I. Introduction

Q. What are your names and positions with Portland General Electric?

A. My name is Pamela G. Lesh. I am PGE's Vice President, Regulatory Affairs and Strategic Planning. My qualifications appear at the end of this testimony.

My name is Randy Dahlgren. I am Director, Regulatory Policy and Affairs. My qualifications also appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to:

- Present our request to include in PGE's retail electricity prices the costs and benefits of the Biglow Wind Project supported by this filing;
- Explain the reasons behind this proposal and why PGE is not seeking retail prices based on a 2008 test year revenue requirement that updates all revenue and expense items included in the just-established revenue requirement adopted by the Commission in Dockets UE 180/181/184; and
- Introduce the rest of PGE's testimony.

II. Requests in this Filing

Q. What is PGE requesting in this case?

A. PGE is asking only that the Oregon Public Utility Commission (OPUC or Commission) approve a supplemental tariff that includes the costs and benefits of the Biglow Canyon wind project currently under construction in Sherman County, Oregon. As discussed below, we are not seeking to reexamine or alter the ratemaking decisions recently made by the Commission in Dockets UE 180/181/184.

Q. What is the Biglow Canyon project?

A. Biglow Canyon is PGE's latest addition to our renewable resource portfolio. This filing includes Phase I of PGE's development of the Biglow Canyon project. This phase includes 76 wind turbines of 1.65 MW capacity each. The expected output of the project is approximately 46 MWa.

Q. Please briefly describe the history behind the Biglow Canyon project.

A. The Final Action Plan in PGE's most recent Integrated Resource Planning docket, acknowledged in Commission Order No. 04-375, called for the acquisition of 65 MWa of wind power. We selected the Biglow Canyon project from a Request for Proposals (RFP) solicitation described in the testimony of PGE Exhibit 200. PGE entered into an agreement with Orion Energy, LLC and Orion Sherman Wind Farm, LLC to acquire the project development assets and rights. The ability to expand on the site increases the value to customers of the Biglow Canyon project. PGE Exhibit 200 provides more detail about the Biglow Canyon project.

In addition to the Biglow Canyon project, PGE is purchasing 27 MWa of wind power from the Klondike II wind project. With these two renewable portfolio additions, PGE has more than met the targets in the Final Action Plan.

Q. When will Biglow Canyon become operational?

A. We expect all 76 turbines to be operational by December 1, 2007.

Q. Is PGE requesting prices to recover Biglow's revenue requirement effective January 1, 2008?

A. Yes. The January 1, 2008, effective date allows us to make just one price change that incorporates net variable power costs (NVPC) through the Annual Update Tariff and the Biglow Canyon supplemental tariff, as well as changes to other supplemental tariffs (Schedules 102 and 105) that we have designed to occur January 1, 2008. We believe the impact of any regulatory lag between incurrence of net costs for Biglow and a January 1, 2008, effective date for rates will be minimal provided PGE is allowed to retain the dispatch benefits of Biglow prior to it going into rates.

Q. Given a projected on-line date of December 1, 2007, how does PGE plan to address Biglow Canyon in the 2007 variance tariff (Schedule 126)?

A. PGE proposes that any power produced by Biglow Canyon prior to January 1, 2008 be valued for power cost purposes at the monthly average of the Mid-C firm on- and off-peak index for determining actual NVPC under Schedule 126, the annual power cost variance mechanism. We plan to separately file a modification to Schedule 126 clarifying this point.

Q. What effect will adding the Biglow Canyon project have on PGE's retail electricity prices?

A. We are pleased to be able to bring this new renewable resource into PGE's portfolio with a very small impact on prices. At PGE's currently authorized return on equity and capital structure, we presently estimate the net increase from inclusion of the Biglow Canyon project at $13 million, for an overall price increase of 0.8%.

The $13 million is the sum of Biglow Canyon's fixed costs, which include O&M and capital cost recovery, and the reduction in PGE's net variable power costs that its very low-cost energy enables. The costs and benefits of the Biglow Canyon project are addressed in more detail in PGE Exhibit 200. As they explain, we anticipate updating both the capital costs and the dispatch benefits of the project later in the year.

Q. Is this the only relief PGE is seeking in this case?

A. Yes.

Q. Given that PGE is requesting a price increase based solely on the net cost of Biglow Canyon, why are you providing testimony regarding other 2008 cost and revenue changes to the 2007 test year revenue requirement just adopted in Dockets UE 180/181/184?

A. While PGE is seeking only to include the costs and benefits of the Biglow Canyon project, current ratemaking rules and practices left us with a dilemma. Because there is no explicit provision for adjusting a recently adopted revenue requirement for only certain identifiable changes (what, in practice, we have typically called a "tracker"), we have taken the conservative route of complying with the rules and regulations regarding a general rate revision. Our testimony demonstrates a need for over $54.2 million in increased revenues for PGE to have an opportunity to earn the cost of capital the Commission authorized in Order No. 07-015. This increase does not include an update to PGE's cost of capital.

Q. Why is PGE not asking to fully update to a 2008 revenue requirement?

A. On January 12, 2007, the Commission issued Order No. 07-015 in UE 180/181/184, a consolidated docket that included a general 2007 test year revenue requirement and an additional filing to include within that test year the costs of the Port Westward generating plant currently under construction. That docket was PGE's first general rate case in over five years. It was a lengthy process, addressing many issues, some of which the parties reached agreement on and some on which they did not. We do not think it is in anyone's interests to revisit many of the same issues again at this time. In addition, PGE has substantial capital-intensive projects on the near horizon for hydro relicensing and other necessary investments. These will likely drive the need for general rate case filings in the foreseeable future. Proceeding with this limited filing provides a brief respite from what will likely be a series of rate filings.

Q. Does the income tax true-up required by SB 408 make this decision more difficult than it would previously have been?

A. Yes. The current formula to determine the taxes authorized to be collected in rates does not recognize the effect of increases or decreases in the costs of regulated utility operations. Thus, the true-up requires utility customers to pay for "taxes" on costs of regulated utility operations that decline or receive refunds for "taxes" on costs of regulated utility operations that increase. Also, costs of regulated operations that the Commission does not recognize when setting rates (for example, disallowed costs) have the perverse impact of generating tax refunds simply because customers do not bear those costs. These factors provide incentives to file full rate cases more frequently and challenge Commission policies regarding various cost categories that may no longer make sense in a post SB 408 environment. All else being equal, our decision to ask only for Biglow Canyon's incremental net costs rather than a full 2008 test year will harm PGE financially. We are hopeful, however, that stakeholders will reach agreement on a way that the Legislature can remove or mitigate this counter-productive effect of SB 408 during its current session.

Q. How does the proposed supplemental tariff work?

A. The tariff is for the net costs of the Biglow Canyon project, spread on an equal cents per kWh basis (adjusted for delivery voltage) to all rate schedules except Schedules 76, 483, and 489. The proposed tariff will be effective January 1, 2008, or later if completion of the project is delayed. PGE Exhibit 400 further describes the proposed tariff.

Q. How long will the tariff be effective?

A. The proposed tariff will only be effective until PGE's next general rate case, when the Biglow Canyon-related costs and benefits will be included in base rates under each schedule. As discussed earlier, due to some capital intensive projects underway or about to be undertaken, we expect to have a general rate case in the near future.

Q. Does this filing interrelate with the Annual Update Tariff?

A. Yes. On April 1, PGE will initiate the Annual Update Tariff (AUT) process for 2008. We presently estimate NVPC for 2008 at $775.6 million, which would result in a price decrease of approximately $7.8 million. That filing will not include Biglow Canyon costs or dispatch benefits. To ensure accurate costs for purposes of setting retail prices, the final AUT run and the calculation of Biglow Canyon's dispatch benefits need to occur concurrently based on the same assumptions, including loads and market curves. If all present assumptions hold, the net result would be a very small price increase on January 1, 2008.

Q. Do you expect any other tariff or price changes on January 1, 2008?

A. Yes. We expect four different changes may affect retail electric prices on January 1, 2008, in addition to the combination of the AUT and this Biglow Canyon filing. First, the Schedule 102 Regional Power Act Exchange Credit will decline by approximately $21 million as we conclude refunding to customers a credit balance in that account. We presently estimate that this will increase the Schedule 7 price by approximately 3%. Second, the completed amortization of the IT credit and the property gain credit will result in a Schedule 105 increase. This change will cause an effective average price increase of approximately 0.5%. Third, a bill before the legislature would change the calculation method for Commission regulatory fees assessed on PGE and other utilities, increasing PGE's regulatory fee. If the legislature enacts an increase in Commission regulatory fees, PGE will seek to recover this increased cost effective January 1, 2008.

The last price change that could occur January 1 relates to PGE's Automated Metering Infrastructure project. Although we plan shortly to file a tariff beginning recovery of incremental costs associated with changing PGE's metering infrastructure to a two-way radio system, we are designing that filing to permit implementation on July 1, 2007, with no price change by including amortization of some credits presently being held for return to customers. These credits would terminate on December 31, 2007, and result in an approximate 0.9% price increase on January 1, 2008.

Q. Are there other issues that the Commission needs to address in this docket?

A. Yes. This docket is a general rate proceeding or other general rate revision under OAR 860-022-0041. The order in this docket will reset the ratios used in the calculation of "taxes authorized to be collected in rates" as used in that rule. PGE Exhibit 200 provides this calculation. As PGE stated in UE 180, the Commission should also adjust "taxes in rates" to reflect disallowed items in rate cases. Given the nature of this filing, however, that issue may not arise here.

Q. Do you recommend that the schedule adopted for this proceeding include times at which PGE will update certain information?

A. Yes. We recommend that the schedule in this docket and the schedule in the AUT provide for PGE to update its pricing and load forecast at the same time in both dockets to culminate in final rates for NVPC in November 2007 (with the schedule to be determined in the AUT proceeding).

III. Overview of PGE's Testimony in this Filing

Q. What testimony is PGE presenting in this case other than this?

A. PGE is presenting the following direct testimony:

Exhibit 200 summarizes the overall 2008 test year revenue requirement including O&M, power operations, administration and general, and other costs. These witnesses also discuss Biglow Canyon costs and benefits and the revenue requirement impact of just Biglow Canyon.

Exhibit 300 supports PGE's cost of capital and use of the return on equity and capital structure recently approved in UE 180/181/184.

Exhibit 400 explains PGE's proposed supplemental tariff.

IV. Qualifications

Q. Ms. Lesh, please describe your qualifications.

A. I received a BA degree from Washington State University in 1978. I received my J.D. from the University of Washington, School of Law in 1981. I was employed by Portland General Electric from 1986 to 1997, becoming Vice President, Rates & Regulatory Affairs in October of 1996. In June 1997, I became a Vice President of Strategy at Connext, Inc., where I supervised product management staff and strategic alliances as well as negotiating client contracts. In January 1999, I returned to PGE as Vice President, Rates & Regulatory Affairs.

Q. Mr. Dahlgren, please describe your qualifications.

A. I received a Bachelor of Science degree from Oregon State University in Electrical Engineering. In addition, I have taken courses from other universities in the areas of engineering economics, systems analysis, and business administration. I also attended the 1980 Public Utilities Executives' Course at the University of Idaho.

I joined PGE in 1973 shortly after graduation and subsequently have been involved in the areas of load research, load and revenue forecasting, price analyses and design, and class cost-of-service analyses. I was appointed Rate Engineer in January 1977 and have held various management positions in the regulatory area since 1978. I entered my present position as Director of Regulatory Policy and Affairs in 2001.

Q. Does this complete your testimony?

A. Yes.

Revenue Requirement

Table of Contents

I. Introduction and Summary

Q. Please state your names and positions with PGE.

A. My name is L. Alex Tooman. I am a project manager for PGE. I am responsible, along with Mr. Tinker, for the development of PGE's revenue requirement forecast. In addition, my areas of responsibility include affiliated interest filings, results of operations reporting, and other regulatory analyses.

My name is Jay Tinker. I am also a project manager for PGE. My areas of responsibility include revenue requirement analyses and other regulatory analyses.

My name is Stephen Schue. I am a senior analyst for PGE. My areas of responsibility include power supply analysis and other regulatory analyses.

Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is two fold. First, we present the incremental revenue requirement of Biglow Canyon (Biglow) to support the supplemental tariff for Biglow as described in PGE Exhibit 100. To determine the revenue requirement of Biglow, we use the same cost of capital, income tax, and other revenue-sensitive cost factors as approved by the Oregon Public Utility Commission (OPUC or Commission) in Order No. 07-015 (Docket UE 180). Under this approach, the incremental revenue requirement of Biglow is $13.0 million. Second, we present PGE's 2008 revenue requirement based on forecast 2008 costs, rate base, and other relevant parameters, except we maintain cost of capital at the level approved in Commission Order No. 07-015. The purpose of this presentation is to show that PGE's revenue requirement needs for 2008 are substantially higher than the $13.0 million requested through the supplemental tariff for Biglow. If PGE were to process a general rate case for 2008, we could support a revenue requirement increase of at least $54.2 million.

Q. How is your testimony organized?

A. The next section describes the Biglow project and provides our estimate of Biglow costs and benefits, including support for the $13.0 million incremental revenue requirement for Biglow using the supplemental tariff approach described in PGE Exhibit 100. The remainder of the testimony provides a 2008 revenue requirement based on forecasts of 2008 costs and rate base and our qualifications.

II. Biglow Canyon Revenue Requirement

A. Description

Q. Please provide an overall description of the Biglow project.

A. This filing reflects Phase I of PGE's development of the Biglow wind site. Phase I includes 76 wind turbines, each with a capacity of 1.65 MW. Vestas-America Wind Technology, Inc. (Vestas) will supply the turbines, pursuant to the Turbine Supply Agreement between Vestas and PGE. The Biglow site is located in Sherman County, near the Columbia River in north-central Oregon. The turbines will be assembled on the site from components manufactured in Vietnam, Spain, England, and Denmark. The components will arrive at the Port of Vancouver (WA) and will be transported by truck to the Biglow site. We expect all 76 turbines to be operational by December 1, 2007.

Q. Is PGE the original developer of the Biglow site?

A. No. Orion Energy, LLC (Orion) is the original developer. PGE pursued acquisition of the development rights from Orion in response to Orion's bid into PGE's 2003 Request for Proposals, which we discuss later in our testimony.

Q. What specific items did PGE acquire from Orion?

A. PGE acquired land easements, an interconnection agreement request with the Bonneville Power Administration (BPA), and detailed data on wind flows at the site.

Q. Does PGE have a Large Generator Interconnection Agreement (LGIA) with the BPA for Biglow?

A. Yes. BPA has issued a LGIA for Biglow.

Q. Please describe Biglow's interconnection with the regional grid in more detail.

A. To facilitate the interconnection of Biglow, BPA will expand its current 500 kV John Day substation, construct a new 230 kV John Day substation, and build a six-mile long 230 kV transmission line from Biglow to John Day. Some of these facilities will also serve to interconnect other wind developments, and could in the future serve to interconnect additional phases of Biglow development.

Q. Does the Biglow wind project complete the Integrated Resource Plan (IRP) Final Action Plan that the Commission acknowledged in Order No. 04-375?

A. Yes. With commercial operation of Port Westward, PGE will have completed all but one of the items included in the action plan listed on page 13 of Order No. 04-375. Phase I of Biglow will complete the final item, "65 MWa (195 MW) of wind generation." Specifically, PGE is already purchasing approximately 27 MWa of wind power from the 75 MW Klondike II project, pursuant to the Final Action Plan. Biglow Phase I will have a 125.4 MW capacity and we expect it to generate approximately 46 MWa of energy. Biglow and Klondike II then combine to exceed the action item target.

B. 2008 Biglow Revenue Requirement

Q. What is Biglow's overall impact on PGE's revenue requirement?

A. PGE currently forecasts that Biglow's fixed costs will be $35 million and its dispatch benefits will be $22 million. The net revenue requirement impact is, thus, approximately $13 million. PGE Exhibit 201 summarizes the development of Biglow's incremental revenue requirement.

Biglow's average 2008 rate base of $234 million, multiplied by the UE 180 pre-tax cost of capital, approximately 11.6%, results in a return cost of $27 million. Depreciation and

O&M costs are $12 million and $6 million respectively. Property taxes are $2 million. These cost components sum to $47 million. Tax credits total $12 million (on a revenue requirement basis), resulting in overall (net) fixed costs of $35 million.

Biglow's dispatch benefits, or impact on net variable power costs, are $22 million. These benefits are net of costs to shape and integrate Biglow's variable wind output.

Q. If the Commission adopts the supplemental tariff to determine Biglow's incremental revenue requirement, should the Commission allow for an update to ratios used to determine taxes collected in rates for AR 499 purposes?

A. Yes. Biglow's incremental revenue requirement includes taxable income associated with equity return on investment as well as tax credits associated with this investment. Since PGE's expected tax liability would change from the impact of Biglow, it is appropriate to update the net to gross and effective tax rates used in AR 499 to reflect this impact.

Q. How should the updated ratios be calculated?

A. The ratios should be computed using the UE 180 approved revenue requirement as modified for Biglow in this supplemental tariff proceeding. For example, based on the $13.0 million Biglow revenue requirement, the ratios for UE 180, and UE 180 modified for Biglow, are provided in PGE Exhibit 201.

Q. What is your estimate for the final Biglow capital costs?

A. We estimate that the capital costs will be $261 million when we close the last project elements to book on November 30, 2007.

Q. What is the depreciation life of the Biglow assets?

A. PGE will depreciate Biglow over a 25-year period.

Q. Does your O&M estimate include the cost of a turbine maintenance agreement?

A. Yes. The 2008 cost of the turbine maintenance agreement is the largest component of our O&M estimate. We describe the agreement in detail later in this section of our testimony.

Q. Do you propose a major maintenance accrual for Biglow?

A. No. Biglow's major maintenance contract provides for a more levelized annual cost, unlike the contract for Coyote Springs. As a result, we do not expect the significant year-to-year volatility that an accrual would help dampen.

Q. How many employees will work at Biglow?

A. Our O&M revenue requirement includes the cost of five employees.

Q. Does your tax credit figure include a renewable energy tax credit?

A. Yes. We include a 2008 renewable energy tax credit of $7.7 million.

Q. What are the key features of the renewable energy tax credit?

A. The Tax Reduction and Health Care Act of 2006 extended the National Energy Policy Act (NEPA) credits for renewable energy resources. Under this legislation, credits based on Biglow's production will begin when the plant becomes operational and will continue for 10 years. They are currently $19 per MWh and we use this figure in our 2008 test year revenue requirement. This figure goes up with inflation, and could increase to $20 per MWh in 2008. If appropriate, we will incorporate this change in our final test year net variable power cost estimate in this proceeding.

Q. What other components do you include in tax credits?

A. We include a Business Energy Tax Credit (BETC) from the State of Oregon, which we will receive over a five-year period, beginning when the plant becomes operational. The test year revenue requirement incorporates the effect of the 2008 BETC credit of approximately $1 million.

Q. Will the Energy Trust of Oregon (ETO) provide funding to cover the difference between the cost of Biglow's power output and the cost of the same power output purchased at expected market prices?

A. Possibly. Final calculations to determine whether Biglow power costs more than market, and if so, by how much, will not be made until costs are known with greater precision. We will update our Biglow calculations as appropriate during this proceeding if we receive ETO funding.

Q. Does Biglow qualify for a property tax "holiday?"

A. It may. We are working with Sherman County and the State of Oregon on this issue, but no agreements have been reached. We include Biglow property taxes in our revenue requirement. We will update these costs as appropriate during this proceeding if we reach a definitive tax "holiday" agreement.

Q. How do you calculate net dispatch benefits?

A. We start with the value of the power that we forecast Biglow will generate during the test year. This is roughly the project's expected annual output multiplied by the average electric price from the forward curve assumed in MONET. However, the calculation in our MONET model is more complex because we include data on expected wind flows, which are not uniform across all hours of the year. Using data developed by the 3Tier Environmental Forecast Group, MONET incorporates hourly wind shaping for Biglow.

From the value of Biglow's output, we then subtract the associated regulation, imbalance, integration, and reserve costs. We describe these in detail later in this section of our testimony.

Q. Do you include PGE's share of interconnection costs in your revenue requirement?

A. Yes. We include PGE's share of these costs, approximately $16 million, in the return on rate base and depreciation components of the test year revenue requirement.

Q. Will Biglow be in BPA's system control area?

A. Yes.

Q. Will BPA provide transmission of power from Biglow to PGE's service territory?

A. Yes. We will move Biglow power to our service territory by redirecting 150 MW of our Rocky Reach to Portland rights under our point-to-point (PTP) transmission agreement with BPA.

Q. Will PGE's payments for BPA transmission services change with this PTP redirection to accommodate Biglow?

A. They may. BPA classifies approximately $13 million of the interconnection costs discussed above under network upgrades. Since PGE paid for upgrades to BPA's network, BPA must repay the $13 million (with interest). Pursuant to the LGIA, BPA is to base repayment credits on the 150 MW PTP redirection. We are not yet able to forecast the exact impact of these credits on Biglow's revenue requirement. However, when we have more information, we will include the credits in our net variable power cost forecast updates during this proceeding.

Q. What must PGE do to handle the intermittent nature of the wind power generated by Biglow?

A. Conceptually there are three distinct services that PGE must either purchase or self-provide. Regulation covers moment-to-moment deviations in output. Imbalance service covers deviations in output between hourly schedules and actual hourly output. In other words, imbalance service deals with deviations in averages within one-hour periods. Integration covers output changes from hour-to-hour.

Q. Which of these services can be purchased under published tariffs?

A. Under BPA's PTP tariff, we could schedule Biglow on an hourly basis. Within hour deviations from schedule would then be covered by BPA and billed to PGE in accordance with the PTP tariff rate for imbalance services. BPA does not currently have a published tariff for regulation, nor does BPA currently have a tariff for integration.

Q. Is PGE analyzing the cost effectiveness of providing these services from its own resources?

A. Yes. PGE has hired EnerNex to estimate the costs of providing for the intermittent nature of Biglow's output with PGE's other resources. We expect EnerNex to complete its study by April 2007.

Q. Does PGE's contract with Pacific Power Marketing (PPM) for the output of the Klondike II wind project contain charges for providing the three services needed to handle wind power?

A. Yes. However, the form of these products and their related charges are specific to Klondike II and are part of an overall contract with PPM.

Q. How have you modeled regulation, imbalance, and integration costs in the MONET estimate of net variable power costs?

A. We have used our best estimate of the cost to purchase and/or self-provide these services during the 2008 test year. The figure that is an input to our MONET model is a per MWh cost that includes all three services. We base our estimate on figures provided in regional discussions, the knowledge of PGE's real time and structuring groups, BPA's tariff rate for the imbalance service, and Klondike II contract negotiations with PPM.

Q. Will you update your estimate during this proceeding if you receive relevant new information?

A. Yes.

Q. Previously you discussed the costs of the turbine maintenance agreement. What specifically does this agreement provide?

A. Under the Service Agreement, Vestas will maintain all equipment supplied under the Turbine Supply Agreement for a period of four years. Although the Service Agreement provides for maintenance, it does not provide for major parts.

Q. Has Vestas provided any warranty that does cover major parts?

A. Yes. Vestas has provided a two year warranty that covers major parts.

Q. Will Vestas maintain spare parts at the Biglow site?

A. Yes. During the four year term of the Service Agreement, Vestas will maintain spare parts at the site.

Q. Does PGE plan to update estimates of Biglow costs and benefits during this proceeding?

A. Yes, for a number of reasons. First, the value of the expected energy from the Biglow project will change as the expected market price of electricity changes. Second, as the project proceeds through the construction phase, we will have better estimates of the total construction costs of the project. Third, PGE has applied for "Strategic Investment Zone" treatment of the facility from Sherman County and the State of Oregon. If this status is granted, it would result in property tax savings for the first several years of operation of the facility. Finally, we are evaluating the potential to receive wheeling credits from BPA. For these reasons, we believe updating Biglow's expected revenue requirement is appropriate.

C. Integrated Resource Planning and Other Context

Q. Please restate how completion of Biglow Phase I will complete the wind target acknowledged in Commission Order No. 04-375.

A. Order No. 04-375 related to the Final Action Plan that PGE developed within the context of its 2002 Integrated Resource Plan (IRP). The Final Action Plan included acquisition of 65 MWa of wind power. Pursuant to the Final Action Plan, PGE is already purchasing 27 MWa of wind power from the Klondike II wind project. We expect the first phase of Biglow to produce 46 MWa, resulting in a total of 73 MWa, which more than meets the wind target.

Q. With this 73 MWa of new wind pursuant to the Final Action Plan, what is PGE's total wind generation?

A. When the 76 turbines in the first phase of our Biglow development become operational, we will have approximately 82 MWa of wind generation. This is roughly 3.6% of our load serving obligation.

Q. You mentioned previously that PGE selected Orion's bid for the development of the Biglow site through a Request for Proposals (RFP) process. Please describe the RFP process in more detail.

A. In June 2003 PGE issued an all-source RFP to acquire resources consistent with needs identified in its 2002 IRP. We received approximately 100 responses, including wind-power bids from eight developers. Several of these wind project developers submitted different bids for different sites, as well as variants related to the same sites. We evaluated all bids that met minimal threshold requirements according to both price and non-price criteria. This evaluation process resulted in scores for all bids evaluated. We then selected a short list of bids, based on scores and overall resource portfolio considerations. Orion was included in this short list.

Orion submitted two variants of its Biglow bid, one for PGE to build and own the turbines, the other for Orion to build and own the turbines, but sell the output to PGE under a long-term contract. Negotiations indicated that PGE ownership was better suited to the needs of the parties, which included PGE's desire to gain experience in operating wind turbines.

An independent evaluator, Merrimack Energy Group, monitored and evaluated all aspects of PGE's RFP process. Merrimack submitted its final report to the Commission on September 6, 2004. This report concluded that PGE's RFP process definitely met industry standards.

Q. What were the primary factors that caused you to select Biglow and Klondike II instead of other wind opportunities?

A. Compared to other wind-based RFP bids, Biglow and Klondike II offered better combinations of price, developer experience, and project feasibility.

Q. Can PGE build further phases of Biglow?

A. Yes. PGE can further develop the site, up to total project limits of either 225 turbines or 450 MW.

Q. Are there cost advantages for further phases?

A. Yes. Further phases would allow PGE to spread certain fixed costs, such as the cost of providing transmission infrastructure, over more output.

Q. Has the Commission already issued orders to allow the development of Biglow?

A. Yes. Order No. 06-293 allowed PGE to grant a lien to Orion on certain substation property and allowed Orion the right to repurchase certain assets from PGE if PGE decides not to fully develop the project. Order No. 06-419 allowed PGE to "seek inclusion of the acquisition of the Biglow Wind Project in its rate base at cost, rather than in its revenue requirement at market price." (Order at 1)

III. 2008 Revenue Requirement

Q. If PGE were to file a 2008 general rate case, what revenue requirement would you support?

A. We would request a $1,629 million revenue requirement for a 2008 test period, including the Biglow Wind project. On an average 2008 rate base of $2,319 million, this revenue requirement would allow PGE an opportunity to earn an 8.29% overall rate of return and a 10.10% return on an average common equity of 50.00% in 2008. PGE Exhibit 202 summarizes the development of our 2008 revenue requirement.

Q. What increase in rates would PGE request?

A. If PGE were to file a 2008 rate case, our revenue requirement would be $54.2 million higher in 2008 than the revenues we would expect based on forecasted rates for the 2008 Annual Update Tariff. Overall, this revenue requirement would produce a rate increase of approximately 3.5%.

Q. Does this revenue requirement change reflect 2008 net variable power costs (NVPC)?

A. No. PGE will seek to change rates to reflect a 2008 forecast of NVPC in the Annual Update Tariff (Schedule 125, or AUT) proceeding. For purposes of presenting a complete 2008 revenue requirement, however, we include a forecast of 2008 NVPC (see Exhibit 202) as well as the related $7.8 million decrease in revenues for 2008 that PGE will initially seek in the AUT proceeding. The total revenue requirement change for 2008 from both the AUT proceeding and this 2008 forecast are thus $46.4 million ($54.2 million less $7.8 million) or approximately 3%.

Q. Is the 2008 forecast of NVPC provided in Exhibit 202 the same as you will file in the AUT proceeding?

A. No. There are some minor changes in NVPC for 2008 that are beyond the scope of changes in the AUT proceeding. Our work papers detail these updates, which currently increase 2008 NVPC by $1.4 million.

Q. Can you summarize the NVPC forecasts and how they are used in the development of PGE's 2008 revenue requirement?

A. Yes. Table 1 below summarizes the three Monet cases, which are provided in our work papers, and their uses in this case.

Table 1
Summary of Monet Cases

Monet Case	2008 NVPC	How the Monet Case is Used
2008 Annual Update Tariff Case (Excludes Biglow)	$775.6 million	This case is used to derive unit NVPC for comparison with Commission approved unit NVPC from UE 180. This comparison provides for a rate decrease of $7.8 million from the AUT, reflected in column 2 of Exhibit 202.
2008 Full NVPC Forecast (Excludes Biglow)	$777.0 million	This case represents the complete 2008 forecast of NVPC, prior to Biglow, including items beyond the scope of the AUT. The NVPC is reflected in column 1 of Exhibit 202. PGE's additional revenue requirement in 2008 of $54.2 million includes $1.4 million of additional NVPC in this case relative to the AUT case ($777.0 million less $775.6 million).
2008 Full NVPC Forecast (Including Biglow)	$755.0 million	This case represents the complete forecast of 2008 NVPC with Biglow. The difference between this case and the case above provides a measure of the net energy value of Biglow, currently forecast at $22 million ($755.0 million less $777.0 million), reflected in column 6 of Exhibit 202 for the 2008 revenue requirement and column 2 of Exhibit 201 for the Biglow Supplemental Tariff revenue requirement.

Q. How did you develop a 2008 revenue requirement?

A. We developed a 2008 revenue requirement based on PGE's 2007 budget, escalated for inflation and adjusted for known and measurable changes.

Q. What inflation rates did you use to escalate the 2007 budget to 2008?

A. We applied the following escalation rates to the 2007 budget:

- Union Labor = 2.85% effective January 1, 2008

- Non-Union Labor = 4.5% effective March 16, 2008
- Executive Labor = 6.00% effective January 1, 2008
- Outside Services (CE 21, 26, 41, 49) = 3.50% effective January 1, 2008
- Direct Materials (CE 31, 36) = 1.50% effective January 1, 2008
- Employee Business Expenses (CE 61, 68) = 1.70% effective January 1, 2008

Q. Please summarize PGE's 2008 revenue requirement.

A. Table 2 summarizes PGE's 2008 revenue requirement (including the impact of Biglow), by major category, and provides a comparison to PGE's 2006 actual costs and the UE 180, 2007 test year amounts as filed (with Port Westward) in that rate case.

Table 2
Revenue Requirement Summary ($000s)

Revenue Requirement Category	2006 Actual[1]	As Filed 2007 Test Year	2008 Rev Req With Biglow
Sales to Consumers	$1,366,738	$1,689,536	$1,628,674
Other Revenue	$18,249	$17,728	$16,103
NVPC[2]	$628,501	$845,222	$755,018
Production O&M	$65,926	$80,627	$91,464
Transmission O&M	$8,975	$10,279	$11,560
Distribution O&M	$63,378	$60,336	$62,962
Customer Service	$61,844	$68,970	$73,767
A&G	$103,801	$110,100	$116,930
Depr. &Amort.	$218,693	$183,899	$191,935
Other Taxes	$75,175	$87,032	$88,506
Income Taxes	$37,859	$79,027	$60,419
Operating Income	$120,834	$181,769	$192,216
ROE	N/A	10.75%	10.10%

1: 2006 Actuals are preliminary. PGE's SEC 10K statement is expected to be filed in March 2007.

2: For 2008, combines the estimated Annual Update Tariff NVPC and updates in this revenue requirement forecast.

Q. Why are you comparing to the 2007 test year "as filed"?

A. We present this detail as another point of comparison for two reasons:

- 2006 actual costs are not normalized.
- Authorized 2007 costs were the result of several compromises in Docket UE 180 and were not the basis of PGE forecasting.

Q. Please describe Operating Income in Table 2.

A. Operating Income consists of a return to those who provide capital to PGE, both equity and debt.

Q. Did you adjust PGE's revenue requirement to reflect previous rate-making decisions and other regulatory policies?

A. Yes. We made the following regulatory adjustments, summarized in Table 3 below.

Table 3
Regulatory Adjustments ($Millions)

Regulatory Adjustment Item	O&M	Rate Base
Retail Services	$(0.4)	$(0.3)
Charitable Contributions	$(1.3)	
Memberships and Dues	$(0.1)	
MDCP	$(5.4)	
SERP	$(2.1)	
Corp Image Advertising	$(1.0)	
Total Adjustments	$(10.3)	$(0.3)

Q. Please explain these regulatory adjustments.

A. As Table 3 shows, we performed six adjustments:

- Retail Services: removed $0.4 million of O&M and $0.3 million of rate base per the SB 1149 unbundling rules.
- Charitable Contributions: removed $1.3 million from cost of service.
- Memberships and Dues: removed $0.1 million, which is 25% of the costs of PGE's membership in several organizations including the Edison Electric Institute (EEI), consistent with our filing in UE 180.
- Managers Deferred Compensation Plan (MDCP): removed $5.4 million to reflect the Commission's historical treatment of MDCP.
- Supplemental Executive Retirement Plan (SERP): removed $2.1 million to reflect the Commission's historical treatment of SERP.

- Corporate Image Advertising: removed $1.0 million to reflect the Commission's historical policy regarding image advertising.

Q. Do you agree with these regulatory adjustments?

A. Not necessarily. We make these adjustments to help narrow the areas of disagreement between parties to the rate case.

A. Other Revenue

Q. What is PGE's 2008 forecast of other revenues?

A. PGE forecasts 2008 other revenue of $17.0 million, which is lower than PGE's filed UE 180 test year other revenue of $17.7 million and actual 2006 other revenue of $17.3 million[2].

Q. Why does Exhibit 202 show $16.1 million of other revenue if you expect $17.0 million?

A. Wheeling charges to Electricity Service Supplier (ESSs), who provide service to direct access customers, generate approximately $0.9 million of other revenue. We impute these revenues in the rate design process. Therefore, to avoid double-counting, we would remove them from the initial derivation of our 2008 revenue requirement.

Q. Did PGE double-count these revenues in the 2007 rate case (UE 180)?

A. Yes. We credited $1.1 million in ESS wheeling revenues to customers twice in UE 180, first through a reduction in test year revenue requirement and again through the rate design process.

Q. Are there any significant changes in other revenue amounts from UE 180?

[2] Total Other Revenue for 2006 was $18.2 million. However, of this, $1.0 million was for power cost related activity that is not included in the forecast of test year other revenue. On a comparable basis, actual other revenue was $17.3 million for 2006.

A. Yes. We expect joint pole rental revenue to decrease from approximately $5.0 million in the UE 180 2007 test year to $3.9 million in 2008, because of an expected decrease in pole attachment rates from the AR 506 proceeding.

Q. What are the sources of other revenue?

A. The primary sources of other revenue are rent of electric property, transmission revenues, joint-pole revenues, steam revenues, and revenue from affiliates. PGE Exhibit 203 provides the sources and amounts of other revenues, summarized in Table 4 below.

Table 4
Other Revenue ($000s)

Other Revenue Item	2006 Actuals	2007 Test Year	2008 Test Year
Utility Prop. Rental	$6,073	$6,083	$5,042
Intertie/Other Trans	$5,827	$5,635	$5,428
Late Payment Charges	$626	$1,250	$800
Steam Sales	$1,507	$1,419	$1,794
Other Misc. Revenues	$3,231	$3,341	$3,917
Total Other Revenue	$17,263	$17,728	$16,980

B. Operations O&M

Q. What is the purpose of this portion of your testimony?

A. We support PGE's $166 million estimate of 2008 costs associated with operating PGE's production, distribution and transmission assets, including Biglow Canyon. Table 5 below summarizes the costs of these activities, including comparisons to 2006 actual costs and the 2007 test year as filed in UE 180.

Table 5
Operations O&M ($000s)

Operations Category	2006 Actuals	2007 Test Year*	2008 Test Year**
Production O&M	$53,926	$68,088	$77,468
Other Power Supply	$11,722	$12,539	$13,996
Transmission O&M	$8,975	$10,279	$11,560
Distribution O&M	$63,378	$60,336	$62,962
Total Operations O&M	$138,001	$151,243	$165,986

*As filed in UE 180, with Port Westward

** With Biglow

We describe each category below.

1. Production and Power Operations O&M

Q. What primary drivers explain the changes in plant-related costs over the 2006-2008 period?

A. Primary drivers are:

- Hydro relicensing costs classified as O&M have increased over the period from less than $1.0 million to $2.2 million.
- Port Westward will come on line in 2007, resulting in higher full time employee and O&M cost levels in 2008 with increased staffing needs over 2007.
- Labor escalations and additional plant operations personnel increase 6% annually.
- Support costs increase because of changes in allocation rates in information technology (IT) and new customers in the dispatchable generation program.

Q. Do you forecast any significant increases in employees between 2006 and 2008?

A. Yes, the Boardman plant will add nine new personnel during the two year period. Three of these include: 1) a mechanical planner, 2) an engineer for performance monitoring and contract management for support and succession planning, and 3) an engineering specialist to improve the use of the Complete Implement Plant Material & Maintenance System (CMMS) capabilities such as failure analysis, root cause analysis, reliability centered maintenance and condition based monitoring. Two additional people in the Boardman control room (Operator and Assistant Operator) and another three new employees (experienced mechanics) are needed to allow for training and reduction of overtime. In addition, one maintenance clerk is required to offset clerical overtime. Increased requirements for Sarbanes-Oxley (SOX), tracking of plant maintenance and operation, as well as the need to support additional engineering positions requires an additional clerical position.

Q. Has PGE previously addressed the need for adding more employees?

A. In UE 180 PGE Exhibit 900, we discussed the need to add new employees to meet the expected retirements in plant operations. We continue to plan for the future by training new plant operations employees to replace the expected retirements. This activity takes years to achieve because of the significant training and licensing requirements.

In addition, we continue to look for ways to increase productivity and effectively offset wage and other cost pressures. Although we project hydro O&M expenses to rise somewhat more than wage and other cost pressures would imply, a substantial portion of this increase relates to new or expanded activities. For example, 2006 O&M costs associated with relicensing totaled less than one million dollars. In 2007, we expect relicensing O&M costs to rise to just over $2 million because PGE has additional requirements per our licenses. For example, PGE will spend $1.4 million on fish resources alone in 2007.

Q. What primary drivers explain the changes in power operations costs over the 2006-2008 period?

A. Two factors drive the changes in power operations costs. These are labor costs and service providers. Labor increases account for approximately $900,000 of the $8.3 million labor costs in power operations. These result from two years of escalation and hiring an additional System Control Room Operator to meet increased NERC and FERC requirements. Service providers such as information technology support, increases in software license fees, purchase of a weather forecasting service, and purchase of backup copy of software for our Pi software, which continuously monitors substation data, account for another 36% of the increase.

2. Transmission O&M

Q. What are the main areas of cost increases for transmission O&M from 2006 to 2008?

A. The primary increases in transmission O&M relate to:

- Costs for transmission planning, analysis, and design are forecast to increase by approximately $470,000. The largest contributing driver is the increase of $263,000 in labor for: 1) new positions, 2) labor moving from capital (work done for our Port Westward and Sullivan plants) to O&M, and 3) labor escalation.
- Costs for maintaining transmission technology and transmission services are forecast to increase by approximately $1.7 million. This increase is attributable to: 1) labor escalation and vacant positions in 2006 to be filled in 2007 and 2008, 2) costs related to participation in various regional transmission groups, 3) preventive maintenance for the Colstrip transmission line and replacement of portions of the line that are damaged, and 4) higher Western Electricity Coordinating Council Unscheduled Flow Administrative Subcommittee costs.

Q. What other factors are contributing to the cost increase in Transmission O&M from 2006 to 2008?

A. Two other factors contribute to the cost increase from 2006 to the 2008 test year: maintenance of station equipment (FERC 570) and maintenance of overhead lines (FERC 571).

Q. How much are these costs increasing, and why?

A. Maintenance of station equipment is increasing by approximately $580,000 and maintenance of overhead lines is increasing by approximately $200,000. These are directly related to PGE's Transmission FITNES Program, which we plan to implement in 2008.

Q. What is PGE's Transmission FITNES Program?

A. The Transmission FITNES Program is a 10-year project to inspect and repair lattice towers on all of PGE's 500 kV and 230 kV lines. Current plans for long-term maintenance and repair work involve climbing each tower and lifting conductors to inspect above-ground suspension, conductor and bolt hardware. In addition, each tower will be inspected for bolt presence and tightness. PGE expects that most repairs and maintenance will be conducted within the inspection process.

3. Distribution O&M

Q. What are the major responsibilities of PGE's distribution department?

A. This department performs four major activities. These are:

- Planning, analysis and design (PAD) of facilities to connect and serve new customers and re-conductor existing lines and facilities. Transmission and distribution engineering ensures that PGE's system capacity and configuration meet customer needs.

- Construction of distribution systems. Our distribution department builds or contracts for the construction of our distribution system.
- Performance of preventive maintenance. We inspect substations, overhead and underground lines, and equipment. We also perform on-going vegetation management to meet regulatory and public safety requirements, reduce outages from tree damage, and minimize the risk of fires.
- Restoration of lines and substations. Our distribution department provides the personnel and materials necessary to return service to customers following outage events.

In 2008, distribution O&M costs consist roughly of operation and maintenance (60%), PAD (20%), and restoration (20%).

Q. Have you determined the major drivers of the O&M decrease from 2006 to 2008?

A. Yes. The approximately $400,000 decrease can be attributed to:

- A $3.5 million decrease in the Distribution, Operation, Supervision, and Engineering (DOSE) allocation to capital. This effect is due to the major storms in 2006 that caused fewer costs to be allocated to capital than we expect to be allocated in 2008, for which we forecast normal storm conditions.
- A $1.8 million reduction in tree trimming costs. PGE engaged in additional work regarding trees in 2006 that we do not expect to recur.

- A $1.1 million increase in planning, analysis, and design activities. This is primarily related to increasing labor costs to address additional customers and growing distribution infrastructure requirements.
- $2.0 million increase in IT costs and related service provider allocations. This is primarily due to a 4.2% increase in the percentage of IT costs allocated to distribution and an overall increase in IT costs.
- A $600,000 increase in joint pole rental expense. These costs are forecast to increase as a function of the amounts other utilities charge PGE to connect to their poles.
- An $800,000 increase related to PGE’s porcelain insulator program. For this program, PGE will replace all 57 kV and 115 kV porcelain horizontal post insulators with polymer insulators over a 16-year period in order to maintain our current high reliability standards.
- A $1.1 million increase in substation O&M. The primary reason for this increase is a multi-year program to replace 21 aged, unreliable, and failing load tap changers. In addition, costs increase compared to 2006 because of labor escalation and because of a switch from a greater focus on Port Westward-related substation capital work in 2006 to a more normal level of substation maintenance in 2008.
- An $800,000 decrease in service restoration costs. The reason for this decrease is a direct function of the 2006 storms mentioned above. PGE’s 2008 forecast contains a normal level of storm restoration costs. The 2006 actuals include the results of four storms which exceeded normal expectations.

C. Support O&M

Q. What is the purpose of this portion of your testimony?

A. We describe the costs associated with operating PGE's customer service, administrative and general, and insurance and benefits costs. We support PGE's $190.7 million estimate of 2008 costs associated with these functions. Table 6 below summarizes the costs of these activities, including comparisons to 2006 actual costs and the 2007 test year as filed in UE 180.

Table 6
Support O&M ($000s)

Support Category	2006 Actuals	2007 Test Year*	2008 Test Year**
Customer Accounts	$53,204	$59,214	$62,785
Customer Services	$8,640	$9,756	$10,982
Admin & General	$45,001	$48,736	$57,601
Insurance & Benefits	$48,766	$59,287	$57,283
General Plant Maint	$1,923	$2,093	$2,058
Total Operations O&M	$157,534	$179,086	$190,709

*As filed in UE 180, with Port Westward
** With Biglow

We describe each category below.

1. Customer Accounting and Services

Q. How did total Customer Accounting and Services costs change from 2006 actuals and 2007 rate case to 2008 test year forecast?

A. These functions, which we will collectively refer to as Customer Service are forecast to increase approximately $11.9 million from 2006 actuals and $4.8 from the 2007 rate case as filed.

Q. What are the primary drivers of the cost increase from 2006 actuals to 2008?

A. Approximately 45% of the increase in Customer Service costs is due to labor and labor escalation. Although PGE continually improves its technologies and systems to maximize efficiency and reduce labor costs, Customer Service still consists of numerous labor-intensive systems and programs. Skilled workers are needed to operate these systems and technologies and interact with customers. Other increases are summarized as follows:

- Approximately $1.7 million for changes in IT allocation rates that increased the customer service share of costs for voice, data, network, communications and office systems relative to other PGE functional areas, as well as an overall increase in total IT costs.
- Approximately $2.5 million for Other Programs and Service Options. This increase relates to customer research, new product development, providing technical energy assistance, managing ESS relationships, and managing utility products & services such as dispatchable standby generation, renewable power programs, E-Manager, etc. Customer research costs are forecast to increase as a result of the Residential Appliance Saturation Study, the AMI Customer Information Study and research related to PGE's Customer Initiative. The primary increases in products and services are attributed to the development of the Critical Peak Pricing Program and the expansion of PGE's Heat Pump Program.

2. Administrative and General

Q. Please explain Administrative and General (A&G).

A. A&G refers to costs that generally cannot be directly assigned to a particular operating function. Two such examples are administrative salaries and employee benefits. Table 7 below addresses the major A&G categories and associated changes from both the 2006 actuals, and 2007 test year forecast as filed.

Table 7
A&G Summary Costs ($ Million)

Category	2006 Actuals	2007 Test Year	2008 Test Year
Major Functional Areas	$51.4	$57.6	$58.7
Other A&G Costs	$52.3	$64.0	$66.6
A&G Offsets	$(8.1)	$(11.6)	$(8.4)
Total A&G	95.7	110.1	116.9

Q. What are the major drivers of these cost changes?

A. As discussed in UE 180 testimony, the primary driver for cost increases is inflation. Some costs, such as benefits (e.g., group health and dental plans) continue to increase nationwide at higher rates. This effect is especially prominent in the change between 2006 actuals and 2008 test year numbers. Changes from 2007 to 2008 forecasts are less pronounced.

Increases in human resource costs are a significant driver of the increase between the 2007 rate case and 2008 test-year forecasts. Other drivers include a substantial rise in regulatory fees, and a decrease in capitalized A&G. Exhibit 211 provides a list of A&G functions plus summary costs for 2006 (actuals), 2007 (rate case as filed), and 2008 (forecast).

3. Total Compensation

Q. Please describe changes in wage and salary costs from 2006 to 2008.

A. PGE expects labor costs to increase by $24.9 million between 2006 and 2008. This is primarily due to labor escalation plus additional positions for Port Westward, PGE's new natural gas generation plant; distribution O&M requirements (with a straight-time labor cost increase offset by a reduction in forecasted overtime), SOX related activities, support for new software applications and systems, and positions converting from part-time and contract to full-time employees.

Q. Please explain the benefits costs changes from 2006 to 2008.

A. Total benefits costs increase from $49.9 million in 2006 to $55.1 million in 2008. The growth is primarily due to cost increases within health and dental plans, 401(k) costs, and changes from actuarial expectations. These increases are partially offset by the 2008 pension cost forecast that is lower than previous projections.

Q. Please describe incentive compensation costs in the test year revenue requirement.

A. Incentives comprise approximately 6% of total compensation cost and represent the smallest component of PGE's total compensation framework. Cost changes are primarily due to a recently implemented stock incentive program for officers and key employees and to market-driven increases to wages and salaries for most employees in the Corporate Incentive Program.

D. Depreciation

Q. What is PGE's estimate for 2008 depreciation expense?

A. We estimate $174.6 million in depreciation expense for the 2008 test year, including Biglow. PGE Exhibit 204 summarizes the test year depreciation expense by plant type and provides a comparison to UE 180. Our work papers show the derivation of depreciation expense using the Commission-approved (Order No. 06-581) depreciation parameters and estimated plant balances.

E. Amortization

Q. What is amortization?

A. Amortization, like depreciation, is a means to allocate the cost of an asset over its useful life, but it relates to intangible assets, such as computer software and regulatory assets. As with depreciation expense, the unamortized balance of assets generally resides in rate base and earns a return at the allowed rate.

Q. Please summarize PGE's 2008 amortization expense.

A. PGE Exhibit 205 details the total 2008 amortization expense of $17.3 million, which we summarize in Table 8. The exhibit also shows comparable figures from the UE 180, 2007 test year, and 2006 actuals. PGE has six sources of amortization expense for the 2008 test period:

- Intangible Plant
- Trojan Decommissioning
- Hydro Relicensing Amortization
- Colstrip Common Facilities
- Coyote Major Maintenance Accrual and Amortization
- Coyote Permit Amortization

We did not include the amortization of deferred property sale gains, or independent spent fuel storage installation (ISFSI) credits because we expect to refund/collect these items through supplemental tariffs.

Table 8
Amortization ($000s)

Amortization Item	2006 Actuals	2007 Test Year	2008 Test Year
Intangible Depreciation	$13,857	$13,251	$10,039
Trojan Decommissioning	$14,041	$4,646	$4,646
Other Reg. Debit Amortization	$34,129	$3,943	$3,520
Other Reg. Credit Amortization	$(4,118)	$(2,992)	$(903)
Total Amortization	$57,908	$18,848	$17,303

Q. Please explain the amortization of Intangible Plant included in PGE's 2008 amortization expense.

A. Total Intangible Plant amortization is $10.0 million, which primarily represents the amortization of capitalized software expense.

Q. Has the Trojan Decommissioning cost estimate changed?

A. No. We propose to continue at the same collection rate of $4.6 million approved in UE 180. We performed an analysis of the annual accrual, updating for the latest trust balances, expected earnings rates, and cost estimates. The annual accrual derived from this forecast remains close to the approved level and thus does not warrant a change. Our updated forecast of Trojan decommissioning costs is provided in our work papers.

Q. Has the Colstrip Common Facilities amortization changed?

A. No. We are continuing to amortize this asset as required under prior Commission order.

Q. What is the Coyote Major Maintenance Accrual and Amortization?

A. In UE 93 (Order No. 95-1216), the Commission approved an accrual and balancing account treatment for Coyote's major maintenance costs. PGE has a long-term service agreement with General Electric to cover major maintenance activities. The major maintenance accrual is based on a multiple-year forecast of major maintenance activities with an accrual estimate designed to bring the balancing account to zero at the end of the multiple-year period. PGE's estimate for the 2008 test year is an accrual of $2.0 million, the same as the UE 180 accrual. We estimate that there will be an average of $(7.5) million in the balancing account in 2008 and include it as a credit against rate base.

F. Income Taxes, Taxes Other Than Income & Fees

1. Income Taxes

Q. What is PGE's 2008 estimate of Income Taxes?

A. PGE's 2008 test period Income Tax expense is $60.4 million, including the impact of Biglow. PGE Exhibit 206 details the test period calculation of Income Tax expense. This compares to 2006 actual Income Tax expense of $38 million and UE 180, 2007 Test Year Income Tax expense of $65 million. The change in 2008 Income Tax expense compared to UE 180 represents the offsetting impacts of a reduction in PGE's effective tax rate and an increase in PGE's taxable income due to higher rate base in 2008 relative to 2007.

Q. Why do you forecast a reduction in PGE's effective tax rate for 2008?

A. The state of Oregon recently announced a change to a single factor (sales) methodology for apportioning taxable income, replacing the prior three-factor methodology. As a result of this change, PGE will apportion to Washington the income related to Mid-Columbia wholesale transactions. We expect this change to reduce the apportionment factor of PGE's net income to Oregon from over 95% to below 80%. Since Washington has no corporate income tax, the combined state tax rate for PGE is expected to decrease from 6.617% in

UE 180 to 5.120% for 2008. In addition, federal and state tax credits from Biglow serve to further reduce PGE's expected effective tax rate in 2008.

Q. Does Senate Bill 408, or the associated OPUC rule-making docket (AR 499), impact your estimate of income taxes for this case?

A. No. SB 408 provides for an Automatic Adjustment Clause to capture differences between "Taxes Authorized to be Collected in Rates" and "Taxes Paid." Because PGE is primarily a stand-alone utility with little non-utility or subsidiary activity, it is not appropriate to include any adjustment to PGE's revenue requirement as a result of SB 408/AR 499.

Q. To which government entities does PGE pay income taxes?

A. PGE pays income taxes to the Federal government and the States of Oregon and Montana. PGE also pays income taxes to local government entities such as Multnomah County.

Q. What are the marginal tax rates for PGE?

A. The Federal marginal tax rate is 35.00%, the State of Oregon marginal tax rate is 6.60%, and the State of Montana marginal tax rate is 6.75%. These are the same marginal tax rates as in UE 180.

Q. What is PGE's composite state tax rate for this filing?

A. PGE's composite state tax rate is 5.120%. The rate is calculated by multiplying the Oregon and Montana marginal tax rates by their respective allocation factors of 73.40% and 4.09% and then summing the weighted rates.

Q. What is PGE's total composite tax rate for this filing?

A. PGE's total composite tax rate for this filing is 38.328%. It is the sum of the Federal marginal tax rate and the state composite tax rate, less the effects of their interaction, or:

$$35.00\% + 5.120\% - (35.00\% * 5.120\%) = 38.328\%$$

Q. Are there any state tax credits included in your estimate of Income Tax expense for 2008?

A. Yes. We project $138,000 of state pollution control tax credit amortization (except ISFSI tax credits) for 2008. This compares to $166,000 of state pollution control tax credit (except ISFSI) amortization in UE 180.

Q. Why did you exclude ISFSI tax credits as a reduction in State Income Tax expense?

A. We exclude ISFSI tax credit amortization because, as required by OPUC Order No. 05-136, PGE is deferring ISFSI tax credits as they are used to offset our current Oregon tax liability. Because customers will receive the benefit of the ISFSI tax credits through the deferral mechanism, we exclude their effects on cost of service in the test year.

Q. Did you exclude Business Energy Tax Credits (BETC) from the calculation of Income Tax expense?

A. Yes. We agreed with the OPUC Staff in 2003 that shareholders should bear the costs and benefits of most BETCs. PGE assigns the cost and benefit of BETCs associated with the Clean Wind Development Fund back to the Fund. However, we have included an estimate of BETCs associated with the Biglow wind project.

Q. Did you include an estimate of the Production Tax Deduction for 2008 as you did in UE 180?

A. No. The 2005 Tax Act provides for a permanent deduction against taxable income that is related to domestic manufacturing; producing electricity is considered domestic manufacturing[3]. The Tax Act provides for a staggered increase in the deduction over time, with an initial deduction of 3% of taxable income that relates to domestic manufacturing,

[3] IRS Section 199 codifies the 2005 Tax Act. Per Section 199(c)(4)(A)(i)(III) of the Tax Code, taxable income from the production of electricity is eligible for the deduction.

increasing to 6% in 2007 and to 9% in 2009. For 2008, we project substantial tax depreciation for Port Westward and Biglow. As a result, we expect taxable income associated with "domestic manufacturing" to be zero. Under this circumstance, the deduction cannot be used and therefore is not included in our 2008 revenue requirement.

2. Taxes Other Than Income & Fees

Q. What is PGE's test period total of Fees and Taxes Other Than Income?

A. As shown in PGE Exhibit 207, total fees and taxes other than income are $88.5 million. This compares to the UE 180, 2007 test year as filed total of $87.0 million. The primary sources of the increase from the UE 180, 2007 test period as filed are:

- franchise fees: from $39.5 million to $38.1 million in 2008.
- Payroll taxes: from $11.6 million to $12.1 million in 2008.
- Property taxes: from $34.7 million to $37.1 million in 2008.

Q. What is PGE's estimate of franchise fees for 2008?

A. The total test period franchise fees are $38.1 million, representing expected costs from the 52 cities that charge PGE franchise fees, consistent with PGE's requested 2008 revenue requirement, including Biglow.

Q. How did PGE estimate franchise fees?

A. The estimate of franchise fees is based on PGE's historical experience of incurred cost relative to retail tariff revenue. While cities have the option of selecting a volumetric method for charging these fees based on OAR 860-022-0040, our experience has been that cities continue to use the revenue-based computation. Based on this rule, cities can charge up to 3.5% of gross revenues and we include the total estimate of these charges in our revenue requirement.

Q. Can cities charge franchise fees in excess of 3.5% of gross revenue?

A. Yes. We charge the incremental franchise fees above 3.5% directly to customers of the franchise area, consistent with OAR 860-022-0040. Therefore, we do not include these costs in PGE's revenue requirement.

Q. Are franchise fees included in PGE's estimate of the net to gross factor for calculating revenue requirements?

A. Yes. Consistent with the unbundling requirements of OAR 860-38-0200, we separately itemize the impact of our incremental revenue needs on franchise fees in order to directly assign the incremental costs to the Distribution function. The franchise fee rate used to determine this revenue-sensitive cost is 2.34%.

Q. Why have franchise fees decreased between the 2007 test period filed in UE 180 and the 2008 test period?

A. The filed franchise fees in UE 180 reflected an assumption that PGE would serve most of its distribution system load. In the fall of 2006, approximately 175 MW of load elected to be served by an ESS. As a result, PGE's expected costs and revenues were reduced in 2007, including franchise fees. The Commission approved level of franchise fees in UE 180 was $36.3 million, reflecting this change, among others, from PGE's filed case. Relative to the approved case in UE 180, 2008 projected franchise fees are increasing $1.8 million to $38.1 million, reflecting our higher revenue requirement in 2008 relative to the approved revenue requirement in UE 180.

Q. What is PGE's estimate of payroll taxes for 2008?

A. PGE has included $12.1 million in payroll taxes for the 2008 test period.

Q. Why have PGE's payroll taxes increased from the UE 180 2007 test year to 2008?

A. Payroll taxes have increased from $11.6 million as filed in UE 180 to $12.1 million in 2008 primarily as a result of a larger payroll, including additional employees and wage increases at PGE. The 10.5% payroll tax rate for 2008 is the same as UE 180, but we applied the rate to a larger wage and salary base in 2008.

Q. What is PGE's estimate of property taxes for 2008?

A. PGE has included $37.1 million in property taxes for the 2008 test period.

Q. Have PGE's property taxes changed from the UE 180, 2007 test year to 2008?

A. Yes. Property taxes have increased from $34.7 million in UE 180 to $37.1 million in 2008. There are two primary drivers of this increase. First, we have included an estimate of $1.1 million for property taxes from the Port Westward project. In UE 180, it was assumed that a tax holiday would result in no property tax liability starting with the on-line date of Port Westward. We now expect the tax holiday to begin with the 2008/2009 biennium. Thus, we expect to incur approximately ½ year of property tax liability for Port Westward in 2008. Second, we have included $2.1 million for property taxes associated with Biglow. Otherwise, we expect assessment levels to remain relatively flat in 2008 compared to 2007.

G. Capital Expenditure

Q. What are PGE's total 2008 capital expenditures?

A. As shown in PGE Exhibit 208 and summarized in Table 9 below, PGE forecasts $438 million in total capital expenditures for 2007 and $252 million for 2008.

Table 9
Capital Expenditures ($ millions)

Capital Expenditures	2006 Act	2007 Test Year	2008 Projected
Steam Production	$10.1	$8.7	$38.8
Hydro Production	$6.9	$1.0	$0.5
Other Production	$1.5	$6.6	$0.7
Port Westward	$155	$12.0	$0.0
Relicensing Construction	$20.2	$12.9	$46.6
Biglow	$47.8	$225.1	$0.0
Transmission	$6.7	$8.9	$11.4
Distribution	$101.3	$119.9	$122.5
General Plant	$14.3	$24.5	$18.6
Intangible Plant/Other	$16.3	$18.0	$12.5
Total Capital Additions	$379.8	$437.6	$251.6

The capital expenditures for 2006 through 2008 period relate to a number of projects detailed in our work papers. Some of the major projects include relicensing work on the Clackamas and Pelton and Round Butte hydro projects as well as the Port Westward and Biglow projects.

Q. How does PGE account for capital expenditures?

A. As PGE spends capital for utility projects, we record it as Construction Work In Progress (CWIP), a non-rate base account. Once the project is completed, PGE moves the capital expenditures (and associated Allowance for Funds Used During Construction) from CWIP to Plant-In-Service accounts. Once moved to Plant-In-Service accounts, the project becomes part of PGE's rate base, with associated depreciation expense and property tax expense recorded in the appropriate income statement accounts.

Q. Have you provided details of PGE's forecast capital expenditures for 2007 and 2008?

A. Yes. Our work papers provide documentation of our projected capital expenditures for 2007 and 2008.

H. Rate Base

Q. What is PGE's 2008 average rate base and what does it include?

A. The total 2008 average rate base is $2,319 million, including Biglow. PGE Exhibit 209 provides the details of the 2008 average rate base, which includes PGE's investment in Plant-In-Service, net of Accumulated Depreciation, Accumulated Deferred Taxes, and Accumulated Investment Tax Credits (ITC). In addition, the average rate base includes Fuel and Materials Inventory, Miscellaneous Deferred Debits and Credits, and Working Cash.

Q. How does PGE's 2008 rate base compare to that in UE 180 for the 2007 test year?

A. PGE Exhibit 210 shows that for the UE 180, 2007 test year, average rate base was $2,009 million. Since UE 180, PGE's average rate base has increased by $310 million as a result of several factors. The changes include:

- Biglow becoming commercially operational, increasing rate base by $234 million.
- Higher fuel stock requirements, reflecting both higher prices for fuel and the need for greater inventories, increasing rate base by $16 million.
- Greater working cash needs as a result of higher operating expenses and a higher working cash rate, increasing rate base by $3 million.
- Hydro relicensing projects of $21 million, including a fish ladder at the River Mill hydro facility, a control flow structure at Sullivan and mitigation and enhancement funding at Pelton Round Butte.
- Miscellaneous other changes, including depreciation of prior vintage Plant-In-Service, additions, deferred tax changes, and other changes that increase rate base by $35 million.

Q. How did you develop the forecast of rate base for the 2008 test year?

A. We built the forecast of 2008 rate base beginning with embedded Plant-In-Service and other rate base elements as of year-end 2006. To this we incorporated a forecast of plant closings and retirements over the two-year period 2007-2008, as well as capitalization of AFUDC and property taxes to develop forecast rate base amounts. Our work papers detail the derivation of rate base from embedded actual Plant-In-Service amounts at year end 2006 through the 2008 test year.

Q. What is working cash?

A. Working cash is the necessary funds provided by investors on a permanent basis to finance the timing difference between the cash received from billings and the cash paid for operating expenses. To determine the necessary working cash allowance, we use a lead-lag study to measure the average number of days between the following activities:

- Providing services and receiving payment, known as revenue lag
- Incurring expenses and making payment, known as expense lag

We determine the number of days between the activity and the payment (a lag) for each source of revenue and expense and multiply it by the amount of the associated revenue or expense to determine the "dollar days." The dollar days represent a weighted lag for each expense and revenue item. The revenue lag minus the expense lag yields the net "excess lag," which is used to determine the working cash allowance factor. In UE 180, the working cash allowance factor was 5.20%.

Q. What working cash allowance factor do you propose for this filing?

A. We propose to use the same working cash figure of 5.20% as adopted in UE 180.

Q. How do you use the working cash factor allowance in this filing?

A. We applied the working cash factor allowance to PGE's total 2008 operating expenses of $1,452 million, resulting in the working cash rate base amount of $75 million. The return on the working cash rate base amount compensates PGE for the financing cost of its excess lag.

I. 2008 Biglow

Q. What is the annual revenue PGE requires as a result of the addition of Biglow?

A. As shown in PGE Exhibit 202, PGE would require approximately $13 million additional revenue requirement annually for Biglow's expected operating costs, net of dispatch benefits, as well as to provide a reasonable return on investment, including a 10.10% ROE.

Q. Is Biglow's 2008 revenue requirement the same for your forecast of 2008 revenue requirement as it is under the supplemental tariff approach you described earlier?

A. No. While the 2008 revenue requirement uses the same cost of capital as UE 180, we have updated 2008 tax rates and added the OPUC fee as a revenue sensitive cost. Thus, while the incremental revenue requirement of Biglow is $12.9 million based on these updated 2008 parameters, the incremental Biglow revenue requirement for a supplemental tariff approach that uses all of the parameters approved in UE 180 is $13.0 million as provided in PGE Exhibit 201.

Q. Other than tax and revenue sensitive cost factors, are the capital and operating cost estimates for Biglow the same in the general rate case and supplemental tariff presentations of Biglow's revenue requirement?

A. Yes.

J. Unbundling

Q. Have you unbundled the revenue requirement presented in this testimony pursuant to OAR 860-38-0200?

A. Yes. PGE Exhibit 212 summarizes the results of unbundling the integrated revenue requirement, as required by OAR 860-38-0200, into the required functional areas or revenue requirement categories. In addition, the unbundled revenue requirement is provided with and without Biglow. Table 10 below summarizes the unbundled revenue requirement for 2008.

Table 10
Unbundled Revenue Requirement ($millions)

Functional Category	2008 Revenue Requirement without Biglow	2008 Revenue Requirement with Biglow
Production	$1,073.2	$1,086.5
Transmission	$32.0	$32.0
Distribution	$416.6	$417.0
Metering	$19.0	$19.0
Billing	$32.5	$32.5
Other Consumer Services	$51.4	$51.4
Ancillary Services	$5.5	$5.5
Retail Services	----------	----------
Public Purposes	Collected by separate tariff	Collected by separate tariff
Total	$1,630.3	$1,644.0

The sum of the unbundled revenue requirements for these services equals the integrated revenue requirement presented in PGE Exhibit 202.

Q. How did you develop the revenue requirement after unbundling costs and rate base?

A. We used traditional revenue requirement methodology – recovery of cost plus a return on investment – to calculate the revenue requirement for each unbundled service in accordance with 860-038-0200(9)(d).

Q. How did you unbundle PGE's expenses and other revenue?

A. We unbundled expenses and other revenue by analyzing each ledger within those categories. First, we determined which ledgers could be directly assigned to one of the functional categories listed in Table 10 above. Second, we evaluated those ledgers that could not be clearly assigned to determine a basis for allocation.

Q. Were most of the expense and other revenue ledgers assigned or allocated?

A. The majority of ledgers have a direct relationship with a single functional area and we assigned these ledgers based on OAR 860-038-0200(9)(b)(A) through (E). The largest category of allocated costs is A&G. We assigned these costs to a "Support" category and then we allocated the costs to the functional areas based on labor dollars for those areas. Other costs, such as property taxes, payroll taxes, income taxes, and the write-off of uncollectible accounts, relate to factors such as net plant, labor, net income, or total revenue. We allocated these costs based on the respective share of those factors per functional area in accordance with OAR 860-038-0200(9)(c)(B)(i) through (ii). For other expenses, such as depreciation and amortization, we "functionalized in the same manner as the respective Plant accounts." (see OAR 860-038-0200(9)(c)(A)).

Q. Did you allocate any expense or other revenue ledgers to retail or non-utility?

A. No, for two reasons. First, we forecast no labor costs in the ledgers we assigned to retail. As a result, the labor allocation factors will include zero percent to retail. Second, while we forecast labor costs in non-utility, "below-the-line" accounts, these ledgers already receive allocations for corporate governance (i.e. A&G / Support costs) and service providers (i.e. facilities, IT, and print and mail services). Therefore, unbundling Support costs to non-utility ledgers would apply these costs twice.

Q. How did you unbundle rate base?

A. There are two broad categories of rate base that we evaluated for unbundling: 1) Plant-In-Service with associated depreciation reserve accumulated deferred taxes, and accumulated investment tax credits; and 2) other rate base. For Plant-In-Service, we assigned most assets and their associated contra accounts in accordance with OAR 860-038-0200(9)(a)(A) through (F). These assets clearly relate to specific functional areas (e.g., thermal and hydro generating plants, transmission towers and conductors, and distribution poles, conductor, substations, transformers, and service drops). Some general and intangible plant was directly assigned but the majority of these two categories consist of many smaller assets so we allocated them based on labor.

Q. How did you unbundle Other Rate Base?

A. We assigned or allocated Other Rate Base based on the criteria established in OAR 860-038-0200(9)(a)(G). Specifically, we evaluated Other Rate Base on a ledger-by-ledger basis and directly assigned where applicable (e.g., fuel inventories were assigned to generation). For other categories, we allocated the costs on an appropriate basis (e.g., deferred credits related to post-retirement medical and life insurance are allocated based on labor).

Q. Why does the Distribution revenue requirement change with Biglow?

A. With the additional revenues necessary to cover Biglow's operating and financing costs, PGE incurs additional franchise fees as well. Pursuant to OAR 860-038-0200(9)(c)(B)(i)(IV), franchise fees are part of the Distribution revenue requirement.

IV. Qualifications

Q. Mr. Tooman, please state your educational background and experience.

A. I received a Bachelor of Science degree in Accounting and Finance from The Ohio State University, a Master of Arts degree in Economics from the University of Tennessee, and a Ph.D. in Economics from the University of Tennessee. I have held managerial accounting positions in a variety of industries and have taught economics at the undergraduate level for the University of Tennessee, Tennessee Wesleyan College, Western Oregon University, and Linfield College. Finally, I have worked for PGE in the Rates and Regulatory Affairs Department since 1996.

Q. Mr. Tinker, please state your educational background and experience.

A. I received a Bachelor of Science degree in Finance and Economics from Portland State University in 1993 and a Master of Science degree in Economics from Portland State University in 1995. In 1999, I obtained the Chartered Financial Analyst (CFA) designation. I have worked in the Rates and Regulatory Affairs department since joining PGE in 1996.

Q. Mr. Schue, please state your educational background and experience.

A. I received a Bachelor of Science degree in Economics from the University of Oregon, a Master of Arts degree in Economics from the University of Minnesota, and a Master of Business Administration degree from the University of Louvain (Belgium). I have taught beginning and intermediate level economics courses at the University of Minnesota, particularly in the area of public finance.

I have been employed at PGE in a variety of positions beginning in 1984, primarily in the Rates and Regulatory Affairs Department. I have worked on Bonneville Power Administration rate cases, particularly in transmission rate design. I was the Project

Manager for PGE's 2000 Integrated Resource Plan (IRP) and I worked on PGE's 2002 IRP and related 2003 Request for Proposals. In addition, I worked at the Oregon Public Utility Commission during 1986 and 1987, where my primary assignment was the economic analysis of conservation programs.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	**Description**
201	Biglow Supplemental Tariff Revenue Requirement
202	Results of Operations (ROO) Summary
203	Summary of Other Revenue Sources
204	Summary of Depreciation Expense by Plant Type
205	Summary of Amortization Expense
206	Summary of Income Taxes
207	Summary of Taxes Other Than Income
208	Summary of Capital Expenditures
209	Summary of Rate Base
210	Reasons for Changes in Rate Base from UE 180
211	Summary O&M and A&G Costs
212	Unbundled Results of Operations Summary

Impact of Biglow Canyon on UE-180 Results
Dollars in $000s

		Order 07-015 2007 UE-180 w/Port West	Biglow Canyon Impact	UE-180 with Biglow Canyon	Biglow Revenues for RROE	UE-180 Results with Biglow Canyon
		(1)	(2)	(3)	(4)	(5)
1	Sales to Consumers	1,550,340		1,550,340	12,959	1,563,299
2	Sales for Resale	-		-		-
3	Other Revenues	19,200		19,200		19,200
4	Total Operating Revenues	1,569,540	-	1,569,540	12,959	1,582,499
5	Net Variable Power Costs	767,112	(21,942)	745,170		745,170
6	Production O&M (excludes Trojan)	80,410	5,906	86,316		86,316
7	Trojan O&M	218		218		218
8	Transmission O&M	10,245		10,245		10,245
9	Distribution O&M	58,713		58,713		58,713
10	Customer & MBC O&M	58,371		58,371		58,371
11	Uncollectibles Expense	8,217	-	8,217	69	8,285
12	A&G, Ins/Bene., & Gen. Plant	97,224	530	97,754		97,754
13	Total Operating & Maintenance	1,080,510	(15,506)	1,065,004	69	1,065,072
14	Depreciation	156,717	11,718	168,435		168,435
15	Amortization	18,848		18,848		18,848
16	Property Tax	34,674	2,094	36,768		36,768
17	Payroll Tax	11,592		11,592		11,592
18	Other Taxes	(1,036)		(1,036)		(1,036)
19	Franchise Fees	36,278	-	36,278	303	36,581
20	Utility Income Tax	65,431	(10,087)	55,344	4,943	60,287
21	Total Operating Expenses & Taxes	1,403,014	(11,781)	1,391,232	5,315	1,396,548
22	**Utility Operating Income**	166,526	11,781	178,308	7,644	185,951
		166,526		178,308		185,951
23	**Average Rate Base**					
24	Avg. Gross Plant	4,589,895	260,742	4,850,637		4,850,637
25	Avg. Accum. Deprec. / Amort	(2,468,445)	(7,142)	(2,475,587)		(2,475,587)
26	Avg. Accum. Def Tax	(207,435)	(18,934)	(226,369)		(226,369)
27	Avg. Accum. Def ITC	(5,005)		(5,005)		(5,005)
28	**Avg. Net Utility Plant**	1,909,010	234,666	2,143,676	-	2,143,676
29	Misc. Deferred Debits	4,689		4,689		4,689
30	Operating Materials & Fuel	50,177		50,177		50,177
31	Misc. Deferred Credits	(28,082)		(28,082)		(28,082)
32	Working Cash	72,957	(613)	72,344	276	72,620
33	**Average Rate Base**	2,008,751	234,053	2,242,804	276	2,243,080
34	**Rate of Return**	8.290%		7.950%		8.290%
35	**Implied Return on Equity**	10.100%		9.420%		10.100%
36	**AR 499 - Net to Gross**	**14.96%**				**15.75%**
37	**AR 499 - Effective Tax Rate**	**28.21%**				**24.48%**

Impact of Biglow Canyon on UE-180 Results
Dollars in $000s

	Order 07-015 2007 UE-180 w/Port West	Biglow Canyon Impact	UE-180 with Biglow Canyon	Biglow Revenues for RROE	UE-180 Results with Biglow Canyon
	(1)	(2)	(3)	(4)	(5)
38 Effective Cost of Debt	6.480%	6.480%	6.480%	6.480%	6.480%
39 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%
40 Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%
41 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%
42 Weighted Cost of Debt	3.240%	3.240%	3.240%	3.240%	3.240%
43 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%
44 Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%
45 State Tax Rate	6.617%	6.617%	6.617%	6.617%	6.617%
46 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%
47 Composite Tax Rate	39.301%	39.301%	39.301%	39.301%	39.301%
48 Bad Debt Rate	0.530%	0.530%	0.530%	0.530%	0.530%
49 Franchise Fee Rate	2.340%	2.340%	2.340%	2.340%	2.340%
50 Working Cash Factor	5.200%	5.200%	5.200%	5.200%	5.200%
51 Gross-Up Factor	1.64747	1.64747	1.64747	1.64747	1.64747
52 ROE Target	10.100%	10.100%	10.100%	10.100%	10.100%
53 Grossed-Up COC	11.560%	11.560%	11.560%	11.560%	11.560%
Utility Income Taxes					
54 Book Revenues	1,569,540	-	1,569,540	12,959	1,582,499
55 Book Expenses	1,337,583	(1,694)	1,335,889	372	1,336,261
56 Interest Deduction	65,084	7,583	72,667	9	72,676
57 Production Deduction	4,017		4,017		4,017
58 Permanent Ms	(7,623)	(1,546)	(9,169)		(9,169)
59 Deferred Ms	(21,840)	76,486	54,646		54,646
60 Taxable Income	192,320	(80,829)	111,490	12,578	124,069
61 Current State Tax	12,725	(5,348)	7,377	832	8,209
62 State Tax Credits	(166)	(1,000)	(1,166)		(1,166)
63 Net State Taxes	12,559	(6,348)	6,211	832	7,043
64 Federal Taxable Income	179,761	(74,481)	105,280	11,746	117,025
65 Current Federal Tax	62,916	(26,068)	36,848	4,111	40,959
66 ITC Amort/Fed Tax Credits	(1,461)	(7,730)	(9,191)		(9,191)
67 Deferred Taxes	(8,583)	30,060	21,476	-	21,476
68 Total Income Tax Expense	65,431	(10,087)	55,344	4,943	60,287
69 Effective Tax Rate	39.21%		34.38%	39.30%	34.74%
70 Regulated Net Income	101,443		105,641		113,276
	101,443		105,641		113,276

2008 Results of Operations
Increase in Base Rates Needed for Reasonable Return
Dollars in (000s)

	2008 Results At 2007* Base Rates	Change for 2008 Update Tariff	2008 Results before Biglow at Annual Update Rates	Change for Reasonable Return	2008 Results before Biglow at Reasonable Return	Annualized Biglow Impact	2008 Results with Biglow	Change for Reasonable Return	2008 Results with Biglow at Reasonable Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Operating Revenues									
Sales to Consumers (Rev. Req.)	1,582,245	(7,788)	1,574,457	41,349	1,615,806	-	1,615,806	12,868	1,628,674
Sales for Resale	-	-	-	-	-	-	-	-	-
Other Operating Revenues	16,103	-	16,103	-	16,103	-	16,103	-	16,103
Total Operating Revenues	1,598,348	(7,788)	1,590,560	41,349	1,631,909	-	1,631,909	12,868	1,644,777
Operation & Maintenance									
Net Variable Power Cost	776,960	-	776,960	-	776,960	(21,942)	755,018	-	755,018
Operations O&M	160,080	-	160,080	-	160,080	5,906	165,986	-	165,986
Support O&M	189,775	(66)	189,710	348	190,058	530	190,588	108	190,696
Total Operation & Maintenance	1,126,815	(66)	1,126,750	348	1,127,098	(15,506)	1,111,592	108	1,111,700
Depreciation & Amortization	180,217	-	180,217	-	180,217	11,718	191,935	-	191,935
Other Taxes / Franchise Fee	85,325	(182)	85,143	968	86,111	2,094	88,205	301	88,506
Income Taxes	53,247	(2,888)	50,359	15,333	65,693	(10,045)	55,648	4,772	60,419
Total Oper. Expenses & Taxes	1,445,605	(3,136)	1,442,469	16,649	1,459,118	(11,739)	1,447,379	5,181	1,452,560
Utility Operating Income	152,743	(4,652)	148,091	24,700	172,791	11,739	184,530	7,687	192,216
Rate of Return	7.331%		7.108%		8.290%		7.959%		8.290%
Return on Equity	8.181%		7.736%		10.100%		9.439%		10.100%

* 2007 Rates including Port Westward

2008 Results of Operations
Increase in Base Rates Needed for Reasonable Return
Dollars in (000s)

	2008 Results At 2007* Base Rates	Change for 2008 Update Tariff	2008 Results before Biglow at Annual Update Rates	Change for Reasonable Return	2008 Results before Biglow at Reasonable Return	Annualized Biglow Impact	2008 Results with Biglow	Change for Reasonable Return	2008 Results with Biglow at Reasonable Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Average Rate Base									
Utility Plant in Service	4,694,115	-	4,694,115	-	4,694,115	260,742	4,954,857	-	4,954,857
Accumulated Depreciation	(2,517,725)	-	(2,517,725)	-	(2,517,725)	(7,142)	(2,524,867)	-	(2,524,867)
Accumulated Def. Income Taxes	(198,310)	-	(198,310)	-	(198,310)	(18,934)	(217,244)	-	(217,244)
Accumulated Def. Inv. Tax Credit	(2,862)	-	(2,862)	-	(2,862)	-	(2,862)	-	(2,862)
Net Utility Plant	1,975,218	-	1,975,218	-	1,975,218	234,666	2,209,884	-	2,209,884
Misc Deferred Debits	5,638	-	5,638	-	5,638	-	5,638	-	5,638
Operating Materials & Fuel	66,264	-	66,264	-	66,264	-	66,264	-	66,264
Misc. Deferred Credits	(38,665)	-	(38,665)	-	(38,665)	-	(38,665)	-	(38,665)
Working Cash	75,171	(163)	75,008	866	75,874	(610)	75,264	269	75,533
Total Average Rate Base	2,083,627	(163)	2,083,464	866	2,084,330	234,056	2,318,385	269	2,318,655
Income Tax Calculations									
Book Revenues	1,598,348	(7,788)	1,590,560	41,349	1,631,909	-	1,631,909	12,868	1,644,777
Book Expenses	1,392,358	(248)	1,392,110	1,316	1,393,426	(1,694)	1,391,732	410	1,392,141
Interest Rate Base @ Weighted Cost of I	67,510	(5)	67,504	28	67,532	7,583	75,116	9	75,124
Production Deduction	-	-	-	-	-	-	-	-	-
Permanent Sch M Differences	(5,311)	-	(5,311)	-	(5,311)	(1,546)	(6,857)	-	(6,857)
Temporary Sch M Differences	(15,844)	-	(15,844)	-	(15,844)	76,486	60,642	-	60,642
State Taxable Income	159,636	(7,535)	152,100	40,005	192,106	(80,829)	111,276	12,449	123,726
State Income Tax	8,036	(386)	7,650	2,048	9,699	(5,139)	4,560	637	5,197
Federal Taxable Income	151,600	(7,149)	144,450	37,957	182,407	(75,691)	106,716	11,812	118,528
Fed Income Tax	53,060	(2,502)	50,558	13,285	63,842	(34,222)	29,620	4,134	33,755
Deferred Taxes	(6,389)	-	(6,389)	-	(6,389)	29,316	22,927	-	22,927
ITC Amort	(1,460)	-	(1,460)	-	(1,460)	-	(1,460)	-	(1,460)
Total Income Tax	53,247	(2,888)	50,359	15,333	65,693	(10,045)	55,648	4,772	60,419

Other Revenue Detail
2004 - 2008 Test Year

Item	FERC Account	PGE Ledger(s)	Actual 2004	Actual 2005	Actual 2006	Budget 2007	UE-180 2007	Test Year 2008
Late Payment Interest	450	M38111	1,092,494	1,022,342	625,520	800,000	1,250,000	800,000
Misc. Service Revenue	451	M31111	767,055	1,233,944	1,393,724	1,421,140	1,021,144	1,421,144
Sales of Water & Water Power	453	M32111	1,234	(9,410)	(46,202)	-	-	-
Property Rents - Supply Energy	454	M33511	30,996	26,122	29,531	-	-	-
Rental Rev - Utility Op Prop	454	M33111	37,595	37,460	37,527	-	-	-
Joint Pole Revenue	454	M33711	5,261,068	4,743,771	4,916,638	3,870,399	4,997,272	3,870,399
Transformer Rentals	454	M33731	517,546	515,507	517,140	521,200	521,200	521,200
Rent from Electric Prop	454	M33811	485,476	535,002	639,111	650,059	564,340	650,059
Coal Car Rentals	454	M33571	-	205,590	294,494	-	-	-
Other Misc Electric Revenues	456	M34191	1,108,395	2,304,662	531,654	1,595,750	1,570,689	1,617,387
Misc Physical Revenues	456	M34819	172,813	164,533	191,418	133,665	145,490	133,665
Steam Sale Revenues	456	M34189	1,111,427	1,866,272	1,506,772	1,794,398	1,419,110	1,794,398
Fish/Wildlife & Rec Facility	456	M34151	27,701	18,239	16,100	-	-	-
Salmon Springs Hosp Grp.	456	M34322	198,352	208,651	292,930	333,500	239,800	333,500
Rev - Utility Non-KWh Prog	456	M34411	244,113	329,647	396,864	392,000	354,500	402,000
Misc Rev - Supply Energy	456	M34511	-	66,073	83,822	-	-	-
Service Fees - ESS	456	M34575	14,083	11,811	9,440	8,900	8,900	8,900
Late Payment Int - ESS	456	M34577	80	180	93	-	-	-
Non Intertie - Trans for Others	456	M34581	1,804,155	2,156,972	447,819	-	1,847,152	-
Non Intertie - Trans for Others	456.1	M34591	-	-	1,322,621	3,089,800	-	1,689,800
Intertie - Trans for Others	456	M34681	3,717,809	4,008,097	1,028,231	-	3,788,000	-
Intertie - Trans for Others	456.1	M34691	-	-	3,027,922	3,738,000	-	3,738,000
Total Other Revenues			16,592,391	19,445,467	17,263,169	18,348,811	17,727,597	16,980,452

Summary of Depreciation
($000)

Property Group	2006 Actual	UE 180 2007 As Stipulated	2008 Test Year
Boardman	11,963	6,704	7,028
Colstrip	10,269	6,863	7,195
Beaver	6,127	7,484	7,846
Biglow Canyon	-	-	11,718
Coyote Springs	6,701	6,697	7,021
Port Westward	-	4,578	8,163
Hydro	7,413	5,932	6,219
Transmission	7,176	8,526	8,938
Distribution	102,916	89,874	94,219
General Plant	15,976	22,028	23,093
TOTAL	168,541	158,686	181,439

Amortiation
2006 - 2008 Test Year

Item	FERC Account	PGE Ledger	Actual 2006	Budget 2007	UE-180 2007	Forecast 2008	Adjustments	Test Year 2008
Software Amort	404	N62111	13,856,584	14,321,100	13,251,500	10,462,959	(423,052)	10,039,907
Coyote Permits	404	N62121	39,502	39,502	39,502	39,502		39,502
Hydro Relicensing	404	N62131	1,107,986	1,106,059	1,038,528	1,106,059	8,324	1,114,383
Trojan Decomm	407	N62452	14,041,000	4,646,000	4,500,000	4,646,000		4,646,000
Coyote Maj Maint	407.3	N62599	4,108,000	2,044,272	2,044,272	2,044,272		2,044,272
Colstrip Common FERC	407.3	N62321	322,140	322,140	322,140	322,140		322,140
Cat A Amort	407.3	N62325	1,174,923	-	-	-		-
Pelton-RB Amort	407.3	N62328	3,675	-	-	-		-
Regulatory Amort	407.3	N62329	8,274,139	-	-	-		-
Regulatory Debits	407.3	N62506	125,249	-	-	-		-
FAS 109 Amort	407.3	N62508	935,512	-	-	-		-
Deferral of Prop Gains	407.3	N62513	275,261	50,000	1,100,000	1,000,000	(1,000,000)	-
Debit - ARO	407.3	N62515	4,057,055	2,139,130	1,665,594	2,139,130	(2,139,130)	-
SB1149 Amort	407.3	N62516	8,203,666	8,268,244	8,242,566	6,919,813	(6,919,813)	-
Deferral of ISFSI Credits	407.3	N62518	4,556,355	2,273,778	2,273,778	2,273,778	(2,273,778)	-
Coyote Maj Main Amort	407.4	N62614	(1,476,104)	(903,465)	(868,611)	(903,465)		(903,465)
SB 1149 Deferral	407.4	N62605	(2,348,780)	(2,123,652)	(2,123,528)	-		-
CS Comm Facilities Sale	407.4	N62607	-	-	-	-		-
Prop Sale Gain Amort	407.4	N62612	-	(4,142,423)	(1,981,313)	-		-
Cat A Costs	407.4	N62613	-	-	-	-		-
BETC Deferral	407.4	N62621	-	-	-	-		-
Amort of ISFSI Credits	407.4	N62624	-	-	(7,678,001)	(13,000,000)	13,000,000	-
Beaver 8 Reg Credit	407.4	N62625	-	-	-	-		-
Accretion Expense	411.1	N62701	945,351	930,531	848,958	930,531	(930,531)	-
Gain from Prop Sales	411.6	N91101	(293,588)	(50,000)	(1,100,000)	(1,000,000)	1,000,000	-
Loss from Prop Sales	411.7	N92101	-	-	-	-		-
	411.6	N91331	-	-	2,011	-		-
Total Amortization			57,907,924	28,921,216	21,577,396	16,980,719	322,020	17,302,739

Income Tax Summary
Reasons For Change (UE-180, 2007 Test Year vs. 2008 Filing)
(000s)

Income Tax Summary	UE-180 2007 Test Year	No Biglow UE-&&& 2008 Test Year	W / Biglow UE-&&& 2008 Test Year
Book Revenues	1,569,540	1,631,909	1,644,777
Book Expenses (including Depreciation)	1,337,584	1,393,426	1,392,141
Interest Deduction	65,083	67,532	75,124
Book Taxable Income	166,872	170,951	177,511
Production Deduction	4,017	-	-
Permanent Sch. M	(7,623)	(5,311)	(6,857)
Temporary Sch. M	(21,840)	(15,844)	60,642
Tax Taxable Income	192,318	192,106	123,726
State Tax @ 6.617% for UE180, 5.120% for 2008	12,725	9,836	6,335
State Tax Credits	(166)	(138)	(1,138)
Net State Income Tax	12,559	9,699	5,197
Federal Taxable Income	179,759	182,407	118,528
Federal Tax @ 35%	62,916	63,842	41,485
Federal Tax Credits	-	-	(7,730)
ITC Amortization	(1,461)	(1,460)	(1,460)
Deferred Taxes	(8,583)	(6,389)	22,927
Total Income Tax	65,430	65,693	60,419
Effective Tax Rate	39.21%	38.43%	34.04%
Change in Taxes		262	(5,273)
Analysis of Tax Change:			
Effective Tax Rate Change		-0.78%	-4.39%
Book Taxable Income (UE 180, 2008 before Biglow)		166,872	170,951
Decrease in Taxes Due to Lower Effective Rate		(1,305)	(7,506)
Change in Book Taxable Income (2008 vs UE180, 2008 W/Biglow vs N		4,079	6,560
2008 Effective Tax Rate		38.43%	34.04%
Increase in Taxes Due to Higher Book Taxable Income		1,567	2,233
Sum of Tax Impacts		262	(5,273)

Taxes Other Than Income
2004 - 2008 Test Year

Item	FERC Account	PGE Ledger(s)	Actual 2004	Actual 2005	Actual 2006	Budget 2007	UE-180 2007	Test Year 2008
Payroll Taxes	408.1	Note 1	10,110,873	10,998,362	11,057,060	12,009,145	11,592,349	12,056,126
Property Taxes - Oregon	408.1	N81111	26,368,610	26,974,653	27,039,948	28,238,064	29,794,800	32,286,864
Property Taxes - Washington	408.1	N81211	71,731	81,064	77,833	63,600	69,600	62,400
Property Taxes - Montana	408.1	N81311	3,224,455	3,312,825	3,410,334	4,314,960	4,813,880	4,744,920
Franchise Fees	408.1	N83111, N83112	31,056,004	31,345,991	32,368,156	34,407,296	39,535,137	38,110,960
Foreign Insurance Excise Tax	408.1	N83211	31,000	30,000	-	-	34,200	-
Montana Production Tax	408.1	N83611	420,037	482,900	416,462	477,200	477,000	477,200
Oregon DOE fee	408.1	N83411	673,896	674,340	727,715	737,354	720,000	767,502
Total Taxes Other Than Income			71,956,606	73,900,135	75,097,509	80,247,619	87,036,966	88,505,972

Note 1: Payroll Tax ledgers include N82111, N82211, N82311, N82411, N82511, N82591, and N82599

Capital Expenditures
2008 Test Period, Dollars in Millions

Category	2006 Actuals	2007 Projected	2008 Projected
Steam Production	10.1	8.7	38.8
Hydro Production	6.9	1.0	0.5
Other Production	1.5	6.6	0.7
Port Westward	155	12.0	-
Relicensing Construction	20.2	12.9	46.6
Biglow Canyon	47.8	225.1	-
Transmission	6.7	8.9	11.4
Distribution	101.3	119.9	122.5
General Plant	14.3	24.5	18.6
Intangible & Other	16.3	18.0	12.5
Total	379.8	437.6	251.6

Steam Production Boardman, Colstrip
Other Production Coyote Springs, Beaver

Average Rate Base
Test Year based on 12 Months Ending 12/31/08
(000s)

		No Biglow 2008 Test Year	Biglow Impact	W/ Biglow 2008 Test Year
Plant In Service		4,694,115	260,742	4,954,857
Less:	Accumulated Depreciation/Amortizat	(2,517,725)	(7,142)	(2,524,867)
	Accumulated Deferred Taxes	(198,310)	(18,934)	(217,244)
	Accumulated Deferred ITC	(2,862)		(2,862)
Net Utility Plant		1,975,218	234,666	2,209,884
Operating Materials and Fuel Stocks		66,264		66,264
Deferred Debits				
	Colstrip Common FERC Adj	2,846		2,846
	Def Wheeling Cost 2 Cities	834		834
	Dispatchable Standby Generation	1,959		1,959
Deferred Credits				
	Coyote Maint. Accrual	(7,486)		(7,486)
	Injuries & Damages	(6,488)		(6,488)
	Customer Deposits	(3,668)		(3,668)
	Customer Advances	(108)		(108)
	Misc. Other	(20,916)		(20,916)
Working Capital		75,874	(341)	75,533
Average Rate Base		2,084,330	234,325	2,318,655

Rate Base Comparison
UE 180, 2007 Test Year vs 2008 Test Year
(000s)

	UE 180 2007 Test Year	Hydro Relicensing Projects	Greater Working Cash Requirements	Higher Inventory Requirements	Misc Other	No Biglow 2008 Test Year	Biglow Impact	With Biglow 2008 Test Year
Plant In Service	4,585,976	21,000			87,139	4,694,115	260,742	4,954,857
Less: Accumulated Depr/Amort	(2,464,526)				(53,199)	(2,517,725)	(7,142)	(2,524,867)
Accumulated Deferred Taxes	(207,435)				9,125	(198,310)	(18,934)	(217,244)
Accumulated Deferred ITC	(5,005)				2,144	(2,862)		(2,862)
Net Utility Plant	1,909,010	21,000	-	-	45,208	1,975,218	234,666	2,209,884
Operating Materials and Fuel Stocks	50,176			16,360	(271)	66,264		66,264
								-
Misc. Debits	4,689				949	5,638		5,638
Misc Credits	(28,082)				(10,583)	(38,665)		(38,665)
Working Capital	72,957		2,917		-	75,874	(341)	75,533
Average Rate Base	2,008,750	21,000	2,917	16,360	35,303	2,084,330	234,325	2,318,655

Summary Plant-Related O&M Costs
($millions)

	2006 Actual	2007 Rate Case	2008 Forecast	Change 2008-2006	Change 2008-2007
Hydro O&M	8.8	10.7	12.0	3.2	1.30
Coal O&M	29.6	28.6	29.2	(0.4)	0.60
Gas O&M	12.8	24.7	25.3	12.5	0.60
Wind	-	-	5.9	5.9	5.90
General Plant O&M	2.7	4.1	5.0	2.3	0.90
Plant Subtotals	53.9	68.1	77.4	23.5	9.3
Power Operations O&M	11.7	12.5	14.0	2.3	1.50
Total	65.6	80.6	91.4	25.8	10.8

Summary of Transmission O&M Costs ($Million)

Categories	2006 Actuals	2007 Rate Case	2008 Forecast	Change 2008-2006	Change 2008-2007
PAD Transmission	1.0	1.3	1.5	0.5	0.2
Maintain Transmission Technology	1.7	2.0	1.4	(0.3)	(0.6)
Transmission Services	3.5	4.1	5.2	1.7	1.1
Maintenance of Station Equipment	0.9	1.3	1.5	0.6	0.2
Maintenance of Overhead Lines	0.6	0.4	0.8	0.2	0.4
Other	1.2	1.1	1.1	(0.1)	-
Total Transmission O&M Expenses	**8.9**	**10.2**	**11.5**	**2.6**	**1.3**

Summary of Distribution O&M Costs ($Million)

Categories	2006 Actuals	2007 Rate Case	2008 Forecast	Change 2008-2006	Change 2008-2007
Operations	16.8	15.9	15.5	(1.30)	(0.40)
Maintenance	37.5	34.0	36.0	(1.50)	2.00
Information Technology	9.1	10.5	11.4	2.30	0.90
Total	63.4	60.4	62.9	(0.5)	2.5

Summary of Customer Service Costs ($ Million)

Categories	2006 Actuals	2007 Rate Case	2008 Forecast	Change 2008-2006	Change 2008-2007
Meter	7.4	7.5	8.0	0.6	0.5
Bill	8.1	8.7	9.3	1.2	0.6
Collect	11.1	14.2	14.2	3.1	-
Respond	12.0	13.6	15.0	3.0	1.4
Information Technology	15.0	15.7	16.7	1.7	1.0
Other Programs & Service Options	5.6	6.7	8.1	2.5	1.4
Customer Communications	2.7	2.6	2.5	(0.2)	(0.1)
Total Customer Service Expenses	**61.9**	**69.0**	**73.8**	**11.9**	**4.8**

Summary of A&G Costs

Category	2007 Authorized UE-180 (a)	2006 Actuals	2007 RC (d)	2008 RC	Delta 2008RC-2006	Delta 2008RC-2007RC
Major Functional Areas						
Facilities and General Plant Maintenance		10.4	10.9	11.4	0.9	0.4
Accounting/Finance		9.8	10.9	10.5	0.7	-0.4
HR/Employee Support (net of capital allocs.)		5.6	5.8	6.2	0.7	0.4
Insurance / I&D		6.7	10.4	10.3	3.7	0.0
Legal		5.9	5.6	5.8	0.0	0.3
Regulatory Affairs		2.7	2.9	2.7	0.0	-0.2
Corporate Governance		2.1	2.1	2.4	0.3	0.3
Business Support Services		2.4	2.3	2.3	-0.1	0.0
Environmental Programs		1.3	1.4	1.5	0.2	0.1
Corporate R&D		0.2	0.7	0.3	0.1	-0.4
SB1149 Project Management		0.0	0.0	0.0	0.0	0.0
Contract Services/Purchasing		1.0	1.1	1.2	0.2	0.1
Security		0.7	0.8	0.9	0.2	0.1
Corp Communications/Public Affairs		1.7	1.6	1.7	-0.1	0.0
Load Research		0.1	0.2	0.2	0.1	0.0
Hydro Licensing		0.2	0.2	0.2	0.0	0.0
Governmental Affairs		0.7	0.7	0.9	0.2	0.3
Subtotal		51.4	57.6	58.7	7.3	1.1
Other A&G Costs						
IT: Direct & Allocated		6.8	8.2	7.2	0.5	-1.0
Other Service Providers to A&G		0.3	0.3	0.3	0.0	0.0
Enron allocations/direct charges		0.0	0.0	0.0	0.0	0.0
Total Comp/Benefits (net of capital allocs.)		28.7	34.3	31.4	2.7	-2.9
PTO Loadings to A&G		3.9	3.8	4.0	0.1	0.2
Corporate Incentive Plan (net of capital allocs.)		3.8	4.8	6.1	2.3	1.3
Management Incentive Plan		4.2	6.8	5.8	1.6	-1.1
Stock Incentive Plan		0.7	0.0	3.7	3.0	3.7
Variable Pay - Coyote & Trojan		0.3	0.5	0.6	0.3	0.0
Regulatory Fees		3.1	5.1	6.6	3.5	1.6
Other Membership Costs		0.5	0.4	0.6	0.1	0.2
Incremental A&G for Biglow Canyon		0.0	0.0	0.5	0.5	0.5
Miscellaneous		0.0	-0.3	-0.2	-0.3	0.1
Subtotal		52.3	64.0	66.6	14.4	2.6
A&G Offsets						
Capitalized A&G		-6.4	-9.8	-6.6	-0.3	3.1
Duplicate Charge Offset (b)		-1.7	-1.8	-1.8	-0.2	-0.1
TOTAL A&G (c)	**97.2**	**95.7**	**110.1**	**116.9**	**21.2**	**6.8**

I&B

Notes:
(a) Authorized UE-180 detail by function is not available.
(b) The duplicate charge offset reverses PGE's charges to itself for electric power.
(c) Variances due to rounding
(d) With Port Westward

Unbundled Results of Operations Summary
2008 Results at Reasonable Return, With Biglow Canyon
Dollars in $000s

	Production	Transmission	Distribution	Ancillary	Metering	Billing	Consumer	Total
Operating Revenues								
Sales to Consumers (Rev. Req.)	1,079,545	31,329	409,451	5,502	19,026	32,474	51,346	1,628,673
Sales for Resale	-	-	-	-	-	-	-	-
Other Operating Revenues	7,523	4,565	6,806	(5,502)	18	23	2,670	16,103
Total Operating Revenues	1,087,069	35,894	416,257	-	19,044	32,497	54,016	1,644,776
Operation & Maintenance								
Net Variable Power Cost	755,018	-	-	-	-	-	-	755,018
Total Fixed O&M	89,051	10,385	66,550	-	-	-	-	165,986
Other O&M	41,183	4,523	52,851	-	17,085	26,788	48,265	190,696
Total Operation & Maintenance	885,252	14,909	119,401	-	17,085	26,788	48,265	1,111,700
Depreciation & Amortization	60,495	6,705	117,118	-	1,041	3,531	3,046	191,935
Other Taxes / Franchise Fee	24,894	2,088	58,143	-	661	983	1,737	88,506
Income Taxes	21,372	3,718	34,609	-	78	354	288	60,418
Total Oper. Expenses & Taxes	992,012	27,420	329,271	-	18,865	31,656	53,336	1,452,560
Utility Operating Income	95,056	8,474	86,986	-	179	841	680	192,216
Rate of Return	8.29%	8.29%	8.29%	N/A	8.29%	8.29%	8.29%	8.29%
Return on Equity	10.10%	10.10%	10.10%	N/A	10.10%	10.10%	10.10%	10.10%
Average Rate Base								
Utility Plant in Service	2,214,506	221,100	2,418,840	-	13,834	46,062	40,515	4,954,857
Accumulated Depreciation	1,072,931	100,529	1,287,356	-	8,748	29,693	25,610	2,524,867
Accumulated Def. Income Taxes	95,202	19,129	87,567	-	2,348	6,428	6,569	217,244
Accumulated Def. Inv. Tax Credit	1,859	82	920	-	-	-	-	2,862
Net Utility Plant	1,044,514	101,360	1,042,997	-	2,738	9,941	8,335	2,209,884
Operating Materials & Fuel	59,739	693	5,833	-	-	-	-	66,264
Misc Deferred Debits	5,638	-	-	-	-	-	-	5,638
Misc. Deferred Credits	(14,835)	(1,260)	(16,661)	-	(1,561)	(1,443)	(2,904)	(38,665)
Working Cash	51,585	1,426	17,122	-	981	1,646	2,773	75,533
Total Average Rate Base	1,146,640	102,218	1,049,291	-	2,157	10,144	8,204	2,318,655

Unbundled Results of Operations Summary
2008 Results at Reasonable Return, Before Biglow Canyon
Dollars in $000s

	Production	Transmission	Distribution	Ancillary	Metering	Billing	Consumer	Total
Operating Revenues								
Sales to Consumers (Rev. Req.)	1,067,023	31,329	409,106	5,502	19,026	32,474	51,346	1,615,805
Sales for Resale	-	-	-	-	-	-	-	-
Other Operating Revenues	7,523	4,565	6,806	(5,502)	18	23	2,670	16,103
Total Operating Revenues	1,074,546	35,894	415,912	-	19,044	32,497	54,016	1,631,908
Operation & Maintenance								
Net Variable Power Cost	776,960	-	-	-	-	-	-	776,960
Total Fixed O&M	83,145	10,385	66,550	-	-	-	-	160,080
Other O&M	40,586	4,523	52,809	-	17,085	26,788	48,265	190,058
Total Operation & Maintenance	900,691	14,909	119,359	-	17,085	26,788	48,265	1,127,098
Depreciation & Amortization	48,777	6,705	117,118	-	1,041	3,531	3,046	180,217
Other Taxes / Franchise Fee	22,800	2,088	57,842	-	661	983	1,737	86,111
Income Taxes	26,646	3,718	34,609	-	78	354	288	65,692
Total Oper. Expenses & Taxes	998,914	27,420	328,927	-	18,865	31,656	53,336	1,459,117
Utility Operating Income	75,632	8,474	86,985	-	179	841	680	172,791
Rate of Return	8.29%	8.29%	8.29%	N/A	8.29%	8.29%	8.29%	8.29%
Return on Equity	10.10%	10.10%	10.10%	N/A	10.10%	10.10%	10.10%	10.10%
Average Rate Base								
Utility Plant in Service	1,953,764	221,100	2,418,840	-	13,834	46,062	40,515	4,694,115
Accumulated Depreciation	1,065,789	100,529	1,287,356	-	8,748	29,693	25,610	2,517,725
Accumulated Def. Income Taxes	76,268	19,129	87,567	-	2,348	6,428	6,569	198,310
Accumulated Def. Inv. Tax Credit	1,859	82	920	-	-	-	-	2,862
Net Utility Plant	809,848	101,360	1,042,997	-	2,738	9,941	8,335	1,975,218
Operating Materials & Fuel	59,739	693	5,833	-	-	-	-	66,264
Misc Deferred Debits	5,638	-	-	-	-	-	-	5,638
Misc. Deferred Credits	(14,835)	(1,260)	(16,661)	-	(1,561)	(1,443)	(2,904)	(38,665)
Working Cash	51,944	1,426	17,104	-	981	1,646	2,773	75,874
Total Average Rate Base	912,333	102,218	1,049,273	-	2,157	10,144	8,204	2,084,330

I. Introduction

Q. Please state your name and position.

A. My name is Patrick G. Hager. I am the Manager of Regulatory Affairs at PGE. I am responsible for analyzing PGE's cost of capital, including its Required Return on Equity. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. I discuss the cost of capital that PGE uses in its calculations of the Biglow supplemental tariff.

Q. What is the overall cost of capital PGE uses in this proceeding?

A. We use our last authorized cost of capital, 8.29%, from Commission Order No. 07-015 in Docket UE 180. We also use our authorized capital structure from the same order, 50% long-term debt and 50% equity. For convenience, these figures are reproduced as Table 1 below.

Table 1
PGE's Weighted Cost of Capital
(Test Year 2007)

Component	Average Outstanding ($000)	Percent of Capital	Cost	Weighted Cost
Long-term Debt	$1,119,050	50%	6.48%	3.24%
Preferred Stock	-	-	-	-
Common Equity	$1,275,487	50%	10.1%	5.05%
Total	**$2,394,537**	**100%**		**8.29%**

Q. Why is PGE not seeking to change its authorized cost of capital in this proceeding?

A. We decided to use PGE's authorized cost of capital and capital structure from the Commisssion's recent rate order for two reasons. First, the Commission has just determined PGE's authorized cost of capital and capital structure for 2007. One would expect that unless the financial markets changed significantly, the expected authorized cost of capital for 2008 would be close to the current one. Second, PGE does not expect to undertake any significant financing activity during 2008 that would require the capital structure or cost rates to be updated. PGE expects to issue $100 million of new long-term debt in 2008, which would have a minor, if any, effect on PGE's capital structure and weighted cost of capital.

Q. Have you estimated PGE's required return on equity for 2008?

A. No. PGE Exhibit 200 shows that even using PGE's currently authorized cost of capital and capital structure, the required revenue requirement increase for 2008 would be much higher than the Biglow Canyon costs that we are requesting. Rather than re-litigate these recently decided and contentious cost of capital issues, we propose to limit the scope of this proceeding to the Biglow Canyon costs. In these circumstances – a rate request that is far less than could be justified under a traditional revenue requirement analysis, and the absence of any significant financing activity by PGE – it is unnecessary to re-visit the cost of capital issues resolved by the Commission in January 2007.

II. Qualifications

Q. Mr. Hager, please state your educational background and experience.

A. I received a Bachelor of Science degree in Economics from Santa Clara University in 1975 and a Master of Arts degree in Economics from the University of California at Davis in 1978. In 1995, I passed the examination for the Certified Rate of Return Analyst (CRRA). In 2000, I obtained the Chartered Financial Analyst (CFA) designation.

I have taught several introductory and intermediate classes in economics at the University of California at Davis and at California State University Sacramento. In addition, I taught intermediate finance classes at Portland State University. Between 1996 and 2004, I served on the Board of Directors for the Society of Utility and Regulatory Financial Analysts.

I have been employed at PGE since 1984, beginning as a business analyst. I have worked in a variety of positions at PGE since 1984, including power supply. My current position is Manager, Regulatory Affairs.

Q. Does this complete your testimony?

A. Yes.

Pricing

Table of Contents

I. Introduction and Summary

Q. Please state your name and position.

A. My name is Marc Cody. I am a Senior Analyst in the Pricing and Tariffs Department. My qualifications are described in Section IV.

Q. What is the purpose of your testimony?

A. This testimony and accompanying exhibits demonstrate how proposed Tariff Schedule 120 recovers PGE's 2008 Biglow Canyon revenue requirement identified in PGE Exhibit 200 from applicable customers, and how I design the associated prices.

II. Estimated Prices and Rate Impacts

Q. Please list the projected prices and accompanying rate impacts for 2008 resulting from this filing.

A. Table 1 below summarizes the prices and the base rate impacts for 2008 for selected Schedules. PGE Exhibit 402 contains more detail on how the prices are developed and PGE Exhibit 403 contains more detailed bill impacts.

Table 1

Schedule	Price (mills/kWh)	Rate Impact
Sch 7 Residential	0.70	0.7%
Sch 32 Small Non-residential	0.70	0.7%
Sch 83 Secondary	0.70	0.9%
Sch 83 Primary	0.68	1.0%
Sch 89 Secondary	0.70	1.0%
Sch 89 Primary	0.68	1.0%
Sch 89 Subtransmission	0.67	1.1%
Overall		0.8%

III. Overview of Rate Schedule Charges

Q. Please explain how you developed the prices for this Tariff.

A. Per Special Condition 1 in the proposed Tariff Schedule 120 presented in Exhibit 401, I designed the prices on an equal cents per kilowatt-hour basis, adjusted for delivery voltage line losses. This rate design approximates the generation rate design used in UE 180. I therefore believe that it is the most appropriate rate design to use for this filing. The basis of the loads over which I spread the $13 million revenue requirement is the same as that contained in UE 180/181, updated for the 2008 test period. In short, the $13 million revenue requirement is spread over total system loads less the loads of those customers currently on Schedule 483 or 489. Should more customers participate in the Schedule 483/489 September 2007 enrollment window, the load forecast will have to be adjusted accordingly. The individual rate schedule loads, on a cycle and calendar basis, are presented in Exhibit 402 as are the proposed Schedule 120 prices.

Q. Does this proposed tariff impact Schedule 128 Short-Term Transition Adjustment?

A. Yes. Because Biglow Canyon is a generation resource, the prices developed in this proceeding will need to be incorporated into the projected 2008 Schedule 128 Transition Adjustment prices. Specifically, the Schedule 120 prices will be added to the Cost-of-Service energy charges when calculating Schedule 128 prices in mid-November. Therefore, there are no specific Schedule 120 charges for Schedule 500 series direct access schedules because the appropriate allocated costs of Biglow Canyon are contained in Schedule 128. This is similar to how Schedule 125 Annual Power Cost Update (the Annual Update Tariff – AUT) is incorporated into the pricing for the Schedule 500 series direct access schedules. More detail is provided in Special Condition 2 of Schedule 120. Also, for tariff simplification, PGE may, should parties be agreeable, consolidate the Schedule 120 and 125 prices into the stated energy charges for Cost-of-Service Schedules. The final November AUT filing could then contain these changes to the energy charges and the prices for both Schedules 120 and 125 could then be set to zero.

Q. How does Biglow Canyon impact Schedule 126 Annual Power Cost Variance Mechanism?

A. Because Biglow Canyon is expected to be operational December 1, 2007 there will be an impact upon the calculation of actual 2007 Net Variable Power Costs. This issue is discussed in both PGE Exhibit 100 and in Special Condition 4 of proposed Schedule 120. PGE intends to separately file a clarifying modification to Schedule 126.

IV. Qualifications of Witness

Q. Mr. Cody, please state your educational background and qualifications.

A. I received a Bachelor of Arts degree and a Master of Science degree from Portland State University. Both degrees were in Economics. The Master of Science degree has a concentration in econometrics and industrial organization.

Since joining PGE in 1996, I have worked as an analyst in the Rates and Regulatory Affairs Department. My duties at PGE have focused on cost of capital estimation, marginal cost of service, rate spread and rate design.

Q. Does this complete your testimony?

A. Yes.

SCHEDULE 120
BIGLOW CANYON I ADJUSTMENT

PURPOSE

This schedule recovers the net costs of the Company's Biglow Canyon I wind project. Approval of this tariff adjustment will be considered a Commission revision of the Company's ratio of net revenues to gross revenues and effective tax rate for purposes of OAR 860-22-0041.

AVAILABLE

In all territory served by the Company

APPLICABLE

To all bills for Electricity Service served under the following rate schedules 7, 15, 32, 38, 47, 49, 75, 83, 87, 89, 91, 92, 93 and 94.

ADJUSTMENT RATE

The Adjustment Rates, applicable for service on and after January 1, 2008, are:

Schedule	Adjustment Rate
7	0.070 ¢ per kWh
15	0.070 ¢ per kWh
32	0.070 ¢ per kWh
38	0.070 ¢ per kWh
47	0.070 ¢ per kWh
49	0.070 ¢ per kWh
75	
Secondary	0.070 ¢ per kWh
Primary	0.068 ¢ per kWh
Subtransmission	0.067 ¢ per kWh
83	
Secondary	0.070 ¢ per kWh
Primary	0.068 ¢ per kWh
87	
Secondary	0.070 ¢ per kWh
Primary	0.068 ¢ per kWh
Subtransmission	0.067 ¢ per kWh
89	
Secondary	0.070 ¢ per kWh
Primary	0.068 ¢ per kWh
Subtransmission	0.067 ¢ per kWh

SCHEDULE 120 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate
91	0.070 ¢ per kWh
92	0.070 ¢ per kWh
93	0.070 ¢ per kWh
94	0.070 ¢ per kWh

SPECIAL CONDITIONS

1. Rates under this schedule will recover the net costs of Biglow Canyon I from all applicable customers on an equal cents per kWh basis adjusted for delivery voltage.

2. The rates contained in this schedule will, if necessary, be revised and refiled on November 15, 2007 to be consistent with the load forecast and forward price curves used in the Annual Power Cost Update also filed on that date. The rates in this schedule will be added to the applicable rate schedules' Cost of Service Energy Charges for purposes of calculating the Schedule 128, Short-Term Transition Adjustment.

3. If the Biglow Canyon I wind project is not expected to achieve commercial operation by January 1, 2008, the Company will notify the Commission by December 31, 2007. In such case, the effective date of the above adjustment rates will be delayed until one day after the Company notifies the Commission that the project has achieved commercial operation.

4. Any power produced by Biglow Canyon 1 prior to January 1, 2008 will be valued for power cost purposes at the monthly average of the daily Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Index) for determining actual NVPC under Schedule 126, Annual Power Cost Variance Mechanism.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

PORTLAND GENERAL ELECTRIC
EQUAL CENTS ALLOCATION OF BIGLOW COSTS TO COS CUSTOMERS
2008

Grouping	COS Calendar Energy	COS Busbar Energy	Allocation Percent	Allocated Biglow Costs ($000)	Biglow Price mills/kWh	Cycle Energy	Cycle Basis Revenues ($000)
Schedule 7	7,704,412	8,346,960	41.77%	$5,413	0.70	7,698,739	$5,389
Schedule 15	23,340	25,286	0.13%	$16	0.70	23,340	$16
Schedule 32	1,541,151	1,669,683	8.36%	$1,083	0.70	1,539,833	$1,078
Schedule 38							
On-peak	53,258	57,700	0.29%	$37	0.70	53,207	$37
Off-peak	54,757	59,324	0.30%	$38	0.70	54,704	$38
Schedule 47	22,241	24,096	0.12%	$16	0.70	21,972	$15
Schedule 49	64,233	69,590	0.35%	$45	0.70	64,497	$45
Schedule 83-S	5,521,281	5,981,756	29.93%	$3,879	0.70	5,513,240	$3,859
Schedule 89-S							
On-peak	441,387	478,198	2.39%	$310	0.70	440,726	$309
Off-peak	234,882	254,472	1.27%	$165	0.70	234,609	$164
Schedule 83-P	308,388	323,437	1.62%	$210	0.68	308,029	$209
Schedule 89-P							
On-peak	1,039,002	1,089,706	5.45%	$707	0.68	1,037,778	$706
Off-peak	673,063	705,908	3.53%	$458	0.68	672,376	$457
Schedule 89-T							
On-peak	432,736	447,319	2.24%	$290	0.67	432,269	$290
Off-peak	320,665	331,471	1.66%	$215	0.67	320,411	$215
Schedule 91	102,866	111,445	0.56%	$72	0.70	102,866	$72
Schedule 92	5,764	6,245	0.03%	$4	0.70	5,764	$4
Schedule 93	554	601	0.00%	$0	0.70	554	$0
TOTAL	18,543,981	19,983,197	100.00%	$12,959		18,524,913	$12,904
			TARGET	$12,959			

TABLE 1
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2008 COS ONLY

CATEGORY	RATE SCHEDULE	CUSTOMERS (Forecast SOCT06E08)	MWH SALES	TOTAL ELECTRIC BILLS CURRENT Base Rates	TOTAL ELECTRIC BILLS PROPOSED Base Rates	Change AMOUNT	Change PCT.
Residential	7	714,472	7,698,739	$760,856,118	$766,245,235	$5,389,117	0.7%
Employee Discount				($799,031)	($801,369)	($2,338)	
Subtotal				$760,057,087	$765,443,867	$5,386,780	0.7%
Outdoor Area Lighting	15	1,351	23,340	$4,244,566	$4,260,903	$16,338	0.4%
General Service <30 kW	32	83,037	1,539,833	$144,213,525	$145,291,408	$1,077,883	0.7%
Opt. Time-of-Day G.S. >30 kW	38	1,235	107,911	$10,380,866	$10,456,403	$75,537	0.7%
Irrig. & Drain. Pump. < 30 kW	47	3,179	21,972	$2,185,709	$2,201,090	$15,380	0.7%
Irrig. & Drain. Pump. > 30 kW	49	1,321	64,497	$4,674,285	$4,719,433	$45,148	1.0%
General Service >30 kW							
Secondary	83-S	12,006	5,513,240	$419,829,648	$423,688,916	$3,859,268	0.9%
Primary	83-P	150	308,029	$21,760,167	$21,969,626	$209,459	1.0%
Schedule 89 > 1 MW							
Secondary	89-S	104	675,334	$49,101,102	$49,573,836	$472,734	1.0%
Primary	89-P	110	1,710,155	$112,415,327	$113,578,232	$1,162,905	1.0%
Subtransmission	89-T	7	752,680	$45,550,101	$46,054,396	$504,296	1.1%
Street & Highway Lighting	91	206	102,866	$16,608,100	$16,680,106	$72,006	0.4%
Traffic Signals	92	18	5,764	$419,203	$423,238	$4,035	1.0%
Recreational Field Lighting	93	27	554	$85,160	$85,548	$388	0.5%
TOTAL (CYCLE YEAR BASIS)		817,223	18,524,913	$1,591,524,845	$1,604,427,003	$12,902,157	0.8%
CONVERSION ADJUSTMENT				$1,638,182	$1,651,463		
TOTAL (CALENDAR YEAR BASIS)			18,543,981	**$1,593,163,028**	**$1,606,078,465**	**$12,915,438**	0.8%

TABLE 2
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2008 COS ONLY

CATEGORY	RATE SCHEDULE	CUSTOMERS (Forecast SOCT06E08)	MWH SALES	TOTAL ELECTRIC BILLS CURRENT with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS PROPOSED with all supplementals except LIA & PPC	Change AMOUNT	Change PCT.
Residential	7	714,472	7,698,739	$670,775,877	$676,164,994	$5,389,117	0.8%
Employee Discount				($708,722)	($711,059)	($2,338)	
Subtotal				$670,067,156	$675,453,935	$5,386,780	0.8%
Outdoor Area Lighting	15	1,351	23,340	$4,158,831	$4,175,169	$16,338	0.4%
General Service <30 kW	32	83,037	1,539,833	$141,592,361	$142,670,244	$1,077,883	0.8%
Opt. Time-of-Day G.S. >30 kW	38	1,235	107,911	$10,314,174	$10,389,712	$75,537	0.7%
Irrig. & Drain. Pump. < 30 kW	47	3,179	21,972	$1,951,554	$1,966,934	$15,380	0.8%
Irrig. & Drain. Pump. > 30 kW	49	1,321	64,497	$4,034,098	$4,079,245	$45,148	1.1%
General Service >30 kW							
Secondary	83-S	12,006	5,513,240	$417,155,685	$421,014,953	$3,859,268	0.9%
Primary	83-P	150	308,029	$21,703,617	$21,913,077	$209,459	1.0%
Schedule 89 > 1 MW							
Secondary	89-S	104	675,334	$49,209,155	$49,681,889	$472,734	1.0%
Primary	89-P	110	1,710,155	$112,740,256	$113,903,161	$1,162,905	1.0%
Subtransmission	89-T	7	752,680	$45,715,690	$46,219,986	$504,296	1.1%
Street & Highway Lighting	91	206	102,866	$16,599,871	$16,671,877	$72,006	0.4%
Traffic Signals	92	18	5,764	$420,183	$424,218	$4,035	1.0%
Recreational Field Lighting	93	27	554	$85,121	$85,509	$388	0.5%
TOTAL (CYCLE YEAR BASIS)		817,223	18,524,913	$1,495,747,753	$1,508,649,910	$12,902,157	0.9%
CONVERSION ADJUSTMENT				$1,539,597	$1,552,878		
TOTAL (CALENDAR YEAR BASIS)			18,543,981	**$1,497,287,350**	**$1,510,202,788**	**$12,915,438**	0.9%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 7
Note: Bill comparison includes Low Income Charge and Public Purpose Charge

	Net Monthly Bill		
kWh	2007 Prices with Port Westward	Proposed Prices	Percent Difference
50	$13.87	$13.91	0.28%
100	$17.12	$17.19	0.40%
200	$23.60	$23.75	0.63%
250	$26.86	$27.04	0.66%
300	$31.00	$31.22	0.71%
400	$39.33	$39.62	0.73%
500	$47.66	$48.02	0.75%
600	$55.96	$56.39	0.77%
700	$64.29	$64.79	0.78%
800	$72.60	$73.18	0.80%
900	$80.92	$81.57	0.80%
1,000	$89.23	$89.95	0.81%
1,100	$97.55	$98.34	0.81%
1,200	$105.86	$106.73	0.82%
1,300	$114.18	$115.11	0.82%
1,400	$122.50	$123.51	0.83%
1,500	$130.83	$131.91	0.83%
1,600	$139.13	$140.29	0.83%
1,700	$147.46	$148.68	0.83%
1,800	$155.77	$157.07	0.84%
2,000	$172.40	$173.85	0.84%
2,300	$197.35	$199.01	0.84%
2,750	$234.79	$236.77	0.84%
3,000	$255.58	$257.74	0.85%
3,500	$297.17	$299.70	0.85%
4,000	$338.75	$341.63	0.85%
4,500	$380.35	$383.59	0.85%
5,000	$421.92	$425.53	0.85%
7,500	$629.86	$635.27	0.86%
10,000	$837.78	$844.99	0.86%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 32, 1-phase Service
Note: Bill comparison includes Low Income Charge and Public Purpose Charge

	Net Monthly Billing (without RPA credit)			Net Monthly Billing (with RPA credit)		
kWh	**2007 Prices with Port Westward**	**Proposed Prices**	**Percent Difference**	**2007 Prices with Port Westward**	**Proposed Prices**	**Percent Difference**
100	$21.41	$21.48	0.33%	$20.21	$20.28	0.35%
500	$57.67	$58.04	0.64%	$51.64	$52.00	0.70%
600	$66.72	$67.15	0.64%	$59.48	$59.91	0.72%
700	$75.78	$76.29	0.67%	$67.33	$67.84	0.76%
800	$84.83	$85.41	0.68%	$75.18	$75.76	0.77%
900	$93.91	$94.56	0.69%	$83.05	$83.70	0.78%
1,000	$102.96	$103.68	0.70%	$90.90	$91.62	0.79%
1,500	$148.27	$149.36	0.74%	$130.18	$131.26	0.83%
1,750	$170.92	$172.19	0.74%	$149.82	$151.08	0.84%
2,000	$193.56	$195.00	0.74%	$169.44	$170.88	0.85%
2,500	$238.87	$240.68	0.76%	$208.71	$210.52	0.87%
3,500	$329.47	$332.00	0.77%	$287.25	$289.78	0.88%
4,000	$374.76	$377.64	0.77%	$326.51	$329.40	0.89%
4,500	$420.07	$423.32	0.77%	$365.79	$369.04	0.89%
5,000	$465.36	$468.96	0.77%	$405.05	$408.65	0.89%
6,000	$532.84	$537.17	0.81%	$460.47	$464.80	0.94%
7,000	$600.33	$605.38	0.84%	$515.90	$520.95	0.98%
8,000	$667.81	$673.58	0.86%	$571.32	$577.09	1.01%
9,000	$735.30	$741.79	0.88%	$626.75	$633.24	1.04%
10,000	$802.79	$810.00	0.90%	$682.17	$689.38	1.06%
14,000	$1,072.73	$1,082.82	0.94%	$903.87	$913.97	1.12%
15,000	$1,140.22	$1,151.03	0.95%	$959.30	$970.11	1.13%
20,000	$1,477.65	$1,492.07	0.98%	$1,236.42	$1,250.84	1.17%
21,900	$1,605.87	$1,621.66	0.98%	$1,341.73	$1,357.52	1.18%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 32, 3-phase Service
Note: Bill comparison includes Low Income Charge and Public Purpose Charge

	Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
kWh	2007 Prices with Port Westward	Proposed Prices	Percent Difference	2007 Prices with Port Westward	Proposed Prices	Percent Difference
100	$25.53	$25.60	0.27%	$24.33	$24.40	0.29%
500	$61.79	$62.16	0.60%	$55.76	$56.12	0.65%
600	$70.84	$71.27	0.61%	$63.60	$64.03	0.68%
700	$79.90	$80.41	0.64%	$71.45	$71.96	0.71%
800	$88.95	$89.53	0.65%	$79.30	$79.88	0.73%
900	$98.03	$98.68	0.66%	$87.17	$87.82	0.75%
1,000	$107.08	$107.80	0.67%	$95.02	$95.74	0.76%
1,500	$152.39	$153.48	0.72%	$134.30	$135.38	0.80%
1,750	$175.04	$176.31	0.73%	$153.94	$155.20	0.82%
2,000	$197.68	$199.12	0.73%	$173.56	$175.00	0.83%
2,500	$242.99	$244.80	0.74%	$212.83	$214.64	0.85%
3,500	$333.59	$336.12	0.76%	$291.37	$293.90	0.87%
4,000	$378.88	$381.76	0.76%	$330.63	$333.52	0.87%
4,500	$424.19	$427.44	0.77%	$369.91	$373.16	0.88%
5,000	$469.48	$473.08	0.77%	$409.17	$412.77	0.88%
6,000	$536.96	$541.29	0.81%	$464.59	$468.92	0.93%
7,000	$604.45	$609.50	0.84%	$520.02	$525.07	0.97%
8,000	$671.93	$677.70	0.86%	$575.44	$581.21	1.00%
9,000	$739.42	$745.91	0.88%	$630.87	$637.36	1.03%
10,000	$806.91	$814.12	0.89%	$686.29	$693.50	1.05%
14,000	$1,076.85	$1,086.94	0.94%	$907.99	$918.09	1.11%
15,000	$1,144.34	$1,155.15	0.94%	$963.42	$974.23	1.12%
20,000	$1,481.77	$1,496.19	0.97%	$1,240.54	$1,254.96	1.16%
21,900	$1,609.99	$1,625.78	0.98%	$1,345.85	$1,361.64	1.17%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 38, 3-phase Service
Note: Bill comparison includes Low Income Charge and Public Purpose Charge
Bill comparison assumes 50% on-peak and 50% off-peak energy consumption

Biglow Canyon

	Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
kWh	2007 Prices with Port Westward	Proposed Prices	Percent Difference	2007 Prices with Port Westward	Proposed Prices	Percent Difference
1,000	$121.25	$121.97	0.59%	$109.19	$109.91	0.66%
3,000	$312.24	$314.40	0.69%	$276.06	$278.22	0.78%
5,000	$503.23	$506.84	0.72%	$442.93	$446.53	0.81%
7,000	$694.23	$699.27	0.73%	$609.80	$614.85	0.83%
10,000	$980.72	$987.93	0.74%	$860.11	$867.32	0.84%
13,000	$1,267.21	$1,276.58	0.74%	$1,110.41	$1,119.79	0.84%
14,000	$1,362.71	$1,372.80	0.74%	$1,193.85	$1,203.94	0.85%
16,000	$1,553.70	$1,565.24	0.74%	$1,360.72	$1,372.25	0.85%
21,000	$2,031.18	$2,046.32	0.75%	$1,777.90	$1,793.04	0.85%
25,000	$2,413.17	$2,431.20	0.75%	$2,111.64	$2,129.66	0.85%
30,000	$2,890.66	$2,912.29	0.75%	$2,528.82	$2,550.45	0.86%
35,000	$3,368.14	$3,393.37	0.75%	$2,945.99	$2,971.23	0.86%
40,000	$3,845.62	$3,874.46	0.75%	$3,363.17	$3,392.01	0.86%
45,000	$4,323.11	$4,355.55	0.75%	$3,780.35	$3,812.79	0.86%
50,000	$4,800.59	$4,836.64	0.75%	$4,197.53	$4,233.58	0.86%
75,000	$7,188.01	$7,242.09	0.75%	$6,283.42	$6,337.49	0.86%
100,000	$9,575.44	$9,647.54	0.75%	$8,369.31	$8,441.41	0.86%
150,000	$14,350.28	$14,458.43	0.75%	$12,541.08	$12,649.23	0.86%
200,000	$19,125.12	$19,269.32	0.75%	$16,712.86	$16,857.06	0.86%
300,000	$28,674.81	$28,891.11	0.75%	$25,056.42	$25,272.72	0.86%
400,000	$38,224.49	$38,512.89	0.75%	$33,399.97	$33,688.37	0.86%
500,000	$47,774.18	$48,134.68	0.75%	$41,743.53	$42,104.03	0.86%
750,000	$71,648.39	$72,189.14	0.75%	$62,602.41	$63,143.16	0.86%
1,000,000	$95,522.60	$96,243.60	0.75%	$83,461.30	$84,182.30	0.86%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 83, Secondary, 3 phase service.
Note: Bill comparison includes Low Income Energy Assistance and Public Purpose Charges

			Net Monthly Billing (without RPA credit)			Net Monthly Bill (with RPA credit)		
Load Factor	kWh	kW	2007 Prices with Port Westward	Proposed Prices	Percent Difference	2007 Prices with Port Westward	Proposed Prices	Percent Difference
30%	6,570	30	$571.67	$576.41	0.83%	$492.43	$497.17	0.96%
	10,950	50	$962.19	$970.09	0.82%	$830.12	$838.02	0.95%
	21,900	100	$1,938.50	$1,954.29	0.81%	$1,674.35	$1,690.14	0.94%
	43,800	200	$3,891.10	$3,922.68	0.81%	$3,362.82	$3,394.40	0.94%
	76,650	350	$6,820.01	$6,875.28	0.81%	$5,895.51	$5,950.78	0.94%
	109,500	500	$9,748.92	$9,827.87	0.81%	$8,428.21	$8,507.16	0.94%
	153,300	700	$13,654.13	$13,764.66	0.81%	$11,805.14	$11,915.67	0.94%
	186,150	850	$16,583.04	$16,717.26	0.81%	$14,337.83	$14,472.05	0.94%
	219,000	1,000	$19,511.95	$19,669.85	0.81%	$16,870.53	$17,028.43	0.94%
50%	10,950	30	$849.30	$857.20	0.93%	$717.23	$725.13	1.10%
	18,250	50	$1,424.91	$1,438.07	0.92%	$1,204.80	$1,217.95	1.09%
	36,500	100	$2,863.94	$2,890.26	0.92%	$2,423.70	$2,450.02	1.09%
	73,000	200	$5,741.99	$5,794.62	0.92%	$4,861.52	$4,914.15	1.08%
	127,750	350	$10,059.07	$10,151.17	0.92%	$8,518.24	$8,610.34	1.08%
	182,500	500	$14,376.14	$14,507.73	0.92%	$12,174.96	$12,306.54	1.08%
	255,500	700	$20,132.25	$20,316.46	0.92%	$17,050.58	$17,234.80	1.08%
	310,250	850	$24,449.32	$24,673.01	0.91%	$20,707.30	$20,930.99	1.08%
	365,000	1,000	$28,766.40	$29,029.56	0.91%	$24,364.02	$24,627.19	1.08%

PORTLAND GENERAL ELECTRIC

Effect of Proposed Rate Change on Monthly Bills

Tariff Schedule 83, Secondary, 3 phase service.

Note: Bill comparison includes Low Income Energy Assistance and Public Purpose Charges

			Net Monthly Billing (without RPA credit)			Net Monthly Bill (with RPA credit)		
Load Factor	kWh	kW	2007 Prices with Port Westward	Proposed Prices	Percent Difference	2007 Prices with Port Westward	Proposed Prices	Percent Difference
70%	15,330	30	$1,126.94	$1,137.99	0.98%	$942.04	$953.09	1.17%
	25,550	50	$1,887.64	$1,906.06	0.98%	$1,579.47	$1,597.89	1.17%
	51,100	100	$3,789.38	$3,826.23	0.97%	$3,173.05	$3,209.89	1.16%
	102,200	200	$7,592.88	$7,666.57	0.97%	$6,360.21	$6,433.90	1.16%
	178,850	350	$13,298.12	$13,427.07	0.97%	$11,140.96	$11,269.91	1.16%
	255,500	500	$19,003.37	$19,187.58	0.97%	$15,921.70	$16,105.92	1.16%
	357,700	700	$26,610.36	$26,868.26	0.97%	$22,296.03	$22,553.93	1.16%
	434,350	850	$32,315.60	$32,628.77	0.97%	$27,076.77	$27,389.94	1.16%
	511,000	1,000	$38,020.84	$38,389.27	0.97%	$31,857.52	$32,225.95	1.16%
90%	19,710	30	$1,404.57	$1,418.78	1.01%	$1,166.84	$1,181.05	1.22%
	32,850	50	$2,350.36	$2,374.04	1.01%	$1,954.15	$1,977.83	1.21%
	65,700	100	$4,714.83	$4,762.20	1.00%	$3,922.40	$3,969.77	1.21%
	131,400	200	$9,443.77	$9,538.51	1.00%	$7,858.91	$7,953.65	1.21%
	229,950	350	$16,537.18	$16,702.97	1.00%	$13,763.68	$13,929.48	1.20%
	328,500	500	$23,630.59	$23,867.44	1.00%	$19,668.45	$19,905.30	1.20%
	459,900	700	$33,088.47	$33,420.05	1.00%	$27,541.47	$27,873.06	1.20%
	558,450	850	$40,181.88	$40,584.52	1.00%	$33,446.24	$33,848.89	1.20%
	657,000	1,000	$47,275.29	$47,748.98	1.00%	$39,351.01	$39,824.71	1.20%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 83, Primary, 3 phase service.
Note: Bill comparison includes Low Income Energy Assistance and Public Purpose Charges

Load Factor	kWh	kW	Net Monthly Bill (without RPA credit): 2007 Prices with Port Westward	Net Monthly Bill (without RPA credit): Proposed Prices	Net Monthly Bill (without RPA credit): Percent Difference	Net Monthly Bill (with RPA credit): 2007 Prices with Port Westward	Net Monthly Bill (with RPA credit): Proposed Prices	Net Monthly Bill (with RPA credit): Percent Difference
30%	21,900	100	$1,907.05	$1,922.39	0.80%	$1,642.91	$1,658.25	0.93%
	43,800	200	$3,721.41	$3,752.09	0.82%	$3,193.12	$3,223.80	0.96%
	76,650	350	$6,442.94	$6,496.63	0.83%	$5,518.44	$5,572.13	0.97%
	109,500	500	$9,164.47	$9,241.17	0.84%	$7,843.76	$7,920.46	0.98%
	142,350	650	$11,886.01	$11,985.71	0.84%	$10,169.08	$10,268.78	0.98%
	186,150	850	$15,514.72	$15,645.10	0.84%	$13,269.50	$13,399.88	0.98%
	219,000	1,000	$18,236.25	$18,389.64	0.84%	$15,594.82	$15,748.21	0.98%
50%	36,500	100	$2,791.14	$2,816.71	0.92%	$2,350.91	$2,376.47	1.09%
	73,000	200	$5,489.59	$5,540.72	0.93%	$4,609.11	$4,660.24	1.11%
	127,750	350	$9,537.26	$9,626.73	0.94%	$7,996.43	$8,085.90	1.12%
	182,500	500	$13,584.92	$13,712.75	0.94%	$11,383.74	$11,511.56	1.12%
	237,250	650	$17,632.59	$17,798.76	0.94%	$14,771.05	$14,937.22	1.12%
	310,250	850	$23,029.48	$23,246.78	0.94%	$19,287.46	$19,504.76	1.13%
	365,000	1,000	$27,077.15	$27,332.79	0.94%	$22,674.77	$22,930.42	1.13%
70%	51,100	100	$3,675.23	$3,711.02	0.97%	$3,058.90	$3,094.69	1.17%
	102,200	200	$7,257.77	$7,329.35	0.99%	$6,025.10	$6,096.69	1.19%
	178,850	350	$12,631.57	$12,756.84	0.99%	$10,474.41	$10,599.67	1.20%
	255,500	500	$18,005.37	$18,184.32	0.99%	$14,923.71	$15,102.66	1.20%
	332,150	650	$23,379.17	$23,611.81	1.00%	$19,373.01	$19,605.65	1.20%
	434,350	850	$30,544.24	$30,848.46	1.00%	$25,305.42	$25,609.64	1.20%
	511,000	1,000	$35,918.05	$36,275.95	1.00%	$29,754.72	$30,112.63	1.20%
90%	65,700	100	$4,559.32	$4,605.34	1.01%	$3,766.90	$3,812.91	1.22%
	131,400	200	$9,025.95	$9,117.98	1.02%	$7,441.09	$7,533.13	1.24%
	229,950	350	$15,725.89	$15,886.94	1.02%	$12,952.39	$13,113.45	1.24%
	328,500	500	$22,425.82	$22,655.90	1.03%	$18,463.68	$18,693.77	1.25%
	427,050	650	$29,125.76	$29,424.86	1.03%	$23,974.98	$24,274.09	1.25%
	558,450	850	$38,059.01	$38,450.15	1.03%	$31,323.37	$31,714.51	1.25%
	657,000	1,000	$44,758.94	$45,219.11	1.03%	$36,834.67	$37,294.83	1.25%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Secondary.
Note: Bill comparison includes Low Income Energy Assistance and Public Purpose Charges
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

			Net Monthly Bill		
Load Factor	**kWh**	**kW**	**2007 Prices with Port Westward**	**Proposed Prices**	**Percent Difference**
30%	219,000	1,000	$18,892.87	$19,050.77	0.83%
	438,000	2,000	$36,117.15	$36,432.94	0.87%
	876,000	4,000	$70,565.69	$71,197.29	0.90%
	1,642,500	7,500	$130,808.62	$131,992.86	0.91%
	2,190,000	10,000	$173,688.63	$175,267.62	0.91%
	3,285,000	15,000	$259,448.64	$261,817.13	0.91%
	4,380,000	20,000	$345,208.66	$348,366.64	0.91%
50%	365,000	1,000	$28,109.72	$28,372.89	0.94%
	730,000	2,000	$54,550.84	$55,077.17	0.96%
	1,460,000	4,000	$107,433.09	$108,485.75	0.98%
	2,737,500	7,500	$199,573.64	$201,547.37	0.99%
	3,650,000	10,000	$265,375.32	$268,006.97	0.99%
	5,475,000	15,000	$396,978.67	$400,926.15	0.99%
	7,300,000	20,000	$528,582.03	$533,845.33	1.00%
70%	511,000	1,000	$37,326.57	$37,695.00	0.99%
	1,022,000	2,000	$72,984.54	$73,721.40	1.01%
	2,044,000	4,000	$144,125.96	$145,599.68	1.02%
	3,832,500	7,500	$268,338.65	$271,101.88	1.03%
	5,110,000	10,000	$357,062.00	$360,746.31	1.03%
	7,665,000	15,000	$534,508.70	$540,035.17	1.03%
	10,220,000	20,000	$711,955.40	$719,324.02	1.03%
90%	657,000	1,000	$46,543.42	$47,017.12	1.02%
	1,314,000	2,000	$91,418.24	$92,365.63	1.04%
	2,628,000	4,000	$180,800.63	$182,695.42	1.05%
	4,927,500	7,500	$337,103.67	$340,656.39	1.05%
	6,570,000	10,000	$448,748.69	$453,485.66	1.06%
	9,855,000	15,000	$672,038.73	$679,144.19	1.06%
	13,140,000	20,000	$895,328.77	$904,802.71	1.06%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Primary, 3 phase service.
Note: Bill comparison includes Low Income Energy Assistance Charge and Public Purpose Charges
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

				Biglow Canyon	
Load Factor	kWh	kW	2007 Prices with Port Westward	Proposed Prices	Percent Difference
30%	219,000	1,000	$18,222.26	$18,375.64	
	438,000	2,000	$34,672.91	$34,979.69	0.88%
	876,000	4,000	$67,574.23	$68,187.78	0.91%
	1,642,500	7,500	$125,109.50	$126,259.90	0.92%
	2,190,000	10,000	$166,055.46	$167,589.34	0.92%
	3,285,000	15,000	$247,947.40	$250,248.21	0.93%
	4,380,000	20,000	$329,839.33	$332,907.08	0.93%
50%	365,000	1,000	$27,012.63	$27,268.27	0.95%
	730,000	2,000	$52,253.65	$52,764.95	0.98%
	1,460,000	4,000	$102,735.71	$103,758.29	1.00%
	2,737,500	7,500	$190,675.93	$192,593.27	1.01%
	3,650,000	10,000	$253,477.37	$256,033.83	1.01%
	5,475,000	15,000	$379,080.26	$382,914.95	1.01%
	7,300,000	20,000	$504,683.15	$509,796.07	1.01%
70%	511,000	1,000	$35,803.00	$36,160.90	1.00%
	1,022,000	2,000	$69,834.40	$70,550.21	1.03%
	2,044,000	4,000	$137,722.67	$139,154.29	1.04%
	3,832,500	7,500	$256,242.36	$258,926.64	1.05%
	5,110,000	10,000	$340,899.28	$344,478.33	1.05%
	7,665,000	15,000	$510,213.12	$515,581.69	1.05%
	10,220,000	20,000	$679,526.96	$686,685.05	1.05%
90%	657,000	1,000	$44,593.37	$45,053.53	1.03%
	1,314,000	2,000	$87,415.14	$88,335.46	1.05%
	2,628,000	4,000	$172,691.44	$174,532.09	1.07%
	4,927,500	7,500	$321,808.79	$325,260.01	1.07%
	6,570,000	10,000	$428,321.19	$432,922.82	1.07%
	9,855,000	15,000	$641,345.99	$648,248.43	1.08%
	13,140,000	20,000	$854,370.78	$863,574.04	1.08%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Transmission
Note: Bill comparison includes Low Income Energy Assistance and Public Purpose Charges
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

Biglow Canyon

Load Factor	kWh	kW	2007 Prices with Port Westward	Proposed Prices	Percent Difference
30%	876,000	4,000	$62,833.49	$63,438.02	0.96%
	1,095,000	5,000	$77,900.69	$78,656.35	0.97%
	2,190,000	10,000	$153,013.97	$154,525.29	0.99%
	4,380,000	20,000	$302,963.25	$305,985.89	1.00%
	8,760,000	40,000	$602,861.80	$608,907.07	1.00%
	10,950,000	50,000	$752,811.07	$760,367.67	1.00%
	15,330,000	70,000	$1,052,709.62	$1,063,288.86	1.00%
50%	1,460,000	4,000	$97,299.62	$98,307.16	1.04%
	1,825,000	5,000	$120,881.10	$122,140.53	1.04%
	3,650,000	10,000	$238,697.49	$241,216.36	1.06%
	7,300,000	20,000	$474,330.28	$479,368.01	1.06%
	14,600,000	40,000	$945,595.86	$955,671.32	1.07%
	18,250,000	50,000	$1,181,228.66	$1,193,822.98	1.07%
	25,550,000	70,000	$1,652,494.24	$1,670,126.29	1.07%
70%	2,044,000	4,000	$131,591.22	$133,001.79	1.07%
	2,555,000	5,000	$163,722.85	$165,486.06	1.08%
	5,110,000	10,000	$324,381.01	$327,907.42	1.09%
	10,220,000	20,000	$645,697.31	$652,750.14	1.09%
	20,440,000	40,000	$1,288,329.93	$1,302,435.57	1.09%
	25,550,000	50,000	$1,609,646.24	$1,627,278.29	1.10%
	35,770,000	70,000	$2,252,278.85	$2,276,963.73	1.10%
90%	2,628,000	4,000	$165,864.63	$167,678.21	1.09%
	3,285,000	5,000	$206,564.61	$208,831.59	1.10%
	6,570,000	10,000	$410,064.52	$414,598.48	1.11%
	13,140,000	20,000	$817,064.35	$826,132.26	1.11%
	26,280,000	40,000	$1,631,064.00	$1,649,199.82	1.11%
	32,850,000	50,000	$2,038,063.82	$2,060,733.60	1.11%
	45,990,000	70,000	$2,852,063.47	$2,883,801.17	1.11%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 47 Summer Period
Note: Bill comparison includes Low Income Energy Assistance and Public Purpose Charges

		Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
kW	kWh	2007 Prices with Port Westward	Proposed Prices	Percent Difference	2007 Prices with Port Westward	Proposed Prices	Percent Difference
10	50	$30.58	$30.61	0.12%	$29.97	$30.01	0.12%
10	100	$35.40	$35.47	0.20%	$34.20	$34.27	0.21%
10	500	$74.01	$74.37	0.49%	$67.98	$68.34	0.53%
10	1,000	$111.97	$112.69	0.64%	$99.91	$100.63	0.72%
10	2,000	$187.89	$189.34	0.77%	$163.77	$165.21	0.88%
10	5,000	$415.66	$419.26	0.87%	$355.35	$358.96	1.01%
20	100	$35.40	$35.47	0.20%	$34.20	$34.27	0.21%
20	200	$45.05	$45.20	0.32%	$42.64	$42.79	0.34%
20	500	$74.01	$74.37	0.49%	$67.98	$68.34	0.53%
20	1,000	$122.27	$122.99	0.59%	$110.21	$110.93	0.65%
20	2,000	$198.19	$199.64	0.73%	$174.07	$175.51	0.83%
20	5,000	$425.96	$429.56	0.85%	$365.65	$369.26	0.99%
20	8,000	$653.72	$659.49	0.88%	$557.23	$563.00	1.04%
30	150	$40.23	$40.34	0.27%	$38.42	$38.53	0.28%
30	500	$74.01	$74.37	0.49%	$67.98	$68.34	0.53%
30	1,000	$122.27	$122.99	0.59%	$110.21	$110.93	0.65%
30	3,000	$284.42	$286.58	0.76%	$248.23	$250.39	0.87%
30	5,000	$436.26	$439.86	0.83%	$375.95	$379.56	0.96%
30	8,000	$664.02	$669.79	0.87%	$567.53	$573.30	1.02%
30	10,000	$815.87	$823.08	0.88%	$695.25	$702.46	1.04%
30	15,000	$1,195.48	$1,206.29	0.90%	$1,014.56	$1,025.37	1.07%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 49 Summer Period
Note: Bill comparison includes Low Income Energy Assistance and Public Purpose Charges

			Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
LF	**kW**	**kWh**	**2007 Prices with Port Westward**	**Proposed Prices**	**Percent Difference**	**2007 Prices with Port Westward**	**Proposed Prices**	**Percent Difference**
20%	35	5,110	$401.28	$404.96	0.92%	$339.64	$343.33	1.08%
40%	35	10,220	$735.60	$742.97	1.00%	$612.34	$619.71	1.20%
60%	35	15,330	$1,069.93	$1,080.98	1.03%	$885.03	$896.08	1.25%
80%	35	20,440	$1,404.26	$1,418.99	1.05%	$1,157.72	$1,172.46	1.27%
20%	50	7,300	$560.01	$565.27	0.94%	$471.96	$477.23	1.12%
40%	50	14,600	$1,037.62	$1,048.15	1.01%	$861.52	$872.05	1.22%
60%	50	21,900	$1,515.23	$1,531.02	1.04%	$1,251.09	$1,266.88	1.26%
80%	50	29,200	$1,992.84	$2,013.89	1.06%	$1,640.65	$1,661.70	1.28%
20%	70	10,220	$771.65	$779.02	0.95%	$648.39	$655.76	1.14%
40%	70	20,440	$1,440.31	$1,455.04	1.02%	$1,193.77	$1,208.51	1.23%
60%	70	30,660	$2,108.96	$2,131.07	1.05%	$1,739.16	$1,761.27	1.27%
80%	70	40,880	$2,777.61	$2,807.09	1.06%	$2,284.55	$2,314.02	1.29%
20%	100	14,600	$1,089.12	$1,099.65	0.97%	$913.02	$923.55	1.15%
40%	100	29,200	$2,044.34	$2,065.39	1.03%	$1,692.15	$1,713.20	1.24%
60%	100	43,800	$2,999.56	$3,031.14	1.05%	$2,471.27	$2,502.85	1.28%
80%	100	58,400	$3,954.78	$3,996.88	1.06%	$3,250.40	$3,292.50	1.30%
20%	200	29,200	$2,147.34	$2,168.39	0.98%	$1,795.15	$1,816.20	1.17%
40%	200	58,400	$4,057.78	$4,099.88	1.04%	$3,353.40	$3,395.50	1.26%
60%	200	87,600	$5,968.22	$6,031.38	1.06%	$4,911.65	$4,974.81	1.29%
80%	200	116,800	$7,878.66	$7,962.87	1.07%	$6,469.90	$6,554.11	1.30%