price Forecast March 31, 2005 - Opal Index

(b) Transport and Distribution Costs based on Costs incorporated in the June 30, 2005 Official Price Projection

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

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1109

Exhibits in Support of Direct Testimony

December 9, 2005

UM-1129/PacifiCorp
September 9, 2005
OPUC Data Request 19

OPUC Data Request 19

Please explain (in narrative format) the methodology utilized to prepare the forecast(s) from nos. 16 and 17.

Response to OPUC Data Request 19

Since PacifiCorp does not produce the forecasts provided in response to OPUC DR 16 and 17, the Company has no specific methodology used to prepare the forecasts. PacifiCorp translates forecasts of annual natural gas prices for Henry Hub and certain western delivery points to monthly prices at required western delivery points using the monthly shaping factors and price bases applied in the workbooks containing the name *Base Gas PIRA* in the electronic files provided in Confidential Attachment OPUC 17 a. In addition, PacifiCorp adjusts PIRA's forecasts to be consistent with PacifiCorp's inflation assumption by deflating PIRA's nominal dollar forecasts using PIRA's assumed inflation rate, then inflate the resultant real dollar forecast to a nominal dollar forecast using PacifiCorp's inflation rate. These calculations are performed in the workbook labeled *PIRA Inflation Adjustment* in the electronic files provided in Confidential Attachment OPUC 17 a.

UM-1129/PacifiCorp
September 9, 2005
OPUC Data Request 18

OPUC Data Request 18

Please provide electronic copies of all the inputs and assumptions for the forecast(s) identified in response to question nos. 16 and 17.

Response to OPUC Data Request 18

Since PacifiCorp does not produce the forecasts provided in response to OPUC DR 16 and 17, the Company has no specific inputs and assumptions for these forecasts.

CASE: UM 1129 - Phase I Compliance
WITNESS: Maury Galbraith

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1200

Direct Testimony

December 9, 2005

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

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

Q. HAVE YOU FILED TESTIMONY PREVIOUSLY IN THIS CASE?

A. No.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found at Exhibit Staff/1201.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to address issues related to setting the resource sufficiency/deficiency period for calculation of avoided costs in PacifiCorp Advice No. 05-006 and Portland General Electric (PGE) Advice No. 05-10. In a ruling issued on November 17, 2005, Administrative Law Judge Kirkpatrick set issues related to the resource sufficiency/deficiency period as Issue No. 18 on the UM 1129 Phase 1 Compliance Issues List.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I address PacifiCorp's calculation of its resource sufficiency period in Advice No. 05-006. Second, I address PGE's calculation of its resource sufficiency period in Advice No. 05-10.

Q. DID YOU PREPARE EXHIBITS FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/1202 in support of my testimony on PacifiCorp Advice No. 05-006 and Exhibit Staff/1203 in support of my testimony on PGE Advice No. 05-10.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. For PacifiCorp Advice No. 05-006, I recommend the Commission:

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

For PGE Advice No. 05-10, I recommend 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.

<u>PacifiCorp's Resource Sufficiency/Deficiency Period</u>

Q. WHAT DOES PACIFICORP CONCLUDE ABOUT ITS RESOURCE SUFFICIENCY PERIOD IN ADVICE NO. 05-006?

A. PacifiCorp concludes that it is resource sufficient through 2009. *See* PacifiCorp Advice No. 05-006, Original Sheet No. 37-2. Based on this determination, PacifiCorp used forward market prices to set avoided costs for 2005-2009 and used the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) to set avoided costs for 2010-2025.

Q. WHAT IS THE BASIS FOR PACIFICORP'S CONCLUSION THAT IT IS RESOURCE SUFFICIENT THROUGH 2009?

A. PacifiCorp determined its resource sufficiency period based on the results of an April 2005 forecast of future monthly load and resource balances. PacifiCorp asserts that its system is resource deficit on an annual basis at the point where the forecast shows insufficient resources to meet both the annual average system energy requirement and the highest monthly capacity requirement of the year. *See* Exhibit Staff/1202, Galbraith/1-3.

Q. CAN YOU ELABORATE ON PACIFICORP'S FORECAST OF ITS LOAD-RESOURCE BALANCES?

A. Yes. On a capacity basis, PacifiCorp forecasts the highest monthly system peak load to occur during July of 2006 through 2010. The system is forecast to be capacity deficit by 864 megawatts (MW) in July 2006. The capacity deficit is expected to grow to 2,406 MW in July 2010. *See* Staff/1202, Galbraith/3.

On an annual energy basis, PacifiCorp forecasts resource surpluses in 2006 through 2009. The largest surplus is 146 average megawatts (MWa) in 2008. The first energy deficit is forecast to occur in 2010 when the system is expected to be short 315 MWa. *See* Staff/1202, Galbraith/3.

The first year in which PacifiCorp forecasts both a capacity deficit and an energy deficit is 2010. Based on this analysis, PacifiCorp concluded that its system is resource sufficient through 2009 and used forward market prices to set avoided costs for 2005-2009 and used the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) to set avoided costs for 2010-2025.

Q. IS IT APPROPRIATE FOR PACIFICORP TO DETERMINE THE RESOURCE SUFFICIENCY/DEFICIENCY PERIOD FOR AVOIDED COSTS USING A DUAL ENERGY AND CAPACITY STANDARD?

A. Yes. Pursuant to the methodology adopted by the Commission in Order 05-584, PacifiCorp and PGE are to use a natural gas-fired CCCT as a proxy for the avoided resource in the period of resource deficiency. *See* Order No. 05-584 at 27. Since a natural gas-fired CCCT is considered to be a base load resource, it is appropriate to determine the resource sufficiency period on both an annual energy and capacity basis. In other words, a utility is unlikely to acquire a base load resource unless it forecasts a significant annual energy and capacity deficit. In the second phase of UM 1129 parties can address whether the planned resource used to determine avoided costs in the deficit period should be based on something other than a natural gas-fired CCCT. *See* Order No. 05-584 at 27. Parties should also consider whether the choice of avoided resource impacts the calculation of the utility's resource sufficiency period.

Q. IS IT APPROPRIATE FOR PACIFICORP TO DETERMINE ITS CAPACITY POSITION BASED ON THE MONTH OF THE YEAR WITH HIGHEST PEAK LOAD?

A. No. PacifiCorp should determine its capacity position based on the month of the year with the largest capacity deficit (or smallest capacity surplus). For example, as I indicated earlier, PacifiCorp forecasts that the highest monthly peak load will occur during July 2007. The forecast also shows that the system will be deficit 1,217 MW of capacity in July 2007. PacifiCorp correctly concludes that its system will be capacity deficit in 2007. However, the forecast shows an even larger capacity deficit of 1,293 MW in August 2007. *See* Staff/1202, Galbraith/3. While this difference does not result in a different resource sufficiency period for PacifiCorp Advice No. 05-006, it could make a difference in future avoided cost filings. When PacifiCorp determines its resource sufficiency/deficiency period in future avoided cost filings it should determine its capacity position based on the largest monthly capacity deficit (or smallest capacity surplus).

Q. IS IT APPROPRIATE FOR PACIFICORP TO DETERMINE THE RESOURCE SUFFICIENCY/DEFICIENCY PERIOD FOR AVOIDED COSTS USING INFORMATION KNOWN AT THE TIME OF ITS AVOIDED COST FILING?

A. Yes. It is standard ratemaking practice to use known and measurable loads and resources when setting cost-of-service rates. This ratemaking practice should also be applied to determining the resource sufficiency/deficiency period when setting avoided costs.

Q. DID PACIFICORP INCLUDE FRONT OFFICE TRANSACTIONS (I.E., SHORT TERM FIRM PURCHASES AND SALES) IN ITS LOAD-RESOURCE BALANCES?

A. Yes. PacifiCorp included the energy and capacity contribution of short term firm purchase and sale agreements signed prior to the time of its avoided cost filing. According to PacifiCorp, short-term firm purchases contribute 575 MW of capacity in July 2006, 200 MW in July 2007, and 100 MW in July 2009. The same purchases provide 225 MWa of energy in 2006, 28 MWa in 2007, and 14 MWa in 2009. *See* PacifiCorp Response to Staff Data Request No. 12, Attachment OPUC 12.xls, at Monthly L&R.

Q. IS IT APPROPRIATE FOR PACIFICORP TO INCLUDE FRONT OFFICE TRANSACTIONS IN ITS LOAD-RESOURCE BALANCES WHEN DETERMINING THE RESOURCE SUFFICIENCY PERIOD FOR AVOIDED COSTS?

A. Yes. However, PacifiCorp may have understated the amount of known and measurable front office transactions. For example, in its 2004 Integrated Resource Plan (IRP), PacifiCorp targeted front office transactions to provide 550 MW of capacity in 2007. *See* PacifiCorp 2004 IRP, Technical Appendix, at 81. The IRP target exceeds the amount the company included in its avoided cost load-resource balance by 350 MW.

Q. WHY IS IT APPROPRIATE TO INCLUDE THE PLANNED LEVEL OF FRONT OFFICE TRANSACTIONS IN THE LOAD-RESOURCE

BALANCES WHEN DETERMINING THE RESOURCE SUFFICIENCY PERIOD FOR AVOIDED COSTS?

A. It is appropriate to include the planned level of front office transactions in the load-resource balance because these transactions are routine and reflect the level of market resources that can reasonably be used to delay large long-term build-or-buy acquisitions.

In Order 05-584, the Commission stated:

> The calculation of avoided costs when a utility is in a resource deficient position should reflect longer term resource decisions that are subject to deferral or avoidance due to QF power purchases. Although a utility may acquire market resources as demand gradually builds, at some point the increase in demand warrants the utility making plans to build or acquire long-term generation resources. At that point, calculation of avoided costs should reflect the potential deferral or avoidance of such generation resources.

See Order No. 05-584 at 27. Although the Commission clearly indicated that market purchases might delay utility plans to build or acquire long-term generation resources, it chose not to provide the amount of market purchases that would be reasonable for this purpose. Of course, a reasonable amount of forward market purchasing may differ by utility.

In its 2004 IRP, PacifiCorp stated:

> The Front Office Transactions included as Planned Resources are based on historical operational data and PacifiCorp's forward market view. These shorter-term, historically-based resources are intended to bridge the gap between reliance on spot market activity and long-term build-or-buy commitments in order to balance the system. Since they are part of the routine system balancing strategy and are based on historical operational data, they are appropriate for inclusion as Planned Resources.

See PacifiCorp 2004 IRP at 52. I believe it is appropriate for PacifiCorp to include the level of planned front office transactions from its 2004 IRP in the load-resource balances used to determine its sufficiency period and avoided costs in PacifiCorp Advice No. 05-006.

Q. IS IT APPROPRIATE TO INCLUDE OTHER PLANNED RESOURCES IN THE LOAD-RESOURCE BALANCES USED TO DETERMINE PACIFICORP'S RESOURCE SUFFICIENCY/DEFICIENCY PERIOD IN AVOIDED COST FILINGS?

A. No. For example, it would be inappropriate for PacifiCorp to include the planned RFP Wind resources from its 2004 IRP in the load-resource balances used in this avoided cost filing because the RFP Wind target is not based on historical operational data and the planned resource additions should not be considered known and measurable for ratemaking purposes.

Q. DO YOU HAVE SPECIFIC RECOMMENDATIONS FOR THE COMMISSION WITH RESPECT TO PACIFICORP'S RESOURCE SUFFICIENCY PERIOD IN ADVICE NO. 05-006?

A. Yes. I recommend that the Commission 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 in Advice No. 05-006. I also recommend that the Commission direct PacifiCorp to determine its annual capacity position based on the largest monthly capacity deficit (or smallest capacity surplus) when determining its resource sufficiency period in future avoided cost filings.

PGE's Resource Sufficiency/Deficiency Period

Q. WHAT DOES PGE CONCLUDE ABOUT ITS RESOURCE SUFFICIENCY/DEFICIENCY PERIOD IN PGE ADVICE NO. 05-10?

A. PGE concludes that it is resource sufficient through 2008. *See* PGE Advice No. 05-10, Second Revision of Sheet No. 201-3 and 2005 Avoided Cost Study Workpapers at 2. Based on this determination, PGE used forward market prices to set avoided costs for 2005-2008 and used the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) to set avoided costs for 2009-2025.

Q. WHAT IS THE BASIS FOR PGE'S CONCLUSION THAT IT IS RESOURCE SUFFICIENT THROUGH 2008?

A. PGE based its determination on an updated load-resource balance from the Final Action Plan of its 2002 IRP. PGE indicated that:

> Although the PGE Final Action Plan showed a negligible deficiency in 2008, recent updates to load forecasts now show a sufficiency period through 2008 due to slower than anticipated load growth. Therefore, from 2005 to 2008 the avoided resource is based on a forward curve that is consistent with the time frame of the IRP Final Action Plan.

See PGE Advice No. 05-10, 2005 Avoided Cost Study Workpapers at 2.

Q. CAN YOU ELABORATE ON THE LOAD-RESOURCE BALANCES INCLUDED IN PGE'S FINAL 2002 INTEGRATED RESOURCE PLAN?

A. Yes. On a capacity basis, PGE's Final Action Plan showed a resource deficit of 1,910 megawatts (MW) in 2007. On an energy basis, PGE's Final Action Plan showed a resource deficit of 773 average megawatts (MWa) in 2007. *See* Staff/1203, Galbraith/1. PGE's capacity deficit and energy deficit were both expected to increase beyond 2007. *See* Staff/1203, Galbraith/2-4.

Q. DO YOU CONSIDER THE RESOURCE DEFICITS SHOWN IN PGE'S 2002 IRP FINAL ACTION PLAN TO BE NEGLIGIBLE?

A. No.

Q. IS IT APPROPRIATE FOR PGE TO UPDATE THE LOAD-RESOURCE BALANCES SHOWN IN ITS FINAL ACTION PLAN TO SET THE RESOURCE SUFFICIENCY PERIOD AND AVOIDED COSTS IN PGE ADVICE NO. 05-10?

A. Yes. PGE should update its load-resource balances used to set its resource sufficiency period and avoided costs to the time of its avoided cost filing. This is consistent with standard ratemaking practice that allows adjustments for known and measurable changes to loads and resources.

Q. HAS PGE ADDED SIGNIFICANT RESOURCES TO ITS RESOURCE PORTFOLIO SINCE ITS 2002 IRP FINAL ACTION PLAN?

A. Yes. For example, PGE has added the TransAlta Centralia Plant purchase power agreement, the PPM Energy Klondike II purchase power agreements, the Morgan Stanley daily on-peak tolling agreement, the

PPM Energy Cold Snap capacity tolling agreement, and the PPM Energy Super Peak capacity tolling agreement.

Q. DID PGE FORECAST GENERATION FROM EXISTING RESOURCES USING THEORETICAL PLANT AVAILABILITY IN ITS 2002 IRP FINAL ACTION PLAN?

A. Yes. *See* Staff/1203, Galbraith/2-4.

Q. IS IT APPROPRIATE FOR PGE TO FORECAST THE GENERATION FROM EXISTING RESOURCES USING THEORETICAL AVAILABILITY WHEN DETERMINING THE RESOURCE SUFFICIENCY PERIOD FOR AVOIDED COSTS?

A. No. PGE should use the same methodology its uses in general rate cases and annual resource valuation mechanism proceedings to adjust plant availability for forced outages.

Q. DID PGE INCLUDE A PLANNING MARGIN IN THE PEAK LOAD-RESOURCE BALANCE IN ITS FINAL ACTION PLAN?

A. Yes. PGE added a 12 percent planning margin to its forecast of cost-of-service peak load. *See* Staff/1203, Galbraith/1.

Q. IS IT APPROPRIATE FOR PGE TO ADD A PLANNING MARGIN TO ITS PEAK LOAD FORECAST WHEN DETERMINING THE RESOURCE SUFFICIENCY PERIOD FOR AVOIDED COSTS?

A. No, not if it also accounts for operating reserves when forecasting the generation from existing resources. The planning margin should be excluded from the peak load obligations because accounting for operating reserves in the generation forecast is standard ratemaking practice, whereas a planning margin is a planning tool that does not reflect a known and measurable addition to cost-of-service loads.

Q. DID PGE INCLUDE PLANNED FRONT OFFICE TRANSACTIONS (I.E., SHORT-TERM PURCHASES) IN ITS 2002 IRP FINAL ACTION PLAN LOAD-RESOURCE BALANCES?

A. No. *See* Staff/1203, Galbraith/1.

Q. IS IT APPROPRIATE FOR PGE TO INCLUDE PLANNED FRONT OFFICE TRANSACTIONS IN THE LOAD-REASOURCE BALANCES USED TO DETERMINE THE RESOURCE SUFFICIENCY PERIOD IN AVOIDED COST FILINGS?

A. Yes. In its 2002 IRP Final Action Plan, PGE targeted using front office transactions to meet the annual energy need of customers that prefer service on indexed rates or short-term arrangements with an electricity service supplier (ESS). PGE forecast that this would amount to 125 MWa in 2007. *See* PGE 2002 IRP, Final Action Plan at 12. In recent years PGE has relied more heavily on forward market purchases to meet both its average energy and capacity requirements. Determining a reasonable level of front office transactions should be an issue in PGE's next IRP. For PGE Advice No. 05-10, it is appropriate to include 125 MWa of front office transactions in PGE's load-resource balances for the purpose of determining its sufficiency period and avoided costs.

Q. IS IT APPROPRIATE FOR PGE TO INCLUDE OTHER PLANNED RESOURCES IN THE LOAD-REASOURCE BALANCES USED TO DETERMINE ITS RESOURCE SUFFICIENCY PERIOD FOR AVOIDED COSTS?

A. No. For example, at this time it would be inappropriate for PGE to include the Port Westward plant in its load-resource balances because the plant cannot be considered a known and measurable resource addition.

Q. DO YOU HAVE SPECIFIC RECOMMENDATIONS FOR THE COMMISSION WITH RESPECT TO PGE'S RESOURCE SUFFICIENCY PERIOD IN ADVICE NO. 05-10?

A. Yes. I recommend 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.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UM 1129 - Phase I Compliance
WITNESS: Maury Galbraith

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1201

Witness Qualification Statement

December 9, 2005

WITNESS QUALIFICATION STATEMENT

NAME: Maury Galbraith

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist, Energy Division

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

EDUCATION: Graduate Student in Environmental Studies Program (1995 – 1997)
University of Montana
Missoula, Montana

Master of Arts in Economics (1992)
Washington State University
Pullman, Washington

Bachelor of Science in Economics (1989)
University of Oregon
Eugene, Oregon

EXPERIENCE: The Public Utility Commission of Oregon has employed me since April 2000. My primary responsibility is to provide expert analysis of issues related to power supply in the regulation of electric utility rates.

From April 1998 through March 2000 I was a Research Specialist with the State of Washington Office of the Administrator for the Courts in Olympia, Washington.

From April 1993 through August 1995 I was a Safety Economist with the Pacific Institute for Research and Evaluation in Bethesda, Maryland.

CASE: UM 1129 - Phase I Compliance
WITNESS: Maury Galbraith

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1202

Exhibit in Support of Testimony on PacifiCorp Advice No. 05-006

December 9, 2005

OPUC Data Request 2

Please explain the rationale for all substantive differences between Table 1, Loads and Resources, and Table F.1 in PacifiCorp's 2004 Integrated Resource Plan (p. 81 of the Technical Appendix). Categorize your responses as follows:

a. Differences resulting from updated load/resource balances

b. Other differences

Response to OPUC Data Request 2

Table F.1 of the IRP, the *Loads & Resource Capacity Report,* identifies the Company's system-wide load and resources balance during the highest peak hour of the summer on a capacity basis. Included are the IRP specified planned resources.

Table 1 of the Oregon Avoided Cost Study summarizes the results of the monthly Loads and Resources Study performed in support of the avoided cost filings (April 2005). It presents a forecast of generated energy (aMW) using the GRID model and includes winter as well as summer peak analysis.

With respect to differences in load/resource balances, there are a number of notable differences:

(1) IRP utilizes thermal resources at their nameplate capacity, while GRID de-rates thermal plants to account for forced outages. Derates for the IRP are included in the planning margin category.
(2) The IRP utilizes planned resources, whereas GRID is operated in the regulatory context and uses only 'known and measurable' inputs.
(3) The IRP load forecast includes both the loads associated with Clark PUD and the South Idaho Load contracts. In GRID both the Clark and South Idaho contracts are modeled as contracts.
(4) The GRID study uses a more current load forecast prepared in February 2005.
(5) The IRP load requirements (meeting retail and contractual load obligations) uses a 15% planning margin. Though helpful for resources planning purposes, this assumption is not used for regulatory applications.

See Attachment OPUC 2 on the enclosed CD for a description of the differences for the overlapping period of CY 2006 and FY 2007.

OPUC Data Request 3

a. Please explain why it is appropriate for PacifiCorp's avoided cost advice filing that the first deficit year is CY 2010, whereas the first deficit year in the company's 2004 Integrated Resource Plan is FY 2009 (summer of 2008) and the company seeks a 525 MW resource in CY 2009 to fill projected needs.

Revised Response to OPUC Data Request 3

(a) The difference in the deficit year between the two filings reflects the use of two different methodologies. The avoided cost filing uses an energy/capacity method to determine the surplus/deficit period, while the IRP measures coincident peak capacity.

The Company's avoided cost methodology, which has been adopted by the commission, deems the system resource deficit when there are insufficient resources to meet system energy and capacity requirements on an annual basis. The avoided cost method is used to evaluate how well the system is able to meet load on an annual basis, while the IRP uses a more granular approach.

Under the IRP methodology, the Company's system-wide hourly coincident peak is deficit in FY 2009. The IRP methodology measures the system at its most stressed single hour.

While the avoided cost L&R substantiates the IRP's analysis showing that the Pacificorp system is resource deficit in the summer of 2008 (see Attachment OPUC 3a on the enclosed CD), it also shows that the company is energy and winter capacity surplus in 2008. Thus, 2008 is not considered the first deficit year under the adopted avoided cost methodology.

See Attachment OPUC 3a for the monthly summary of the Company's energy position and winter capacity.

(b) See the Company's response to (a).

Loads and Resources
Calendar Years 2005 through 2010

Energy (aMW)

Balance after Reserves	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	# of Deficit Months
							Summer	Summer	Summer	Summer				
2005	29	(286)	(138)	(326)	248	396	(49)	165	125	60	(50)	98	90	5
2006	71	(7)	(179)	(157)	188	343	176	(143)	(73)	(99)	91	398	305	6
2007	95	(11)	(171)	(72)	144	376	311	(267)	(339)	207	198	575	187	5
2008	146	297	200	448	586	485	245	(605)	(661)	(63)	129	499	214	3
2009	66	148	106	369	508	327	135	(653)	(686)	(27)	117	401	80	3
2010	(315)	(206)	(254)	7	140	(47)	(337)	(1,107)	(1,138)	(406)	(223)	73	(250)	9

Peak (MW)

Balance after reserves	Peak	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	# of Deficit Months
		Winter	Winter	Winter									Winter	
2005	(561)	(477)	(47)	(247)	870	609	(398)	(330)	(561)	(80)	606	408	391	7
2006	(864)	70	158	460	946	382	(540)	(864)	(837)	(655)	284	378	261	4
2007	(1,217)	(336)	(224)	(319)	503	260	(441)	(1,217)	(1,293)	(19)	(189)	485	349	8
2008	(1,756)	602	762	901	1,379	708	(767)	(1,756)	(1,823)	(465)	(4)	679	513	5
2009	(1,804)	349	496	741	1,157	480	(933)	(1,804)	(1,885)	(436)	(44)	695	416	5
2010	(2,406)	75	215	329	776	125	(1,372)	(2,406)	(2,474)	(929)	(422)	302	65	5

CASE: UM 1129 - Phase I Compliance
WITNESS: Maury Galbraith

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1203

Exhibit in Support of Testimony on Portland General Electric Advice No. 05-10

December 9, 2005

Appendix 1 – Load-Resource Balance Details

Table 19. 2007 Load-Resource Balance Details

	Annual Average Energy MWa	January Peak Capacity MW
Plants		
Boardman	314	362
Colstrip	263	296
Beaver	398	500
Coyote	207	245
Oak Grove	27	42
North Fork	27	40
Faraday	23	32
River Mill	13	18
Bull Run	6	15
Sullivan	9	14
Round Butte	77	220
Pelton	32	73
Total Plants	1,397	1,857
Contracts		
Wells	94	137
Rocky Reach	87	136
Wanapum/Grant PUD Settlement	140	205
Priest Rapids	0	0
Canadian Entitlement Ext.	-16	-27
Portland Hydro	10	20
Vansycle Ridge	8	8
WWP Capacity	0	150
EWEB Capacity	0	10
Ogden Martin	9	16
Glendale Long-Term Sale	-20	-20
Glendale Exchange	0	30
Chelan Exchange In	7	0
Chelan Exchange Out	-8	0
Wells Settlement Agrmnt.	11	11
Tribes	0	0
Cove Replacement	-1	-1
Total Contracts	322	675
Total Resources	**1,719**	**2,532**
Total Load	2,502	3,984
Customers Leaving COS (5-yrs opt-out)	(10)	(11)
12% Reserve Margin in IRP	-	470
Total COS Load	**2,492**	**4,442**
Resources Gap	**773**	**1,910**

Numbers may not foot due to rounding

Update of Our Load-Resource Balance

As a result of the changes described above in "Updated Building Blocks and Signposts," we have updated our load-resource balance for energy and capacity. In this chapter we reconcile these updates to the information provided in our *Supplement*, and describe the resulting new projections for loads and supplies. Topics include:

- Reconciling with the *Supplement*
- Energy and Capacity Requirements

Reconciling with the *Supplement*

Table 7, below, shows how we recalculated our load-resource balance, beginning with information contained in our *Supplement*. We now show our full capacity needs *before* filling our energy needs, because this gives a more accurate accounting of actual capacity requirements.

The most significant change in assumptions from our *Supplement* is that we no longer assume that we will receive any physical power through BPA's Residential and Small Farm Exchange. We also assume that less load will move to direct access on a long-term basis. While these assumptions increase our load demand, other assumptions, such as a reduced load forecast and use of average hydro to measure our resources, work in the other direction. The following table reconciles the energy and capacity needs identified in our *Supplement* to those shown above in Table 3.

Table 7. Reconciliation of *Supplement* to *Final Action Plan*

	Energy (MWa)	*Capacity (MW)*
2007 Resource Need in *Supplement*	650	950
Remove capacity credit from energy actions in *Supplement*	-	720
Remove assumed 2007 BPA power	140	240
Move to average hydro*	(115)	-
Reduce estimate of customers not served by PGE	115	120
Remove embedded estimate of energy efficiency	35	50
Add Bull Run contract extension	-6	-12
Updated (reduced) load forecast	(46)	(158)
Updated 2007 resource need	773	1,910

Includes minor rounding.

* We stated in our *Supplement* (p. 2), that moving to a critical hydro planning standard added 125 MWa to our customer load. This was based on PGE and contract hydro resources as of 2003. In moving to an average hydro standard, we subtract only 115 MWa from our 2007 load because we lose some of the energy acquired through our Mid-Columbia (hydro) contracts by 2007.

Energy and Capacity Requirements

Because the focus of integrated resource planning is long term, and because we have a major energy resource contract expiring late in 2006, we prepared the tables below based on 2007 requirements. PGE has energy and capacity needs in 2005 and 2006 as well, most of which we will meet with short-term purchases in a manner similar to that of the last several years. Some of the contracts offered under our RFP, however, will start in 2005. We will update OPUC Staff and IRP participants regarding our strategy for short-term energy and capacity acquisitions and our actual actions during the quarterly meetings discussed in the "Introduction."

While the energy and capacity balance tables in Appendix 1 show our energy and capacity needs in 2007, the spirit of integrated resource planning requires that we take a long view as well. The charts below show upcoming changes in our current portfolio of resources.

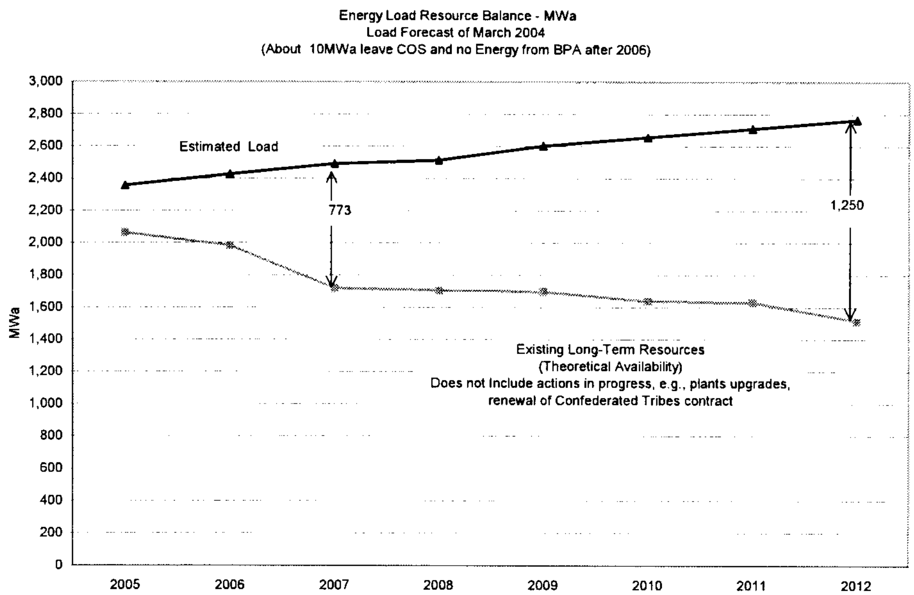


Figure 9. Energy Load-Resource Balance (MWa)

By 2012, our energy need is 1,250 MWa, if no longer-term energy actions are taken in the interim. Assuming that we fill our 773 MWa energy gap in 2007 based on the actions in this Plan, by 2012 we will have an additional energy need of about 480 MWa. This is due to contracts from this Action Plan expiring, loss of other resources, and load growth.

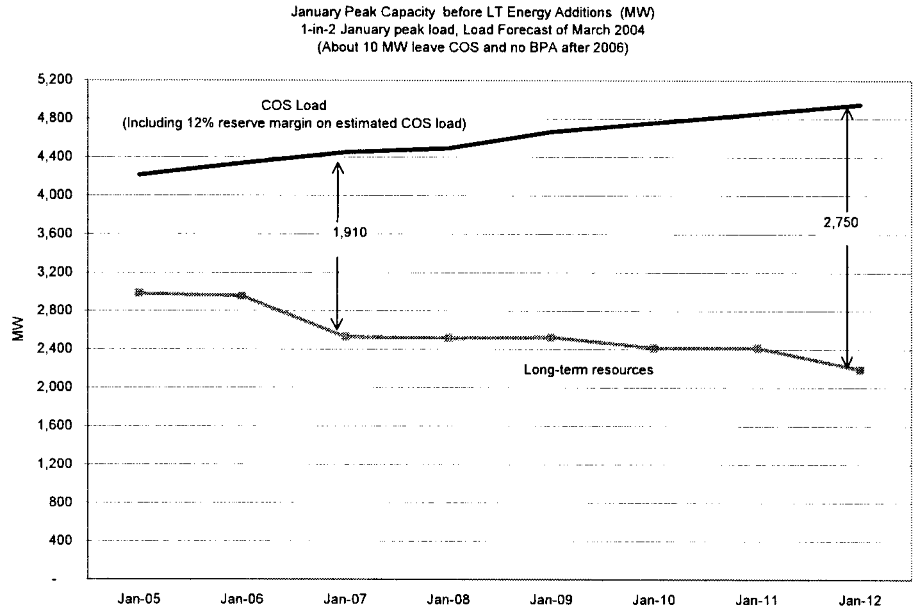


Figure 10. Capacity Load-Resource Balance (MW)

By 2012, our capacity need will be 2,750 MW if no longer-term capacity actions are taken. This represents an additional capacity gap of 840 MW, provided we fill our projected 2007 capacity gap as described in this Plan.

PGE's need to acquire new resources over the next 20 years is evident, even if our load did not increase. These graphs confirm that we should take action to fill our current deficit and return to balance, so that we have a solid base from which to address the upcoming needs caused by future contract termination, resource retirement and load growth.

CASE: UM 1129 - Phase I Compliance
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1300

Direct Testimony

December 9, 2005

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

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

Q. HAVE YOU FILED TESTIMONY PREVIOUSLY IN THIS CASE?

A. No. However, I adopt and will sponsor the testimony of Staff witness Breen in Staff 100 and Staff 500 (filed in the now completed original UM 1129 proceeding) concerning insurance issues for the remainder of this proceeding.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/1301.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to discuss issues 9.a and 9.b of UM 1129 – Phase 1 Compliance Investigation, Consolidated Issues List.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/1302, consisting of 5 pages.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

ISSUE 1, ISSUE 9.A

Q. WHAT IS ISSUE 9.A?

A. Issue 9.a states "It is reasonable and appropriate for PacifiCorp and Idaho Power to require the Qualifying Facility to carry insurance only with companies rated not lower than "A-" by the A.M. Best Company? Is it reasonable and appropriate for PGE to require the Qualifying Facility to carry insurance only with companies rated no less than "A" by the A.M. Best Company?"

Q. ARE THE ISSUE 9.A. REQUIREMENTS REASONABLE?

A. No. A Qualifying Facility (QF) should be allowed to obtain insurance from any insurance company that writes insurance coverage in Oregon. A utility should not restrict the QF from obtaining an insurer based on criteria (i.e. the A.M. Best rating) that is not used by the Oregon Department of Consumer and Business Services, Insurance Division (Insurance Division) when it allows an insurance company to write insurance coverage in Oregon. However, if the Commission decides to use the A.M. Best ratings as a benchmark, then the QF should be allowed carry insurance with companies rated not lower than "B+", which is considered "Very Good (Secure)" by A.M. Best.

Q. WHAT IS THE A. M. BEST COMPANY?

A. According to its website:

> "A.M. Best Company is the leading provider of ratings, news and financial data for the insurance industry worldwide and Best's Ratings are recognized as the

> benchmark for assessing the financial strength of insurance related organizations and the credit quality of their obligations."[1]

Additionally:

> A Best's Financial Strength Rating is an independent opinion, based on a comprehensive quantitative and qualitative evaluation, of a company's balance sheet strength, operating performance and business profile. A.M. Best's rating process incorporates specific methodologies designed to address the Property/Casualty (Non-Life) and Life/Health/HMO industry segments as well as Non-U.S. and U.K. domiciled insurance companies.[2]

Q. PLEASE EXPLAIN THE A. M. BEST RATINGS.

A. A Best's Financial Strength Rating (FSR) is an opinion of an insurer's ability to meet its obligations to policyholders.[3] The rating is basically broken down into two general categories, Secure and Vulnerable. The following table shows the ratings for each category:

Table 1 – A. M. Best Ratings[4]

Secure	Vulnerable
A++, A+ (Superior)	B, B- (Fair)
A, A- (Excellent)	C++, C+ (Marginal)
B++, B+ (Very Good)	D (Poor)
	E (Under Regulatory Supervision)
	F (in Liquidation)
	S (Rating Suspended)

Q. SO BASED ON THE ABOVE TABLE, IT APPEARS THAT PGE DOESN'T CONSIDER AN INSURANCE COMPANY WITH AN A.M. BEST RATING OF EXCELLENT (A-) SECURE ENOUGH FOR THE QF;

[1] A.M. Best Company web-site, www.ambest.com.
[2] *Ibid.*
[3] *Ibid.*
[4] *Ibid.*

OR THAT PACIFICORP AND IDAHO POWER DO NOT CONSIDER AN INSURANCE COMPANY WITH A VERY GOOD RATING (B++) SECURE ENOUGH FOR THE QF?

A. Yes. Based on the table, it appears that if a QF uses an insurance company that has received an “Excellent” rating (A-) by A.M. Best to write its risk, the QF would not be able to transact business with PGE because PGE does not consider an “A-“ rated insurance company secure enough to meet the requirements of the PGE QF contract.

It also appears that if a QF uses an insurance company that has received a “Very Good” rating (B++) by A.M. Best to write its risk, the QF would not be able to transact business with PacifiCorp or Idaho Power because PacifiCorp and Idaho Power do not consider an “B++” rated insurance company secure enough to meet the requirements of the PacifiCorp or Idaho Power QF contracts.

Q. ARE THE UTILITIES BEING REASONABLE IN THIS REQUIREMENT?

A. No. These limitations are not reasonable. As I previously mentioned, if an insurance company is allowed to write insurance coverage in Oregon and is able and willing to write commercial general liability insurance for the QF, then the QF should be able to obtain a policy from the willing insurance company.

Q. IS THERE ANY RELATIONSHIP BETWEEN THE A.M. BEST RATINGS AND THE REQUIREMENTS A COMPANY MUST SATISFY TO OPERATE AS AN INSURER IN THE STATE?

A. No. Simply put, there is no relationship between the two. According to the Insurance Division, A.M. Best ratings do not have anything to do with insurance companies being authorized to do business in Oregon. The Insurance Division, working with the National Association of Insurance Commissioners, has financial and corporate oversight of insurance companies doing business in Oregon. The mission of the Insurance Division is:

> "to administer the Insurance Code for the protection of the insurance-buying public while supporting a positive business climate.
>
> We ensure the financial soundness of insurers and promote the availability and affordability of insurance and the fair treatment of consumers by doing the following:
>
> - Licensing insurance companies and monitoring their solvency.
> - Reviewing insurance products and premium rates for compliance.
> - Licensing insurance producers and consultants.
> - Resolving consumer complaints.
> - Investigating and penalizing companies and producers for violations of insurance law.
> - Monitoring the marketplace conduct of insurers and producers.
> - Educating the public about insurance issues.
> - Advocating reforms that protect the insurance buying public."[5]

Additionally, the Oregon Insurance Guaranty Association, with a limit up to $300,000 for each liability claim, has been established to protect insureds

[5] Department of Consumers and Business Services, Insurance Division, www.cbs.state.or

when an admitted insurance company goes insolvent and is unable to pay the costs of doing business (ORS 734.510 to ORS 734.710).[6]

Q. DO YOU BELIEVE THAT A STATE AGENCY THAT IS CHARGED TO ENSURE THE FINANCIAL SOUNDNESS OF INSURERS IS AN ADEQUATE AND APPROPRIATE BENCHMARK FOR DETERMINING THE FINANCIAL STABILITY OF AN INSURER?

A. Yes. According to the Insurance Division website:

> "The Financial Regulation Section of the Insurance Division is responsible for financial and corporate oversight of insurers transacting business in Oregon. This includes licensing insurers as well as ongoing financial analysis and examination. The section collects and audits insurance taxes. In cases of insolvency of an insurance company, Financial Regulation is responsible for rehabilitation and liquidation efforts. Security deposits by insurers are also supervised and monitored. Lastly, section staff maintains surplus lines, risk retention and purchasing group filings."[7]

As the above indicates, authorization to write insurance in Oregon by the Insurance Division is the appropriate benchmark to use when determining the financial stability of an insurer.

Q. BASED ON YOUR RESEARCH, WHAT IS THE NUMBER OF INSURERS THAT WRITE INSURANCE COVERAGE IN OREGON?

A. Based on information from the National Association of Insurance Commissioners provided by the Insurance Division, there are 378 insurance companies that are admitted and 105 companies that are not admitted in

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[6] *Ibid*
[7] Department of Consumers and Business Services, Insurance Division, www.cbs.state.or

the State of Oregon.[8] Both the admitted and non-admitted companies write insurance coverage in Oregon.[9]

Q. DID YOU PERFORM A SAMPLING OF COMPANIES IN BOTH CATEGORIES TO DETERMINE WHAT THE A. M BEST RATING WAS FOR SELECTED COMPANIES?

A. Yes. For the admitted companies, I examined the top 50 companies in terms of net premiums written (monetary amounts) plus 27 additional companies, including companies such as Allianz, XL Insurance, and AIG that write policies for the energy sector. A sample of 77 companies was determined using a confidence level of 95 percent and a confidence interval of 10. Of the 77 companies, 76 were rated "A-" or better by A.M. Best, while one company was not assigned a rating by A.M. Best.

For non-admitted companies, which include surplus line insurers (ORS 735.400 to ORS 735.495) and risk retention and risk purchasing groups established by federal law (ORS 735.500 to ORS 735.565), I examined each company's A.M. Best rating. Of the 105 companies, 84 (80 percent) have an A.M. Best rating of "B+ (Very Good)" or better rating, 19 (18 percent) were not rated by A.M. Best for various reasons, such as "insufficient data" and "insufficient size", and only 2 (4 percent) were rated "B (Fair)" or lower. Of the 84 companies that have an A.M. Best rating of

[8] Information was derived from the National Association of Insurance Commissioners, www.naic.org.
[9] A non-admitted insurer can transact insurance in Oregon through a surplus line licensee that is allowed to place insurance on risks resident, located or to be performed in Oregon with non-admitted insurers eligible to accept such insurance. (ORS 735.405).

"B+ (Very Good)" or better, 78 (74 percent of the 105 companies) were rated "A- (Excellent)" or better by A.M. Best. Ratings for both admitted and non-admitted insurance companies are listed in Exhibit Staff 1302.

The strength of the above ratings indicates that financial regulation of insurance companies by the Insurance Division is effective and should be the criteria for determining the insurance company that the QF is allowed to transact business with.

Q. AS A COMPARISON, ARE THE UTILITIES' GENERATION FACILITIES INSURED BY INSURANCE COMPANIES WITH AN A. M. BEST RATING OF "A-" OR BETTER?

A. Yes; however, there is one exception that I noted. PacifiCorp uses a captive insurer for "deductible buy-down" insurance for its property and liability insurance. Scottish Power's captive insurer, Dornoch International Insurance Limited (DIIL) does not have an A. M. Best rating. According to PacifiCorp, DIIL is required to meet the minimum capital solvency requirements of the Irish Financial Services Regulatory Authority. Additionally, pursuant to Oregon statutes, DIIL is required to hold a trust fund of $1.5 million for the benefit of policyholders.[10]

Q. PLEASE EXPLAIN THE $300,000 GUARANTY.

A. When an insurance company providing liability is insolvent, and is unable to pay the costs of doing business, the Oregon Insurance Guaranty

[10] UM 1129/PacifiCorp response to Staff Data Request No. 23.

Association (OIGA) provides protection to the insured up to a limit of $300,000.[11]

Q. HOW DO GUARANTY FUNDS OPERATE?

A. As previously mentioned, when an admitted Oregon insurance company becomes insolvent and is liquidated by a court order, the guaranty funds will pay covered claims. The guaranty funds will not pay any claim the insurance company would not have paid. Claims are paid according to the terms of the original insurance policy.[12]

Q. WHO IS COVERED?

A. The fund covers only Oregon residents and only pays claims against insurers that were admitted to do business in Oregon at the time of the insolvency.[13]

Q. ARE BOTH ADMITTED AND NON-ADMITTED INSURANCE COMPANIES COVERED BY THE GUARANTY?

A. No. According to information provided by the Insurance Division, the 105 non-admitted companies previously mentioned are not covered by the guaranty.

Q. IS IT A CONCERN THAT NON-ADMITTED INSURERS ARE NOT COVERED BY THE GUARANTY?

A. No.

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[11] Department of Consumers and Business Services, Insurance Division, www.cbs.state.or
[12] *Ibid.*
[13] *Ibid.*

Q. PLEASE EXPLAIN.

A. I am not concerned that the guaranty fund does not cover non-admitted insurers for the following reasons: (1) As previously mentioned, 84 of the 105 non-admitted company are rated "B+ (Very Good)" or better, 74 which are rated "A- (Excellent)" or better by A.M. Best (only two of the non-admitted companies were rated "B (Fair)" or lower by A. M. Best); (2) these non-admitted insurance companies are financially regulated by the state in which the company is domiciled; (3) these companies are required to file annual statements with the National Association of Insurance Commissioners, which can be accessed by the Insurance Division; and (4) the "producing insurance producers"[14] (e.g. agent, broker) that are qualified to place the surplus line insurance are financially regulated by the Insurance Division.

Additionally, based on my research, insurance companies that write energy sector risk (e.g. XL Insurance, Allianz, AIG) that are admitted in Oregon have an A.M. Best rating of "A" or better. Also, as Staff Witness Jack Breen pointed out in Staff/100, Breen/10, "no utility was able to provide an example where it was liable for damages because of the actions of a QF."

Q. IN CONCLUSION, DO YOU SUPPORT THE INCLUSION OF LANGUAGE IN THE AGREEMENTS THAT REQUIRE A QF TO OBTAIN

[14] "Producing insurance producer" means the individual insurance producer dealing directly with the party seeking insurance. (ORS 735.405)

INSURANCE FROM COMPANIES THAT HAVE AN A. M. BEST "A" OR "A-" OR BETTER RATING?

A. No. Because of the multiple reasons explained in this testimony, a QF should be able to obtain insurance from any insurance carrier allowed to write insurance coverage in Oregon. However, if Commission decides to use the A.M. Best ratings as a benchmark, then the QF should be allowed to obtain insurance with companies rated not lower than "B+", which is considered "Very Good (Secure)" by A.M. Best. This would only exclude 20 of the non-admitted insurers (18 that are non-rated, one rated at "B" and one rated at "C++"); and one of the admitted insurers that was sampled by Staff.

Q. DOES THIS INCLUDE YOUR TESTIMONY CONCERNING ISSUE 9.A.?

A. Yes.

ISSUE 2, ISSUE 9.B.

Q. WHAT IS ISSUE 9.B.

A. Issue 9.b. states: "Should the utilities instead require Qualifying Facilities to use insurance companies that are typically and reasonably used for the type of generating equipment used by the Facility?"

Q. IS THE ISSUE 9.B. REQUIREMENT REASONABLE?

A. No. As previously mentioned, the QF should be able to obtain insurance from any insurance company that is allowed to write insurance coverage in Oregon. The utility should not dictate the insurer or type of insurer the QF is able to transact business with.

Q. PLEASE EXPLAIN.

A. If a utility or a QF decides to use insurance companies "that are typically and reasonably used for the type of generating equipment used by the Facility", that is a corporate decision. However, under no circumstance should the utility prescribe the insurer or type of insurer from which the QF obtains insurance. The QF, and not the utility, is paying the insurance bill. Because the QF is paying the bill and signing the contract with the insurer, the QF should be allowed to choose the insurance company of its choice as long as the insurer is allowed by the Insurance Division to write insurance coverage in Oregon.

Q. ALTHOUGH YOU PREVIOUS POINTED OUT THAT THERE WERE HUNDREDS OF INSURANCE COMPANIES ALLOWED TO WRITE

INSURANCE COVERAGE IN OREGON, WOULD THE QF BE ABLE TO OBTAIN INSURANCE FROM ANY OF THESE COMPANIES?

A. It is unclear. Many of the insurance companies listed appear to specialize in different risks, and may not have a program for the insurance required by the QF. However, based on information I have received, some insurance companies may be willing to look at the QF risks on a submit basis. Premiums would be based on the type of operation, receipts, payroll, etc.[15] A company that I was referred to that would not be considered an insurer that is "typically and reasonably used for the type of generating equipment used by the Facility" and may be willing to look at the QF risk, is Scottsdale Insurance Company.[16]

Additionally, the QF may decide to use an insurance broker to obtain the required insurance. The broker may be able to secure insurance from insurers that are not "typically and reasonably used for the type of generating equipment used by the Facility." If this is the case, the QF should be able to obtain the necessary insurance through the broker.

A QF may also decide to obtain insurance directly or through a broker from an insurer that is "typically and reasonably used for the type of generating equipment used by the Facility." One such broker that I was

[15] Information received from the Commercial Underwriting Manager, MidValley General Agency, LLC, Salem Oregon, www.midvalleyga.com.
[16] Per its website, www.scottsdaleins.com, Scottsdale is a "wholly owned subsidiary of Nationwide, Scottsdale Insurance Company benefits from the backing of one of the largest insurance and financial service providers in the United States, an A.M. Best Rating of A+XV (superior) and a Standard & Poor's "A" rating." Also based on data in Exhibit Staff/1302, Scottsdale is ranked number 5 in terms of net policies written in Oregon.

able to contact is Energy Insurance Brokers[17] which is located in California. I was informed by a representative of Energy Insurance Brokers that it transacts business with available highly rated insurance companies that are allowed to write insurance coverage in Oregon.

Because of these available options, a QF should be able to obtain insurance from any insurance company that is allowed to write insurance coverage in Oregon. The utility should not be able to dictate the insurer or type of insurer the QF is able to transact business with. Since the QF is paying the insurance bill, it should be able to obtain insurance from any allowed insurer that offers the QF favorable terms and conditions.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

[17] Per its website, Energy Insurance Brokers "endeavors to utilize reliable insurance market facilities, offer fair competitive pricing, and conduct business with the highest degree of honesty and integrity. www.energyinsurancebrokers.com

CASE: UM 1129 - Phase I Compliance
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1301

Witness Qualification Statement

December 9, 2005

WITNESS QUALIFICATION STATEMENT

NAME:	MICHAEL DOUGHERTY
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	PROGRAM MANAGER, CORPORATE ANALYSIS AND WATER REGULATION
ADDRESS:	550 CAPITOL ST. NE, SALEM, OR 97310-1380
EDUCATION:	Master of Science, Transportation Management, Naval Postgraduate School, Monterey CA (1987)
	Bachelor of Science, Biology and Physical Anthropology, City College of New York (1980)
EXPERIENCE:	Employed with the Oregon Public Utility Commission as the Program Manager, Corporate Analysis and Water Regulation. Also serve as Lead Auditor for the Commission's Audit Program.
	Performed a five-month job rotation as Deputy Director, Department of Geology and Mineral Industries, March through August 2004.
	Employed by the Oregon Employment Department as Manager - Budget, Communications, and Public Affairs from September 2000 to June 2002.
	Employed by Sony Disc Manufacturing, Springfield, Oregon, as Manager - Manufacturing, Manager - Quality Assurance, and Supervisor - Mastering and Manufacturing from April 1995 to September 2000.
	Retired as a Lieutenant Commander, United States Navy. Qualified naval engineer.

CASE: UM 1129 – Phase I Compliance
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1302

Exhibits in Support of Direct Testimony

December 9, 2005

Licensed (Admitted) Insurers - A. M. Best Ratings

Year: 2004 State: OR (Premiums in thousands)

Cocode	Company Name	Domicile	Net Premiums	A. M. Best Rating
19445	National Union Fire Ins Co Of Pitts	PA	27,311	A+
20281	Federal Ins Co	IN	15,297	A++
19704	American States Ins Co	IN	12,970	A
20443	Continental Cas Co	IL	9,328	A
25143	State Farm Fire And Cas Co	IL	9,275	A+
24767	St Paul Fire & Marine Ins Co	MN	8,865	A+
29459	Twin City Fire Ins Co Co	IN	8,395	A+
22667	Ace American Ins Co	PA	7,776	A+
16535	Zurich American Ins Co	NY	7,612	A
19429	Insurance Co Of The State Of PA	PA	6,004	A+
20338	Northwestern Pacific Ind Co	OR	5,684	A++
35181	Executive Risk Ind Inc	DE	5,461	A++
19380	American Home Assur Co	NY	4,552	A+
13935	Federated Mut Ins Co	MN	4,519	A+
25674	Travelers Property Cas Co Of Amer	CT	3,898	A+
21652	Farmers Ins Exch	CA	3,857	A
24074	Ohio Cas Ins Co	OH	3,564	A-
23892	North Pacific Ins Co	OR	3,530	A
41181	Universal Underwriters Ins Co	KS	3,455	A
21857	American Ins Co	NE	3,400	A
37885	XL Specialty Ins Co	DE	3,341	A+
22314	RSUI Ind Co	NH	3,320	A
24147	Old Republic Ins Co	PA	3,267	A+
16691	Great American Ins Co	OH	3,114	A
22322	Greenwich Ins Co	DE	3,113	A+
24791	St Paul Mercury Ins Co	MN	3,111	A+
31194	Travelers Cas & Surety Co Of Amer	CT	3,083	A+
11071	Safeco Ins Co of OR	OR	3,074	A
19801	Argonaut Ins Co	CA	2,958	A
38962	Genesis Ins Co	CT	2,683	A++
25747	Unigard Ins Co	WA	2,569	A-
14907	Oregon Mut Ins Co	OR	2,530	A-
19917	Liberty Ins Underwriters Inc	NY	2,483	A
25895	United States Liability Ins Co	PA	2,452	A++
20494	Transportation Ins Co	IL	2,282	A
23922	Oregon Automobile Ins Co	OR	2,270	A
20532	Clarendon Natl Ins Co	NJ	2,163	A-
13331	American Hardware Mut Ins Co	OH	2,044	A
41580	Red Shield Ins Co	WA	2,020	A
10698	Valley Prop & Cas Ins Co	OR	2,015	A
11991	National Cas Co	WI	1,856	A+
26247	American Guarantee & Liability Ins	NY	1,840	A
14761	Mutual Of Enumclaw Ins Co	WA	1,829	A-
18058	Philadelphia Ind Ins Co	PA	1,779	A+

19232	Allstate Ins Co	IL	1,767	A+
25658	Travelers Ind Co	CT	1,660	A+
34207	Westport Ins Corp	MO	1,619	A
24732	General Ins Co Of Amer	WA	1,510	A
22217	Gulf Ins Co	CT	1,493	No rating
19275	American Family Mut Ins Co	WI	1,493	A
27154	Atlantic Specialty Ins Co	NY	1,289	A
23043	Liberty Mut Ins Co	MA	1,243	A
23035	Liberty Mut Fire Ins Co	MA	1,195	A
35300	Allianz Global Risks US Ins Co	CA	1,151	A
11118	Federated Rural Electric Ins Exch	KS	956	A-
41939	Liberty Northwest Ins Corp	OR	891	A
21326	Empire Fire & Marine Ins Co	NE	643	A
23787	Nationwide Mut Ins Co	OH	634	A+
23809	Granite State Ins Co	PA	511	A+
37257	Insurance Corp Of Hannover	IL	488	A
24740	Safeco Ins Co Of Amer	WA	365	A
28223	Nationwide Agribusiness Ins Co	IA	363	A+
16217	National Farmers Union Prop & Cas	CO	354	A-
42404	Liberty Ins Corp	IL	341	A
20370	AXIS Reins Co	NY	339	A
19682	Hartford Fire In Co	CT	333	A+
26042	Wausau Underwriters Ins Co	WI	314	A
13838	Farmland Mut Ins Co	IA	298	A+
40142	American Zurich Ins Co	IL	253	A
24554	XL Ins Amer Inc	DE	249	A+
10472	Capitol Ind Corp	WI	247	A
16608	New York Marine & Gnrl Ins Co	NY	144	A
25968	USAA Cas Ins Co	TX	133	A++
12904	Tokio Marine & Nichido Fire Ins Co	NY	123	A++
12890	Eagle West Ins Co	CA	119	A
22551	Mitsui Sumitomo Ins USA Inc	NY	83	A+
20796	AIG Premier Ins Co	PA	67	A+
34789	AIG Centennial Ins Co	PA	15	A+
	77 Licensed Companies in Report		**238,632**	

Unlicensed (Non-admitted) Insurers - A. M. Best Ratings

Year: 2004 State: OR (Premiums in thousands)

Company Code	Company Name	Domicile	Net Premiums	A.M. Best Rating
26883	American Intl Specialty Lines Ins Co	AK	10,988	A+
41297	Scottsdale Ins Co	OH	9,567	A+
19437	Lexington Ins Co	DE	9,548	A+
27960	Illinois Union Ins Co	IL	4,833	A+
10639	Attorneys Liab Assur Society Inc RRG	VT	4,799	NR-1
24856	Admiral Ins Co	DE	4,672	A+
43095	Clarendon Amer Ins Co	NJ	3,807	A-
35378	Evanston Ins Co	IL	3,265	A
31127	Columbia Cas Co	IL	3,042	A
10851	Everest Ind Ins Co	DE	2,943	A+
17370	Nautilus Ins Co	AZ	2,676	A
35351	American Empire Surplus Lns Ins Co	DE	2,610	A
21199	Arch Speciality Ins Co	WI	2,435	A-
44792	Executive Risk Speciality Ins Co	CT	2,388	A++
26387	Steadfast Ins Co	DE	2,305	A
42846	Atlantic Cas Ins Co	NC	2,232	A-
27790	Canal Ind Co	SC	2,143	A+
39993	Colony Ins Co	VA	2,087	A
42811	Gulf Underwriters Ins Co	CT	2,012	A+
10725	Liberty Surplus Ins Corp	NH	1,694	A
10328	Capitol Specialty Ins Corp	WI	1,650	A
10020	United Educators Ins RRG Inc	VT	1,601	A
42374	Houston Cas Co	TX	1,540	A+
30481	St Paul Surplus Lines Ins Co	DE	1,539	A+
10172	Westchester Surplus Lines Ins Co	GA	1,315	A+
29696	Travelers Excess & Surplus Lines Co	CT	1,166	A+
37532	Great American E&S Ins Co	DE	1,142	A
26522	Mount Vernon Fire Ins Co	PA	1,136	A++
39608	Nutmeg Ins Co	CT	1,110	A+
34916	First Specialty Ins Corp	MO	1,068	A
37362	General Star Ind Co	CT	1,032	A++
22829	Interstate Fire & Cas Co	IL	1,018	A
13064	United Natl Ins Co	PA	999	A
10932	Starr Excess Liability Ins Co Ltd	DE	940	A+
10786	Princeton Excess & Surplus Lines Ins	DE	910	A
44016	National Home Ins Co RRG	CO	827	NR-2
34452	Homeland Ins Co of NY	NY	822	A
37982	Tudor Ins Co	NH	809	A+
36940	Indian Harbor Ins Co	ND	740	A+
13196	Western World Ins Co	NH	719	A+
37150	Western Heritage Ins Co	AZ	657	A+
25433	American Safety Ind Co	OK	626	A
17159	Usf Ins Co	PA	599	A-

39020	Essex Ins Co	DE	580	A
19489	Allied World Assur Co US Inc	DE	552	A+
10046	Pacific Ins Co Ltd	CT	535	A+
10657	First Mercury Ins Co	IL	527	A-
27987	Northfield Ins Co	IA	510	A
10833	Gemini Ins Co	DE	355	A
26743	Maxum Ind Co	DE	341	A-
37079	Hudson Specialty Ins Co	NY	311	A++
10717	Aspen Specialty Ins Co	ND	276	A-
36951	Century Surety Co	OH	220	A-
10164	Cpa Mut Ins Co Of Amer RRG	VT	215	NR-4
43915	Rainier Ins Co	AZ	213	A
10101	Premier Ins Exchange RRG	VT	183	A-
36056	NIC Ins Co	NY	175	A
25448	American Safety RRG Inc	VT	149	A
10673	Penn-Star Ins Co	PA	143	A-
10113	Terra Ins Co RRG	VT	141	A
44776	Alea North Amer Specialty Ins Co	DE	139	B++
40940	Western Pacific Mut Ins Co RRG	CO	121	A-
34991	Genesis Ind Ins Co	ND	113	A++
12300	American Contractors Ins Co RRG	TX	89	A
14249	Founders Ins Co	IL	82	A-
10083	National Catholic RRG	VT	60	NR-1
38466	Evergreen USA RRG Inc	VT	47	B
16551	Savers Prop & Cas Ins Co	MO	24	B++
10234	National Srvc Contract Ins Co RRG	DC	22	NR-4
32808	Illinois Emcasco Ins Co	IA	22	A-
34118	Colony Natl Ins Co	VA	18	A
10476	Steel Tank Ins Co RRG	VT	6	A-
11033	Automotive Underwriters Ins Co A RRG	HI	6	NR-5
26620	AXIS Surplus Ins Co	IL	6	A
10075	Consumer Specialties Ins Co RRG	VT	5	B+
10691	Residential Ins Co Inc A RRG	HI	5	NR-2
39640	Firemans Fund Ins Co Of OH	OH	3	A
44105	Ophthalmic Mut Ins Co RRG	VT	3	A-
10353	Ooida RRG Inc	VT	2	NR-1
10893	Primeguard Ins Co Inc A RRG	HI	1	NR-1
20559	General Security Ind Co of AZ	AZ	0	B++
24317	ZC Specialty Ins Co	TX	0	NR-4
21822	First State Ins Co	CT	0	NR-3
11460	Homestead Ins Co	PA	0	NR-3
11100	Safeco Surplus Lines Ins Co	WA	0	A-
34266	Frontier Ins Co	NY	0	NR-5
10803	Columbia Natl RRG Inc	VT	0	NR-5
36420	Allianz Underwriters Ins Co	CA	0	A
44237	Mental Health RRG	VT	0	NR-1
38580	Great American Protection Ins Co	OH	0	A
34487	Professional Undrwtrs Liab Ins Co	UT	0	B++
10903	American Excess Ins Exchange RRG	VT	0	NR-5
25909	Unitrin Preferred Ins Co	NY	0	A
40428	Voyager Ind Ins Co	GA	0	A-
41858	Great American Fidelity Ins Co	DE	0	A

10182	Usf&G Specialty Ins Co	MD	0	A-
19607	XL Select	OK	0	A+
37338	Pacific Ins Co	IL	0	A
37958	Acceptance Ins Co	NE	0	NR-1
10967	Newport Mut Ins RRG Inc	HI	-1	NR-2
25445	TIG Specialty Ins Corp	CA	-1	B+
33189	Monticello Ins Co	DE	-8	NR-3
44520	Crum & Forster Specialty Ins Co	AZ	-17	A-
10213	Discover Specialty Ins Co	IL	-98	A+
41807	Royal Surplus Lines Ins Co	CT	-98	C++
	105 Unlicensed Companies in Report		**109,988**	

Not Rated Categories (NR) are assigned to companies reported on by A.M. Best, but not assigned a Best's Rating. The five categories and descriptions are listed below.

NR-1: Insufficient Data
NR-2: Insufficient Size and/or Operating Experience
NR-3: Rating Procedure Inapplicable
NR-4: Company Request
NR-5: Not Formally Followed

CASE: UM 1129 – Phase I Compliance
WITNESS: J. R. Gonzalez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1400

Direct Testimony

December 9, 2005

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

A. My name is J. R. Gonzalez. I am employed by the Public Utility Commission of Oregon (Commission) as Program Manager for the Safety & Reliability Section. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. HAVE YOU FILED TESTIMONY PREVIOUSLY IN THIS CASE?

A. Yes. I filed Staff/900 and Exhibit Staff/901 in the original UM 1129 proceeding.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to address the reasonableness of the interconnection costs included in the avoided cost estimates for Portland General Electric (PGE) and PacifiCorp based on each utility's proxy plant, meter accuracy requirements for PGE and PacifiCorp, and Idaho Power's rights of way and access requirement on the QF's line facilities.

Q. DID YOU PREPARE AN EXHIBIT?

A. Yes. I prepared Exhibit Staff/1401, consisting of 13 pages.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

Issue 19d. Interconnection Costs

Issue 22. Metering Error Corrections

Issue 34. Rights of Way and Access

ISSUE 19D. INTERCONNECTION COSTS

Q. ARE THE INTERCONNECTION COSTS ASSIGNED TO THE PROXY PLANT THAT PGE AND PACIFICORP USE TO CALCULATE THEIR AVOIDED COSTS REASONABLE?

A. This question has two components. First it requires critical equipment and work elements of the proxy plant to be identified as part of the interconnection cost. The second part of the question is the cost for the interconnecting components, which includes installation.

Based on my previous work experience with Generation Plant Engineering at Puget Sound Power & Light Co. (1981-82), now PSE, I believe both PGE's and PacifiCorp's responses to Staff's data requests identified the proper work elements and equipment to be included in the interconnection costs, which were: 1) Network Upgrades, 2) Switchyard, 3) Circuit Breakers, 4) Step-up Transformers, 5) Communications, including protection schemes, and 6) Standby Power Interconnection.

Regarding the estimated costs presented by each company, which include direct installation costs (no contingencies; overhead or financing charges were included), I did not contact equipment manufacturers or consulting engineering companies in the business of designing and building Combined-Cycle Combustion Turbine generation facilities. However, when considering that the total cost for PGE's 500 MW Port Westward plant is approximately $285 million[1], and PacifiCorp's 525 MW Currant Creek plant is approximately $350 million[2],the respective estimates of $3.7 million and $11.43 million for interconnection costs fall within an acceptable range of 1% to 4% of the total cost. Based on this simple evaluation I believe the interconnection cost assigned to the proxy plants to be reasonable. *See* PGE's response to Staff Data Requests 35 and 46; Staff/1401, Gonzalez/1-3. *See* PacifiCorp's response to Staff Data Requests 48, 51-53; Staff/1401, Gonzalez/4-12.

[1] The cost estimate for the Port Westward Plant was derived from the following weblink;http://www.portlandgeneral.com/about_pge/current_issues/portwestward/faq.asp?bhcp=1

[2] The cost estimate for the Currant Creek Plant was obtained from the weblink; http://www.nephitimesnews.com/0605/062905/1.htm

ISSUE 22. METER ERROR CORRECTIONS

Q. IS IT REASONABLE FOR PACIFICORP TO CORRECT FOR METER READING ERRORS "EITHER FAST OR SLOW" AS SPECIFIED IN SECTION 8.3 OF THE CONTRACT, INSTEAD OF ONLY "SLOW," GIVEN THAT PACIFICORP DESIGNS, FURNISHES, INSTALLS, OWNS, INSPECTS, TESTS, MAINTAINS, AND REPLACES ALL METERING EQUIPMENT AS DESCRIBED IN SECTION 8.1?

A. Yes. It is reasonable for PacifiCorp to correct meter reading errors "either fast or slow." This is standard industry practice in the U.S., and required by OAR 860-023-0015 – Testing Gas and Electric Meters, and OAR 860-021-0135 – Adjustment of Utility Bills. Meter reading errors occur for a variety of reasons, many of which are outside of the control of the Company or the QF facility.

Q. IS SECTION 8.3 OF PGE'S CONTRACT SIMILARLY REASONABLE?

Yes, for the same reasons I cite above.

ISSUE 34. RIGHTS OF WAY AND ACCESS

Q. IS IT REASONABLE FOR IDAHO POWER TO SEEK TO ACQUIRE RIGHTS OF WAY AND ACCESS TO THE SELLER'S FACILITY FOR UTILITY LINES AND EASEMENTS TOTALLY UNRELATED TO THE FACILITY (SECTIONS 13.2 THROUGH 13.4)?

A. Yes. I believe it is reasonable for Idaho Power to seek the rights of way and access to Seller's facilities for utility lines for both distribution and transmission use considering the following: The Company may need to utilize the rights of way to bring service to areas where the Seller's line facilities cross. Such rights of way and access will eliminate the possible need for duplicate line facilities crossing the same street or fields. Further, Idaho Power's Interconnection Agreement Article XIII titled Land Rights, Section 13.4 - Conditions of Use, subsection (2), provides for equitable sharing of the costs of installing, owning and operating jointly used facilities and rights-of-way. *See* Idaho Power's response to Staff Data Request 30; Staff/1401, Gonzalez/13.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UM 1129 – Phase I Compliance
WITNESS: J. R. Gonzalez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1401

Exhibits in Support of Direct Testimony

December 9, 2005

November 17, 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 2, 2005
Question 035

Request:

Please itemize the interconnection costs assigned to the proxy plant PGE used to calculate standard avoided costs, list the cost of each item, and explain the basis for calculating each cost.

Response:

The following costs are based on the Port Westward project and are adjusted for steel price increases and general inflation ($000):

PGE Network Upgrades	$1,286
Switchyard and Circuit Breakers	1,333
Standby Power Interconnection	564
BPA Tower Modifications	594
Total	$3,747

This cost estimate was prepared by PGE's Transmission Engineering Department except for switchyard and circuit breaker costs which are based on estimates prepared by independent electrical contractors. The PGE Network Upgrades represent the cost of reconductoring 230 kV transmission lines, which are necessary to accommodate the Port Westward project. Standby Power Interconnection represents the cost of connecting Port Westward to the Beaver plant, and BPA Tower Modifications represents the cost of increasing the height of some BPA towers near the Allston substation to accommodate the Port Westward transmission line.

December 5, 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 18, 2005
Question 046

Request:

Please refer to staff data request 35. Provide a detailed site layout representative of the utility proxy plant PGE used to calculate standard avoided costs showing interconnecting points, including detailed line diagrams for all lines, switches, metering points, transformers and generating plant.

Response:

We do not have a detailed interconnection layout and related cost data for the avoided proxy plant. The interconnection costs supplied in PGE's Response to OPUC Staff Data Request No. 035 use projected costs for Port Westward as a reference. The Port Westward project costs were used to develop the proxy plant costs by evaluating their applicability to a QF interconnection using engineering experience. If Staff has a desire to better understand these costs it may be helpful to review Port Westward project diagrams and related cost data with PGE's engineering staff.

To further explain the proxy plant calculations Attachment 046-A is included which shows a breakdown of the major cost categories used to develop the proxy plant and interconnection costs.

UM - 1129 / Advice No. 05-10 Attachment 046-A

PORTLAND GENERAL ELECTRIC COMPANY

Construction Work-in-Progress Model

Composite Cost of Capital	9.55%
Cost of Debt	7.51%

Port Westward Overnight Capital Cost	$253,028
Add: Synergies	3,800
Subtract: Duct Firing	(6,250)
Subtract: Transmission Line	(16,000)
Steel price increases	23,458
1 year Inflation	6,451
Greenfield G Overnight Capital Cost	$264,486

Port Westward Synergies	
Demineralized and Potable Water	1,500
Backup Power Supply	1,000
Communication Equipment	200
Road, Rail Spur, Dock	100
Gas Pipeline Spur	1,000

	CWIP Analysis						Tax Basis Analysis				Drawdown Schedule	
	Month	Drawdown Percentage	Expend.	Property Taxes	Interest	Cumulative	Interest	Tax Basis	Deferred Taxes	Equity AFDC	Port Westward	Cumulative CWIP Less Prop Tax
Dec 2005	1	0.020	5,393	-	21	5,393	17	5,410	(3)	13	0.02039	5,414
Jan	2	0.000	93	-	43	5,486	34	5,537	(7)	26	0.00035	5,550
Feb	3	0.001	221	-	45	5,707	35	5,793	(7)	27	0.00084	5,816
Mar	4	0.002	592	-	48	6,299	38	6,424	(8)	29	0.00224	6,456
Apr	5	0.011	2,982	-	62	9,281	50	9,455	(10)	38	0.01127	9,500
May	6	0.011	2,883	-	85	12,468	68	12,406	(14)	52	0.01090	12,468
Jun	7	0.032	8,383	-	133	20,852	104	20,893	(20)	80	0.03170	20,984
Jul	8	0.010	2,526	-	176	23,377	139	23,558	(27)	107	0.00955	23,686
Aug	9	0.010	2,545	-	196	25,922	155	26,258	(31)	119	0.00962	26,427
Sep	10	0.016	4,210	-	223	30,132	178	30,645	(35)	135	0.01592	30,860
Oct	11	0.024	6,474	-	266	36,606	212	37,331	(42)	161	0.02448	37,599
Nov	12	0.050	13,156	83	344	51,182	275	50,845	(55)	209	0.04974	51,099
Dec	13	0.028	7,437	-	437	58,619	341	58,624	(67)	265	0.02812	58,973
Jan	14	0.021	5,602	-	489	64,221	384	64,610	(76)	297	0.02118	65,064
Feb	15	0.028	7,417	-	541	71,638	428	72,454	(84)	328	0.02804	73,021
Mar	16	0.036	9,402	-	608	81,040	483	82,339	(96)	369	0.03555	83,031
Apr	17	0.021	5,604	-	667	86,644	533	88,476	(106)	405	0.02119	89,302
May	18	0.032	8,378	-	723	98,486	580	97,434	(116)	439	0.03168	98,403
Jun	19	0.079	20,941	-	867	119,427	675	119,050	(131)	526	0.07917	120,211
Jul	20	0.197	52,046	-	1,158	171,472	908	172,004	(178)	702	0.19678	173,414
Aug	21	0.057	14,996	-	1,424	186,468	1,123	188,123	(221)	864	0.05670	189,834
Sep	22	0.054	14,227	-	1,541	200,696	1,222	203,572	(242)	935	0.05379	205,602
Oct	23	0.074	19,468	-	1,675	220,164	1,335	224,375	(266)	1,016	0.07361	226,745
Nov	24	0.045	11,799	976	1,803	241,406	1,444	238,594	(289)	1,094	0.04461	240,347
Dec	25	0.045	11,815	-	1,968	253,220	1,530	251,939	(297)	1,194	0.04467	254,129
Jan	26	0.032	8,537	-	2,049	261,758	1,603	262,080	(313)	1,243	0.03228	264,716
Feb	27	0.012	3,071	-	2,095	264,829	1,650	266,801	(324)	1,271	0.01161	269,882
Mar	28	0.012	3,071	-	2,120	267,900	1,679	271,552	(332)	1,286	0.01161	275,074
Apr	29	0.006	1,602	-	2,138	269,502	1,704	274,858	(339)	1,298	0.00606	278,814
May	30	0.003	875	-	2,148	282,896	1,723	277,456	(345)	1,304	0.00331	281,837
Jun	31	0.003	875	-	2,255	283,771	1,739	280,070	(335)	1,368	0.00331	284,967
Jul 2008	32	0.030	7,867	-	2,290	291,638	1,777	289,714	(345)	1,389	0.02974	295,123
	33	0.000	0	-	0	296,182	0	289,714	0	0		295,123
	34	0.000	0	-	0	296,182	0	289,714	0	0		295,123
	35	0.000	0	-	0	296,182	0	289,714	0	0		295,123
	36	0.000	0	-	0	296,182	0	289,714	0	0		
	37	0.000	0	-	0	296,182	0	289,714	0	0		
	38	0.000	0	-	0	296,182	0	289,714	0	0		
	39	0.000	0	-	0	296,182	0	289,714	0	0		
	40	0.000	0	-	0	296,182	0	289,714	0	0		
	41	0.000	0	-	0	296,182	0	289,714	0	0		
	42	0.000	0	-	0	296,182	0	289,714	0	0		
		1.00000	$264,486	$1,059	$30,637		$24,168		($4,763)	$18,591		

Total Rate Base	$300,945	1,085
Book Basis Less Equity AFDC	277,592	
Non-Equity AFDC Portion	0.937232787	

		Steel Price Increase	1-year Inflation	Total Interconnection Costs
Right-of-way & siting	2,100			
Interconnect Facilities - Station/Transmission	13,915			
Network Upgrade - Station/Trans	1,141	114	31	1,286
Switchyard/ Interconnection/Breaker	1,182	118	33	1,333
Standby Power Interconnection	500	50	14	564
BPA Transmission Tower Mods	500	50	14	564
	19,338			3,747

Staff/1401
Gonzalez/3

UM-1129/PacifiCorp
November 15, 2005
OPUC Data Request 48

OPUC Data Request 48

Please itemize the interconnection costs assigned to the proxy plant PacifiCorp used to calculate standard avoided costs, list the cost of each item, and explain the basis for calculating each cost.

Response to OPUC Data Request 48

The brownfield CCCT (dry cooling) used the budget estimates for a second Currant Creek plant as a starting point. Direct budget values were as follows in 2004 $:

Interconnection - $5,200,000
Communications - $500,000
Switchyard - $3,100,000
Step-up Transformers - $2,633,902

In general, we have included the cost of the switchyard, interconnection costs from the transmission system to the switchyard (including the costs to go from the step-up transformers to the switchyard and from the switchyard to plant boundary), communications infrastructure at the plant, and step-up transformers in the generation portion of the cost estimate.

UM-1129/PacifiCorp
December 5, 2005
OPUC Data Request 51

OPUC Data Request 51

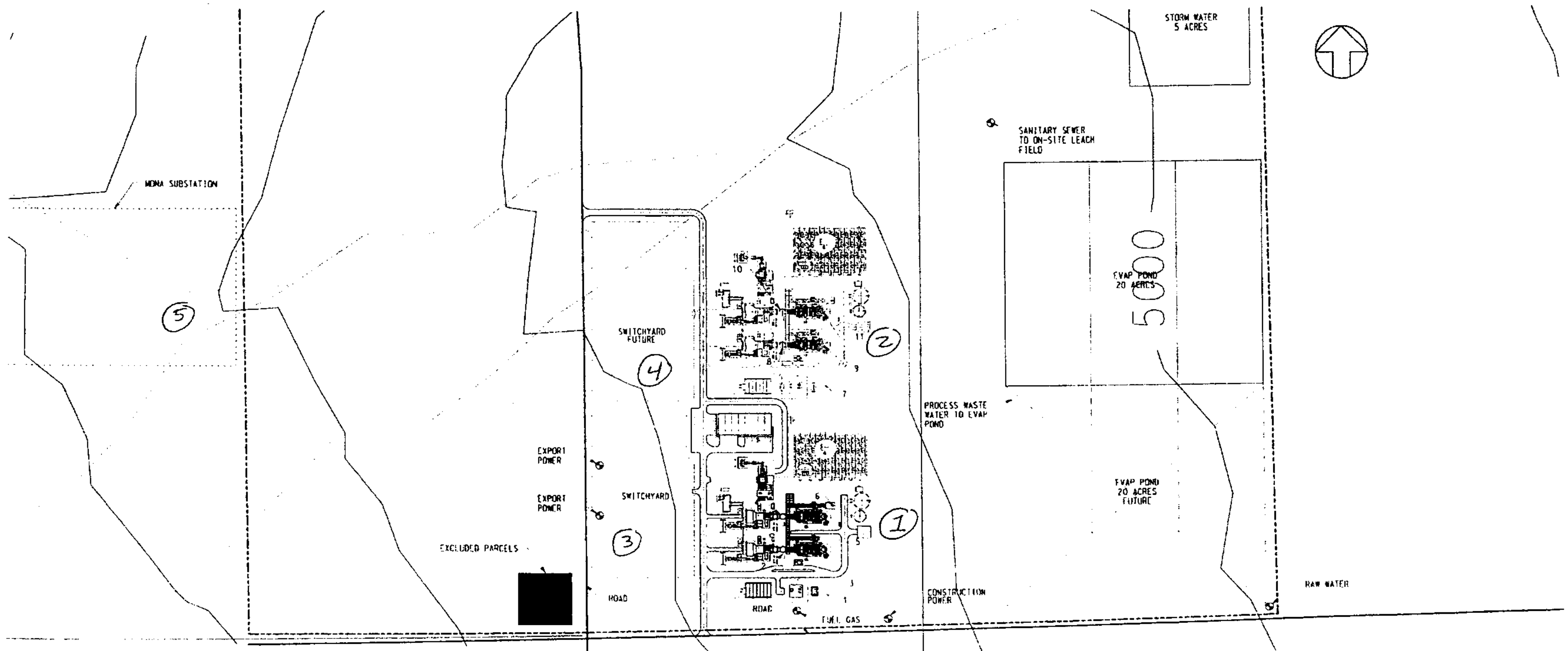
Please refer to staff data request 48. Provide a detailed site layout representative of the utility proxy plant PacifiCorp used to calculate standard avoided costs showing interconnecting points, including detailed line diagrams for all lines, switches, metering points, transformers and generating plant.

Response to OPUC Data Request 51

The utility proxy plant proposed is a second combined cycle plant at the Currant Creek site. Shown on Attachment OPUC 51 is the drawing 59321-DM-011A-C, which is a layout of the Currant Creek site with the second plant, added in dashed lines. The second plant was assumed to interconnect with a second switchyard assumed to be similar to the first switchyard. An illustration of the existing Currant Creek switchyard is given in drawing 110895.001 in Attachment OPUC 51.

The second Currant Creek switchyard would connect to the Mona Substation via a short (1/4 mile) line similar to the line between the existing switchyard and Mona. Drawing N2533-1700, in Attachment OPUC 51, illustrates the additions required at Mona to accommodate the new line for the second plant. This drawing also illustrates the additions that were made to accommodate the first line at Mona. The items referenced in the answer to request 48 are shown in the diagram with numbered bullets corresponding to answers in questions 52 and 53.

59321-



EMISSION POINT COORDINATES			PERMIT DESCRIPTION	
ITEM NO	NORTHING	EASTING		DIMENSION (DIA/HEIGHT)
1	14462797'	1389559'	DEWPOINT HEATER STACK 1	24"O.D. @ 35' HIGH
2	14462975'	1389397'	SIMPLE CYCLE STACK 1A1	23'I.D. @ 140' HIGH
3	14462975'	1389553'	HRSG STACK 1A2	16'-10"I.D. @ 150' HIGH
4	14463105'	1389398'	SIMPLE CYCLE STACK 1B1	23'I.D. @ 140' HIGH
5	14463105'	1389554'	HRSG STACK 1B2	16' 10"I.D. @ 150' HIGH
6	14463148'	1389593'	AUX STEAM BOILER STACK	24"O.D. @ 35' HIGH
7	14463956'	1389596'	DEWPOINT HEATER STACK 2	24"O.D. @ 35' HIGH
8	14463785'	1389402'	SIMPLE CYCLE STACK 2A1	23'I.D. @ 140' HIGH
9	14463784'	1389558'	HRSG STACK 2A2	16' 10"I.D. @ 150' HIGH
10	14463915'	1389403'	SIMPLE CYCLE STACK 2B1	23'I.D. @ 140' HIGH
11	14463914'	1389559'	HRSG STACK 2B2	16' 10"I.D. @ 150' HIGH

ALL COORDINATES SHOWN ARE UTM (83) ZONE 12

WATERCOURSE

PRELIMINARY

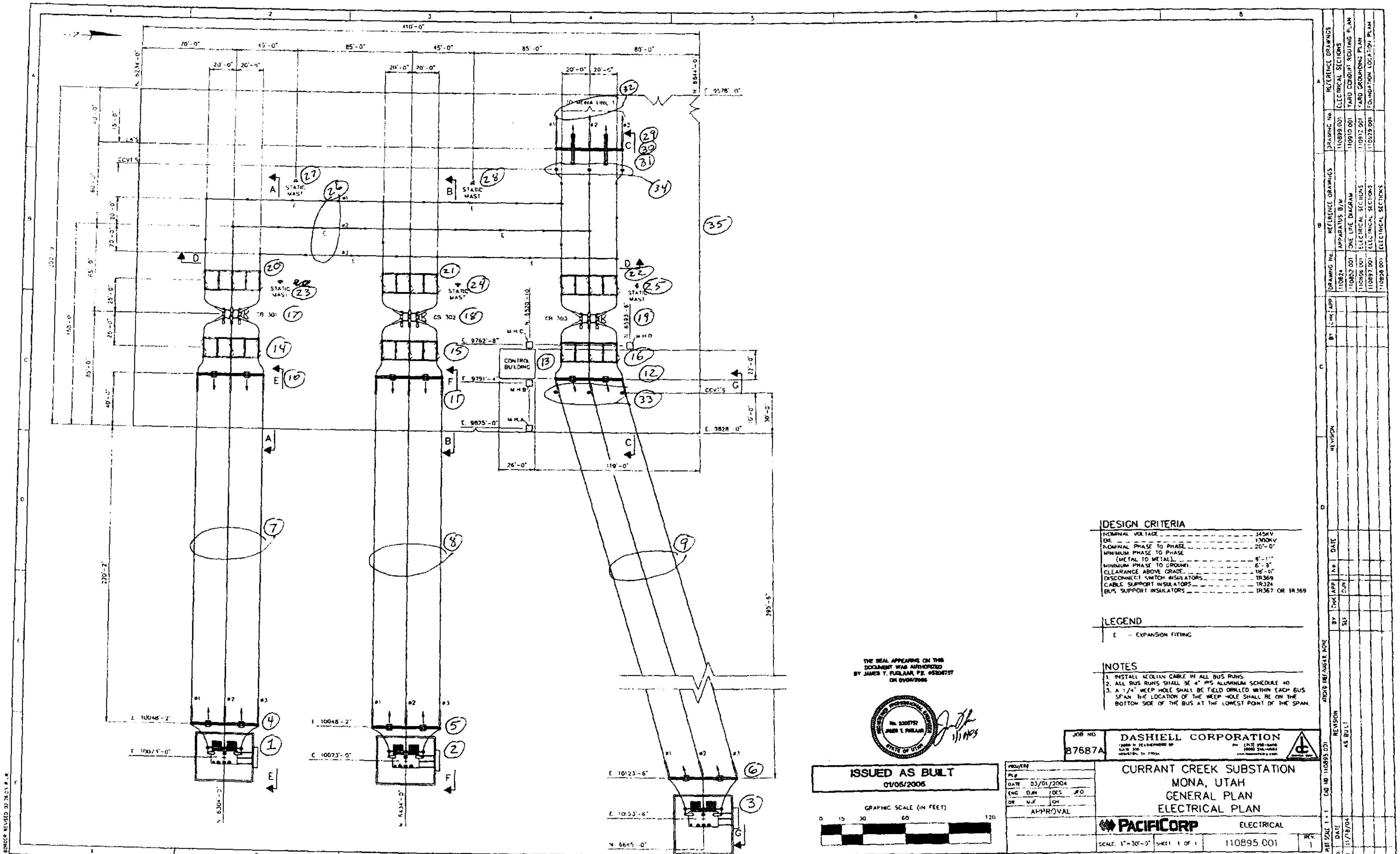
0 100' 200' 400' 600'
SCALE: 1" = 200'

CURRANT CREEK POWER PROJECT
UNIT NO. 1
(2) - 500MW 2x1 COMBINED CYCLE
SITE PLAN
PACIFICORP
MONA, UTAH

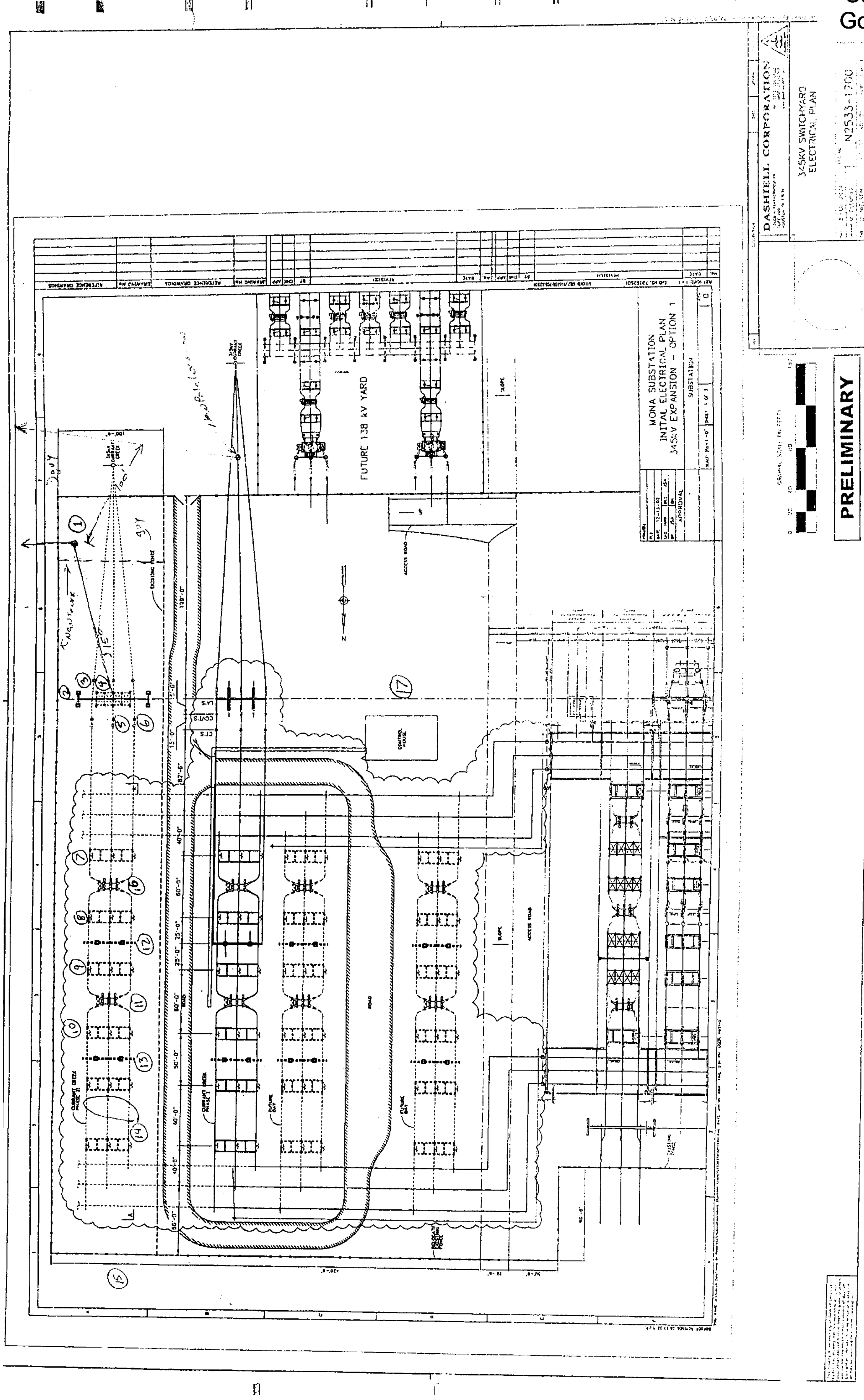
Shaw Stone & Webster, Inc.

59321-DM-011A-C

Staff/1401
Gonzalez/6



Staff/1401
Gonzalez/7


DASHIELL CORPORATION
345KV SWITCHYARD
ELECTRICAL PLAN
N2533-1700
MONA SUBSTATION
INITAL ELECTRICAL PLAN
345KV EXPANSION - OPTION 1
FUTURE 138 kV YARD
CONTROL HOUSE
ACCESS ROAD
ROAD
SLOPE
PRELIMINARY

UM-1129/PacifiCorp
December 5, 2005
OPUC Data Request 52

OPUC Data Request 52

Provide a description (name/type/size/function/quantity) for each of the above items and identify them in the detailed layout.

Response to OPUC Data Request 52

See attachment to OPUC Data Request 51 (Attachment OPUC 51), which includes three layout drawings illustrating the second block of Currant Creek as follows:

Drawing 59321-DM-011A-C
Item 1 – Currant Creek I
Item 2 – Currant Creek II
Item 3 – Currant Creek Switchyard – Existing
Item 4 – Currant Creek Switchyard – Proposed
Item 5 – Mona Switchyard

Drawing 110895.001
Item 1 – 3 Generator Step-up transformers
Item 4 – 6 Transformer Take-off dead-end structures
Item 7- 9 Transmission line spans to Switchyard
Item 10-12 Transmission dead-end structures
Item 13 Control building – contains relay and communications equipment
Item 14-16 Air-break switches
Item 17-19 Circuit Breakers
Item 20-22 Air-break switches
Item 23-25, 27, 28 Static Masts for lightning protection
Item 26 High voltage bus work
Item 29 Air-break switch and Grounding switch
Item 30 Lightning arrestor
Item 31 Dead-end structure
Item 32 Line to Mona
Item 33,34 Potential transformers
Item 35 Fence, civil work, cable trench, grounding, etc.

Drawing N2533-1700

Item 1 – Transmission Angle Structure
Item 2 – Transmission dead-end structure
Item 3 – Lightning Arrestor
Item 4 – Air-break switch and grounding switch
Item 5 – Currant Transformer
Item 6 – Potential Transformer

UM-1129/PacifiCorp
December 5, 2005
OPUC Data Request 52

Item 7-10 Air-break switches
Item 11, 16 Circuit Breakers
Item 12,13 Support structures
Item 14 Bus work
Item 15 Fence, civil, grounding, cable trench etc.
Item 17 Relays and communications equipment

UM-1129/PacifiCorp
December 5, 2005
OPUC Data Request 53

OPUC Data Request 53

Please provide a detailed cost breakdown for each of the following items, as they apply to the plant identified above:

a. Interconnection cost breakdown, detailed to its lowest cost element
b. Communication cost breakdown, detailed to its lowest cost element
c. Switchyard cost breakdown, detailed to its lowest cost element
d. Step-up transformers cost breakdown, detailed to its lowest cost element

Response to OPUC Data Request 53

a. Interconnection costs (i.e. the cost of the Mona Substation additions) were not broken down in the second block estimate, rather an allowance for the second block cost was estimated using the cost estimates for the first block since the equipment additions would be a duplication. The original estimate for the first block was $6,500,000. The second block was estimated at 80% of the first block at $5,200,000. Equipment and installation costs are direct and do not include contingencies, overheads, and financing in the form of AFUDC. Approximately 17.6% should be added for contingencies and another 11.6% for AFUDC. AFUDC will be higher for the second block of Currant Creek because it would not be constructed as a two phase operation with a portion of the plant put into service early.
b. Communication costs were not broken down in the second phase estimate, rather an allowance for the second phase cost was estimated using the cost estimates for the first phase since the equipment additions would be a duplication. The original estimate for the first block was $600,000. The second block was estimated at $500,0000. Equipment and installation costs are direct and do not include contingencies, overheads, and financing in the form of AFUDC. Approximately 17.6% should be added for contingencies and another 11.6% for AFUDC. AFUDC will be higher for the second block of Currant Creek because it would not be constructed as a two phase operation with a portion of the plant put into service early.
c. The Switchyard cost (i.e. Currant Creek switchyard) breakdown used in the second phase cost was estimated using the cost estimates for the first phase since the equipment additions would be a duplication. The original estimate for the first block was $4,000,000. The second block was estimated at $3,100,000. Equipment and installation costs are direct and do not include contingencies, overheads, and financing in the form of AFUDC. Approximately 17.6% should be added for contingencies and another 11.6% for AFUDC. AFUDC will be higher for the second block of Currant Creek because it would not be constructed as a two phase operation with a portion of the plant put into service early.
d. The step-up transformer estimate of $2,633,902 is shown below to the lowest cost element. This estimate is for equipment only. Installation cost is included in the plant cost proper and interconnection costs from the transformer are included in the $3.1M switchyard cost. Equipment costs are

direct only and do not include contingencies, overheads and financing in the form of AFUDC. Approximately 17.6% should be added for contingencies and another 11.6% for AFUDC. AFUDC will be higher for the second block of Currant Creek because it would not be constructed as a two phase operation with a portion of the plant put into service early.

190 MVA GSU Transformer	$	804,000
190 MVA GSU Transformer	$	804,000
270 MVA GSU Transformer	$	990,450
New CT's Aux Transformers ($1,835 / unit)	$	3,670
Boxing Ring ($9,835 / unit)	$	27,305
Lightning Arrestor	$	2,929
2nd CT change	$	1,548
	$	2,633,902

REQUEST STAFF 30:

Please explain why Idaho Power seeks to acquire rights of way and access to the Seller's facility for utility lines and easements unreleased to the QF, per § 13.2 to 13.4.

IDAHO POWER'S RESPONSE TO REQUEST STAFF 30:

The reason for inclusion of § 13.2 through 13.4 in the agreement is to avoid a problem that surfaced in Idaho where a QF developer decided it wanted to utilize the available public right-of-way to build a line from its project to interconnect to the utility in a location where retail customers of Idaho Power had requested retail service in the same vicinity. Idaho Power was faced with the choice of building a second line in public right-of-way across the road from the QF developer's line to serve the retail customers (not favored by the local planning entity for aesthetic and safety reasons) or advising the retail customer(s) that they would have to pay the excess cost demanded by the QF developer for Idaho Power to purchase the line from the QF developer in order to provide services. Idaho Power has approximately 75 QF contracts containing this provision and it has eliminated the problem of duplicate facilities without any adverse impact on QF development.

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 9th day of December, 2005.

Mike Weirich
Assistant Attorney General
Of Attorneys for Public Utility Commission's Staff
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Telephone: (503) 378-6322

UM 1129 – Phase I Compliance
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