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Douglas C. Tingey
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August 15, 2008

Via Messenger

Oregon Public Utility Commission
Attention: Filing Center
550 Capitol Street NE, #215
PO Box 2148
Salem OR 97308-2148

Re: UE 197

Attention Filing Center:

Enclosed for filing in UE 197 are an original and five copies of :

Rebuttal Testimony of Portland General Electric Company:

- **(PGE/1300-1302/Piro/Policy);**
- **(PGE/1400-1406, 1407C, 1408, 1409C, 1410-1411, 1412C, 1413, 1414C/Tooman-Tinker/Revenue Requirements);**
- **(PGE/1500-1501, 1502C, 1503, 1504C, 1505-1507/Barnett-Bell/Compensation);**
- **(PGE/1600-1601, 1602C, 1603C, 1604C, 1605/Hawke/Transmission and Distribution O&M);**
- **(PGE/1700-1706/Hawke/Customer Accounting and Service);**
- **(PGE/1800, 1801C, 1802/Quennoz/Generation O&M);**
- **(PGE/1900-1903/Piro-Tooman/A&G);**
- **(PGE/2000-2008/Kuns-Cody-Lynn/Pricing); and**
- **(PGE/2100/Cavanagh/Decoupling).**

Also enclosed for filing is an original and three copies of:

- **Workpapers.**

Included are confidential and non-confidential portions. The confidential portion is subject to protective order 08-133 and therefore not to be posted on the OPUC website.

An extra copy of this cover letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided.

Thank you in advance for your assistance.

Sincerely,

DOUGLAS C. TINGEY

DCT: jbf
Enclosures
cc: Service List-UE 197

Table of Contents

I. Initial Filing and Subsequent Events

Q. What is your name and position with PGE?

A. My name is James J. Piro. I am the Executive Vice President and Chief Financial Officer for PGE. My qualifications appear in PGE Exhibit 100, Section VIII.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the policy issues raised by other parties in this proceeding as well as apparent misunderstandings or mischaracterizations of PGE's operations. I also introduce other PGE testimony that addresses the remaining unresolved issues in UE 197.

Q. How is your testimony organized?

A. In this section, I provide an overview of this rate case, comparing the initial filing to PGE's revised request based on updates, stipulations, and other adjustments. In the next section, I respond to CUB's assertions regarding the timing for this general rate case and their concerns regarding PGE's systems for cost control and containment. I then address an issue raised by Staff regarding certain costs in PGE's 2009 test year forecast. Specifically, these relate to Ballot Measure 9 and PGE's use of an average forecasted rate base, and claims that PGE's request includes one-time costs. I follow with a response to CUB's proposal for a 1% "discretionary cost reduction." I then summarize the overall effects of the other parties' proposals, if they are implemented. I conclude with a discussion of our decoupling proposal.

Q. How has PGE approached this case?

A. PGE works hard to be transparent in rate case proceedings so that our regulators and our customers can see that we are being direct with them as we plan our operations to serve their need for responsible, reliable electricity at a reasonable price – and as we ask them to pay the costs associated with that service, including appropriate levels of compensation for our employees and earnings for our shareholders. In our diligence in trying to respond to questions raised on a fact-by-fact basis, however, we may appear to miss the broader points and fail to convey an accurate general sense of how we do business. With that in mind, we will use the testimony that follows as well as subsequent exhibits to demonstrate that:

- PGE has a deeply ingrained culture of operational excellence and constantly strives for cost efficiencies. We continually review how we operate our system and serve our customers and ask how we can do our job better and more cost effectively. Ironically, our success in this effort can make ongoing efforts to fine tune our operations for cost effectiveness less satisfying to potential critics – a business that already closely manages costs has fewer opportunities for dramatic reforms and across-the-board reductions than others might.
- We fully appreciate that the current state of the economy and rising costs are major concerns for our customers. Like any business, we understand that in tough times we must evaluate whether a given expenditure needs to be made now, or if a greater benefit can be achieved by deferring costs to a later time. However, unlike many businesses, PGE is responsible for a crucial portion of the public infrastructure. Some costs can and should be deferred in a tough economy. Other costs cannot be deferred because public policy decisions made by the state legislature or Congress give us no discretion to defer them. And still other costs cannot be deferred without affecting our ability to continue providing customer service and the reliable and reasonably priced electricity that is essential to the

short- and long-term economic well being of the communities we serve. In addition, deferred maintenance simply adds costs to future years and increases risk to public at large to our customers.

- PGE and its shareholders are not immune to the cost pressures facing many sectors of the economy. Our costs are increasing significantly, including fuel costs to operate our thermal plants and material costs to maintain and expand our system on behalf of a growing customer base.
- No business – and no utility – can continue to attract investment and maintain strong credit ratings if it is not allowed to recover its prudently incurred costs. If PGE is not allowed the opportunity to recover prudent costs of providing service to its customers,[1] the company will have to make very difficult tradeoffs between quality and reliability of service and prudent financial management. This tradeoff is not reasonable for either customers or shareholders.
- With rising energy costs across the board, it becomes more important than ever for PGE to engage with its customers and help them manage their costs and become more energy efficient. This filing seeks to further our ability to do that, building on our long history of innovation in this area as well as recent actions; for example PGE's support for increased energy efficiency in SB 838. The fact that we recognize the need and have attempted to respond within existing frameworks does not mean that the frameworks do not need to be improved if we and our customers want to make further progress.

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[1] The effects of which are exacerbated by SB 408.

Notwithstanding the above, as well as many specific factors that will be described below, this testimony also addresses cost reductions. Notably, while our most recent forecast of purchased power and fuel costs increased dramatically, the potential volatility of those factors has been illustrated over the past several weeks. Power prices have been declining, so if current trends continue, our overall increase will be less than we predicted in July. We've also updated other numbers so the overall increase in operations and maintenance costs is less than previously forecasted. Even as this rate case proceeds, PGE is constantly looking for efficiencies, more effective strategies to control costs, and opportunities to leverage market forces to our customers' advantage.

Q. Mr. Piro, as you consider the overall impacts of the recommendations of the other parties in this case, what is your response?

A. I am concerned that these recommendations, if adopted, will lead to either a significantly weakened financial condition or substantial cuts in O&M which will impact service and reliability to customers and increase future costs.

Q. Why are healthy financial conditions important?

A. First, they are important because they have a direct impact on our financing costs. Over the next four years, we expect to need to finance over $1 billion. Most of this will go toward the construction of new generation facilities to serve customers and for retrofits of existing generation to reduce our environmental impact. Weak financial conditions will increase our financing costs and thus the prices our customers see.

Likewise, our ability and cost to access wholesale energy markets is a function of our financial condition and resulting bond ratings. If our unsecured bond rating were to slip two steps (to below investment grade), our access would be severely limited.

Q. How could PGE's financial condition be weakened by the proposals in this case?

A. To the extent that we cannot match the proposed reductions in revenue requirements with reductions in costs, our earnings will be reduced below authorized levels and our balance sheet will suffer. The effect is magnified by the infamous "double whammy" effect of SB 408.

Q. So, would cuts in O&M be the answer?

A. At one level, they would have to be. However, there are risks and trade-offs which include lower reliability from reduced or deferred maintenance, increased chances of fines or other actions as a result of failing to comply with the requirements and regulations of the many bodies to which we are held accountable, and reduced service levels (e.g. longer wait times on the phone). While we have never in the past expected customers to be responsible for fines or assessments resulting from failure to comply with a governmental requirement, one must ask the question whether it might be appropriate to do so if we are not allowed sufficient resources to meet our responsibilities.

Q. Does this imply that you made no changes to your original proposal?

A. No. We have reached two settlements with other parties that reduced costs by approximately $18.6 million as follows:

- A stipulation that reduced power costs by approximately $5.1 million.
- A partial stipulation that reduced non-power costs by approximately $13.6 million, including $12.9 million for a lower return on equity (ROE).

We appreciate the other parties' efforts in achieving these agreements. In addition, we have thoroughly reviewed the other parties' testimony and exhibits. Based on that review, and as described below, we are reducing our request by an additional $16.2 million.

Q. Is PGE submitting other Rebuttal Testimony?

A. Yes. The following exhibits respond to unresolved issues in the following areas:

- Exhibit 1400 – Revenue Requirements
- Exhibit 1500 – Compensation
- Exhibit 1600 – Transmission and Distribution O&M
- Exhibit 1700 – Customer Accounting and Service
- Exhibit 1800 – Generation O&M
- Exhibit 1900 – A&G
- Exhibit 2000 – Pricing
- Exhibit 2100 – Decoupling

A. Initial Filing (UE 197)

Q. What evidence have you submitted to justify PGE's test year operating costs?

A. On February 27, 2008, PGE provided 276 pages of direct testimony and 55 exhibits. Additionally, in support of our case, PGE submitted two disks with numerous electronic files of work papers, responded to over 870 data requests, held workshops to discuss PGE operations, and participated in settlement meetings. In addition, we offer more information in PGE's rebuttal testimony. In total, the information in these documents justifies PGE's operations as quantified in our 2009 test year.

Q. The testimony and exhibits appear to be less lengthy than in previous rate cases. Is PGE providing less support for this filing and less justification for its costs?

A. No. In PGE's more recent rate cases, UE 115 and UE 180 (2002 and 2007 test years), we had gone at least five years between rate cases, and as a result, we explained our full operations in considerable detail. Because UE 197 (2009 test year) occurs only two years after UE 180, we focused primarily on the changes since UE 180 and did not reiterate detail regarding existing operations. Naturally, the strength of a filing cannot be measured by the length of the testimony and exhibits.

Q. Certain parties have been particularly dismissive of PGE's documentation, analyses, and processes. Are these characterizations accurate?

A. No. In this and prior testimony, PGE demonstrates that these characterizations are not justified by the facts. Specifically, PGE demonstrates that the company has a strong culture of cost control supported by rigorous budgeting and analysis of cost effectiveness in its expenditures. Other assertions appear based on misperceptions, are inconsistent with past testimony offered by the parties, or ask the Commission to make decisions about PGE's operations based on speculation rather than on a thorough review of the facts.

Q. What was the proposed effect of your initial filing on prices?

A. PGE's initial filing proposed to increase our revenue requirement by approximately $145.9 million, which increased base prices by approximately 8.9%. The overall increase consisted roughly of one-third power costs, one-third operation and maintenance (O&M) and A&G costs, and one-third other (e.g., cost of capital, higher rate base, etc.).

B. Updates to the Initial Filing

Q. Did PGE submit any updates to its initial filing?

A. Yes. On April 3, 2008 PGE submitted an Errata Filing to incorporate seven corrections to the revenue requirement contained in our original filing. These corrections consisted of the following:

- State Tax rate: Updated the composite state tax rate to reflect taxable income allocation percentages to Oregon and Montana as used in PGE's 2006B tax return.
- Heat Pump expenses: Removed certain program expenses inadvertently included in PGE's initial filing.
- Additional FERC positions: Updated the forecast of full time equivalent employees (FTEs) in support of FERC compliance activities.
- Equity Issuance Fees: Updated the forecast of equity issuance costs to reflect certain third party fees.
- Economic Stimulus Act: Updated the forecast of accumulated deferred taxes to reflect the impact of additional bonus depreciation from the Economic Stimulus Act.
- Bull Run Decommissioning: Updated the forecast of depreciation expense, income taxes and rate base to reflect the results of an RFP for work at Bull Run.
- Union Wage Escalation: Corrected an error in the development of union wages for 2009.

Q. What was the effect of these corrections?

A. The net effect of the seven errata items was to increase PGE's proposed revenue requirement by $1.3 million.

Q. What other updates has PGE made to its original filing?

A. PGE has also updated its load forecast, which had an overall impact on prices of approximately $10.0 million.

Q. Has PGE submitted any updates to its power cost forecast?

A. Yes. On April 1, 2008 and July 11, 2008, PGE submitted updates to its net variable power costs (NVPC). The April 1 update reflected an additional increase to NVPC of approximately $21 million over our original filing. The July 11 update also reflected an increase, which was approximately $92 million over the April 1 total for NVPC. The load update mentioned above, had a gross impact of approximately $25.7 million on the increase in power costs.

C. Partial Stipulation

Q. What stipulations have been signed regarding the 2009 test year forecast?

A. Staff, CUB, ICNU, and PGE have signed a stipulation settling all issues regarding NVPC in UE 198. These parties have also signed a partial stipulation in this proceeding, UE 197, settling issues regarding Cost of Capital, Other Revenue, and certain O&M and capital costs.

Q. What impact did these stipulations have on PGE's revenue requirement?

A. Although the final revenue requirement impact will change based on any updates to revenue sensitive costs, the current impact of the power cost stipulation is a reduction of approximately $5.0 million and the current impact of the partial stipulation is a reduction of approximately $13.6 million.

Q. What is the total effect of all the updates and stipulations on PGE's revenue requirement?

A. After all the updates and stipulations, the estimated increase in PGE's revenue requirement for the 2009 test year is approximately $229.1 million. Of this increase, approximately two-thirds are due to power costs and all remaining costs represent approximately one-third of the increase. Based on recent changes to power costs, PGE currently projects that NVPC are approximately $30 million lower than those forecasted in the July 11, 2008 update.

Q. Does PGE propose any further reductions in its rebuttal testimony?

A. Yes. Because all power cost issues have been resolved and comprise approximately $150.9 million out of PGE's $229.1 million proposed increase, the remaining $78.2 million increase is related to O&M, A&G, and other costs. Of the $78.2 million, approximately $49.0 million relate to O&M and A&G while the remaining $29.3 million relate to all other costs such as depreciation/amortization, taxes, and rate base changes. As detailed in other sections of rebuttal testimony, PGE proposes to reduce the $78.2 million by an additional $16.2 million, with the concentration of these adjustments focused on O&M and A&G.

The combined effect of the updates, stipulations, and further adjustments proposed in rebuttal will reduce PGE's initial increase in the two combined non-power cost areas from approximately $94.2 million (as filed in our direct case) to approximately $62.0 million. The table below summarizes the changes from PGE's initial filing, including updates, stipulations, and the proposals included in rebuttal testimony.

Table 1

Revenue Requirement Increase ($ millions)

	NVPC	O&M/A&G	All Other	Total
Initial filing	53.0	52.4	40.5	145.9
Errata filing	-	0.6	0.7	1.3
PGE direct case	**53.0**	**53.0**	**41.2**	**147.2**
Effects of power cost / load updates through July 11, 2008	103.0	-3.0	0.6	100.5
Effect of stipulations	-5.1	-1.0	-12.5	-18.7
PGE case before rebuttal	**150.9**	**49.0**	**29.3**	**229.1**
PGE proposals in rebuttal	-	-13.1	-3.1	-16.2
PGE case including rebuttal	**150.9**	**35.8**	**26.2**	**213.0**
Percent price increase	9.4%	2.2%	1.6%	13.2%
PGE case including current forecast of NVPC	**120.9**	**35.8**	**26.2**	**183.0**
Percent price increase	7.5%	2.2%	1.6%	11.4 %

II. Timing for the General Rate Case

Q. CUB questions the timing of this rate case for several reasons. Can you please summarize them?

A. CUB gives four arguments in questioning the timing. CUB's first argument is that 2007 actual results show PGE is "over-earning". CUB's second argument is that it is too soon after PGE's previous rate case (UE 180). Third, CUB believes PGE does not exercise adequate cost control. Fourth, CUB believes that rising power costs and upcoming investments should preclude the increases requested in UE 197. I address each of these below and show that CUB is in error on each of its arguments.

A. 2007 Actual Results

Q. Do you agree with CUB's suggestion that PGE's "over earnings" in 2007 are an indication that the UE 197 case is unnecessary?

A. No. When PGE filed its 2007 Results of Operations Report (ROO) on June 2, 2008, we noted that there were two reasons for the favorable return in our Regulated Adjusted Results of Operations: the NVPC variance and SB 408 effect. These reasons are inconsistent with CUB's implication that the favorable result is related to "the cost removal of the Management Deferred Compensation Plan and a portion of incentive pay" (CUB/100, Jenks/3). The NVPC variance is precisely what the Commission addressed in authorizing the power cost adjustment mechanism (PCAM) in UE 180. Because 2007 power costs were significantly lower than forecasted in our test year, PGE filed for a refund to customers of \$15.8 million for the 2007 PCAM (Docket UE 201). The SB 408 effect is simply the "double whammy" that results from the accrual of additional revenue for taxes paid above taxes collected from customers (i.e., a good financial year is made even better for PGE by SB 408). In addition, the SB 408 effect is compounded in 2007 by two out-of-period items that increased taxes paid over taxes collected.

Q. What would PGE's 2007 results have been without the NVPC variance and the SB 408 effect?

A. As PGE noted on page 2 of the cover letter to our 2007 ROO (provided as PGE Exhibit 1301), "If PGE were to remove both the NVPC variance and SB 408 effect from the regulated adjusted results, the ROE would decline from 11.58% to 9.61%." In other words, absent these two, one-time events, PGE would have under earned in 2007.

Q. Are PGE's 2007 O&M costs indicative of a company with no cost control?

A. No. As PGE listed in Table 2 of the cover letter to our 2007 ROO, PGE's actual O&M and A&G costs were $315.9 million versus the authorized level of $313.4 million from UE 180 (2007 test year). The difference is less than 1% from the authorized level, which would indicate that a company is in control of its costs. It also shows that lower O&M spending is not a source of PGE's 2007 favorable results.

B. Proximity to Last Rate Case

Q. Why does CUB believe that the timing of PGE's previous rate case impacts PGE's current filing?

A. CUB believes that utilities have a "regulatory incentive" to promote efficient utility operations between rate cases because those gains would accrue to shareholders. For this to occur, however, CUB believes that general rate cases should be sufficiently far enough apart for these gains to be realized, and that if general rate cases are too close together, the utility has less incentive to find efficiency gains.

Q. Is CUB's argument valid?

A. No. In fact, in UE 115 (six years after the previous rate case, UE 88) CUB took exception to PGE's potential to derive savings over a longer period.

Q. Why is that view misleading?

A. It is misleading because it presupposes that the reasons for increasing costs are either unjustified or that other costs can be easily reduced to offset those increases. As noted above, PGE provided considerable documentation to justify the cost increases discussed in this proceeding, and we provide additional testimony here to further support those programs. Many of these increases relate to new compliance requirements, customer and system growth, and cost escalation due to general inflation or constrained / limited resources. These are much less discretionary (if at all) than CUB would suggest. I address the issue of cost control in the next section, but before I do, I have one final observation. The cost pressures that the industry is experiencing coupled with our substantial capital requirements will likely lead to more frequent rate cases. This is magnified by SB 408 since it is imperative that we keep the filed ratios used to calculate "taxes collected" up to date. Unfortunately, frequent price changes are likely to be a fact of life, rather than an indication of lack of cost control.

C. Cost Control

Q. What issues has CUB raised regarding cost control?

A. CUB has challenged PGE's commitment to cost control, in particular given the degree to which prices are currently rising due to increases in NVPC plus future increases due to projected capital expenditures. CUB also dismisses certain cost-savings efforts by PGE and cites four specific examples where they allege that PGE did not perform adequate cost-benefit analysis or justify the costs being incurred. I address all of these concerns below.

Q. Is PGE "without any internal culture of cost control"? (CUB/100, Jenks/8)

A. No, just the opposite. PGE has a strong culture of cost control and we pursue it in all aspects of our operations:

- System investments: For several decades, we have made long-term investments to keep low-cost, low-impact hydro available for customers. We also have made ongoing investments in distribution and transmission upgrades to assure reliable power for our customers.
- Stringent review of all capital expenditures: This review ensures that all investments are necessary and cost-effective. PGE also uses a strict annual budgeting process to ensure that expenditures are prudent, and reviews results to ensure costs are within expected ranges and variances are justified.
- Generation improvements: We have upgraded power plants over the past 10 years to increase capacity by 108 MW – equivalent to building a new plant – thus increasing the availability of low-cost power and reducing cost exposure to the volatile wholesale market.
- Highly efficient generation: We recently brought Port Westward and fuel-free Biglow Canyon 1 online, which also reduce exposure to wholesale market costs.
- Construction costs: We negotiated fixed-price contracts for Port Westward that brought the plant in on-budget even as material costs rose significantly.

- Implementation of a smart meter system: We project approximately $18 million in annual operating savings that will only increase throughout the life of the system. This produces an estimated net present value (NPV) of approximately $34 million over the 20 years of the project.
- Health insurance costs: We work to reduce costs through an active employee wellness program and aggressive negotiation with insurance providers. In addition, our employees now bear a greater percentage of their health insurance costs.
- Automated outage reporting system: This new system has improved outage response, reduced costs, and enhanced customer service.
- Marmot dam removal: The decision to remove the dam rather than upgrade the fish passage system saved our customers money.
- System security: High-tech monitoring and low-tech construction has reduced costly theft of metals and equipment and improved the security of our power supply.
- Other savings: Listed in PGE Exhibit 100, Section V.

The above is a partial list of the efficiencies we have initiated in recent years. We make cost efficiency and cost reduction a priority every day and it is reflected in the daily work of our employees. Unfortunately, there is not one or two areas that can produce large savings. Instead, we must focus on finding efficiencies in every area.

Q. CUB compares PGE's prices per kWh with Idaho Power and PacifiCorp and argues that power costs alone do not account for this differential by observing that "PGE

spends vastly more than PacifiCorp on customer service and information" (CUB/100, Jenks/8). Is this a reasonable conclusion?

A. No. CUB relies on flawed information for its conclusion. For example, the referenced Customer Service and Information costs include Category A advertising that can vary significantly from the authorized amounts. In 2006, PGE spent almost $1 million more than authorized which meant that these costs were not recovered and were adjusted out of the 2006 ROO. In the 2009 forecast, PGE has included only the "one-eighth of one percent" allowable amount, which reflects a decrease from 2006 actuals. Another example is that support costs can be allocated and loaded with a variety of methods so that comparisons of certain levels of costs between PacifiCorp and PGE are likely to be an "apples-to-oranges" comparison and thus erroneous.

In addition, CUB's simplistic comparisons are problematic. To be performed correctly, such comparisons would require considerable research to normalize all the components that are not directly comparable. They would then need to be evaluated for the level of programs, services, and benefits that each utility provides. In other words, complete benchmarking studies would have to be performed to draw conclusions between PGE and other utilities. CUB's analysis does not represent such a study. Consequently, CUB has failed to demonstrate that power costs are not the main driving factor between the prices charged by the referenced utilities.

Q. What is your response to CUB's observation that PGE can only identify $1 million in savings out of a revenue requirement of $1.7 billion for an annual savings of "approximately 6/100 of 1%"? (CUB/100, Jenks/23)

A. PGE continually pursues efficiencies and savings in our operations through efforts to hold budgets flat or to implement new equipment and processes that may not result in outright savings, but rather allow for lower costs than would otherwise be incurred.[2] CUB's assertion, that PGE could only identify a small list of cost saving measures in its initial rate case filing, assumes that the examples given were the only measures taken. That is simply not the case and seriously distorts the company's operations.

Q. CUB notes several lessons learned from UE 115, including the impact of price increases, and that "In January 2002, PGE identified $14.8 million in budget cuts" (CUB/100, Jenks/5) as a result of revenue shortfalls. Are these fair representations and are they applicable to 2009?

A. No, not really. First, CUB's implications are a bit distorted. Mr. Jenks's testimony suggests that PGE's 2002 price increase alone contributed to the economic downturn and the decline in load: "As a result, rates went up dramatically, the economy sputtered, and customers responded with a significant reduction in usage which PGE had not forecast" (CUB/100, Jenks/5). In reality, until late summer of 2001, no economic forecasters had predicted the severe recession of 2002, which was national in scope and contributed to a significant reduction in PGE's load. Another contributing factor was customers responding to the energy crisis of 2001 and 2002.

Second, the $14.8 million that CUB cites consisted of a *temporary* reduction based on activities that could be delayed for a short period of time without a significant negative impact on reliability and customer service. These costs consisted of: 1) activities that could

[2]It is not valid to compare O&M savings to the full revenue requirement, which consists of significant non-O&M components such as NVPC, rate base, cost of capital, depreciation and amortization, and taxes. Of these items, NVPC and cost of capital have been settled in UE 197 and CUB has agreed to the results. Further, depreciation and amortization have not been raised as issues by any party. Finally, NVPC is over 50% of the total revenue requirement.

be deferred for later expenditure, 2) reductions to “below-the-line” or unregulated activities, and 3) potential revenue from short-term transmission sales.

Q. Can PGE do this again?

A. Possibly, but these alternatives are limited as follows:

- While some O&M might be deferrable, PGE would not recommend it because of the impacts on customer service and reliability and the long-term cost implications of doing so.
- Unlike 2002, we currently have very little unregulated activity, so we do not have a similar ability to make significant cost reductions in those programs.
- Potential revenue from short-term transmission sales is already included in the test year forecast.

Q. Has PGE pursued other cost savings?

A. Yes. A more complete listing of cost savings from that time can be found in PGE Exhibit 500 from UE 180 testimony that identified numerous instances of cost savings and efficiencies captured between 2002 and 2005. These savings are of a more *permanent* nature than the ones identified by CUB.[3]

Q. Still, aren’t more cost savings available?

A. Yes, and CUB ignored the largest component of cost savings identified in testimony (PGE Exhibit 100, page 13), which is the operational savings from the advanced metering infrastructure (AMI) project – a large project that will engage significant resources of numerous PGE departments over several years. PGE has estimated that the annual operational savings from AMI will be approximately $18.2 million after full deployment is

[3] Because UE 180 had occurred five years after the previous rate case, it is understandable that PGE would have more savings efforts identified there than in UE 197, which occurred only two years after the previous rate case.

completed in 2010, which produces an estimated NPV of approximately $34 million over the 20 years of the project.

CUB also questions savings that PGE identified in its Customer Focus Initiative (CFI) by noting that it is not only too little, but something PGE should have been doing anyway. It is ironic that CUB would insist on savings and then dismiss them when achieved. As noted in PGE Exhibit 1700, the CFI is a company-wide, <u>long-term</u> initiative dedicated to developing cost efficient, customer-focused practices at PGE. We view CFI as an important program to motivate PGE's employees to provide the service customers expect while at the same time pursuing efficiencies and cost savings.

Q. Can you please summarize PGE's position on cost control?

A. Certainly. PGE consistently and continuously pursues cost savings and efficiencies in a culture that emphasizes this approach. PGE has identified significant outright savings in UE 180 and UE 197 testimony that provide on-going benefits in contrast to the transitory savings advocated by CUB. PGE has committed considerable resources to implement the AMI project that will provide significant operational savings and a platform from which additional customer and system benefits can be derived. Equally important, PGE also pursues projects that provide efficiencies to keep costs lower than they would otherwise be (e.g., IT projects such as WebSphere in UE 197 and the high bandwidth, SONET fiber ring in UE 180). PGE has also created the CFI and our generation excellence program to place even greater emphasis on efficiency, safety, and regard for customers. PGE addresses these two programs in Exhibits 1700 and 1800.

C. Rising Power Costs and Future Investments

Q. Do you agree that rising power costs and upcoming capital projects represent real considerations for rate increases?

A. Yes. However, I dispute Mr. Jenk's testimony, which suggests that the rate impact should be the primary consideration or that PGE has inadequate cost-benefit analysis for project evaluation.

Q. How important are rate impact considerations?

A. PGE agrees that price impacts are a significant consideration for evaluating projects because cost-benefit analysis reflects either outright savings or avoided costs (i.e., lower costs than would otherwise occur, all else being equal). In short, PGE's goal is to choose the most efficient projects with which to provide safe, reliable service, while at the same time meeting all of our regulatory requirements and achieving the state's renewable energy standard. We can only do so by showing that benefits exceed costs over the expected life of a project or minimize the project's costs,[4] which justifies the price impacts because the alternative would lead to higher prices over time. An over-emphasis on immediate rate impacts would lead to a short-term focus and would result in sacrificing long-term benefits associated with many projects. But let me be clear, choosing the most efficient project does not necessarily mean that prices will not increase. It may mean that prices will not increase as much as they otherwise would have. However, doing nothing is not an option if we are to continue to meet our obligation to provide safe, reliable service at the level that meets our customers' and regulators' expectations.

Q. Does PGE perform cost-benefit analysis on all of its projects?

[4] There may be additional non-economic criteria such as reliability.

A. No. We might justify projects based on non-economic criteria:

- Some projects or costs are necessary by regulatory or service requirements, or have minimum discretionary components. For example, PGE has increasing compliance requirements from agencies such as FERC, NERC, and WECC. In such instances, cost-benefit analysis is not appropriate because doing nothing is not an option. PGE has identified numerous incremental compliance costs in its UE 197 filing. Many projects are necessary for safety and reliability reasons.
- Some projects do not have easily quantifiable benefits. This does not mean that the benefits are not real, but rather that they are more qualitative at the present time and may become quantifiable over time. One example is PGE's integrated absence management program (more detail provided in PGE Exhibit 1500). We implemented these changes because we believed our prior employee-leave policies were no longer as efficient as they should be. Although the benefits are not readily quantifiable, the program is valid for qualitative reasons and is designed to enhance efficiency.
- Some projects provide needed capabilities that existing systems do not. Many of PGE's IT projects address growing requirements for information or communication efficiencies that existing systems are incapable of providing. Again, the benefits may be difficult to quantify, but are fully valid, if not required by regulating agencies (e.g., PGE's new energy management system that meets emerging reliability and cyber security requirements from FERC and NERC that are not supported in the current system – see PGE Exhibits 500 and 600).

Q. How do you respond to CUB's claim that it was only after repeated questioning that PGE provided rate impact detail on certain projects?

A. PGE provided the information when it became available. While PGE had performed cost-benefit analysis on the referenced projects, we had not performed specific price-impact analysis at the time of CUB's first data request, which only asked for the price-impact analysis. At the time CUB submitted a follow-up data request, PGE had performed a preliminary estimate of the price impacts and we provided those estimated impacts accordingly. We also provided a subsequent supplemental response when additional information became available.

Q. Is CUB correct in saying that "PGE's capital review process, however, does not appear to concern itself with rates"? (CUB/100, Jenks/10)

A. No, we just consider price impacts in a different way than CUB appears to be suggesting. As noted above, cost-benefit analysis provides the justification for outright savings or lower costs than would otherwise be the case over the life of the project. This implies lower prices over time. CUB appears to be focused on only the immediate price impacts and dismisses the long-term or complete-project view. Unfortunately, this means that CUB's approach would negate any project with front-end costs, no matter how large the subsequent benefits.

Q. Can you be more specific regarding how these considerations factor into your capital review process?

A. Certainly. PGE has two categories of capital projects: base business and strategic. The target for base business projects is set considering factors such as the amount spent in prior years and price impact. These projects are ranked based on a matrix of priorities and do not require individual price-impact analysis because it has been done in total. After jobs have been ranked, the overall target is reviewed considering the jobs "on the edge". Discretionary projects are not funded if the demand for capital exceeds availability. The strategic projects are much larger and are individually justified by relevant factors such as cost-benefit analysis.

Q. How do you respond to CUB's arguments that PGE does not perform adequate cost-benefit analysis?

A. I strongly disagree. We perform rigorous cost-benefit analyses on qualified economic jobs and must do so because of the limited funding resources available for our projects. Without such an approach, a company would not know which projects to pursue or how to prioritize them. For example, PGE's review of 2009 base-business capital projects entailed 170 projects for approximately $157 million. Of these, PGE deferred or cancelled 53 projects in their entirety representing $14 million. Of the remaining 117 approved projects, 32 were approved but with $28 million in 2009 cost reductions.

Q. What about the four examples, which CUB claims "demonstrate that PGE does not have a good system in place to ensure that projects are cost effective" (CUB/100, Jenks/12)?

A. I disagree with CUB's characterizations of these projects for the reasons I describe below and those in Exhibits 1600 and 1800.[5] The four projects that CUB cites are the 2000 Boardman upgrade, AMI, the Boardman simulator, and the new helicopter. In the first two examples (Boardman upgrade and AMI), CUB is inappropriately trying to re-litigate other proceedings (UE 196 and UE 189) in this docket. For the Boardman upgrade, PGE's analysis and subsequent experience have demonstrated that the benefits more than offset the

[5] PGE implements hundreds of projects each year and they are supported by project profile documentation. CUB has mischaracterized four of these in an apparent attempt to discredit them all.

cost of the turbine installation (as well as the deferral amount that is the subject of the UE 196 docket).

Q. How do you address CUB's comments regarding AMI?

A. CUB is correct that the AMI discussions did proceed for the time indicated. However, the duration of the proceeding was based on the time necessary to complete contract negotiations with the AMI vendors so as to have signed contracts as the basis for PGE's cost analyses. PGE also needed more time for the meter vendor to supply host system software in order to have a functioning system with which to proceed with systems acceptance testing. During that time, Staff reviewed PGE's AMI analysis to understand the modeling and assumptions, and also inquired at length about AMI-related programs that were not part of the filing. PGE characterized these as customer and system benefits and made numerous commitments regarding them in the Conditions Document that was included in the final stipulation with Staff.[6] Further, PGE updated its inputs to the AMI analysis as more current information became available, but the basic modeling/analysis changed very little from the original UE 180 filing until the final version in UE 189, and did not include any customer and system benefits or their associated costs.

Q. What, then, is the basis for CUB's arguments regarding these projects?

A. CUB's opposition in UE 196 and UE 189 requires them to take positions in this proceeding against the turbine upgrade and AMI, in spite of the benefits these projects provide to customers. In fact, as Staff notes, "customers continue to save approximately $6.8 million annually on power costs" (UE 196, Staff/100 Durrenberger/15, lines 14-17) from the Boardman upgrade. In addition (and contrary to CUB's assertions in UE 189 that AMI

[6] The customer and system benefits are derived from projects for which AMI provides a platform to implement but are not part of the AMI system as installed. Consequently, they are not part of the tariff as filed and approved in UE 189.

deployment should be delayed for years), given the dramatic increases in energy prices, AMI deployment appears more timely than ever.

Q. How do you counter CUB's statements regarding the Boardman simulator and the new helicopter?

A. We address those topics in PGE Exhibits 1600 and 1800. However, I note here that CUB is particularly in error regarding PGE's lack of justification for the new helicopter. In reality, the helicopter is a prime example of project justification through fully substantiated cost-benefit analysis. CUB's testimony regarding the helicopter is simply based on a misunderstanding of the underlying costs of other options and errors in their analysis.

III. Use of Forecasted Test Years

A. Staff's Proposed Capital Expenditure Adjustment (S-5)

Q. Please explain your understanding of Staff's proposal with respect to what is included in test-year capital expenditures?

A. Staff appears to believe that major capital projects that close to plant (i.e., become operational) after January 1, 2009, may not be included in prices because customers will not receive the benefit of those projects when prices go into effect on January 1, 2009. (Staff/100, Owings/23) In other words, Staff's position appears to be that customers' prices may not include those capital expenditures that are not in service on the date when customers purchase electricity. As a result, Staff proposes to exclude from rate base capital expenditures for Boardman, the Selective Water Withdrawal (SWW) Tower, and certain hydro re-licensing costs that are scheduled to be completed during 2009.

Q. Does this reflect good policy?

A. No, In fact, Staff's approach reflects poor regulatory policy. If adopted, Staff's position could prohibit the use of "test years" (either forecasted or historic) as the basis for establishing prices without offering any reasonable alternative framework.

Q. Why do you say that Staff's approach is inconsistent with the use of forecasted "test years" to set prices?

A. The Commission uses "test years" to reflect costs and revenues that will fairly represent the period when prices from the docket will be in effect. For capital expenditures, the test year rate base reflects the average effect of closing the capital expenditures over the course of the year. Because capital expenditures close to plant-in-service at a particular point in time, the component parts of rate base will change over the course of the test-year (forecasted or historic) as the useful life of some capital expenditures are retired throughout the year and new capital expenditures close to plant-in-service throughout the year. Because annual prices are set, invariably, there is a certain mismatch within the year between capital expenditures and customers' usage. Customers paying for service in January will be paying prices that include costs for some capital expenditures that do not close to plant-in-service until later in the year. Similarly, customers paying for service in December will be paying prices that include costs for some capital expenditures that were retired during the test year. The use of average rate base helps to ensure that such mismatches throughout the year are roughly balanced and do not cause undue intergenerational inequities within the test year.[7]

Staff's proposal would require the elimination of average rate base. It would essentially require daily or monthly pricing to ensure that customers pay only for capital expenditures that are used and useful at that specific point within the test year. We believe this is untenable, unjustified, and inconsistent with the Commission's long-standing policy of using test years to set prices.

Q. Staff also claims that there is a legal prohibition against including these costs in prices. Do you agree?

A. We will address this issue in briefs as necessary. However, I am informed by counsel that Ballot Measure 9 applies only to new facilities and does not apply to capital improvements, like the Boardman capital improvements, or other capital expenditures related to generating facilities that are currently used and useful, which is the case with the SWW Tower and the hydro relicensing costs. See UM 989, Order No. 02-227 ("ORS 757.355 does not apply to

[7] The averaging calculation ensures that only a portion of a project's costs are included in rates because rate base reflects only the part of the year in which the project is in service. This also means that absent a rate case in the ensuing year, projects such as the SWW Tower continue to be in rates at only a fraction of their annual revenue requirement impact.

routine construction work in progress attached to an operating plant. Ballot Measure 9, codified as ORS 757.355, was intended to apply to CWIP that reflects preconstruction commercial operating plants, not smaller projects attached to an operating plant").

Q. Staff also claims that PGE's forecasted date for completion of these projects is not accurate or reliable. Do you agree?

A. No. As discussed elsewhere, PGE's forecast is accurate and reliable with respect to the expected completion of the Boardman improvements and PGE has adjusted the expected completion date of the SWW Tower by one month, given more recent information. PGE has removed the hydro relicensing costs from the rate request given that it appears this project may not receive the FERC license during the test year and, hence, be completed.

Q. Does the OPUC have alternatives available to address this issue?

A. Yes. The Commission has the discretion regarding the rate treatment of larger capital projects such as the SWW Tower. PGE believes our proposal is good for customers by limiting the number of rate changes in a year, but we would be willing to track in these projects under the following conditions (similar to Port Westward in UE 180 / UE 181 / UE 184):

- The prudence of the project is already determined in the preceding general rate case.
- The price change will be based on the annualized revenue requirement impact of the project with all associated costs and benefits.
- No further updates will be performed until the next general rate case.

B. One-Time Costs in a Forecasted Test Year

Q. Based on your comments regarding normalization, above, how do you respond to Staff's claims that PGE's "request for general costs seemed to be based on one-time events or replacing aging equipment"? (Staff/100, Owings/5)

A. The largest example of this relates to Staff adjustment S-11, which we discuss in PGE Exhibit 1800. For Production O&M related to the Boardman, Colstrip, and Beaver plants, PGE is willing to reduce the 2009 revenue requirement by approximately $5.0 million in order to spread these costs over five years. Under Staff's proposal, PGE would never recover these necessary and reasonable costs for proper plant maintenance.

Q. What other types of one-time costs did Staff identify?

A. Staff reviewed historical 2007 costs, which they assume relate to PGE's 2009 forecast. Because Staff determined a number of these historical costs to be based on "one-time" items, Staff proposes that they be removed from the 2009 test year.

Q. Do the 2007 actual costs relate to the 2009 forecast?

A. No. PGE prepared its 2008 budget (as with all budgets) from a bottom-up approach, where each cost and FTE is justified based on the activities expected in that year. The 2009 test year forecast is then created by escalating the 2008 budget and including known and measurable changes (such as new compliance requirements). PGE could not have based the 2008 budget or 2009 forecast on 2007 actuals because we prepared the 2008 budget during 2007 and did not have all of 2007 actual costs to consider.

Q. What types of one-time costs did Staff identify in 2007 transactions?

A. One example is in Staff adjustment S-9, where Staff proposes to remove $174,000 related to PGE's Energy Management System (EMS) because it involved the completion of program development. Ironically, Staff is not proposing to remove EMS's incremental 2009 O&M costs that we identified in PGE Exhibits 500 and 600, or any of the capital costs associated with this project. Instead, they only propose to remove certain 2007 O&M costs, because in Staff's view, they are "one-time" costs.

Q. Are they "one-time" costs?

A. No, they are not. Neither are they nonrecurring in 2009 nor extraordinary.

Q. How can this be?

A. Very simply, because they are performed in the normal course of business. In the EMS development example, those particular costs represent PGE *labor* that was redeployed to a new IT project upon completion of the EMS project. The new IT project could have been a capital job or O&M, but would have been part of ordinary IT activity. Because PGE's IT activities involve specific areas (e.g., software applications, communication networks, and hardware), particular projects such as EMS represent distinct but continuous efforts of those areas. This is true for a large portion of PGE's costs that relate to a continuous series of projects that are ordinary and part of normal business. In that sense, Staff's adjustment involves the arbitrary rejection of certain legitimate costs without considering how they fit into the normal level of activity for the respective operations.

Q. How does Staff justify their adjustments?

A. Staff justifies their adjustment by citing Chapter 15 of Staff's Utility Rate Case Guide (provided as PGE Exhibit 1302), which states: "Nonrecurring expenses are unusual expense variations due to some extraordinary or nonrecurring event in a test period that materially distort a utility's normal financial position." As discussed above, the disallowed activities do not fall under this definition.

Q. How do you address Staff's claim that PGE's filing is also based on replacing aging equipment?

A. The primary examples of this type of activity are found in PGE Exhibit 500, Section II (H), under IT. Given the rate of change occurring in IT, it is understandable that aging systems need to be replaced when the vendors no longer support them or they cannot meet current regulatory or compliance requirements. PGE's activities in this regard are exactly what a responsible utility should be doing. It is unclear why Staff would choose to dismiss PGE's filing on this basis, while proposing no adjustments in this regard.

IV. Discretionary Cost Reduction

Q. What is the nature of the discretionary cost adjustment as proposed by CUB?

A. CUB proposes that the Commission authorize a 1% reduction of PGE's entire revenue requirement (approximately $17 million) "in light of PGE's lack of rigorous financial analysis and the Company's lack of aggressive cost management" (CUB/100, Jenks/32).

Q. Is this an acceptable proposal?

A. No. It is not acceptable for the following reasons:

- In earlier parts of this testimony and in subsequent exhibits, PGE demonstrates that we do have rigorous financial analysis and aggressive cost management. CUB is simply wrong on this point.
- The adjustments that CUB cites from prior rate cases represent amounts that are much smaller than the one proposed by CUB in UE 197. The UE 88 example is for $1.6 million and the UE 115 example is for $3.5 million.
- As noted in footnote 2 above, the majority of PGE's revenue requirement is in the form of NVPC and cost of capital has been settled in UE 197 (where NVPC alone is over 50% of the total revenue requirement). In addition, depreciation and amortization have not been raised as issues by any party. By applying an adjustment that effectively covers these areas, CUB either negates those stipulations or implies a much larger percent on the O&M costs to which it is intended to apply.
- This level of cost reduction would have a significant adverse impact on PGE's operations and could result in a reduction of over 150 employees.

Consequently, this adjustment is not only unwarranted, but as I describe in the next section, it would be detrimental to both PGE and its customers.

V. Effects of Other Parties' Proposals

Q. What would be the overall impact of adopting the other parties' (including CUB's) proposals?

A. The overall impact would be harmful to PGE and our customers. In 2009, we anticipate issuing $200 million in equity and $275 million of debt to fund needed investment in system replacement and upgrades, cost-effective new renewable resources, and environmental mitigation projects. In anticipation of our need to access equity and debt markets, we have placed a high priority on strong fiscal management. Keeping healthy financial conditions and maintaining investment-grade credit ratings are essential to accessing debt and equity markets on reasonable and competitive terms. The proposals of other parties will undermine our efforts to build a utility that can deliver safe, reliable, and reasonably priced power and secure necessary energy supplies at this critical time.

Q. CUB has also complained about the frequency of PGE's rate cases. If CUB's 1% cost reduction or other cost-cutting measures were adopted, what impact would they have on the frequency of PGE's rate cases?

A. PGE will be forced to file rate cases on a more frequent basis than it otherwise would. PGE will not be able to eliminate all the programs and expenditures required by the other parties' proposals, causing the company to fund expenditures without rate recovery. SB 408 magnifies the financial impact on PGE for such unfunded expenditures. As PGE's actual costs vary from rate case estimates, SB 408 applies a multiplying effect in the form of the tax impact associated with such variation, magnifying the impact on PGE. This "double whammy" impact usually develops over time as costs move away from rate case forecasts. In this case, the proposals would establish an immediate variance between actual costs and the cost in prices. That immediate disconnect and the "double whammy" impact from SB 408 will place increasing pressure on PGE to file another rate case to bring its actual costs in alignment with the costs in prices. This would appear to be the antithesis of what CUB and the other parties want.

VI. Decoupling

Q. The reply testimony submitted by others in this case have been critical of PGE's decoupling proposal . Do you still support decoupling?

A. Yes, we do. For all the reasons outlined in my opening testimony, we believe that decoupling is an important tool to get us where, I believe, we all want to be – an environment where a utility can fully embrace and support energy efficiency and distributed generation without being concerned that its "bottom line" will suffer. I wholly reject the notion of some (not any that are parties to this case) that utilities should promote use of their service while an independent entity (such as the Energy Trust) should promote energy efficiency. Only when we work together will we achieve our collective goal of maximizing energy efficiency.

Rather than repeat my arguments made in my opening testimony, we have asked a leading national expert in decoupling, Ralph Cavanagh of the National Resources Defense Council, to give his perspective on our proposal. While we are sponsoring his testimony, he is completely independent (as anyone who knows Ralph can attest) and is receiving no remuneration from PGE. We believe that his perspective is important and needs to be heard in this proceeding. His testimony is included as PGE Exhibit 2100.

Q. Are there any specific criticisms of PGE's decoupling proposal to which you would like to respond here?

A. Yes. Mr. Cavanagh provides a comprehensive response to each of the criticisms of the other parties, but there are a few on which I would also like to comment. First, Staff indicates that one reason to deny our proposal is that PGE could not identify any energy efficiency initiatives that have not been pursued for lack of decoupling. In one respect Staff is correct.

PGE has been aggressive in advocating efficiency and distributed generation without decoupling. PGE was instrumental in getting SB 838 passed during the last legislative session and has implemented incremental funding of energy efficiency authorized under it. Recently we took positions in OPUC Docket No. DR 40 that were very supportive of solar installations even though they will likely reduce our load. Thus, we have taken positive actions that might be considered contrary to our best financial interests. This does not imply, however, that the incentives and disincentives described in my opening testimony do not exist. In fact, as our incremental energy efficiency proposal was under consideration, we indicated that we reserved the right to "reconsider future support if these adverse financial impact issues are not resolved by 2010."[8] PGE should not be penalized for doing the right thing. Is Staff suggesting that if we had been opposed to incremental energy efficiency and solar, they would be inclined to support decoupling? I hope that is not true.

CUB makes a related argument that PGE could not identify new programs and that we implemented our incremental energy efficiency funding without decoupling. Again, they are correct; however, it is not a complete picture. We have supported incremental energy efficiency funding. We could not have identified in advance the opportunity we had to support solar installations in DR 40. We are currently working on our next Integrated Resource Plan. The Legislature will be in session next year and energy issues will likely be in the forefront. Building codes are likely to be reconsidered. I'm confident that we will have multiple opportunities to exhibit our commitment to energy efficiency. The fact that energy efficiency programs are delivered through the Energy Trust of Oregon does not eliminate our involvement and influence in these policy issues.

[8] February 1, 2008 letter to Public Utility Commission of Oregon regarding Advice No. 07-25.

Q. Staff suggests that decoupling "shifts the burden of regulatory lag towards ratepayers and away from shareholders." (Staff/600, Storm/22) Do you agree?

A. No. This is not a regulatory lag issue. Bonbright defines regulatory lag as "the quite usual delay between the time when reported rates of profit are above or below standard and the time when an offsetting rate decrease or rate increase may be put into effect by commission order or otherwise." (Principles of Public Utility Rates, James C. Bonbright, 1961, page 53) The issue here is really about rate design. Decoupling allows the benefits of simultaneously providing customers with a price signal more closely aligned with marginal costs while allowing recovery of fixed costs through fixed charges.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1301	Cover letter to PGE's 2007 Results of Operations Report
1302	Utility Rate Case Guide – Nonrecurring Expenses

NONRECURRING EXPENSES

Original Staff Author: Tom Turner

Nonrecurring expenses are unusual expense variations due to some extraordinary or nonrecurring event in a test period that materially distort a utility's normal financial position. Examples of nonrecurring expenses are:

1. Extraordinary repair expenses for property damaged by storm, fire, or other disaster;
2. Corporate relocation costs (for example, moving expenses);
3. Acquisition expenses due to mergers and property purchases;
4. Start-up costs for major data processing systems and for corporate restructuring;
5. Write-offs due to extraordinary or premature plant retirements; and
6. Unusual expenses due to litigation and rate case activity.

Why are nonrecurring expenses important in a rate case? Rate cases result in setting rates that last in perpetuity or at least until the next rate case. Therefore, it is important that the revenue requirement analyst establish a financial test period that reflects a reasonably normal operation to ensure that the utility actually needs a rate adjustment. Nonrecurring expenses distort the test period revenue requirement and result in incorrect rate setting.

How are nonrecurring expenses treated in a rate case? Nonrecurring expenses are handled or adjusted in one of two ways: They are either normalized or amortized, depending on the nature of the expense and the judgment of the analyst.

Normalization adjustments simply remove or "disallow" the nonrecurring expense thereby establishing a "normal" level of operating costs for rate making in the test period. (Also see "Expenses Other Than Depreciation".)

An amortization adjustment allows the expense but spreads it over a number of years so that the test period includes only a portion of the expense. Amortization adjustments may be for rate making only, or for rate making and accounting. If the adjustment is to be recorded in the accounts, the deferred expense or credit would be recorded as a regulatory asset (Account 182.3 or 186) or a liability (Account 254) and written off over a defined period. Generally, the use of deferred accounts and the associated amortization accounting requires explicit OPUC approval under ORS 757.259.

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June 2, 2008

Ed Busch
Administrator, Electric and Natural Gas Division
Oregon Public Utility Commission
550 Capitol Street, NE, Suite 215
Salem, Oregon 97301-2551

Re: **PGE's Regulated Results of Operations for 2007**

Ed:

Enclosed are five copies of the Regulated Results of Operations Report for the period January 1, 2007 to December 31, 2007. The enclosure includes two copies of the summary work papers. To create the regulated adjusted and pro forma earnings views, we apply the stipulations identified in this report from UE-180 and the OPUC letter dated March 25, 1992 (RE: Semiannual Adjusted Results of Operations Reports).

Table 1: PGE 2007 Financial Results

	Actual Financial Statements	Regulated Utility Actuals	Regulated Adjusted Results	Pro Forma Results
Rate of Return (ROR)	10.17%	8.77%	9.30%	6.87%
Return on Equity (ROE)	13.21%	10.59%	11.58%	7.28%

PGE's UE 180 base rates authorized through Order 07-015 were effective January 17, 2007. For purposes of this report, Type I Regulatory Adjustments assume that UE 180 base rates were effective January 1, 2007.

PGE's 2007 operating revenues, earnings and return on equity (ROE) have increased compared to 2006. This financial outcome stems primarily from lower than expected net variable power costs (NVPC) and an accrual for an SB 408 collection from customers. If the effects of the NVPC variance and the additional revenue related to SB 408 are reversed, PGE's 2007 Regulated Adjusted Return on Equity would be significantly reduced from 11.58% to 9.61%.

Actual Financial Statements

PGE's actual financial results come directly from PGE's General Ledger system. The primary drivers of the results for PGE's actual financial statements are detailed below:

- PGE recorded a $20.4 million deferral related to PGE's Boardman plant as authorized by Commission Order 07-224 (UM 1234).
- A $5.6 million reduction in the Company's wholesale credit reserve, related to the settlement with certain California parties involving wholesale energy transactions in prior years.
- Based on preliminary calculations of the Power Cost Adjustment Mechanism (PCAM), the variance of base power cost less actual power cost is $35 million. PGE has accrued approximately $16 million as a refund to customers. Our preliminary estimates indicate that the major drivers for the power cost variance are favorable thermal plant availability, wheeling resale, and slightly better than expected hydro. PGE will provide a more detailed analysis on power costs in the July 1 PCAM filing.
- PGE recorded a $15 million accrual in 2007 based on the effect of actual income tax versus the amount determined in rates per SB 408 rules. This amount arises from the power cost variance described above as well as the $20 million Boardman deferral and $6 million California refund.

Regulated Utility Actuals

Regulated utility actual results are computed by adjusting actual recorded results for:

- Reclassification of $210 million, consisting of sales for resale, steam sales, and gas resales from revenue to net variable power cost;
- Adjustment of $23 million to remove effects associated with out-of-period or one-time, extraordinary items including the Boardman deferral and the California settlement;
- Other accounting adjustments, as specified at pages ii and iii of the Report.

The regulated actual return on equity is 10.59%. The regulated utility actuals are used to calculate the "Regulated Adjusted Results of Operations," which is consistent with the stipulations and OPUC Order of our most recent rate case (UE-180).

Regulated Adjusted Results of Operations

The regulated adjusted results are computed by adjusting the regulated utility actuals of Table 1 for disallowances and stipulations agreed upon in the last rate case, as well as other regulatory adjustments specified at pages iii through iv of the Report. Due to PGE's PCAM, authorized in Docket UE 180, Order 07-715, we did not normalize power costs or weather, because we do not believe it is appropriate to assume away the conditions that produce the power cost variance. The regulated adjusted return on equity is 11.58%. As noted above, this is primarily due to the NVPC variance and SB 408 effect, which we have also not normalized. If PGE were to remove both the NVPC variance and SB 408 effect from the regulated adjusted results, the ROE would decline from 11.58% to 9.61%. PGE's O&M and A&G, in contrast, were not drivers of PGE's 2007 results. Actual costs exceeded the UE 180 authorized amounts as shown in Table 2 below.

Table 2
O&M and A&G Cost Comparison

	UE 180 Authorized	2007 Regulated Adjusted Results	% Change
Fixed Plant Cost O&M	80,627	77,693	-3.64%
Transmission O&M	10,245	9,490	-7.37%
Distribution O&M	58,713	63,397	7.98%
Customer Accounts/ Service	66,588	64,508	-3.12%
Admin & General/ OPUC Fee	97,224	100,856	3.74%
	$ 313,398	**$ 315,944**	**0.81%**

Pro Forma Results

Finally, the OPUC requires utilities to estimate "Pro Forma" results, or a forward look, using the Results of Operations. Utilities are required to:

- Reflect end-of-period rate base (approximately $393 million increase) and O&M expenses ($4.6 million increase). This increase in rate base is the result of Port Westward and Biglow Canyon, which became operational in June and December. Consequently, ROE is reduced in the pro forma statements because the average rate base due to these additional plants increases to year end levels, with results still based on average revenue.
- Estimate additional costs and revenues that would have occurred if the utility had the year-end number of customers for the entire year. For PGE, this adjustment would increase revenues by $7.5 million and power costs by $5.4 million;
- Remove significant nonrecurring events in accordance with the OPUC letter dated March 25, 1992:
  - Reverse PGE's share of the 2007 power cost variance to reflect normal power costs, which is more indicative of future results. Because this encompasses gas financial activity, PGE does not specifically adjust that component of power costs as we had in 2004, 2005, and 2006.
  - Remove nonrecurring transmission resale revenues, which netted approximately $1.8 million in revenues. Consequently, we added this value to wheeling costs.
  - Reverse PGE's $15 million accrual for SB 408. This amount is primarily due to the 2007 power cost variance and one time, extraordinary items including the Boardman deferral and California settlement. Similar to the power cost variance, we normalize this effect because it does not represent expected on-going revenues, but is only a function of 2007 activity.

The impact of these adjustments decreases the regulated ROE from 11.58% (Regulated Adjusted Results) to 7.28% (Pro Forma Basis).

If you have any questions, please call me at (503) 464-7580, or Alex Tooman at (503) 464-7623.

Sincerely,

Patrick G. Hager
Manager, Regulatory Affairs

encl.
cc: Bob Jenks, CUB
Melinda Davis, ICNU

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Table of Contents

I. Introduction

Q. What are your names and positions with PGE?

A. My name is 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 results of operations reporting, power cost filings, and other regulatory analyses.

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

Our qualifications appear in PGE Exhibit 200, Section IX.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address the issues raised by other parties relative to PGE's revenue requirement. These are topics that do not relate to specific functional areas (e.g., taxes) or are broader in scope than can be covered in individual functional areas (e.g., overall employment level).

Q. What is PGE's revised revenue requirement increase request in UE 197/UE 198?

A. PGE's revised revenue requirement increase is $213 million, or about 13% overall. Table 1 below summarizes the changes to PGE's requested revenue requirement increase since our direct filing.

Table 1
(Revenue Requirement Increase Summary)

Filing	**NVPC (UE 198)**	**All Other (UE 197)**	**Total (UE 197/198)**
PGE Direct Filing	$53.0 million	$92.9 million	$145.9 million
Errata Filing Effect	$ ---	$1.3 million	$1.3 million
Rev. Req. Stip. Effect	$ ---	$(13.6) million	$(13.6) million
July 11 NVPC/Load Effect	$103.0 million	$(2.5) million	$100.5 million
NVPC Stipulation Effect	$(5.1) million	$ ---	$(5.1) million
Rebuttal Testimony Effect	$ ---	$(16.2) million	$(16.2) million
Net Rev. Req. Increase	$150.9 million	$62.0 million	$213.0 million

Q. How is your testimony organized?

A. In the next section, we present PGE's revenue requirement for the 2009 test year as currently proposed, given the stipulated items, recent power cost updates, and the proposals described in PGE's rebuttal testimony. We then discuss the overall increase in employment as presented in this rate case and we address the proposed adjustment to PGE's employee related costs. Finally, we address issues concerning PGE's taxes.

II. Revenue Requirement Summary

Q. What is the purpose of this section of testimony?

A. We summarize PGE's revenue requirement including the impact of stipulations on power costs and certain revenue requirement issues. In addition, the revenue requirement reflects the most recent update of power costs for 2009. Finally, we update PGE's filed revenue requirement to reflect changes supported in PGE's rebuttal testimony.

Q. What is PGE's revised revenue requirement for the 2009 test year?

A. PGE's revised revenue requirement is $1,821 million for 2009, as shown in PGE Exhibit 1401. This revenue requirement will allow PGE an opportunity to earn a 10.1% ROE on a 50% equity capital structure, with an overall cost of capital of 8.334%, as agreed in a partial revenue requirement stipulation.

Q. What is the overall revenue requirement increase relative to 2009 revenues at current prices?

A. The revenue requirement is $213 million above 2009 revenues at current prices, and would result in an overall rate increase of approximately 13%.

Q. What is the composition of the increase in revenue requirement between power costs and all other costs?

A. The $213 million increase in revenue requirement consists of $151 million of additional revenues due to higher unit power costs and $62 million due to all other costs.

Q. What is the forecast of power costs included in PGE Exhibit 1401?

A. The forecast of power costs is $919.3 million as filed on July 11, 2008. However, as described in PGE Exhibit 1300, more recent forecasts of 2009 power costs are approximately $30 million lower than the July 11 update filing.

Q. Does this forecast reflect a stipulation in UE 198 regarding power costs?

A. Yes. The power cost forecast is net of the impact of a stipulation on power costs that reduced the forecast of power costs by approximately $5 million.

Q. Does PGE plan to file additional updates to the forecast of power costs?

A. Yes. The remaining schedule in the rate case requires updates to be filed on September 26, November 3, and November 14.

Q. Please summarize the adjustments to PGE's filed case supported in its rebuttal testimony.

A. Table 2 below summarizes the $16.2 million of revenue requirement adjustments supported in PGE's rebuttal testimony, along with references to the supporting rebuttal testimony describing the basis of the adjustment.

Table 2 (Revenue Requirement Adjustments)

Item	Staff Issue No.	Approx Rev. Req. Impact	Reference
State Tax Rate to 5.120%	S-16	$(0.6) million	PGE Exhibit 1400
Adjust R&D	S-2	$(0.5) million	PGE Exhibit 1900
Remove FERC 890A FTEs	S-3	$(0.8) million	PGE Exhibit 1600
Remove Officer Incentives	S-4	$(3.6) million	PGE Exhibit 1500
Remove Clackamas Relicensing from 2009 / Adjust SWW one month	S-5	$(1.5) million	PGE Exhibit 1800
Remove Director Compensation	S-9	$(0.3) million	PGE Exhibit 1500
Remove Other Benefits	S-9	$(0.1) million	PGE Exhibit 1500
Adjust Insurance	S-9	$(0.9) million	PGE Exhibit 1900
Adjust Uninsured Losses	S-9	$(1.8) million	PGE Exhibit 1900
Adjust Unscheduled Flow Mitigation	S-10	$(0.1) million	PGE Exhibit 1600
Recover Non-Recurring Plant O&M over 5 yrs.	S-11	$(5.0) million	PGE Exhibit 1800
Adjust Property Taxes	S-14	$(1.0) million	PGE Exhibit 1400
Totals		**$(16.2) million**	

III. Overall FTEs

Q. What adjustments have the other parties proposed for overall employment levels?

A. The Oregon Public Utility Commission Staff (OPUC Staff or Staff) and Ellen Blumenthal, witness for the combined Industrial Customers of Northwest Utilities and Citizens' Utility Board (ICNU-CUB) have proposed adjustments to PGE's overall level of employment for the 2009 test year forecast, which we quantify through full-time equivalent employees (FTEs). We address each proposal separately below.

Q. What is an FTE?

A. An FTE represents 2,080 hours of work. Consequently, it does not represent employees or head count so much as a level of effort needed to perform PGE's regulated activities. PGE Exhibit 800, Section II, provides a description of the process used to calculate FTEs.

A. Staff Adjustment

Q. Please summarize Staff's proposed FTE adjustment.

A. In summary, Staff has taken a 2007 estimate of actual FTEs, escalated it at an arbitrary growth rate (loosely based on a calculation of actual growth rates), and then compared this result to PGE's unadjusted 2009 forecasted FTEs. This difference is their adjustment, which they then converted to a dollar amount using an average wage plus loadings. Staff then further allocated the adjustment between capital and expense.

Q. Do you agree with Staff's proposed adjustment?

A. No. We do not agree for three reasons. First, Staff's (and ICNU-CUB's) adjustment is simply formulaic and makes no effort to evaluate the basis for the individual positions being proposed or the validity of the services or requirements PGE is trying to accomplish with them. The 2009 forecast for FTEs is not about sterile numbers that can be simply plugged into a formula, but about the resources needed to provide safe, reliable power and meet all of PGE's regulatory and compliance requirements. PGE provided detail in our direct testimony and subsequent data requests to explain why the forecasted increase in FTEs from 2007 to 2009 is appropriate.

Q. What is the second reason you disagree with Staff's adjustment?

A. The second reason is that Staff's adjustment leads to a reduction in FTEs greater than PGE's request.

Q. Please explain.

A. Staff claims that PGE is requesting an increase of 130 FTEs, but actually, PGE's revenue requirement reflects an increase of 87 FTEs – not 130. This occurs because our initial filing reflected 130 FTEs but we made several adjustments to the filing (listed below) that reduced the increase by 27 FTEs. In addition, 16 FTEs are related to the Biglow Canyon Wind Project and Port Westward that are already approved in rates through UE 180 and UE 188.

Q. Why would Port Westward and Biglow reflect increasing FTEs if they became operational in 2007?

A. Port Westward did not become operational until June 2007 and Biglow did not become operational until December 2007. This means that their 2007 O&M costs and FTEs would reflect only partial year activity for 2007. For 2009, however, Port Westward and Biglow have a full year of activity so there appears to be an increase compared to 2007 although they have been fully authorized in rates through Commission Order Nos. 07-015 (UE 180) and 07-573 (UE 188).

Q. What is the third reason you disagree with Staff's adjustment?

A. The third reason is that Staff's analysis is based on erroneous inputs at each stage of the calculation. The following list summarizes these errors:

- Incorrect starting value for 2007 actual FTEs.
- No adjustment for Trojan lay-offs.
- Arbitrary and inappropriately low FTE growth rate assumed for 2008 and 2009.
- Incorrect loading rate for employee-related costs.
- Incorrect allocation between capital and expense.

Q. Please explain why Staff has an incorrect starting value for 2007 actual FTEs.

A. Staff's analysis is based on PGE's Response to OPUC Data Request No. 203, Attachment 203-B, which unfortunately was in error when it listed actual FTEs for 2007 as 2,560. In PGE's 2007 Results of Operations Report, PGE correctly calculated the 2007 actual FTEs as 2,612 and noted this correction to Staff and other parties' weeks prior to their testimony. We also issued a supplemental response to OPUC Data Request No. 203, with the corrected value for 2007 actual FTEs. The corrected value for 2007 is comparable to all other values in Table V at Staff/100, Owings/16.

Q. Why is there a difference in the two FTE figures for 2007?

A. The 2,560 figure contains no overtime for exempt employees but the corrected 2,612 figure includes these overtime hours.

Q. Why should actual FTEs include overtime for exempt employees?

A. The FTE figure should represent the amount of work and effort needed to accomplish PGE's regulated activities. For example, an exempt employee will put in significant overtime to "cover" for an unfilled position until the position is filled. Once filled, PGE will reflect two FTEs for the two positions. Under Staff's (and ICNU-CUB's) approach, actual hours will reflect only one FTE and the growth rate to the subsequent year will appear inordinately large. With PGE's amounts, the hours and FTEs represent the actual amount of work necessary to perform all tasks and correctly reflect a smaller and more accurate growth rate. Finally, the 2,612 figure is determined on the same basis as all other actual FTEs in Staff Table V.

Q. Do you need to adjust actual amounts for layoffs at Trojan?

A. Yes. We do so because Staff and ICNU-CUB focus on FTE growth from 2005 to 2007 and 2005 represents the last year with significant Trojan layoffs.[1] We adjust for Trojan by reducing 2004 FTEs by the amount of layoffs in 2005. This adjustment backs out the layoffs from 2005 actual FTE growth and provides a more accurate summary and comparison of PGE's FTE activity from 2005 to 2007.

Table 3
Actual FTE Growth 2005-2007

Category	2004	2005	2006	2007
Actual FTEs	2531	2518	2554	2612
Adjust Trojan Layoffs	-29			
Adjusted Actual FTEs	2502	2518	2554	2612
Yearly Growth Rates		0.64%	1.43%	2.27%
Average Growth 2005-2007				1.45%

As shown in the table above, the correct growth rate for 2004 through 2007 is 1.45%, not the 0.38% growth rate calculated by Staff.

Q. Given the corrected growth rate and starting point for 2007, what level of FTEs does Staff's method provide for 2009.

A. Beginning with 2,612 FTEs in 2007 and applying a 1.45% annual growth rate yields 2,688 FTEs for 2009.

[1] Staff appears to acknowledge this aspect, "Staff believes that the decrease in FTE over the five-year period can be attributed to the final; closing of the Trojan plant" but then dismisses it by claiming that "however, even in consideration of such, the major closing of the Trojan plant took place many years earlier" (Staff/100, Owings/16).

Q. How does this compare to PGE's forecasted level of FTEs for 2009?

A. In 2009, PGE initially forecasted 2,733 FTEs, which we then revised by several adjustments to PGE's revenue requirement to affect the following changes to FTEs:

Table 4
Adjustments to 2009 FTEs

Original 2009 FTEs	2,733
Removed four FTEs associated with PGE's heat pump program so it is not included in rates	-4
Removed 20 distribution FTEs as unfilled positions (offsetting credit included)	-20
Removed 10 customer service representative FTEs as unfilled positions (offsetting credit included)	-10
Added seven FTEs to meet additional FERC/NERC/WECC compliance requirements	+7
Adjusted 2009 FTEs	2,706

As a result, PGE's forecasted FTEs for 2009 total 2,706, which is just 18 over the calculated amount using Staff's method.

Q. What is the associated cost of these 18 FTEs?

A. The average cost of an FTE is $75,764.[2] If we multiply this average cost times the 18 FTEs, the total cost is approximately $1.4 million.

Q. Staff also applied loadings[3] to their adjustment for labor related costs. What should that rate be?

A. The correct rate for 2009 would be 48.5%, which includes employee benefits, payroll taxes, incentives, and employee support. If we apply that rate to the $1.4 million wage adjustment above, the total adjustment is approximately $2.0 million.[4]

Q. Staff's final calculation was to allocate the adjustment between capital and O&M expense. Was this done correctly?

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[2] See PGE's Response to CUB Data Request No. 088, provided as PGE Exhibit 1402.
[3] Staff incorrectly notes that PGE refers to these as PTO. PTO refers only to paid time off, which is for vacation and holiday pay, and is only used as a loading when total annual pay is not in use. Because we are using total annual pay in these calculations, PTO-related labor is already included and does not have to be added separately.
[4] Staff incorrectly applies 2007 loading rates onto 2009 labor. This is inappropriate because each year has its own loading rates based on the ratios of associated costs.

A. No. In PGE's Response to OPUC Data Request No. 203, Attachment 203-E (provided as PGE Exhibit 1403), PGE identified how total labor is split between capital and O&M based on the most recent year of actual activity, 2007. This is the same method that PGE employs annually in its Results of Operations Report. Rather than use total labor as a basis to allocate the wage and salary adjustment, Staff incorrectly bases their allocation on <u>incentives</u>, which are not included in wages and salaries.

Q. What are your conclusions about Staff's approach?

A. We do not believe that Staff's formulaic approach represents a valid basis on which to evaluate the additional 87 FTEs that PGE has requested. PGE described its FTE growth in detail in direct testimony and in data responses. If the Commission were to decide that the formulaic approach is appropriate, however, then it should be corrected for input errors as we described above and would produce a $2.0 million total adjustment in contrast to Staff's $14 million estimate. As noted above, Staff's adjustment is illogical because it would remove more FTEs (120) than PGE is actually requesting (87).

B. ICNU-CUB adjustments

Q. How did ICNU-CUB calculate their adjustment to PGE's labor costs?

A. ICNU-CUB used 2005 through 2007 actual FTE detail[5] from which they calculated an average growth rate and then escalated from the incorrect 2007 amount forward to 2009. As we described in Section II (A) above, this method includes significant input errors, removes more FTEs than PGE is actually requesting, and it is overly simplistic.

Q. Did ICNU-CUB make any other errors in their testimony regarding labor costs?

A. Yes. ICNU-CUB made the following errors, which we address in detail below:

[5] ICNU-CUB also included the incorrect starting amount for 2007 and a 2005 amount that was unadjusted for Trojan layoffs

- Misrepresented PGE's budgeted wages and salaries and overall budgeting process.
- Incorrectly listed the incremental components of PGE's labor costs.
- Ignored overtime FTEs in comparison of budgeted to actual FTEs.
- Used arbitrary escalation rates to determine salary increases.
- Performed a flawed analysis to determine payroll-related costs.

Q. How did ICNU-CUB misrepresent PGE's wage and salary budget?

A. They state that PGE's wage and salary budget "is based on assumptions which are then compounded by further assumptions" (ICNU-CUB/100, Blumenthal/5). The only support for this claim appears to be ICNU-CUB's observation that PGE's documentation for compensation consists of "*forecasted* 2007, *budgeted* 2008, and *budgeted* 2009" (ICNU-CUB/100, Blumenthal/3, emphasis in original). They then quote a PGE data response, which stated that "For labor, the 2008 budget is based on actual labor costs from Q2-2007" (ICNU-CUB/100, Blumenthal/3), with escalation to 2008 and then 2009.

Q. What is the point of these disjointed comments?

A. ICNU-CUB's point appears to be that PGE's 2009 test year forecast is not based on actual data. To some extent this is true because PGE does create its budgets using a company-wide, bottom-up process to evaluate all positions and costs needed to perform all of PGE's regulated activities for the coming year. Part of this process to develop the 2008 budget utilized "actual labor costs from Q2-2007" *id*. This statement, however, does not refer to total labor costs, but in keeping with our bottom-up approach, it refers to individual wage rates for FTEs currently in the system.

Q. Does ICNU-CUB misrepresent any other aspects of PGE's filing?

A. Yes. ICNU-CUB notes that "The information in PGE's filing includes 2007 forecasted amounts, but not 2007 actual amounts. The 2009 test year amounts are based on 2009 numbers" (ICNU-CUB/100, Blumenthal/5). The first comment is misleading because the 2007 forecast in PGE's initial filing represents nine months of actual data and three months of budgeted data.[6] (At the time PGE filed the UE 197 rate case, 2007 actuals were unavailable.) PGE subsequently provided 2007 actual detail to Staff and other parties, when it was available. The second comment is misleading because the 2009 test year forecast is based on the 2008 budget, which is escalated for inflation and updated for known and measurable changes. To say that it is based on "2009 numbers" suggests some process that does not exist or is indicative (along with the previous examples) that the ICNU-CUB witness is unfamiliar with PGE's budgeting processes.[7]

Q. How did ICNU-CUB incorrectly list the incremental components of PGE's labor costs?

A. They suggest that PGE's FTEs increase by 266 from 2007 to 2009 (2,733 straight time FTEs plus 93 overtime FTEs for 2009 less 2,560 FTEs for 2007). This calculation is incorrect because it includes overtime FTEs for 2009, but not 2007. In addition, their calculation uses the incorrect figure for 2007 FTEs. Both of these errors seriously inflate the difference between 2007 and 2009 FTEs – the omission of 2007 overtime FTEs from ICNU-CUB's formula distorts the result by 103 FTEs. PGE, in contrast, correctly calculated the increase

[6] ICNU-CUB's response to PGE Data Request No. 005 (provided as PGE Exhibit 1404) indicates that they did not read PGE's testimony at Exhibit 200, page 7, line 5 and were not aware of the definition of PGE's 2007 forecast.

[7] ICNU-CUB summarizes their position as: "PGE has provided no testimony regarding the assumptions and parameters that underlie either the 2008 or the 2009 budget" (ICNU-CUB/100, Blumenthal/5). As noted in PGE Exhibit 1300, PGE has provided 276 pages of direct testimony, 55 exhibits, 2 disks with numerous electronic files of work papers, responded to over 870 data requests, held workshops to discuss PGE operations, participated in settlement meetings, and we offer more information in rebuttal testimony. PGE has described all of its proposed 2009 forecast and the assumptions behind it in great detail.

as 130 in its original filing, less the adjustments noted in Section II (A) above, that reduced it to a net increase of 87 FTEs.

Q. What was ICNU-CUB's error in ignoring overtime FTEs in their comparison of budgeted to actual FTEs?

A. This error relates to ICNU-CUB's attempt to demonstrate that "there is no guarantee" that PGE will fill all of its incremental positions. They do so by providing a table that compares budgeted FTEs with actual FTEs (ICNU-CUB/100, Blumenthal/6).

Q. What does ICNU-CUB's table demonstrate?

A. The table shows that PGE budgeted more FTEs than we actually employ by approximately 54 FTEs on average over the last four years of actual activity. ICNU-CUB then use this information to suggest that "If rates in this case are set using PGE's budgeted FTEs, it more likely than not that a (*sic*) significant number of these positions will go unfilled" (ICNU-CUB/100, Blumenthal/6).

Q. Is this a reasonable conclusion to draw?

A. No. ICNU-CUB's table is very misleading because it ignores non-exempt (hourly) over-time FTEs. PGE provided a more complete table, which lists both straight-time and over-time FTEs, in our response to CUB Data Request No. 064 (provided as PGE Exhibit 1405). As this more-complete table shows, the difference between PGE's budgeted and actual straight-time FTEs is considerably offset by actual over-time FTEs exceeding budgeted over-time FTEs.

Q. What, specifically, does this mean?

A. This means that on average, approximately 20 of the unfilled straight-time positions are covered by PGE hourly employees working over-time.

Q. What about the remaining unfilled 30 FTEs?

A. Those FTEs are the very ones for which PGE reduced its 2009 revenue requirement by approximately $2.0 million (20 distribution FTEs and 10 customer service representative FTEs) as unfilled positions (see Section II (A), page 7, above) and are part of our explanation that the original 130 FTEs incremental to this case reduce to 87 FTEs.

Q. Please explain ICNU-CUB's error in escalating rates in an arbitrary manner to determine salary increases.

A. This error relates to ICNU-CUB's efforts to convert their FTE adjustment to financial values. They rely on historical information, which appears to be during a period of particularly low inflation, and then arbitrarily adjust certain values to even lower amounts. They then average these increases and project them forward from 2007 to 2009 to calculate wages for their erroneously determined FTE total. This arbitrary and unjustified approach creates an unreasonably low level of both FTEs and wages for PGE to adequately perform its regulated activities and recover reasonable labor costs.

Q. Please describe ICNU-CUB's flawed analysis to determine payroll-related costs.

A. They begin with labor costs comparing: 1) PGE's total as filed but not reduced by adjustments already made, and 2) ICNU-CUB's total as calculated. They then multiply total labor costs times labor-loading rates. However, the rates used with PGE's labor total are inappropriately high and the rates used with ICNU-CUB's labor total are artificially low. Finally, they add ICNU-CUB's calculated incentive costs to the product of their labor-times-loading calculation.

The end result of these calculations produces ICNU-CUB's two versions of labor-related costs, which are then compared to produce the $38 million cost reduction.

Q. You have already described how ICNU-CUB's version of labor costs is misrepresented. How are the loading rates distorted?

A. The 55.40% rate cited from PGE's errata filing (Attachment 2, page 4) is, unfortunately, due to an error on PGE's part. This particular calculation is the only one in which the 55.40% rate was used in PGE's entire filing. In addition, because this rate was used to reduce PGE's costs in the errata filing, it lowered costs more than they should have been.

Q. What is the correct rate for PGE's loadings and how can you demonstrate it?

A. The correct rate is 48.50%. This rate consists of employee benefits, payroll taxes, incentives, and employee support. The difference between the 55.40% rate and 48.50% rate is 6.90% for pension costs, which do not apply. The ICNU-CUB witness also agrees with this: "I exclude pension benefit costs because PGE/800, Barnett-Bell/16, states 'PGE requests no pension benefit cost in this proceeding because future benefit obligations are less than the expected value of the assets currently held in the plan.'" (ICNU-CUB/100, Blumenthal/12)

Q. If 48.50% is the correct rate, how does ICNU-CUB establish their "artificially low" rate?

A. ICNU-CUB first deducts the incentive loading from their rate because they adjusted "this component of total payroll related costs separately" (ICNU-CUB/100, Blumenthal/12). ICNU-CUB then explains why they reduce PGE's $14.8 million for 2009 proposed incentive compensation by $9.7 million and apply the remaining $5.1 million to their proposed payroll-related costs.

Q. Is it incorrect to adjust incentives separately?

A. No. The problem here is that ICNU-CUB make the adjustment only on one side of the equation (i.e., the comparison). By failing to treat the "PGE proposed side" of the equation in a similar manner, ICNU-CUB multiplies the 6.90% rate times PGE's total labor costs (including straight-time and over-time labor) when the actual labor base used to determine the 6.90% rate is much smaller.[8] This technique creates an "apples-to-oranges" comparison that artificially exaggerates the difference between ICNU's proposal and what they incorrectly calculate and claim is PGE's proposal.

Q. What is the second reason that ICNU-CUB's rate is "artificially low"?

A. They eliminate the 3.13% employee support loading from their proposed rate.

Q. Why do they eliminate the employee support loading?

A. They state that "there is no testimony or data of any kind in PGE's filing to support this item, except that a line item is included on PGE/500, Piro-Tooman/2, entitled 'HR/Employee Support/Ethics and Compliance' and is again included as a line item at PGE/501, Piro-Tooman/1" (ICNU-CUB/100, Blumenthal/12).

Q. Are they correct?

A. No. As PGE noted in direct testimony (PGE/500, Piro-Tooman/4), we previously described each functional area in detail in our last general rate case, UE 180, which was quite recent. Thus, we focus on only the major areas of cost increases from 2007 to 2009, in UE 197.

This department has been in existence for a very long time and its costs were approved in UE 180 (Commission Order No. 07-015). In addition, PGE's current loadings and allocations methodology has been in existence for many years and the OPUC Staff have not only audited them, but did not identify any issues associated with the Employee Support

[8] PGE's labor base for the incentive loading is straight time labor that excludes the following: 1) all over-time labor; 2) all labor related to PGE's generating plants, because they have their own individual plans; and 3) all paid time off labor.

loading. Finally, the Employee Support loading is also included in the Allocation and Loading Manual that PGE provides annually with its Affiliated Interest Report in accordance with OAR 860-027-0048(6). In short, these costs have been fully justified.

Q. Can you briefly summarize employee support costs and explain the increase in the referenced A&G function?

A. The Employee Support loading represents the cost of administering PGE's compensation program, equal opportunity and employee relations, employee training and development, and Human Resources administration. Because the category "HR/Employee Support/Ethics and Compliance" is one of the most labor intensive, labor escalation represents a significant aspect of its cost increase which was described in PGE Exhibit 500, Section II (A). Another aspect of this increase is $150,000 in 2009 for the Generation Excellence program, which CUB has raised as an issue and is addressed in PGE Exhibit 1800. Finally, one credit entry in 2007 gives the appearance of a cost increase in this area but is offset by costs in other operational areas of PGE.

Q. What is the nature of this apparent cost increase?

A. In the budget component of the 2007 forecast,[9] PGE included a $900,000 cost reduction to represent the fourth quarter adjustment for unfilled positions as identified in UE 180. This means that PGE reduced its costs in this one area to represent the total reduction in FTEs in UE 180, similar to the $2.0 million reduction PGE applied in 2009 for 30 unfilled FTEs. Although the cost reduction is applied to the budget under employee support, the actual cost reductions occurred in other operating areas. Hence, the nine months of actual data reflect lower FTEs in PGE's operating areas and the three months of budgeted data reflect lower

[9] As noted above, the 2007 forecast represents nine months of actual data and three months of budgeted data.

FTEs in the employee support function. Final actual costs for 2007 (including the fourth quarter) will reflect all of the unfilled positions in operating areas; hence, this does not represent a real cost increase for employee support from 2007 to 2009.

Q. Can you please summarize the issues regarding overall FTEs?

A. PGE took a straightforward approach in preparing its 2009 forecast by developing a 2008 budget, escalating it, including known and measurable changes, and applying all loadings and allocations. ICNU-CUB, in contrast, has compared incomplete or incorrect data to calculate erroneous differences. These should not be the basis for any adjustments to PGE's proposed revenue requirement.

In addition, Staff and ICNU-CUB have proposed a reduction to PGE's FTEs that is greater than the increase that we are requesting. Staff's and ICNU-CUB's proposals completely disregard the FTEs already authorized for Port Westward and Biglow Canyon and they give no consideration to the FTEs needed for increasing compliance demands (including hydro licensing and FERC/WECC requirements). They do not recognize the importance of PGE's Business Continuity and Emergency Management efforts, whose costs were acknowledged by the Commission (see PGE's Response to OPUC Data Request No. 103, provided as PGE Exhibit 1406); the credit PGE has already taken for unfilled positions in 2009; or the growth in FTEs needed for increasing numbers of customers, larger capital investment in plant and equipment, or increasing IT requirements (five FTEs in IT resulted in specific O&M savings). In short, historical FTEs (especially when calculated incorrectly) are not a valid basis for determining future needs especially when PGE faces increasing compliance requirements.

IV. Tax Issues

A. Property Taxes

Q. What adjustment was proposed by the parties regarding 2009 test year property taxes?

A. Staff proposed a $4.2 million adjustment to property taxes (Staff/300, Ball-Dougherty/23-26). Staff began with adjusted actual 2007 property taxes, escalated that amount for two years at CPI, and then added $2.0 million for the effects of Biglow 1. Finally, Staff compares their derived figure of $32.7 million for 2009 to PGE's filed amount of $36.9, and uses the difference as their adjustment. Staff claims that their approach is reasonable because it "aligns PGE's actual property taxes to its budgeted expenses" (Staff/300, Ball-Dougherty/25).

Q. Does Staff provide another reason as the basis for this adjustment?

A. Yes. Staff also claims that PGE's forecast of property taxes in 2009 is unreasonable since Staff "does not support increasing PGE's property tax expense based on increased rate base because those assets are not yet determined to be used and useful." In any event, Staff claims that increases in rate base may not translate into additional property tax expense due to the limits of Maximum Assessed Value (MAV) from Ballot Measure 50 (Staff/300, Ball-Dougherty/25), as well as the treatment of intangible property by the Oregon Department of Revenue (Staff/300, Ball-Dougherty/26). Ultimately, Staff concludes that "the property tax expense for the 2009 test period should reasonable *(sic)* reflect the final rate base amount determined in the UE 197 rate proceeding and not an estimate of future rate base additions" (Staff/300, Ball-Dougherty/26).

Q. Does PGE agree with Staff's conclusion regarding the goal of a 2009 property tax estimate?

A. No. We agree that the property tax expense for the 2009 test period should reflect the final rate base amount determined by the Commission in UE 197. However, we do not agree that this estimate should ignore future rate base additions reflected in this case. This issue clearly relates to the issue of capital additions in this rate case (Staff issue S-5), which we address in Policy Testimony (PGE Exhibit 1300) as well as in our briefs since this is primarily a legal issue. We note, however, that any method used for deriving 2009 property tax expense should be flexible enough to account for the Commission's decision regarding allowed capital additions. The goal of a property tax estimate is to forecast actual 2009 expenses as accurately as possible.

Q. Did Staff make any errors in deriving their estimate of 2009 test period property tax expense?

A. Yes. Staff made an adjustment to actual 2007 property tax expense that removed $2.4 million related to Port Westward. Staff made this adjustment to remove the Port Westward related tax expense from the 2007 total tax expense because they expect that PGE will receive a temporary exemption of property taxes related to Port Westward that will be in effect in 2009.

Q. Will PGE receive an exemption for Port Westward in 2009?

A. Yes.

Q. Did Staff perform the adjustment to 2007 actual property taxes correctly?

A. No. Staff removed more Port Westward property tax expense from 2007 than was actually recorded in 2007.

Q. Please explain.

A. PGE made a property tax payment of $2.4 million in November 2007. However, that payment relates to the fiscal year July 1, 2007 through June 30, 2008. Thus, only ½ of the payment, or $1.2 million, was included as a 2007 expense. The remainder of the payment was a prepayment for 2008, and was expensed in the first half of 2008. Confidential PGE Exhibit 1407 documents that only $1.2 million of Port Westward property tax expense was incurred in 2007. Thus, even if the Commission accepts Staff's method of deriving a reasonable forecast of 2009 property tax expense, a corrected Staff adjustment for 2009 would yield an adjustment of only $3.0 million as provided in PGE Exhibit 1408.

Q. Does PGE agree that Staff's method of deriving a reasonable 2009 test year expense is appropriate?

A. No. Property taxes are a function of PGE's assets, the value of those assets, and the millage rates applied to those assets by various taxing jurisdictions. The Staff method, while grounded in 2007 actuals, does not provide for a proper adjustment to reflect the changes in rate base since 2007. Indeed, property taxes are not dependent upon CPI, which Staff uses to escalate 2007 actuals.

Q. Are Staff's claims valid that some additional rate base would not translate into additional property tax expense either because of Ballot Measure 50 or due to the Oregon Department of Revenue's treatment of intangible property?

A. No. Ballot Measure 50 provides for a 3% limitation on the growth of Maximum Assessed Value (MAV). The 3% limitation applies before the consideration of additions, which are not subject to any limitation. Further, the MAV is then compared to the Real Market Value (RMV) and the lesser[10] of the two figures is used for purposes of determining a centrally

[10] See ORS 308.146, provided as PGE Exhibit 1410.

assessed value by the Oregon Department of Revenue (DoR). However, this 3% constraint is only relevant if the RMV is, or would be, above the MAV. That is, the limitation is only relevant if the DoR would otherwise assess PGE's property at a higher value than the MAV. This is not the case for PGE. Confidential PGE Exhibit 1409 provides a copy of the most recent Measure 50 template from the DoR for the 2008-2009 tax year. As shown near the bottom of Confidential PGE Exhibit 1409, PGE's RMV for assessment purposes is significantly below the MAV. Thus, the 3% limitation regarding the MAV is not a real constraint for PGE. In other words, the DoR could increase our centrally assessed value by an amount that exceeds 3% from one year to the next.

Staff's claims regarding the DoR's treatment of intangible property for assessment purposes are in error. ORS 308.510 defines property as including "…all property, real and personal, tangible and <u>intangible</u>, used or held by the company as owner, occupant, lessee, or otherwise…" (Emphasis added). A copy of ORS 308.510 is provided as PGE Exhibit 1410. Thus, intangible property such as relicensing costs are <u>not</u> exempt from assessments by the DoR.

Q. Is Staff's method of determining 2009 test year property taxes flexible in regards to the Commission's treatment of rate base additions identified as Staff Issue S-5?

A. No. Staff's method of using 2007 adjusted actuals, adjusted for CPI and the addition of Biglow 1, effectively assumes that the Commission will determine that no rate base additions for 2009 are warranted and that the proposed adjustment in Staff Issue S-5 will be accepted by the Commission. It is unclear how Staff would remedy their method under the assumption that the Commission approves all, or part of, the rate base additions at issue under Staff Issue S-5.

Q. Can PGE suggest a method of determining test year 2009 property tax expense that both meets Staff's stated goals of aligning 2009 forecast to 2007 actuals and can adjust to reflect the Commission's treatment of rate base additions?

A. Yes. PGE Exhibit 1411 provides the derivation of a reasonable level of 2009 property tax expense that is aligned with 2007 actuals, is based on rate base changes rather than CPI, and can adjust to reflect the Commission's determination of Staff Issue S-5.

Q. How did you derive 2009 property tax expense in PGE Exhibit 1411?

A. We also began with PGE's 2007 actual property tax expense. We then removed $1.2 million of actual property tax expense in 2007 for Port Westward. Next, we compared this adjusted 2007 actual property tax expense to the level of rate base reported in PGE's results of operations report for 2007, column 1. This yields a ratio of 1.59%, or the incurred level of property tax expense, adjusted for Port Westward, relative to the assets that are the basis of assessments. We then apply this ratio to PGE's 2009 forecast test year rate base without Biglow 1. The result is a measure of 2009 property tax expense, before consideration of Biglow 1, based on 2007 actual experience. Finally, we include an additional $2.0 million to reflect reduced Biglow 1 property taxes under the SIP for 2009. This method provides for a 2009 test year figure of $36.0 million, or about $1.0 million less than PGE's original filing.

Q. Does PGE propose to adjust its test year property tax figure by $1.0 million?

A. Yes. PGE believes it is reasonable to reduce the forecast level of property tax expense by $1.0 million relative to our initial filing.

Q. Does this new approach to determining 2009 test year property tax expense meet the goals of an estimate as stated by Staff?

A. Yes. It aligns the forecast of 2009 property tax expense to 2007 actual property tax expense. It also reflects the savings related to the unique property tax treatment received both by Port Westward and Biglow 1. Further, this method can reasonably reflect any adjustments the Commission might make to PGE's forecast of additions to rate base. That is, to the extent the Commission approves changes to PGE's 2009 test year rate base, an additional amount of 1.59% should be added to reflect the change in property taxes.

B. Combined State Income Tax Rate

Q. What adjustment was proposed by the parties regarding the combined state income tax rate?

A. Staff proposed that the Commission use a combined rate of 5.120% as initially filed by PGE, rather than the combined rate of 5.375% filed by PGE in our errata filing.

Q. Why does Staff believe that the initially filed combined state tax rate is more reasonable than PGE's update?

A. Staff claims that the apportionment factors, and hence the combined state tax rate, is subject to year-to-year changes and that since PGE's most recent SB 408 proceeding (UE 178) provides for a refund, it would not be appropriate for the Commission to increase PGE's presumed combined state tax rate in this proceeding. Staff notes that SB 408 will eventually true up any differences between presumed 2009 state tax expenses and actual 2009 state tax expenses (Staff/100, Owings/28).

Q. Does PGE agree that state apportionment factors are subject to annual changes?

A. Yes. Apportionment factors can, and do, change on an annual basis. In particular, the degree to which PGE can allocate income to Washington (which has no state income tax) varies due to variation in Mid-Columbia wholesale purchase and sale activity.

Q. Does PGE agree that the current UE 178 refund is relevant in determining whether a state tax rate should be increased or not?

A. No. The refund in UE 178 relates to 2006. The purpose of this rate case is to provide a reasonable forecast of test year 2009. If such activity were relevant, we note that PGE has booked an expected receivable from customers due to our application of SB 408 for calendar year 2007. While this will not be the subject of a docket until later this fall, the receivable indicates that PGE's most recent experience has been an under, rather than over, collection of income taxes. Second, the reasons for a refund (or collection) can be varied. It is not clear the extent to which a state tax rate mis-forecast was a contributor to the refund in 2006 under UE 178, or the anticipated collection related to 2007.

Q. Does PGE agree with Staff that SB 408 will eventually true up the difference between the presumed level of state tax expense in this proceeding and actual state tax expenses?

A. Yes, assuming the legislature does not modify or terminate the law prior to application to the 2009 calendar year. However, we re-iterate that one of the purposes of a rate case is to provide the most reasonable forecast of 2009, not to look exclusively back at historical experience.

Q. Can PGE accept Staff's proposed 5.120% combined state tax rate for the 2009 test year?

A. Yes. PGE's proposed rate of 5.375% in the errata filing represented our most recent actual experience. However, we also believe the apportionment factors are subject to annual change and are somewhat difficult to forecast. Since the difference in question is not significant, and due to the eventual true up of differences under SB 408, we would agree to a combined state tax rate of 5.120%. The impact of PGE accepting Staff's proposal reduces PGE's revenue requirement by $0.6 million.

C. Domestic Production Activities Deduction (DPAD)

Q. What adjustment was proposed by the parties regarding the DPAD?

A. Fred Meyer proposes to include a DPAD of between zero and $1.1 million, depending on the allowed revenue increase authorized by the Commission in this proceeding, with allowed increases in excess of $166 million resulting in a DPAD of $1.1 million. Allowed revenue increases below $85.4 million would result in zero DPAD. Amounts between $85.4 million and $166 million would result in a pro-rated DPAD between zero and $1.1 million (FM/100, Higgins 15-16).

Q. Did PGE include a DPAD in its forecast of 2009 test year tax expense?

A. No. We did not include a DPAD for 2009 because we do not expect to have taxable income related to production activities in 2009. In our data response on this topic, included as Confidential PGE Exhibit 1412, we demonstrated that we expect our production related income to be approximately 33% of total 2009 taxable income. After taking into account the expected accelerated tax depreciation related to Biglow 2, PGE's production related taxable income is below zero for 2009.

Q. How then, does Fred Meyer derive an expected DPAD for 2009?

A. Fred Meyer assumes that approximately 50% of our 2009 taxable income will be related to production activities on the basis that approximately 50% of our 2009 rate base is related to production.

Q. Is this a reasonable assumption?

A. No. The benefits of accelerated depreciation are not spread pro-rata throughout PGE's rate base. PGE has made, and expects to continue to make, significant additions to generation. These generating facilities are subject to significant accelerated depreciation for tax purposes. For example, Biglow 1 is depreciated over 5 years using the MACRS tax schedule. Port Westward is also subject to significant tax depreciation over the next several years. PGE's distribution assets, by contrast, are largely embedded assets whose tax depreciation is not nearly as aggressive.

Q. Can you give an example of how Fred Meyer's assumption of using rate base to derive assumed share of taxable income can be in error?

A. Yes. PGE Exhibit 1413 provides the level of UE 180 approved generation and total rate base. If we applied the same methodology used by Fred Meyer, we would have assumed that 38% of taxable income in 2007 would relate to production activities. However, as shown in Confidential PGE Exhibit 1412, only 21% of actual 2007 taxable income related to production.

Q. Even if the Commission accepts Fred Meyer's contention that 50% of taxable income in 2009 will relate to production activities, do you agree that PGE's DPAD could be as high as $1.1 million in 2009?

A. No. PGE, and a number of other parties (including Fred Meyer), have stipulated to the elements of cost of capital, including a 10.1% ROE. Fred Meyer's analysis is based on a 10.75% ROE as originally filed by PGE. Confidential PGE Exhibit 1414 updates that analysis to reflect the 10.1% ROE stipulated to in this case. Based on this update alone, the maximum DPAD, even assuming a 50% factor of taxable income, falls to $0.8 million.

Q. Do you agree that there are a range of potential 2009 DPADs that depend upon the Commission's level of authorized revenues in this case?

A. No. First, we believe that the most likely DPAD is still zero even if the Commission grants PGE our full request. This is based on Confidential PGE Exhibit 1412, which we believe provides a reasonable forecast of the share of taxable income related to domestic activities in 2009.

Moreover, the assumed linear relationship between levels of revenues granted by the Commission and the resulting DPAD as presented by Fred Meyer is overly simplistic. For example, a Commission approved reduction to PGE's rate base would have a different impact on PGE's overall tax capacity than would a Commission approved reduction to O&M expense, even if the two adjustments had the same revenue requirement effect. As another example, increases or decreases in allowed revenue that reflect updates to PGE's net variable power costs in this case represent dollar for dollar changes in revenue to reflect costs changes. As such, they have no impact on PGE's expected level of taxable income. Thus, the assumed simple linear relationship that Fred Meyer is suggesting is not reasonable.

Q. What is the most likely DPAD for 2009?

A. The most likely DPAD for 2009 is zero. This follows from the likely share of 2009 taxable income related to production activities. In addition, the DPAD would be zero even if the Commission allows recovery of the revenue requirement supported in this case by PGE under an assumed ROE of 10.1%.

Q. To the extent that unforeseen circumstances result in an actual DPAD in 2009, would SB 408 true up for this difference?

A. Yes. To the extent that a forecast of zero DPAD proves to be in error, SB 408 will true up this difference, just as it will the state tax rate forecast discussed earlier.

D. Rate Case Margin and Effective Tax Rate for SB 408 Purposes

Q. Have you calculated the margin and effective tax rate ratios to be used for SB 408 purposes?

A. Yes. PGE Exhibit 1401 provides the ratios based on PGE revenue requirement in UE 197/198. The results, however, should be updated to reflect the final Commission Order in these dockets.

Q. What are the results of your calculations?

A. We have calculated a margin ratio of 14.37% and an effective tax rate of 25.30% pursuant to the methodology used to derive these ratios previously approved by the Commission.

Q. Should these be the ratios used by the Commission for purposes of determining taxes collected in rates for SB 408 purposes?

A. No. The Commission should consider the impact of disallowed costs in determining the effective tax rate and margin for SB 408 purposes. To do otherwise would effectively allow customers to receive tax benefits from utility costs for which customers are not responsible.

Q. How should the ratios be modified to reflect the impact of disallowed costs in this rate case?

A. The ratios should be modified to reflect the tax effect of disallowed costs in this rate case. PGE Exhibit 1401 provides the calculation of adjusted ratios to reflect SERP costs that PGE adjusted out of our direct case (see PGE Exhibit 200, pgs. 5-6) as well as PGE's proposal to absorb officer incentive and director compensation costs as described in PGE Exhibit 1500. We propose to adjust the SB 408 ratios for these costs since they are a contractual obligation

(SERP) or they are likely to be incurred (Officer Incentives/Director Compensation) even if they are not recovered through rates. The result of these adjustments is a modified margin ratio of 14.1% and a modified effective tax rate of 25.0%.

Q. Should these modified ratios also be updated pursuant to the Commission's final Orders in UE 197 and UE 198?

A. Yes. For example, to the extent that the Commission agrees with other parties that costs should be disallowed from rates, the ratios should be similarly adjusted to reflect the tax effect of the underlying cost.

Q. Is PGE attempting to obtain recovery of disallowed costs by adjusting SB 408 ratios in the manner you have suggested?

A. No. PGE is not suggesting the Commission reverse the effect of its Orders. Rather, we are requesting that the Commission recognize that certain utility costs will not be recovered in this proceeding, and therefore, to avoid giving customers tax benefits from such costs, the margin and effective tax rate ratios should be adjusted for purposes of future SB 408 tax true-up proceedings.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1401	UE 197/198 Revenue Requirement
1402	Copy of PGE's Response to CUB Data Request No. 088
1403	Copy of PGE's Response to OPUC Data Request No. 203, Attachment 203-E
1404	ICNU-CUB Response to PGE Data Request No. 005
1405	Copy of PGE Response to CUB Data Request No. 064, Attachment 064-A
1406	Copy of PGE Response to OPUC Data Request No. 103, Attachment 103-B
1407C	**Columbia County Property Tax Statements**
1408	Staff Adjustment to Property Taxes with Port Westward Error Corrected
1409C	**2008/2009 DoR Ballot Measure 50 Template for PGE**
1410	Copy of ORS 308.510 and ORS 308.146
1411	Revised 2009 Property Tax Expense Calculation
1412C	**Copy of PGE Response to Fred Meyer Data Request No. 002**
1413	UE 180 Production Share of Rate Base
1414C	**Fred Meyer DPAD adjustment updated for 10.1% ROE**

Portland General Electric Company
2009 Revenue Requirement (Revised)
Dollars in $000s
Reflects PGE Rebuttal, July 11 NVPC Update, net of NVPC Stip, and Partial Rev Req Stip, including 10.1% ROE

	At UE 180 / UE 188 / UE 19 Rates	Adjustments to Filed Case	Adjusted 2009 Results	GRC Change for RROE	2009 Results at Resonable Return
	(1)	(2)	(3)	(4)	(5)
1 Sales to Consumers	1,586,821	21,652	1,608,473	212,956	1,821,429
2 Sales for Resale	-	-	-		-
3 Other Revenues	19,346	(455)	18,891		18,891
4 Total Operating Revenues	1,606,167	21,197	1,627,364	212,956	1,840,320
5 Net Variable Power Costs	806,699	112,557	919,256		919,256
6 Production O&M (excludes Trojan)	108,111	(5,336)	102,775		102,775
7 Trojan O&M	129	-	129		129
8 Transmission O&M	11,639	(1,578)	10,061		10,061
9 Distribution O&M	67,910	288	68,198		68,198
10 Customer & MBC O&M	65,412	(177)	65,235		65,235
11 Uncollectibles Expense	7,617	104	7,721	1,022	8,743
12 OPUC Fees	4,959	68	5,026	665	5,692
13 A&G, Ins/Bene., & Gen. Plant	115,107	(6,895)	108,212		108,212
14 Total Operating & Maintenance	1,187,584	99,030	1,286,614	1,688	1,288,301
15 Depreciation	176,327	(799)	175,528		175,528
16 Amortization	18,764	17	18,781		18,781
17 Property Tax	36,965	(1,129)	35,836		35,836
18 Payroll Tax	12,793	63	12,856		12,856
19 Other Taxes	1,411	-	1,411		1,411
20 Franchise Fees	39,893	544	40,437	5,354	45,791
21 Utility Income Tax	14,632	(27,256)	(12,624)	78,867	66,243
22 Total Operating Expenses & Taxes	1,488,367	70,471	1,558,838	85,909	1,644,746
23 **Utility Operating Income**	117,799	(49,274)	68,526	127,048	195,574
					195,574
24 **Average Rate Base**					
25 Avg. Gross Plant	5,173,287	(9,936)	5,163,351		5,163,351
26 Avg. Accum. Deprec. / Amort	(2,675,492)	554	(2,674,938)		(2,674,938)
27 Avg. Accum. Def Tax	(265,949)	(20,913)	(286,862)		(286,862)
28 Avg. Accum. Def ITC	(271)	-	(271)		(271)
29 **Avg. Net Utility Plant**	2,231,574	(30,295)	2,201,279	-	2,201,279
30 Misc. Deferred Debits	23,755	6,322	30,077		30,077
31 Operating Materials & Fuel	67,707	-	67,707		67,707
32 Misc. Deferred Credits	(37,755)	-	(37,755)		(37,755)
33 Working Cash	77,395	3,664	81,060	4,467	85,527
34 **Average Rate Base**	2,362,677	(20,309)	2,342,368	4,467	2,346,835
35 **Rate of Return**	4.986%		2.925%		8.333%
36 **Implied Return on Equity**	3.405%		-0.716%		10.100%

Portland General Electric Company
2009 Revenue Requirement (Revised)
Dollars in $000s
Reflects PGE Rebuttal, July 11 NVPC Update, net of NVPC Stip, and Partial Rev Req Stip, including 10.1% ROE

	At UE 180 / UE 188 / UE 19: Rates	Adjustments to Filed Case	Adjusted 2009 Results	GRC Change for RROE	2009 Results at Resonable Return
	(1)	(2)	(3)	(4)	(5)
37 Effective Cost of Debt	6.567%	6.567%	6.567%	6.567%	6.567%
38 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%
39 Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	3.284%	3.284%	3.284%	3.284%	3.284%
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%
43 Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%
44 State Tax Rate	5.120%	5.120%	5.120%	5.120%	5.120%
45 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%
46 Composite Tax Rate	38.328%	38.328%	38.328%	38.328%	38.328%
47 Bad Debt Rate	0.480%	0.480%	0.480%	0.480%	0.480%
48 Franchise Fee Rate	2.514%	2.514%	2.514%	2.514%	2.514%
49 Working Cash Factor	5.200%	5.200%	5.200%	5.200%	5.200%
50 Gross-Up Factor	1.621	1.621	1.621	1.621	1.621
51 ROE Target	10.100%	10.100%	10.100%	10.100%	10.100%
52 Grossed-Up COC	11.472%	11.472%	11.472%	11.472%	11.472%
53 OPUC Fee Rate	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%
Utility Income Taxes					
54 Book Revenues	1,606,167	21,197	1,627,364	212,956	1,840,320
55 Book Expenses	1,473,735	97,726	1,571,462	7,041	1,578,503
56 Interest Deduction	77,578	(667)	76,912	147	77,058
57 Production Deduction	-	-	-		-
58 Permanent Ms	(13,234)	(4,751)	(17,985)	-	(17,985)
59 Deferred Ms	42,599	-	42,599	-	42,599
60 Taxable Income	25,488	(71,111)	(45,624)	205,768	160,145
61 Current State Tax	1,305	(3,641)	(2,336)	10,536	8,200
62 State Tax Credits	(2,084)	-	(2,084)	-	(2,084)
63 Net State Taxes	(779)	(3,641)	(4,420)	10,536	6,116
64 Federal Taxable Income	26,267	(67,470)	(41,204)	195,232	154,029
65 Current Federal Tax	9,193	(23,615)	(14,421)	68,331	53,910
66 Federal Tax Credits	(8,363)	-	(8,363)	-	(8,363)
67 ITC Amort	(1,456)	-	(1,456)	-	(1,456)
68 Deferred Taxes	16,036	-	16,036	-	16,036
69 Total Income Tax Expense	14,632	(27,256)	(12,624)	78,867	66,243
70 SB 408 Ratio - Net to Gross	8.35%		3.48%		14.37%
71 SB 408 Ratio - Effective Tax Rate	11.05%		-22.58%		25.30%
72 Check SB 408 Calc	-		-		-
73 Regulated Net Income	40,221		(8,386)		118,515
74 Check Regulated NI					118,515

Margin and Effective Tax Rate in UE-197/198
Adjusted for SERP, Officer Incentives and Other Disallowed Costs
Example Using Updated PGE Filing as Base
Dollars in $000

	PGE Results	SERP	Officer Incentives	Director Comp	Blank	Blank	Adjusted Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Operating Revenues							
Sales to Consumers (Rev. Req.)	1,821,429						1,821,429
Sales for Resale	-						-
Other Operating Revenues	18,891						18,891
Total Operating Revenues	1,840,320	-	-	-	-	-	1,840,320
Operation & Maintenance							
Net Variable Power Cost	919,256						919,256
Total Fixed O&M	181,163						181,163
Other O&M	187,882	1,942	3,417	325			193,566
Total Operation & Maintenance	1,288,301	1,942	3,417	325	-	-	1,293,985
Depreciation & Amortization	194,309						194,309
Other Taxes / Franchise Fee	95,893						95,893
Income Taxes	66,243	(745)	(1,311)	(125)	-	-	64,063
Total Oper. Expenses & Taxes	1,644,746	1,197	2,106	200	-	-	1,648,250
Utility Operating Income	195,574	(1,197)	(2,106)	(200)	-	-	192,070
Rate of Return	8.33%						N/A
Return on Equity	10.10%						N/A
Average Rate Base							
Utility Plant in Service	5,163,351						5,163,351
Accumulated Depreciation	(2,674,938)						(2,674,938)
Accumulated Def. Income Taxes	(286,862)						(286,862)
Accumulated Def. Inv. Tax Credit	(271)						(271)
Net Utility Plant	2,201,279	-	-	-	-	-	2,201,279
Misc Deferred Debits	30,077						30,077
Operating Materials & Fuel	67,707						67,707
Misc. Deferred Credits	(37,755)						(37,755)
Working Cash	85,527	62	110	10	-	-	85,709
Total Average Rate Base	2,346,835	62	110	10	-	-	2,347,017
Income Tax Calculations							
Book Revenues	1,840,320	-	-	-	-	-	1,840,320
Book Expenses	1,578,503	1,942	3,417	325	-	-	1,584,187
Interest Rate Base @ Weighted Cost of I	77,058	2	4	0	-	-	77,064
Temporary Sch M Differences	42,599						42,599
Permanent M Differences	(17,985)						(17,985)
State Taxable Income	160,145	(1,944)	(3,421)	(325)	-	-	154,455
State Income Tax	6,116	(100)	(175)	(17)	-	-	5,825
Federal Taxable Income	154,029	(1,845)	(3,245)	(309)	-	-	148,630
Fed Income Tax	45,547	(646)	(1,136)	(108)	-	-	43,657
Deferred Taxes	16,036						16,036
ITC Amort	(1,456)						(1,456)
Total Income Tax	66,243	(745)	(1,311)	(125)	-	-	64,063
Net to Gross Margin	14.37%						14.06%
Effective Tax Rate	25.30%						25.01%
Check	66,243						64,063

Portland General Electric
UE 197, 2009 Test Year
Change in Revenue Requirement from Initial Filing
Dollars in $000s

Original Requested Increase	145,892	
Errata Items:		
PGE-1 (Update State Tax Rate)	-	
PGE-2 (Remove Heat Pump Costs)	(306)	
PGE-3 (Add'l FERC positions)	450	
PGE-4 (Economic Stim Act)	(2,482)	
PGE-5 (Update Equity Issuance Fees)	48	
PGE-6 (Update Bull Run Decommissioning)	2,556	
PGE-7 (Correct Union labor escalation)	582	
Total Errata Items	848	
Stipulated Items:		
Other Revenue	471	
KB Pipeline O&M	(1,040)	
PW/Biglow True-up to 2007 YE	(112)	
NVPC Update to July 11 (net of NVPC Stip)	117,101	
Load Forecast Update (Revenue Impact only)	(21,647)	
ROE to 10.1%	(12,906)	
Total Stipulated Items	81,865	
Add'l Changes per Rebuttal Testimony:		
S-2 R&D	(520)	
S-3 Remove FERC 890A FTEs	(807)	
S-4 Officer Incentives	(3,555)	
S-5 Cap Ex	(1,518)	
S-9 Director Compensation	(338)	
S-9 Insurance	(860)	
S-9 Uninsured Losses	(1,809)	
S-9 Other Benefits	(151)	
S-10 Unscheduled Flow Mitigation	(104)	
S-11 Fixed Plant Costs	(4,965)	
S-14 Property Taxes	(1,019)	
Total Rebuttal Changes	(15,646)	Note removal of State Tax Rate Change is above
Rounding	(2)	
Revised Requested Increase	212,956	
Check	212,956	
Total Effect of Changes to Original Filing	67,067	
Excluding ROE Effect	79,973	
Check	79,973	

Adjustments to Filed Case
Dollars in $000s

	Remove Update State Tax Rate PGE-1	Remove Heat Pump Costs PGE-2	Add'l FERC Positions PGE-3	Economic Stimulus Act PGE-4	Update Equity Issue Fees PGE-5	Update Bull Run Decomm PGE-6
1 Sales to Consumers						
2 Sales for Resale						
3 Other Revenues						
4 Total Operating Revenues	-	-	-	-	-	-
5 Net Variable Power Costs						
6 Production O&M (excludes Trojan)			(93)			
7 Trojan O&M						
8 Transmission O&M			288			
9 Distribution O&M						
10 Customer & MBC O&M		(210)				
11 Uncollectibles Expense	-	-	-	-	-	-
12 OPUC Fees	-	-	-	-	-	-
13 A&G, Ins/Bene., & Gen. Plant		(84)	238			
14 Total Operating & Maintenance	-	(294)	433	-	-	-
15 Depreciation						(546)
16 Amortization					17	
17 Property Tax						
18 Payroll Tax						
19 Other Taxes						
20 Franchise Fees	-	-	-	-	-	-
21 Utility Income Tax	-	113	(166)	263	(2)	2,016
22 Total Operating Expenses & Taxes	-	(181)	267	263	15	1,470
23 **Utility Operating Income**	-	181	(267)	(263)	(15)	(1,470)
24 **Average Rate Base**						
25 Avg. Gross Plant						
26 Avg. Accum. Deprec. / Amort						554
27 Avg. Accum. Def Tax				(20,890)		(23)
28 Avg. Accum. Def ITC						
29 **Avg. Net Utility Plant**	-	-	-	(20,890)	-	531
30 Misc. Deferred Debits					162	
31 Operating Materials & Fuel						
32 Misc. Deferred Credits						
33 Working Cash	-	(9)	14	14	1	76
34 **Average Rate Base**	-	(9)	14	(20,876)	162	607
35 **Rate of Return**						
36 **Implied Return on Equity**						

Adjustments to Filed Case
Dollars in $000s

	Remove Update State Tax Rate PGE-1	Remove Heat Pump Costs PGE-2	Add'l FERC Positions PGE-3	Economic Stimulus Act PGE-4	Update Equity Issue Fees PGE-5	Update Bull Run Decomm PGE-6
37 Effective Cost of Debt	6.567%	6.567%	6.567%	6.567%	6.567%	6.567%
38 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
39 Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	3.284%	3.284%	3.284%	3.284%	3.284%	3.284%
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
43 Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
44 State Tax Rate	5.120%	5.120%	5.120%	5.120%	5.120%	5.120%
45 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
46 Composite Tax Rate	38.328%	38.328%	38.328%	38.328%	38.328%	38.328%
47 Bad Debt Rate	0.480%	0.480%	0.480%	0.480%	0.480%	0.480%
48 Franchise Fee Rate	2.514%	2.514%	2.514%	2.514%	2.514%	2.514%
49 Working Cash Factor	5.200%	5.200%	5.200%	5.200%	5.200%	5.200%
50 Gross-Up Factor	1.621	1.621	1.621	1.621	1.621	1.621
51 ROE Target	10.100%	10.100%	10.100%	10.100%	10.100%	10.100%
52 Grossed-Up COC	11.472%	11.472%	11.472%	11.472%	11.472%	11.472%
53 OPUC Fee Rate	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%
Utility Income Taxes						
54 Book Revenues	-	-	-	-	-	-
55 Book Expenses	-	(294)	433	-	17	(546)
56 Interest Deduction	-	(0)	0	(685)	5	20
57 Production Deduction						
58 Permanent Ms					(17)	(4,734)
59 Deferred Ms	-					
60 Taxable Income	-	294	(433)	685	(5)	5,260
61 Current State Tax	-	15	(22)	35	(0)	269
62 State Tax Credits						
63 Net State Taxes	-	15	(22)	35	(0)	269
64 Federal Taxable Income	-	279	(411)	650	(5)	4,991
65 Current Federal Tax	-	98	(144)	228	(2)	1,747
66 Federal Tax Credits						
67 ITC Amort						
68 Deferred Taxes		-	-	-	-	-
69 Total Income Tax Expense	-	113	(166)	263	(2)	2,016
70 Rev Req Effect	-	(306)	450	(2,482)	48	2,556

Adjustments to Filed Case
Dollars in $000s

	Correct Union Labor Esc PGE-7	Other Rev Stip 1	KB Pipeline Inspec Stip 2	PW/Biglow True-up Stip 3	NVPC Update Net of Stip Stip 4	Load Forecast Update PGE-8
1 Sales to Consumers						21,652
2 Sales for Resale						
3 Other Revenues		(455)				
4 Total Operating Revenues	-	(455)	-	-	-	21,652
5 Net Variable Power Costs					112,557	
6 Production O&M (excludes Trojan)	233					
7 Trojan O&M						
8 Transmission O&M	10		(1,000)			
9 Distribution O&M	288					
10 Customer & MBC O&M	33					
11 Uncollectibles Expense	-	-	-	-	-	104
12 OPUC Fees	-	-	-	-	-	68
13 A&G, Ins/Bene., & Gen. Plant	(96)					
14 Total Operating & Maintenance	468	-	(1,000)	-	112,557	172
15 Depreciation				(24)		
16 Amortization						
17 Property Tax						
18 Payroll Tax	63					
19 Other Taxes						
20 Franchise Fees	-	-	-	-	-	544
21 Utility Income Tax	(207)	(174)	384	18	(43,186)	8,019
22 Total Operating Expenses & Taxes	324	(174)	(616)	(6)	69,370	8,735
23 **Utility Operating Income**	(324)	(281)	616	6	(69,370)	12,917
24 **Average Rate Base**						
25 Avg. Gross Plant	250			(735)		
26 Avg. Accum. Deprec. / Amort						
27 Avg. Accum. Def Tax						
28 Avg. Accum. Def ITC						
29 **Avg. Net Utility Plant**	250	-	-	(735)	-	-
30 Misc. Deferred Debits						
31 Operating Materials & Fuel						
32 Misc. Deferred Credits						
33 Working Cash	17	(9)	(32)	(0)	3,607	454
34 **Average Rate Base**	267	(9)	(32)	(735)	3,607	454
35 **Rate of Return**						
36 **Implied Return on Equity**						

Adjustments to Filed Case
Dollars in $000s

	Correct Union Labor Esc PGE-7	Other Rev Stip 1	KB Pipeline Inspec Stip 2	PW/Biglow True-up Stip 3	NVPC Update Net of Stip Stip 4	Load Forecast Update PGE-8
37 Effective Cost of Debt	6.567%	6.567%	6.567%	6.567%	6.567%	6.567%
38 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
39 Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	3.284%	3.284%	3.284%	3.284%	3.284%	3.284%
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
43 Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
44 State Tax Rate	5.120%	5.120%	5.120%	5.120%	5.120%	5.120%
45 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
46 Composite Tax Rate	38.328%	38.328%	38.328%	38.328%	38.328%	38.328%
47 Bad Debt Rate	0.480%	0.480%	0.480%	0.480%	0.480%	0.480%
48 Franchise Fee Rate	2.514%	2.514%	2.514%	2.514%	2.514%	2.514%
49 Working Cash Factor	5.200%	5.200%	5.200%	5.200%	5.200%	5.200%
50 Gross-Up Factor	1.621	1.621	1.621	1.621	1.621	1.621
51 ROE Target	10.100%	10.100%	10.100%	10.100%	10.100%	10.100%
52 Grossed-Up COC	11.472%	11.472%	11.472%	11.472%	11.472%	11.472%
53 OPUC Fee Rate	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%
Utility Income Taxes						
54 Book Revenues	-	(455)	-	-	-	21,652
55 Book Expenses	531	-	(1,000)	(24)	112,557	716
56 Interest Deduction	9	(0)	(1)	(24)	118	15
57 Production Deduction						
58 Permanent Ms						
59 Deferred Ms						
60 Taxable Income	(540)	(455)	1,001	48	(112,675)	20,921
61 Current State Tax	(28)	(23)	51	2	(5,769)	1,071
62 State Tax Credits						
63 Net State Taxes	(28)	(23)	51	2	(5,769)	1,071
64 Federal Taxable Income	(512)	(431)	950	46	(106,906)	19,850
65 Current Federal Tax	(179)	(151)	332	16	(37,417)	6,947
66 Federal Tax Credits						
67 ITC Amort						
68 Deferred Taxes	-	-	-	-	-	-
69 Total Income Tax Expense	(207)	(174)	384	18	(43,186)	8,019
70 Rev Req Effect	582	471	(1,040)	(112)	117,101	(21,647)

Adjustments to Filed Case
Dollars in $000s

	R&D S-2	Remove FERC 890 FTEs S-3	Officer Incentives S-4	Cap-Ex S-5	Director Comp S-9	Insurance S-9
1 Sales to Consumers						
2 Sales for Resale						
3 Other Revenues						
4 Total Operating Revenues	-	-	-	-	-	-
5 Net Variable Power Costs						
6 Production O&M (excludes Trojan)						
7 Trojan O&M						
8 Transmission O&M		(776)				
9 Distribution O&M						
10 Customer & MBC O&M						
11 Uncollectibles Expense	-	-	-	-	-	-
12 OPUC Fees	-	-	-	-	-	-
13 A&G, Ins/Bene., & Gen. Plant	(500)		(3,417)		(325)	(827)
14 Total Operating & Maintenance	(500)	(776)	(3,417)	-	(325)	(827)
15 Depreciation				(229)		
16 Amortization						
17 Property Tax				(150)		
18 Payroll Tax						
19 Other Taxes						
20 Franchise Fees	-	-	-	-	-	-
21 Utility Income Tax	192	298	1,311	264	125	317
22 Total Operating Expenses & Taxes	(308)	(478)	(2,106)	(115)	(200)	(510)
23 **Utility Operating Income**	308	478	2,106	115	200	510
24 **Average Rate Base**						
25 Avg. Gross Plant				(9,451)		
26 Avg. Accum. Deprec. / Amort						
27 Avg. Accum. Def Tax						
28 Avg. Accum. Def ITC						
29 **Avg. Net Utility Plant**	-	-	-	(9,451)	-	-
30 Misc. Deferred Debits						
31 Operating Materials & Fuel						
32 Misc. Deferred Credits						
33 Working Cash	(16)	(25)	(110)	(6)	(10)	(27)
34 **Average Rate Base**	(16)	(25)	(110)	(9,457)	(10)	(27)
35 **Rate of Return**						
36 **Implied Return on Equity**						

Adjustments to Filed Case
Dollars in $000s

	R&D S-2	Remove FERC 890 FTEs S-3	Officer Incentives S-4	Cap-Ex S-5	Director Comp S-9	Insurance S-9
37 Effective Cost of Debt	6.567%	6.567%	6.567%	6.567%	6.567%	6.567%
38 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
39 Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	3.284%	3.284%	3.284%	3.284%	3.284%	3.284%
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
43 Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
44 State Tax Rate	5.120%	5.120%	5.120%	5.120%	5.120%	5.120%
45 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
46 Composite Tax Rate	38.328%	38.328%	38.328%	38.328%	38.328%	38.328%
47 Bad Debt Rate	0.480%	0.480%	0.480%	0.480%	0.480%	0.480%
48 Franchise Fee Rate	2.514%	2.514%	2.514%	2.514%	2.514%	2.514%
49 Working Cash Factor	5.200%	5.200%	5.200%	5.200%	5.200%	5.200%
50 Gross-Up Factor	1.621	1.621	1.621	1.621	1.621	1.621
51 ROE Target	10.100%	10.100%	10.100%	10.100%	10.100%	10.100%
52 Grossed-Up COC	11.472%	11.472%	11.472%	11.472%	11.472%	11.472%
53 OPUC Fee Rate	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%
Utility Income Taxes						
54 Book Revenues	-	-	-	-	-	-
55 Book Expenses	(500)	(776)	(3,417)	(379)	(325)	(827)
56 Interest Deduction	(1)	(1)	(4)	(311)	(0)	(1)
57 Production Deduction						
58 Permanent Ms						
59 Deferred Ms						
60 Taxable Income	501	777	3,421	690	325	828
61 Current State Tax	26	40	175	35	17	42
62 State Tax Credits						
63 Net State Taxes	26	40	175	35	17	42
64 Federal Taxable Income	475	737	3,245	654	309	785
65 Current Federal Tax	166	258	1,136	229	108	275
66 Federal Tax Credits						
67 ITC Amort						
68 Deferred Taxes	-	-	-	-	-	-
69 Total Income Tax Expense	192	298	1,311	264	125	317
70 Rev Req Effect	(520)	(807)	(3,555)	(1,518)	(338)	(860)

Adjustments to Filed Case
Dollars in $000s

	Uninsured Losses S-9	Other Ben S-9	Unscheduled Flow Mitig. S-10	Fixed Plant S-11	Prop Taxes S-14	Total Adjustments
1 Sales to Consumers						21,652
2 Sales for Resale						-
3 Other Revenues						(455)
4 Total Operating Revenues	-	-	-	-	-	21,197
5 Net Variable Power Costs						112,557
6 Production O&M (excludes Trojan)				(5,476)		(5,336)
7 Trojan O&M						-
8 Transmission O&M			(100)			(1,578)
9 Distribution O&M						288
10 Customer & MBC O&M						(177)
11 Uncollectibles Expense	-	-	-	-	-	104
12 OPUC Fees	-	-	-	-	-	68
13 A&G, Ins/Bene., & Gen. Plant	(1,739)	(145)				(6,895)
14 Total Operating & Maintenance	(1,739)	(145)	(100)	(5,476)	-	99,030
15 Depreciation						(799)
16 Amortization						17
17 Property Tax		-			(979)	(1,129)
18 Payroll Tax						63
19 Other Taxes						-
20 Franchise Fees	-	-	-	-	-	544
21 Utility Income Tax	667	56	38	2,024	376	(27,256)
22 Total Operating Expenses & Taxes	(1,072)	(89)	(62)	(3,452)	(603)	70,471
23 **Utility Operating Income**	1,072	89	62	3,452	603	(49,274)
24 **Average Rate Base**						-
25 Avg. Gross Plant						(9,936)
26 Avg. Accum. Deprec. / Amort						554
27 Avg. Accum. Def Tax						(20,913)
28 Avg. Accum. Def ITC						-
29 **Avg. Net Utility Plant**	-	-	-	-	-	(30,295)
30 Misc. Deferred Debits				6,160		6,322
31 Operating Materials & Fuel						-
32 Misc. Deferred Credits						-
33 Working Cash	(56)	(5)	(3)	(180)	(31)	3,664
34 **Average Rate Base**	(56)	(5)	(3)	5,980	(31)	(20,309)
35 **Rate of Return**						
36 **Implied Return on Equity**						

Adjustments to Filed Case
Dollars in $000s

	Uninsured Losses S-9	Other Ben S-9	Unscheduled Flow Mitig. S-10	Fixed Plant S-11	Prop Taxes S-14	Total Adjustments
37 Effective Cost of Debt	6.567%	6.567%	6.567%	6.567%	6.567%	6.567%
38 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
39 Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	3.284%	3.284%	3.284%	3.284%	3.284%	3.284%
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
43 Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
44 State Tax Rate	5.120%	5.120%	5.120%	5.120%	5.120%	5.120%
45 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
46 Composite Tax Rate	38.328%	38.328%	38.328%	38.328%	38.328%	38.328%
47 Bad Debt Rate	0.480%	0.480%	0.480%	0.480%	0.480%	0.480%
48 Franchise Fee Rate	2.514%	2.514%	2.514%	2.514%	2.514%	2.514%
49 Working Cash Factor	5.200%	5.200%	5.200%	5.200%	5.200%	5.200%
50 Gross-Up Factor	1.621	1.621	1.621	1.621	1.621	1.621
51 ROE Target	10.100%	10.100%	10.100%	10.100%	10.100%	10.100%
52 Grossed-Up COC	11.472%	11.472%	11.472%	11.472%	11.472%	11.472%
53 OPUC Fee Rate	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%
Utility Income Taxes						
54 Book Revenues	-	-	-	-	-	21,197
55 Book Expenses	(1,739)	(145)	(100)	(5,476)	(979)	97,726
56 Interest Deduction	(2)	(0)	(0)	196	(1)	(667)
57 Production Deduction						-
58 Permanent Ms						(4,751)
59 Deferred Ms						-
60 Taxable Income	1,741	145	100	5,280	980	(71,111)
61 Current State Tax	89	7	5	270	50	(3,641)
62 State Tax Credits						-
63 Net State Taxes	89	7	5	270	50	(3,641)
64 Federal Taxable Income	1,652	138	95	5,009	930	(67,470)
65 Current Federal Tax	578	48	33	1,753	325	(23,615)
66 Federal Tax Credits						-
67 ITC Amort						-
68 Deferred Taxes	-	-	-	-	-	-
69 Total Income Tax Expense	667	56	38	2,024	376	(27,256)
70 Rev Req Effect	(1,809)	(151)	(104)	(4,965)	(1,019)	79,973

General Rate Case - UE 2009 Test Year
Capital Structure / Revenue Sensitive Costs
(000s)

Capital Structure:	**Amount**	**Share**	**Cost**	**Weighted**
Common Equity	N/A	50.00%	10.100%	5.050%
Preferred	N/A	0.00%	0.00%	0.000%
Long-Term Debt	N/A	50.00%	6.567%	3.284%
Total	N/A	100.00%		**8.334%**

Revenue Sensitive Costs:		Adjusted
Revenues	1.00000	1.00000
OPUC Fees	0.00313	0.00313
Franchise Fees	0.02514	0.02514
O&M Uncollectibles	0.00480	0.00480
State Taxable Income	0.96694	0.96694
State Tax @ 5.12%	0.04951	0.04951
Federal Taxable Inc.	0.91742	0.91742
Federal Tax @ 35%	0.32110	0.32110
Total Income Taxes	**0.37061**	0.37061
Total Rev. Sensitive Costs	**0.40367**	0.40367
Utility Operating Income	0.59633	0.59633
Net To Gross Factor	**1.67693**	1.67693
RSC Gross-Up Factor	1.0342	1.0342
Working Cash Factor	0.0023	0.0023
NTG w/Working Cash	1.6808	1.6808
RSC Gross-Up w/Working Cash	1.0366	1.0366

State Income Tax:				Updated:		
	Appor	Rate	Weighted	Appor	Rate	Weighted
Montana	4.09%	6.75%	0.276%	4.09%	6.75%	0.276%
Oregon	73.40%	6.60%	4.844%	73.40%	6.60%	4.844%
State			5.120%			5.120%
Composite Tax Rate:			**38.328%**			**38.328%**

Check:	Fed Tax	35.00%	35.00%
	State Tax	5.120%	5.12%
	Tax Shield	-1.79%	-1.79%
	Composite	38.328%	38.328%

July 7, 2008

TO: Lowrey Brown
Citizens' Utility Board

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to CUB Data Request
Dated June 25, 2008
Question No. 088

Request:

What is the average annual salary of a full-time PGE employee?

Response:

Attachment 088-A is a calculation of average annual salary per FTE. The calculation is based on data available in PGE's original workpapers identifying straight-time wages and salaries, and in PGE's Supplemental Response to ICNU Data Request No. 267, confidential Attachment 267-A, where PGE calculates 2009 officer salaries to be deducted. The information provided to ICNU is included as Attachment 088-B. Attachment 088-B is confidential and subject to Protective Order No. 08-133.

UE 197
Attachment 088-A

Calculation of Average Annual Salary per FTE

Provided Electronically (CD) Only

PGE Response to CUB Data Request No. 088
Attachment 088-A

Average Annual Salary per FTE

	2009	Source
Utility Straight-Time Wages & Salaries	$ 209,609,741	Exhibit 800, Workpaper 2
Less: 2009 Officer Salaries	$ 3,445,416	PGE Supplemental Response to ICNU Data Request No. 267, Attachment 267-A
Total	$ 206,164,325	
Total Utility Straight-Time FTE	2,733	Exhibit 800, Workpaper 1
Less: Officer FTEs	12	
Total	2,721	
	$ 75,764	**Average annual salary per FTE**

April 25, 2008

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to OPUC Data Request
Dated April 10, 2008
Question No. 203

Request:

Please provide worksheets in both hard copy and electronically that show the following utility labor-related information for the twelve months ending December 2002, December 2003, December 2006 and December 2007:

a. **Actual Wages and salaries, annualized and as well as end-of-period, separated by employee category (officer, exempt, non-exempt and union). Please include paid time off and exclude overtime, bonuses and incentive pay.**
b. **Actual end-of-period employee counts for full-time, part-time FTEs as well as temporary employees for each calendar year of 2002, 2003, 2006, 2007 as well as forecasts for 2008 and 2009.**
c. **Overtime data for calendar years 2002, 2003, 2006, 2007 as well as forecasted amounts for 2008 and 2009.**
d. **Actual union wage escalation rates for 2002 through 2007 as well as forecasted amounts for 2008 and 2009.**
e. **Percentage of total wages and salaries booked to OMAG as well as percentage booked to capital by year for 2002, 2003, 2006 and 2007.**

Response:

PGE objects to this request on the basis that it is overly burdensome. Subject to and without waiving its objection, PGE responds as follows:

First, PGE does not forecast end-of-period employee counts. Instead, managers forecast required FTEs by estimating the amount of labor hours needed to fulfill their responsibilities. Second, PGE does not have 2008 and 2009 budgeted FTEs broken out by employee category. PGE budgets wages and salaries by escalating at the responsibility center (RC) level based on the employee classes within the RC. Consequently, detail for specific employee classes is not retained within the system.

a) Attachment 175-A provides wages and salaries for 2002, 2003, 2006, and 2007, separated by employee category, omitting overtime, bonus, and incentive pay. Total forecasted wages and salaries for 2008 and 2009 are provided because PGE does not forecast these values by employee category.

b) PGE does not forecast end-of-period employee counts and has not budgeted 2008 and 2009 FTEs by employee category. Subject to and without waiving its objection, Attachment 175-B provides actual FTEs for 2002, 2003, 2006, and 2007, separated by employee category, as well as total FTEs for 2008 and 2009.

c) Attachment 175-C provides overtime expense for 2002, 2003, 2006, and 2007 as well as forecasted overtime expense for 2008 and 2009.

d) Attachment 175-D contains union wage escalation rates for 2002 through 2008 for the main bargaining unit as well as the Coyote Springs/Port Westward. 2009 actual union wage escalation rates are not known at this time. The 2009 IBEW Main Agreement is not yet signed and annual wage increases for Coyote Spring and Port Westward are based on changes in the IPP market per the IPP wage survey and will not be known until the end of the year.

e) Attachment 175-E provides the percentage of total wages and salaries booked to O&M and A&G as well as percentage booked to capital by year, for 2002, 2003, 2006, and 2007.

UE 197
Attachment 203-E

OMAG / Capital Labor Cost Percentages

UE 197
PGE Response to OPUC Data Request No. 203
Attachment 203-E

UE 197
PGE's Response to OPUC Data Request No. 203
Attachment 203-E

OMAG and Capital Labor

Year	Labor Expense % OMAG	Labor Expense % Capital
2002 Actual	68.43%	31.57%
2003 Actual	69.86%	30.14%
2006 Actual	72.68%	27.32%
2007 Actual	71.75%	28.25%

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PORTLAND GENERAL ELECTRIC
UE 197
PGE's Second Set of Data Requests to ICNU
Question No. 005

Data Request No. 005:

Please explain Blumenthal's meaning of "forecast" in the context of "The information included in PGE's filing includes 2007 forecast amounts, but not 2007 actual amounts" (ICNU-CUB/100, Blumenthal/3).

Response to Data Request No. 005:

Ms. Blumenthal simply used the term used by PGE in its filing. For example, Table 1 on PGE 800/2 contains a column headed "Forecast 2007." Presumably, these figures are forecasted rather than the actual results of operations for 2007.

June 23, 2008

TO: Lowrey Brown
Citizens' Utility Board

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to CUB Data Request
Dated June 11, 2008
Question No. 064

Request:

According to the Company's response to CUB 46: "The outboard adjustment discussed at the May 8th workshop refers only to twenty transmission and distribution and ten customer service new hires. The average costs of these specific new FTEs are less than the average cost for all new FTEs."

a. **At the workshop it was stated that the 20-person outboard adjustment was meant to represent the expected employee shortfall in the budget for the test year, and, while the adjustment was classified as T&D and customer service, it actually represented unfilled positions throughout the company. Does the 20 number only represent shortfalls in T&D and customers service personnel?**
b. **If not, how many non-T&D positions in the test year does PGE forecast to be unfilled?**
c. **If yes, why is it relevant that the average cost of these positions is less than other parts of the Company?**

Response:

PGE provided Attachment 064-A at the May 8 workshop. Attachment 064-A is a comparison of budget and actual FTEs for 2004 through 2007, separated by category.

PGE averages approximately 30 unfilled FTEs annually. Transmission and Distribution is the source of the bulk of the unfilled FTEs and was allocated 20 of the 30-FTE adjustment to PGE's filing (see work papers to PGE Exhibit 200).

Furthermore, the over-filled FTEs in A&G and Customer Service more than offset the unfilled positions in Generation, leaving unfilled positions in Customer Accounts. The 10 customer service new hires are a part of the Customer Accounts category.

Regarding part (c), the average cost of new positions in both Transmission and Distribution and Customer Accounts are below that of the Company average. PGE's adjustment to wages and salaries was in accordance with this lower than average cost for entry-level new hires. The calculation of the approximate $2 million adjustment is described in PGE's Response to CUB Data Request No. 044.

UE 197
Attachment 064-A

Comparison of Budget and Actual FTEs
2004 Through 2007

UE 197
PGE Response to CUB Data Request No. 064
Attachment 064-A

PGE Utility Full-Time Equivalents (FTE)
by Year, by Division

Category	2004	2005	2006	2007	2008	2009	Average 2004-2007
Actuals							
Straight-Time							
Administrative and General	584.8	611.7	635.0	649.8			
Customer Accounts	495.2	497.8	503.2	505.9			
Customer Service	72.2	70.4	72.9	79.6			
Generating	410.8	387.2	391.4	405.1			
Transmission and Distribution	946.4	937.4	937.1	956.6			
Total Actual Straight-Time	**2,509.4**	**2,504.4**	**2,539.6**	**2,597.0**			
Over Time							
Administrative and General	2.1	1.8	2.2	2.1			
Customer Accounts	16.5	9.5	13.5	10.9			
Customer Service	-	0.0	0.0	0.0			
Generating	15.9	14.4	15.8	21.3			
Transmission and Distribution	78.6	71.7	94.6	81.6			
Total Actual Over-Time	**113.2**	**97.4**	**126.2**	**116.0**			
Total Actual FTEs	**2,622.6**	**2,601.8**	**2,665.7**	**2,713.0**			
Budget / Forecast							
Budgeted Straight-Time							
Administrative and General	584.0	591.1	608.7	642.9	656.2	665.3	
Customer Accounts	489.0	507.7	512.4	523.7	525.6	534.6	
Customer Service	70.0	63.3	69.1	68.0	76.5	80.5	
Generating	421.9	399.0	414.5	422.8	430.9	445.7	
Transmission and Distribution	984.1	1,001.0	998.2	994.4	1,002.8	1,007.1	
Total Budgeted Straight-Time	**2,549.1**	**2,562.1**	**2,602.9**	**2,651.8**	**2,692.0**	**2,733.2**	
Budgeted Over-Time							
Administrative and General	2.7	2.4	2.3	1.8	1.8	1.7	
Customer Accounts	10.4	10.5	9.1	9.8	9.5	9.5	
Customer Service	0.0	0.0	-	-	-	-	
Generating	21.1	20.1	20.1	23.8	23.9	23.9	
Transmission and Distribution	56.1	56.9	61.3	59.4	56.5	58.4	
Total Budgeted Over-Time	**90.2**	**89.8**	**92.8**	**94.9**	**91.7**	**93.5**	
Total Budgeted FTEs	**2,639.4**	**2,651.9**	**2,695.7**	**2,746.7**	**2,783.7**	**2,826.6**	
Delta (Budget - Actuals)							
Straight-Time							
Administrative and General	(0.8)	(20.6)	(26.3)	(6.9)			(13.6)
Customer Accounts	(6.3)	10.0	9.2	17.7			7.7
Customer Service	(2.2)	(7.1)	(3.8)	(11.6)			(6.2)
Generating	11.1	11.8	23.1	17.7			16.0
Transmission and Distribution	37.8	63.6	61.1	37.8			50.1
Total Actual Straight-Time	**39.7**	**57.7**	**63.3**	**54.8**			**53.9**
Over Time							
Administrative and General	0.5	0.6	0.1	(0.3)			0.2
Customer Accounts	(6.1)	0.9	(4.4)	(1.1)			(2.7)
Customer Service	0.0	0.0	(0.0)	(0.0)			(0.0)
Generating	5.2	5.6	4.2	2.5			4.4
Transmission and Distribution	(22.5)	(14.8)	(33.3)	(22.2)			(23.2)
Total Actual Over-Time	**(22.9)**	**(7.6)**	**(33.4)**	**(21.1)**			**(21.3)**
Total Delta FTEs	**16.8**	**50.1**	**30.0**	**33.7**			**32.6**

April 24, 2008

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to OPUC Data Request
Dated March 25, 2008
Question No. 103

Request:

For the following items (identified in UE197/PGE 100, Piro/6), please provide a detailed description on how and when the following increases associated with compliance will be spent, as well as an explanation justifying the need for each increase:

a. **$750,000 for FTE employees to comply with FERC Order 890-A**
b. **$400,000 to establish a Business Continuity and Emergency Management department.**
c. **$650,000 for additional FERC compliance activities.**

Response:

a. To achieve compliance with Paragraph 947 of FERC Order 890A, PGE could be required to make immediate and significant changes in the way its Real Time Trading desk personnel conduct business. However, PGE has joined several other northwest utility companies in making a filing, under Section 205 of the Federal Power Act (FPA), to request a clarification from FERC that, if accepted, would avoid the need to make such significant changes. If FERC does not accept the FPA 205 filing, PGE will need to hire the additional 7.5 FTEs in 2009 to accommodate the significant changes in the conduct of its Real Time Trading business. See Attachment 103-A for a detailed description and justification. *See Also,* PGE's Response to OPUC Data Request 104.

b. The Energy Sector has been designated by Homeland Security as one of the top 17 national infrastructure groups that provide essential services and social normalcy during large scale emergency.

In addition, the Oregon Public Utility Commission recognized the focus of security of emergency infrastructure, cyber attack and other "real threats" the energy utilities experience on a daily basis. In a letter received from Lee Sparling dated August 6, 2004, the Commission indicated it would consider rate relief to utilities who carry out security programs that are not covered within existing rates. See Attachment 103-B.

Customers, industry and regulators expect PGE to withstand a variety of disaster scenarios and be able to recover in a reasonable period of time with minimal disruption.

PGE has recognized the need to ensure the necessary steps are taken to identify and mitigate the impact of potential losses, maintain viable recovery strategies, develop recovery plans and provide for the continuity of services. In June 2007, officers directed the establishment of the new department, Business Continuity and Emergency Management to:

1) Mitigate and respond to risks, hazards and emergency events;
2) Ready company resources to maintain critical/essential services during adverse conditions;
3) Comply with regulatory requirements; and
4) Stabilize shareholder confidence.

This department will be focused on the following strategic objectives:

- Conduct a Risk Assessment - identification of all risks to the company and the critical functions necessary for the company to continue business operations based on probabilities of threat.
- Conduct a Business Impact Analysis - prioritization of business functions by assessing the quantitative and qualitative impact that might result if an organization was to experience a disaster and lose critical processes.
- Identify all Critical/Essential Positions and related Skills Inventory
- Develop Business Continuity Plans for Critical/Essential Work Units and related Emergency Staffing Plans
- Train, Drill and Exercise Plans to insure and strengthen Response
- Evaluate the current company Emergency Operations Center Site and plan for backup capabilities
- Security Hardening of Critical Infrastructure (physical and cyber)
- Create an Emergency Communications Infrastructure/Network to communicate internally and externally during a disaster

-
- Ensure that all practices are in compliance with regulatory requirements, standards and certification guidelines
- Establish partnerships with government, utility industry, private business and other critical sectors to coordinate communication, response and recovery efforts.

In the last quarter of 2008, a Training Coordinator will be hired to drill/exercise company plans for readiness as will an administrative position to support database management and compliance reporting as well as training logistics and plan development and production.

In 2009 professional services and equipment costs will support the purchase of field responder/survival kits; training and exercise curriculum and materials; publication costs associated with compliance reporting, designing plan templates; developing a company crisis communication plan and procedures; monthly costs to support communication infrastructure/network devices for emergency responders such as satellite phones; supplies for critical/essential personnel to be stored, inventoried and monitored at secure locations such as food, water and medicine.

c. Background:
The Energy Policy Act of 2005 (EPAct 2005) significantly changed FERC's role in electricity and natural gas markets and enhanced FERC's civil penalty authority to $1 million per day per violation. The increase in FERC activity due to EPAct is not limited to a specific one-time spike in rules / workloads but rather is expected to be ongoing. Since EPAct 2005, FERC has:

- Promulgated 21 final rules, including Orders 890 and 890A which extensively revised the rules for providing transmission service;
- Created 11 reports for Congress
- Of the total 145 electric and gas orders noted as of major importance by FERC and issued since 1992:
    - 21 were issued prior to 2000, 124 have been issued since 2000
    - 94 of the 124 orders have been issued since 2005
- Instigated three different audits and one investigation of various aspects of PGE operations.; The earliest audit began in June of 2006, and PGE has responded to 252 data requests, completed 5 site visits by FERC auditors and PGE Management has completed five trips to Washington D.C. to meet with FERC audit staff. All of the audits and the investigation are still ongoing.
- FERC Activity related to Mandatory Reliability Standards:
    - 86 Standards of which 74 apply to PGE with more than 600 requirements and sub-requirements
    - 8 WECC Regional standards of which 4 apply to PGE; and
    - 8 additional Cyber Security Standards

PGE has gathered 12 banker boxes of documents in preparation for WECC/NERC/FERC's May, 2008 audit to determine PGE's compliance with the Reliability Standards. These hard copy documents are in addition to electronic files and numerous computer systems. PGE has 2.5 FTEs dedicated to the Company's compliance efforts related to the Reliability Standards.

PGE is actively involved in over 32 FERC dockets (not including hydro) and is closely monitoring several others. These dockets have implications for PGE's power operations, transmission and reliability services, hydro operations, financial reporting and gas pipeline activities. PGE also monitors the hundreds of rulings issued by FERC each month to identify any that are relevant to PGE operations.

As a result of the changes in the FERC regulatory environment, PGE has determined that it will need to hire seven additional employees in 2008 to ensure compliance with FERC regulations. The following describes where the new employees will be needed and the duties they will need to fulfill:

<u>Two</u> positions in PGE's FERC Compliance department

1. A FERC compliance analyst to manage company-wide projects related to FERC, NERC, and WECC, and to develop PGE's auditable compliance with mandatory reliability standards
2. A specialist to assist with PGE's responses to emerging FERC issues and initiatives. This will include drafting, editing, and electronically filing PGE pleadings and interventions.

<u>One</u> position in PGE's Power Operations department - FERC Tariff Analyst will coordinate all aspects of FERC-related orders for both power and natural gas. The analyst's responsibilities will include documentation, monitoring industry forums, develop written policies and procedures, coordinate training and PGE self-audits, and work with IT on automated solutions.

<u>Three</u> positions in Transmission and Reliability Services (T&R)

1. One supervisor to administer the open access tariff, interconnection requests, FERC Order 890, regional representation, and FERC governance;
2. One specialist to perform billing and reporting; FERC, NERC, WECC data collection reporting; process service agreements, and address energy imbalances issues; and
3. One specialist to interpret and implement new orders, rules, and regulations, and coordinate: 1) efforts of T&R's subject matter experts, 2) the development, documentation, and implementation of resulting business policies and procedures, and 3) T&R's development, documentation, and implementation of relevant policies and procedures.

One position in PGE's Transmission and Distribution Operations and Planning department. An Engineer will perform studies to ensure PGE's compliance with NERC requirements. This position will also represent PGE in coordinating NERC activities with other constituents such as NWPP, BPA, PacifiCorp, and WECC members.

UE 197
Attachment 103-B

Public Utility Commission Letter

Oregon
Theodore R. Kulongoski, Governor

Public Utility Commission
550 Capitol Street NE, Suite 215
Mailing Address: PO Box 2148
Salem, OR 97308-2148
Consumer Services
1-800-522-2404
Local: 503-378-6600
Administrative Services
503-373-7394

August 6, 2004

JAMES C MILLER
IDAHO POWER
PO BOX 70
BOISE ID 83707

DARRELL T GERRARD
PACIFICORP
825 NE MULTNOMAH SUITE 1600
PORTLAND OR 97232

PEGGY Y FOWLER
PORTLAND GENERAL ELECTRIC
121 SW SALMON STREET
PORTLAND OR 97204

The August 2003 Northeast Blackout and 9/11 have brought considerable focus to the security of energy infrastructure all across the United States. Furthermore, increases in the frequency and impacts of cyber attacks have brought real threats to energy utilities on a daily basis. These incidents have led policy-makers in the energy sector to rethink the level of security protection needed. You and we are being asked tough questions about the vulnerability of and the level of protection needed by energy utilities and providers. In response, NERC and WECC have developed standards and guidelines to harden the security of the nation's electricity grid. We support their efforts to develop industry standards and best practices for security that make sound operational and business sense.

The Commission has directed staff to perform security reviews of regulated energy utility security on an annual basis. A member of staff will be contacting your company's security representative in the near future to arrange a meeting to review your company's activities in complying with the attached NERC and WECC standards. The sensitivity and confidentiality of such information will be respected. Our goal is to have a follow-up executive session with the Commissioners late this year on the security preparedness of Oregon's energy utilities.

In consideration of the above, the Commission has indicated it will consider rate relief for regulated utilities in carrying out prudent security programs and measures that are not already covered within existing rates. Obviously, your company will need to justify and support, as always, such applications for increased cost recovery.

If you have any questions about this letter or future activities, please feel free to contact Jerry Murray at (503) 378-6626.

Lee Sparling

Lee Sparling
Director
Utility Program

Attachment

\security electric utility ltr.doc

Staff Adjustment to Property Taxes with Corrected Port Westward Adjustment

	2007 Actual	Adjustment	Adjusted 2007
Property Tax			
Oregon	$ 28,519,422	$ (1,212,985)	$ 27,306,437
Montana	$ 3,451,819	$ -	$ 3,451,819
Total OR & MT Property Tax	$ 31,971,241	$ (1,212,985)	$ 30,758,256

	2009 Forecasted	Adjustment	Staff's 2009	UE 197	DR's
Property Tax					
Oregon	$ 28,353,693	$ 2,000,000	$ 30,353,693	$ 32,650,774	DR 75, 76
Montana	$ 3,584,203		$ 3,584,203	$ 4,279,200	DR 75, 77
Total OR & MT Property Tax	$ 31,937,897	$ 2,000,000	$ 33,937,897	$ 36,929,974	

Total OR & MT Prop Tax Per UE 197	$ 36,929,974.00
Total OR & MT Prop Tax Per Staff	$ 33,937,896.63
Adjustment	$ (2,992,077.37)

308.510 "Property" defined; real and personal property classified. (1) "Property," as used in ORS 308.505 to 308.665, includes all property, real and personal, tangible and intangible, used or held by a company as owner, occupant, lessee or otherwise, for or in use in the performance or maintenance of a business or service or in a sale of any commodity, as set forth in ORS 308.515, whether or not such activity is pursuant to any franchise, and includes but is not limited to the lands and buildings, rights of way, roadbed, water powers, vehicles, cars, rolling stock, tracks, wagons, horses, office furniture, telegraph, telephone and transmission lines, poles, wires, conduits, switchboards, machinery, appliances, appurtenances, docks, watercraft irrespective of the place of registry or enrollment, merchandise, inventories, tools, equipment, machinery, franchises and special franchises, work in progress and all other goods or chattels. "Property" does not include items of intangible property that represent claims on other property including money at interest, bonds, notes, claims, demands and all other evidences of indebtedness, secured or unsecured, including notes, bonds or certificates secured by mortgages, and all shares of stock in corporations, joint stock companies or associations.

(2) All land of any railroad, logging road, electric rail or trackless transportation company, or railroad switching and terminal company, including land used or held and claimed exclusively as right of way, with all the tracks and substructures and superstructures that support the same, together with all sidetracks, second tracks, turnouts, station houses, depots, roundhouses, engine houses, machine shops, buildings or other structures, without separating same into lands and improvements, is real property and the rolling stock and all other property is personal property.

(3) Without especially defining and enumerating the treatment, the Department of Revenue shall treat all land of any company as real property, and except as provided in subsection (2) of this section, all docks, hangars, landing fields, exchanges, office buildings, bridges, power plants, dams, reservoirs, substations, relay stations, telegraph, telephone or transmission and distribution lines located upon property owned by the company, and all other buildings, structures, improvements or fixtures of a permanent character thereon, as real property, and all other property as personal property.

(4)(a) Except as provided in ORS 308.517 (2) and in paragraphs (b) and (c) of this subsection, the renting, leasing, chartering or otherwise assigning of property exclusively for the use or benefit of another shall not constitute a use by the lessor.

(b) A lessor shall be deemed the user of property rented, leased or otherwise furnished by it to its employee as an incident of employment.

(c) A rail transportation company shall be deemed the user of property situated within its station ground reservations or rights of way notwithstanding the fact that such property may be leased, rented or otherwise assigned by it for the use or benefit of another.

(5) Property found by the department to have an integrated use for or in more than one business, service or sale, where at least one such business, service or sale is one enumerated in ORS 308.515, shall be classified by the department as being within or without the definition of property under subsection (1) of this section, according to the primary use of such property, as determined by the department.

(6) For purposes of determining the maximum assessed value of property under section 11, Article XI of the Oregon Constitution, "property" means all property assessed to each company that is subject to assessment under ORS 308.505 to 308.665. [Amended by 1957 c.711 §2; 1977 c.602 §2; 1997 c.154 §32; 1997 c.541 §203; 2003 c.46 §18]

308.146 Determination of maximum assessed value and assessed value; reduction in maximum assessed value following property destruction; effect of conservation or highway scenic preservation easement. (1) The maximum assessed value of property shall equal 103 percent of the property's assessed value from the prior year or 100 percent of the property's maximum assessed value from the prior year, whichever is greater.

(2) Except as provided in subsections (3) and (4) of this section, the assessed value of property to which this section applies shall equal the lesser of:

(a) The property's maximum assessed value; or

(b) The property's real market value.

(3) Notwithstanding subsections (1) and (2) of this section, the maximum assessed value and assessed value of property shall be determined as provided in ORS 308.149 to 308.166 if:

(a) The property is new property or new improvements to property;

(b) The property is partitioned or subdivided;

(c) The property is rezoned and used consistently with the rezoning;

(d) The property is first taken into account as omitted property;

(e) The property becomes disqualified from exemption, partial exemption or special assessment; or

(f) A lot line adjustment is made with respect to the property, except that the total assessed value of all property affected by a lot line adjustment shall not exceed the total maximum assessed value of the affected property under subsection (1) of this section.

(4) Notwithstanding subsections (1) and (2) of this section, if property is subject to partial exemption or special assessment, the property's maximum assessed value and assessed value shall be determined as provided under the provisions of law governing the partial exemption or special assessment.

(5)(a) Notwithstanding subsection (1) of this section, when a portion of property is destroyed or damaged due to fire or act of God, for the year in which the destruction or damage is reflected by a reduction in real market value, the maximum assessed value of the property shall be reduced to reflect the loss from fire or act of God.

(b) This subsection does not apply:

(A) To any property that is assessed under ORS 308.505 to 308.665.

(B) If the damaged or destroyed property is property that, when added to the assessment and tax roll, constituted minor construction for which no adjustment to maximum assessed value was made.

(c) As used in this subsection, "minor construction" has the meaning given that term in ORS 308.149.

(6)(a) If, during the period beginning on January 1 and ending on July 1 of an assessment year, any real or personal property is destroyed or damaged, the owner or purchaser under a recorded instrument of sale in the case of real property, or the person assessed, person in possession or owner in the case of personal property, may apply to the county assessor to have the real market and assessed value of the property determined as of July 1 of the current assessment year.

(b) The person described in paragraph (a) of this subsection shall file an application for assessment under this section with the county assessor on or before the later of:

(A) August 1 of the current year; or

(B) The 60th day following the date on which the property was damaged or destroyed.

(c) If the conditions described in this subsection are applicable to the property, then notwithstanding ORS 308.210, the property shall be assessed as of July 1, at 1:00 a.m. of the assessment year, in the manner otherwise provided by law.

(7)(a) Paragraph (b) of this subsection applies if:

(A) A conservation easement or highway scenic preservation easement is in effect on the assessment date;

(B) The tax year is the first tax year in which the conservation easement or highway scenic preservation easement is taken into account in determining the property's assessed value; and

(C) A report has been issued by the county assessor under ORS 271.729 within 12 months preceding or following the date the easement was recorded.

(b) The assessed value of the property shall be as determined in the report issued under ORS 271.729, but may be further adjusted by changes in value as a result of any of the factors described in ORS 309.115 (2), to the extent adjustments do not cause the assessed value of the property to exceed the property's maximum assessed value.

(8)(a) Notwithstanding subsection (1) of this section, when a building is demolished or removed from property, for the year in which the demolishment or removal of the building is reflected by a reduction in real market value, the maximum assessed value of the property may be reduced to reflect the demolishment or removal of the building.

(b) This subsection does not apply:

(A) To any property that is assessed under ORS 308.505 to 308.665.

(B) If the demolished or removed property is property that, when added to the assessment and tax roll, constituted minor construction for which no adjustment to maximum assessed value was made.

(c) As used in this subsection, "minor construction" has the meaning given that term in ORS 308.149. [1997 c.541 §6; 1999 c.1003 §1; 2001 c.925 §12; 2003 c.46 §15; 2003 c.169 §7; 2007 c.450 §1; 2007 c.516 §1]

Revised 2009 Property Tax Expense

2007 Actual Montana/Oregon Property Tax Expense	31,971,241	
Remove PW Expense in 2007 Actuals	$ (1,212,985)	
Adjusted 2007 Actual Property Tax Expense	$ 30,758,256	
2007 Actual Average Rate Base per 2007 ROO	$ 1,939,421,000	
Ratio of 2007 Property Tax Expense to Rate Base	1.59%	
PGE Filed 2009 Average Rate Base	$ 2,365,737,000	
Less Estimated Biglow I rate base	$ (225,000,000)	
2009 Rate Base w/o Biglow	$ 2,140,737,000	
Non Biglow Estimated 2009 Property Tax expense	$ 33,951,028	Apply 1.59% to 2009 Non-Biglow RB
Add Biglow Property Taxes	$ 2,000,000	
Estimated 2009 Property Taxes	$ 35,951,028	
2009 Montana/Oregon as filed by PGE	36,929,974	
Adjustment to 2009 Montana/Oregon Property Taxes	$ (978,946)	

Rate Base in UE 180 ($000s)
Per OPUC Order 07-015
Including Port Westward

		Share
Production	762,634	38.0%
Transmission	112,883	5.6%
Distribution	1,105,682	55.0%
Metering	3,326	0.2%
Billing	12,850	0.6%
Consumer	11,374	0.6%
Total	2,008,749	100%

Table of Contents

I. Introduction

Q. Please state your name and positions with PGE.

A. My name is Arleen Barnett. My position is Vice President, Administration. My responsibilities include establishing compensation policy and employee policies; creating a positive work environment; overseeing employee relations, health and safety; managing employee development; and overseeing Business Continuity and Security. My responsibilities also include oversight for PGE's Information Technology Department.

My name is Joyce Bell. My position is Director of Compensation and Benefits in the Human Resources Department.

Our qualifications are in our direct testimony, PGE Exhibit 800, Section V.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is two-fold. First, we update our request regarding compensation, removing several items and lowering our request by approximately $4.1 million. Second, we summarize and respond to other parties' positions regarding four areas: wages and salaries, incentives, medical and other benefits, and the employee discount. In particular, we show that:

- ICNU-CUB's proposed change to the escalation rate for wages and salaries would not allow PGE to compete successfully for qualified employees. Further, the escalation rates PGE used to develop the forecast of wages and salaries are based on objective criteria, such as market surveys and Bureau of Labor statistics, and are therefore reasonable.
- The Parties' proposed disallowances for incentives are based on outdated information. We show that PGE's incentive costs are a reasonable and critical

part of employees' total compensation that allows PGE to attract and retain qualified employees.

- Staff's proposed disallowances to several of PGE's other benefits are unreasonable. We demonstrate that these benefits are a necessary part of an employee's total compensation.
- The proposed full disallowance of PGE's employee discount is unjustified. We demonstrate that the employee discount is a low-cost part of PGE's total compensation package.

The table below summarizes parties' positions in terms of the amount proposed to be removed.

Table 1
Summary of Proposed Reductions

	Incentives	Medical & Dental	Directors' Incentives & Misc.	Other Benefits	Employee Discount	Total
PGE Update	$3,416,826	$0	$325,100	$144,615	$0	**$3,886,540**
Staff	$9,076,792	$1,283,621	$325,100	$424,307	N/A	**$11,109,820**
ICNU-CUB	$9,418,467	N/A	N/A	N/A	$885,846	**$10,304,313**

Q. How is your testimony organized?

A. In addition to this Introduction, our testimony has five sections. In Section II, we discuss PGE's updates to its original filing and PGE's compensation philosophy. In Section III, we rebut ICNU-CUB's proposal to change the escalation rates used for wages and salaries. In Section IV, we discuss how PGE's incentives are based on objectives that benefit customers. In Section V, we rebut Staff's adjustments to the cost of union medical and dental benefits and the allocation of medical and dental expense to non-utility. In Section VI, we address Staff's various adjustments to other benefits and other parties' proposed disallowance of the employee discount.

II. PGE Adjustments and Compensation Philosophy

Q. Have you modified your compensation forecast for 2009?

A. Yes. We have removed the officer vehicle plan and executive financial planning functions and associated costs from the test year, lowering costs by $135,300. We also removed $9,315 from PGE's other benefits for costs associated with life insurance for retired officers.

Q. Has PGE made any other adjustments?

A. Yes. We have decided not to pursue the recovery of incentives for officers and directors in this proceeding. We believe these incentives are a necessary part of total compensation for these groups but we also believe that given other upward pressures on electric rates this is an adjustment that PGE should make in the spirit of compromise. Table 2 outlines PGE's proposed adjustments.

Table 2
PGE's Proposed Adjustments

	2009
Officer ACI	$1,736,870
Officer SIP	$1,679,956
Directors' Incentives & Miscellaneous	$325,100
Other	$144,615
Total Reduction	**$3,886,541**

Q. What is the purpose of PGE's total compensation strategy?

A. As we noted in our previous testimony (PGE Exhibit 800, Section I), the purpose of PGE's total compensation strategy is to provide competitive compensation in order to attract qualified applicants, retain employees, and motivate employees to achieve company goals by rewarding them for their performance.

Q. Please describe the benefits to customers of PGE's CIP and Non-Officer incentive programs.

A. PGE's incentive programs focus employees' efforts on controlling costs, increasing productivity, and making smart business decisions in carrying out PGE's roles and responsibilities. These priorities translate into lower costs company-wide while providing customers with excellent, safe and reliable service.

PGE offers a combination of fixed base pay and pay-at-risk (incentives) that allows PGE to adjust incentives downward when performance and/or market forces dictate. Including incentives as a component of compensation also lowers PGE's benefit costs because they are excluded from the company 401(k) savings match and final average earnings for pension calculations.

III. Wages and Salaries

Q. Please summarize ICNU-CUB's proposed escalation rates.

A. ICNU-CUB proposes to escalate PGE's wages and salaries at 0% for officers, 2% for exempt and union employees, and 3% for hourly employees.

Q. Does PGE agree with ICNU-CUB's methodology?

A. No. We find four significant problems with their methodology:

1. ICNU-CUB's methodology excludes 2005 and 2007 escalations for exempt employees on the basis that the increases are greater than those for union and non-exempt, and "they were unusual when compared to the other years" (ICNU-CUB Exhibit 100, pg. 9). By that logic, one could just as easily remove the increases for 2003 and 2004 exempt employees because they are <u>less</u> than those for union and non-exempt employees for those years, resulting in a higher escalation rate, or 4.6%. ICNU-CUB's methodology is simply result-driven and arbitrary, and should not be adopted.
2. ICNU-CUB states that "the salaries of PGE's officers increased disproportionately in both 2006 and 2008" (ICNU-CUB Exhibit 100, pg. 9). This analysis fails to recognize that the addition of one officer in 2006 caused a significant portion of that year's supposed "escalation." ICNU-CUB also ignores the realignment of officers' salaries with the market in 2006 and 2007. Independent analyses determined that PGE Officers' salaries were below market and, as a result of the increases, are now approximately at market. Keeping salaries at market level helps to attract and retain qualified, experienced candidates. ICNU-CUB also fails to adjust its analysis for the de-escalation in 2004 as a result of one fewer officer.

3. ICNU-CUB fails to consider actual historical events that affected PGE's wages and salaries. For example, PGE did not provide merit increases in 2003, which had an impact on wages and salaries in both 2003 and 2004.
4. ICNU-CUB's analysis uses incorrect FTEs for 2007. The data response to which they refer was revised to make 2007 consistent with information provided for other years and provided significantly different FTEs for 2007.

For these four reasons, ICNU-CUB's analysis and recommendations regarding wages and salaries should be rejected.

Q. What would be the result of using ICNU-CUB's proposed escalation rates?

A. PGE's wages and salaries in 2009 would be unjustifiably low compared to the market. PGE would find itself at a disadvantage in hiring and retaining qualified individuals.

Q. On what criteria should the wages and salaries escalation rate be based?

A. PGE's escalation rate should be based on objective criteria, such as market surveys and Bureau of Labor statistics. In addition, employee merit changes must be considered. In fact, this is the method that PGE used to determine its 4.5% escalation rate.

Q. Is there any recent information available that supports PGE's estimate?

A. Yes. Preliminary market surveys (Exhibit 1501) from the Economic Research Institute indicate that projected escalation rates for 2009 will be in the mid-four percent range.

IV. Incentives

Q. Please describe Staff's and ICNU-CUB's proposed adjustments to Corporate Incentives.

A. Staff proposes to disallow a portion of PGE's incentives by removing almost all (92.49%) of PGE's Stock Incentive Plan (SIP) and Officer Annual Cash Incentive (ACI), and half (50%) of Non-Officer ACI, the Corporate Incentive Plan (CIP) and Notable Achievement Awards (Notables) (Staff Exhibit 100, pg. 19). Staff incorrectly correlates the SIP, ACI and CIP incentives with PGE's financial performance based on their review of a past Commission Order (Order No. 87-406), a "recent" 2005 audit, and a PGE data response (PGE's Response to ICNU Data Request No. 262).

ICNU-CUB proposes to disallow all of SIP and Officer ACI, and half the remaining incentives including CIP, Non-Officer ACI and Notables. ICNU-CUB contends that the SIP motivates beneficiaries of this plan to only focus on increasing PGE's stock price.

Table 3 below outlines the positions of PGE Staff and ICNU-CUB.

Table 3
Amount Recommended

							Recommended	
	Officer SIP	Non-Officer SIP	Officer ACI	Non-Officer ACI	CIP	Notables	**Amount Included**	**Amount Removed**
PGE Update	$0	$1,132,765	$0	$3,443,936	$6,093,815	$200,000	**$10,870,516**	**$3,416,826**
Staff	$126,165	$85,071	$130,438	$1,721,968	$3,046,908	$100,000	**$5,210,550**	**$9,076,793**
ICNU-CUB	$0	$0	$0	$1,721,968	$3,046,908	$100,000	**$4,868,876**	**$9,418,467**

Q. Will you be addressing Officer ACI or Officer SIP in this testimony?

A. No. As discussed in Section II, PGE has chosen to remove these items from the test year and we do not need to address them in this testimony.

A. Staff's Analysis Contains Several Errors

Q. Does Staff Exhibit 106 support their testimony?

A. No. Rather than using the percentage disallowances indicated in their testimony, Staff uses an alternative methodology based on data from PGE's work papers.

Q. Does Staff's methodology contain errors?

A. Yes. Staff first calculates PGE's CIP, but erroneously double counts the portion of CIP applied to capital projects. Staff then uses this figure to calculate a ratio of CIP to total incentives of 92.79%, which is then applied to PGE's Officer ACI and total SIP. Next, Staff divides the remaining incentives in half and removes $363,681 based on reduced incentives associated with their proposal to remove 121 FTEs from PGE's forecast (Staff Exhibit 105, pg. 2).

In PGE Exhibit 1400, PGE corrects Staff's FTE adjustment to reflect a reduction of only 18 FTEs. Given the corrected FTE adjustment, the associated reduction of incentives would be approximately $54,000. Staff then applies a different capital/O&M allocation ratio from the one that PGE provided to Staff in PGE's Response to OPUC Data Request No. 203. Their calculation of this ratio also double counts the capitalized portion of CIP.

Q. Staff supports their disallowances by referencing several documents including PGE's Response to ICNU Data Request No. 262, Staff's 2005 audit of CIP and ACI, and a prior Commission Order (No. 87-406) (Staff Exhibit 100, pg. 18). Are any of Staff's references relevant to PGE's current incentive plans?

A. No. Each of these citations is based on what are now outdated incentive plan materials. In particular, Staff relied on PGE's 2006 ACI Master Plan in PGE Response to ICNU Data Request No. 262 for their analysis. Staff should have used PGE's current incentive plans (i.e., 2008), one of which was provided in PGE's Response to ICNU Data Request No. 265

(Confidential PGE Exhibit 1502), and subsequently provided to Staff in PGE's Response to OPUC Data Request No. 391.

The audit referred to by Staff was conducted in 2005 and was based on incentive plans then in effect. However, those plans have been replaced and have no bearing on PGE's proposed incentive costs for the 2009 test year. Therefore, this audit should not form the basis of any incentive disallowance for the 2009 test year.

With regard to Order No. 87-406, in that docket the Commission held that Pacific Northwest Bell's (PNB) officer compensation should be reduced as a component of Oregon rates because it found that Oregon ratepayers contributed to only a fraction of PNB's (subsequently US West's) total operations. This finding is not relevant to PGE's rate case because all of PGE's customers are in Oregon and there are no out-of-state operations to which PGE's Oregon customers contribute. Thus, this Order should also not provide a basis of any disallowance of PGE's incentives.

Q. Staff bases its disallowances on the notion that incentives should not be supported if they are "based on the financial performance of the utility" (Staff Exhibit 100, pgs. 18 - 19). Are PGE's current ACI and CIP plans based solely on financial performance?

A. No. PGE's current cash incentive programs (ACI and CIP) are an integral part of PGE's total compensation package. These programs have been modified to more closely align incentive compensation with benefits to customers, as we described in our direct testimony (PGE Exhibit 800, pg. 9). Table 4 provides the four objectives on which both ACI and CIP are based.

Table 4
Incentive Objectives

Objective	Weight
Overall Customer Satisfaction	20%
Power Distribution Quality and Reliability	20%
Generation Plant Availability	30%
Financial Strength	30%

PGE's ability to meet each of these goals, coupled with the weighting above, is used to determine the incentive pool for participants.

Q. How do the four objectives benefit customers?

A. We described in detail the four customer-focused objectives in our direct testimony (PGE Exhibit 800, Section III). Briefly, these objectives provide the following direct benefits to customers:

- Overall Customer Satisfaction: Customer satisfaction drives our good business practices through our understanding and responding to customer needs and desires.
- Power Distribution Quality and Reliability: PGE works to provide high-quality and reliable power to customers, resulting in fewer outages and shorter outage durations.
- Generation Plant Availability: PGE works to maintain a stable platform of resources to provide power for customers. Plant availability influences power cost through forced outage rates. As a result, power costs are less than they would be otherwise.
- Financial strength: Consistent, solid financial results reduce customer prices through greater access to the capital markets and lower borrowing costs, and thus lower cost of capital. Solid financial performance also enables PGE to invest more funds into its transmission, distribution and generation, to provide a better product for customers.

Q. How do PGE's Non-Officer ACI and CIP align with the four objectives?

A. Non-Officer ACI awards are dependent on the size of the funding pool, which is based entirely on PGE's achievement of the four objectives described above. Individual awards are also based, in part, on employees achieving their scorecard goals (key initiatives in their work unit which support PGE's objectives). This individual contribution is rated on a scale of 1 to 5 and then used as a factor in determining the individual's payout from that pool.

CIP awards, like Non-Officer ACI, are dependent on the funding pool and PGE's achievement of the four objectives. CIP awards are also based on employees achieving their annual scorecard goals, many of which directly benefit PGE's customers.

Q. Are Notable Achievement Awards directly tied to financial performance or profitability objectives?

A. No. As we discussed in our direct testimony (PGE Exhibit 800, Section III), Notables are awarded to employees on a case-by-case basis, based on manager/supervisor recommendations[1]. Notables reward employees for performance that is above and beyond normal contributions, such as an extraordinary effort to complete a major project. The ability for PGE to supply recognition and reward immediately following the individual's contribution is highly motivating to employees. Awards are generally relatively small, usually less than $1,000.

B. ICNU-CUB

Q. Does ICNU-CUB provide support for their proposed incentive adjustments?

A. No. With the exception of the Stock Incentive Plan (SIP), ICNU-CUB provides no support for their recommendations.

Q. How has ICNU-CUB characterized the purpose and impact of the SIP?

[1] Participants in the ACI plan are not eligible to receive Notables.

A. ICNU-CUB asserts that by making employees shareholders, their primary motivation is then to increase PGE's stock price (ICNU-CUB Exhibit 100, pg. 13, lines 12-14). ICNU-CUB's implication is that PGE employees who participate in this SIP shift their focus away from customer benefits and towards PGE's stock price.

Q. Is ICNU-CUB's characterization of the SIP accurate?

A. No. ICNU-CUB has mischaracterized the purpose and impact of PGE's SIP. As we noted in our direct testimony (PGE Exhibit 800, Section III), the Commission approved PGE's stock issuance associated with this plan and accurately summarized its goals: "The Plan is part of the Company's overall compensation package and is intended to provide incentives to <u>attract, retain, and motivate</u> officers, directors, and key employees of the Company" (Order No. 06-356, p.1) (*emphasis added*).

Q. How does the SIP work?

A. Awards are earned and paid out over a period of several years, which helps retain essential personnel. The awards are shares of restricted stock. The number of shares is based on the pre-determined dollar amount of the award and the stock price at the time of each grant. The dollar amount of the award and the period over which it is earned incents participants to continue to work at PGE and to make PGE a better performing company.

Furthermore, unlike stock options, restricted stock awards are not solely based on increasing stock price. The value of the stock grant is based on market compensation. The ultimate value of the grant is dependent on the achievement of preset goals. The value of past grants is based on the achievement of the four objectives: customer satisfaction, power quality and reliability, generation plant availability and financial strength. The 2008 grant is based on being efficient, earning our authorized return on equity, and managing asset growth (e.g. Biglow Canyon Phases 2 and 3, Advanced Metering Infrastructure, etc.). Thus, participants' focus is on these objectives rather than purely PGE's stock price. There is an indirect connection in that a company's viability in the market place (and thus its stock price) is invariably linked with meeting customers' needs.

C. Appropriate Standards

Q. Has the Commission provided useful guidance regarding incentives and the appropriate standard for their inclusion in rates?

A. Yes. OPUC Order No. 97-171, p.74, states "Staff concludes that the performance goals under USWC's management incentive plans were designed to benefit shareholders but were not in the ratepayers' interest." Later in that same order, the Commission indicates that the incentives in question would be disallowed based "…on the purpose for which the bonuses were awarded" (p.76).

Having made this disallowance, the Commission went on to describe what incentives could be included in future rate cases: "If in a future rate case USWC submits employee incentive plans with goals that would benefit both ratepayers and shareholders, we will include those expenditures in revenue requirement" (p.76). We believe PGE's incentive plans meet these criteria.

Q. Do PGE's incentives provide customer benefits?

A. Yes. PGE's incentive programs benefit both customers and shareholders because they allow PGE to attract, retain, and motivate qualified employees and therefore should be included in our 2009 revenue requirement.

Q. Are PGE's incentive costs above market?

A. No. On the contrary, as we discussed in PGE Exhibit 800 and demonstrated in associated work papers, PGE's incentive package is slightly below market, but at requested levels should be sufficient for PGE to attract, retain and motivate qualified employees.

Q. Is it reasonable to expect PGE to compete for, and succeed in hiring, qualified individuals with a total compensation package significantly below market, as it would be if Staff's or ICNU-CUB's recommendations were to be followed?

A. No. PGE needs to pay competitive compensation, including incentives, if we are to hire qualified individuals in a competitive labor market and continue to provide quality service to customers.

Q. In summary, what is PGE's position on incentives?

A. PGE's incentive programs (pay-at-risk) are part of a total compensation package designed to achieve PGE's goal of attracting and retaining qualified employees while rewarding employees for performance. PGE's incentives are already below market and any disallowance would only serve to widen this competitive disadvantage.

Furthermore, the adjustments made by Staff and ICNU-CUB are not supported and do not fully consider PGE's alignment of incentives to focus on goals that deliver customer benefits.

V. Medical and Dental

Q. Please describe Staff's proposed adjustment to Medical and Dental benefits.

A. Staff proposes to remove approximately $1.3 million based on three adjustments (Staff Exhibit 300, pgs. 3-4). First, Staff applies an 8.5% escalation rate to PGE's 2007 union expense and makes an adjustment for the duration of the existing union contract. Second, Staff adjusts PGE's non-union employer/employee cost sharing allocation from 85/15 to 84/16[2]. Third, Staff removes 1.79% of the adjusted medical and dental expense total to account for non-utility.

Q. Is Staff's methodology for the calculation of union medical and dental benefit costs correct?

A. No. Staff incorrectly used a beginning 2007 base for medical and dental benefit costs. They used an estimate from PGE's Response to OPUC Data Request No. 256. However, this response was solely based on cash payments (premiums), as requested by Staff, for medical and dental benefit costs. Staff should have used the amount PGE booked in 2007 as expense.

Q. What is the correct methodology?

A. As we mentioned above, Staff should have used the amount that PGE booked in 2007 as an expense, or $1,199,155 for union retirees and $9,235,367 for active union employees. Staff should have considered these costs separately. First, the cost for union retirees is forecasted by Towers Perrin and is expected to decrease due to an expectation that an enhanced union post-retirement benefit, provided in the most recent main bargaining unit contract, will not be renewed. The resulting cost, or $814,000, is what was originally included in the 2009

[2] PGE's data responses to parties regarding the cost sharing allocation should have indicated that PGE was already budgeting at 84/16. Please refer to Confidential PGE Exhibit 1504.

test year. Second, active union medical and dental costs are a negotiated benefit and are managed by a Taft Hartley Trust. We anticipate that these costs will increase at a rate similar to that of non-union medical and dental benefit costs, or approximately 10% annually. The resulting cost, or $11,259,900, is what was originally included in the 2009 test year.

Q. Staff proposed an 84/16 non-union cost sharing allocation for medical and dental benefits. Did Staff apply this ratio correctly?

A. No. Staff applied the ratio to program premium costs found in PGE's Response to OPUC Data Request No. 300 (PGE Exhibit 1503), which included both active and non-active PGE employees. However, this ratio should only be applied to the active non-union portion of PGE's benefits cost of $17,595,181 (employer share only). PGE's costs to non-union retirees is a fixed cost and not subject to an employer/employee split.

Q. Is it appropriate to adjust PGE's non-union cost sharing allocation to 84/16 as Staff proposes (Staff Exhibit 300, pg. 4)?

A. No. While PGE <u>targets</u> an 85/15 cost sharing allocation, PGE's forecast for the 2009 test year already uses an 84/16 cost sharing allocation. Thus, Staff's proposed adjustment has already been made and no further adjustment is necessary. See Confidential PGE Exhibit 1504.

Q. Staff attempted to adjust for non-utility employee's benefits. Should they have done so?

A. No. PGE's filed revenue requirement includes only utility employee medical and dental costs. That is, PGE already allocated non-utility employee medical and dental costs below the line. Staff's recommendation to apply a non-utility allocation percentage is thus inappropriate.

Q. Has PGE demonstrated its efforts to control health plan costs?

A. Yes. As we discussed in our direct testimony (PGE Exhibit 800, Section IV), the 2007 Towers Perrin Health Care 360 Performance Study found that PGE has lower overall health plan costs than the energy/utilities industry benchmark. PGE is able to control its health plan costs by doing the following:

- Using an outside consulting firm with broad and in-depth knowledge of the industry to negotiate health and welfare renewals.
- Selecting providers with proven records of controlling costs. For example, one of our providers, Kaiser, mitigates its costs through health care information technology, the promotion and practice of preventive care, and effective management of prescribing practices and pharmacy utilization.
- Providing employees with "flex" dollars to pay for their company-sponsored benefits, allows them to choose those benefits that best meet their needs. Those seeking to control their own costs will use the flex dollars to help pay for lower cost plans such as Kaiser and the Providence High Deductible Plan, which also lowers PGE's overall health costs since flex dollars are based on a weighted average of employees' medical choices.
- Committing to improving the health of employees through its wellness program - Energy for Life. This program increases health awareness and provides opportunities to make healthy lifestyle changes. For example, PGE offers an annual on-site health screening to test for cholesterol, blood pressure, body mass

index and to check for early signs of heart disease and diabetes. Early detection of a pending health condition enables an employee to take action and can dramatically reduce health care costs and improve an employee's future quality of life. Other wellness programs include tobacco cessation, weight control, exercise programs and organized group activities to encourage employees to stay active and increase fitness.

- Employing two nurses who provide counseling and referral services to employees experiencing health-related problems. They answer health questions and assist employees in carrying out physician's advice or recommended treatment, which is crucial to keep certain medical conditions and the resulting costs from escalating.

Q. How are the benefits that PGE provides to its employees valued relative to the market?

A. PGE's benefits have a value that is slightly below average. Benefits are surveyed under a study called 'BENVAL,' which is conducted by Towers Perrin, a national compensation and benefits consulting firm. The analysis compares the value of each benefit to the employee as well as the overall value of the benefits program. The results of the 2007 BENVAL indicate that the value of PGE's medical and dental benefits contribution is 8.9% below the average. Staff's proposals would only serve to lower the value of PGE's plans, causing attracting and retaining qualified employees to be increasingly difficult.

Q. In summary, why should the Commission reject Staff's remaining proposed adjustments to medical and dental benefits?

A. PGE has lower health plan costs than the energy/utilities industry benchmark. Additionally, the medical and dental benefits that PGE provides have a value that is slightly below average. To reduce the amount of Union benefit, adjust the cost sharing allocation, or adjust for non-utility expense when such an adjustment is uncalled for, would only serve to further devalue PGE's benefits package and total compensation package and make it harder for PGE to attract and retain qualified employees in a competitive market.

VI. Other Benefits

A. Miscellaneous Benefits

Q. Please compare PGE's and Staff's positions on other benefits.

A. The difference is fairly small given the overall compensation revenue requirement. Nevertheless, Staff proposes to remove approximately 36% of these benefits. Table 5 outlines PGE's and Staff's positions.

Table 5
Summary of Misc. Benefits

Expense	**PGE Update**	**Staff**	**Staff Proposed Adjustments**
Occupational Health	$253,360	$224,434	($28,926)
Ergonomics and IAM	$75,297	$34,251	($41,046)
Occupational Fitness	$58,620	$47,976	($10,644)
Recreation Program	$25,825	$0	($25,825)
Health Club Partial Reimbursement	$100,000	$65,000	($35,000)
Commuter Program	$25,101	$12,550	($12,551)
Service Awards	$225,000	$112,500	($112,500)
Retiree Activities	$13,200	$0	($13,200)
Executive Financial Planning	$0	$0	$0
Other	$0	$0	$0
Total	**$776,403**	**$496,711**	**$279,692**

Q. Are Staff's adjustments to other benefit expenses reasonable?

A. No, for several reasons, as we discuss below:

- Occupational Health – Participation in PGE's wellness programs, including health screens, increased 46% between 2006 and 2008, which increased the cost. This trend is likely to continue. These programs should be supported because multiple studies show that the return on investment in wellness and occupational health programs can be as much as 300%[3]. Early identification of health risk factors and diseases, coupled with strong disease management, health coaching and programs

[3] Source: April 2006 *Forbes.com* article referring to Wellness Council of America study.

to address these trends, are likely to significantly reduce medical costs, increase productivity, and reduce absenteeism, all of which will reduce customer costs in the future. Therefore, Staff's adjustment is short-sighted and should not be adopted.

- Health Club Partial Reimbursement – PGE offers programs such as health club reimbursement and wellness reimbursements at low cost levels primarily because these programs encourage employees to reduce high risk health factors through a variety of traditional and non-traditional activities based on employee preferences. These programs are low cost (maximum of $150 per year per employee) and encourage employees to lead a healthier lifestyle, which is expected to lead to increased productivity and lower long-term benefit costs. Therefore, Staff's adjustment here is also short-sighted and should be rejected.
- Integrated Absence Management (IAM) – PGE's IAM program, launched in October 2007, is designed to centralize absence information. One goal of this effort is to decrease short-term and long-term costs through increased efficiency in managing absences, which is expected to reduce the number of days employees are off work. It assists managers in creating limited duty positions. PGE is currently in the process of developing key metrics to monitor the program's direct and indirect benefits, and expects to have limited monitoring in place in 2008. Staff's adjustment in this area would be counter-productive.
- Occupational Fitness – Proper pre-employment testing is essential to hiring employees qualified to provide safe and reliable service to customers. While it is true that drug testing is not a new type of cost, PGE is experiencing higher costs

for drug and other pre-employment testing due to workforce turnover. From January through June 2008, PGE hired 158 full-time and temporary external employees and another 156 positions were filled internally. This is an increase of 8 external hirings and 31 changes in position internally as compared to the same period in 2007.

Table 6 below demonstrates the increases in the number of tests performed since 2005. The sharp increase in the number of tests between 2007 and 2008 is primarily due to an increase in the number of retirements requiring replacement hiring, as well as the transfer of meter readers into other positions at PGE in anticipation of AMI deployment. Many of these tests are dictated by Federal and State law. For example, meter readers transferring into a Groundman's job require a commercial driver's license, a physical, a physical capacity test, and random drug and alcohol testing. Adjustments to these costs would send the wrong message to other regulators and employees.

Table 6
Employment Testing

Program	2005	2006	2007	2008*	% Increase (2007 - 2008)	CAGR** (2005 - 2008)
Pre-employment drug tests	279	321	345	422	22%	15%
Pre-employment physicals	94	104	100	206	106%	30%
Apprenticeship physicals	12	21	26	36	38%	44%
Physical capacity tests	30	58	65	76	17%	36%

* Six months of actuals annualized.
** Compounded annual growth rate.

- <u>Recreation Program</u> – PGE's recreation program engages employees outside of work. These activities promote team-building, healthier lifestyle choices, and a sense of loyalty to PGE. The results are better retention and healthier employees, who are more engaged and use fewer medical services. This is a low-cost, long-standing program that has seen minimal increases over the years.

- Commuter Program – PGE encourages the use of alternative forms of transportation by supporting transportation fairs. This program also covers the cost of administration of PGE's Commuter Check Direct (CCD) program which offers pre-tax deductions for public transit expenses.

  In 1996, the Department of Environmental Quality (DEQ) established the Employer Commute Options Rule to reduce employee auto trips by implementing programs that encourage employees to use alternatives to driving alone. To be in compliance, PGE is required to survey employees to find out how they are getting to work, and make a good faith effort to reduce single occupancy trips. The DEQ requires that PGE provide incentives for employees to use alternative commute options, and the CCD program is a relatively inexpensive option compared to free or subsidized mass transit passes.

- Service Awards – Providing recognition to an employee for long time service through service awards reinforces retention goals and helps to minimize the cost of turnover. For example, the cost of training a new groundman is approximately $3,000, and a new customer service representative is approximately $9,800. Customers benefit if these costs are kept to a minimum. Additionally, service awards are commonly provided by many companies and government agencies.

- Retiree Association and Retiree Luncheon – Providing funding for a retiree association and sponsoring the retiree luncheon provide opportunities for past and present employees to network with one another and share information and ideas.

This benefits customers by promoting continuity through consultation on historical issues at PGE. This helps to ensure that valuable knowledge is not lost.

- Executive Financial Planning – PGE has chosen to remove this benefit from the 2009 test year.

Q. In summary, why should the Commission allow PGE's costs for other benefits and reject Staff's proposed adjustments?

A. PGE's other benefits are a critical part of the overall benefits package to attract and retain qualified employees. By supporting healthy lifestyle choices, rewarding years of service, performing appropriate testing and managing absences, PGE is able to minimize increases in the cost of healthcare for its employees, minimize the cost of turnover and maximize productivity. Benefits such as these are a necessary part of a healthy and cost efficient organization.

B. Directors' Fees and Officer Vehicle Plan

Q. Will you be addressing Directors' Fees and the Officer Vehicle Plan in this testimony?

A. No. As discussed in the introduction, PGE has chosen to remove the officer vehicle plan and certain components of Directors' fees from the test year and therefore we do not address them in this testimony.

C. Employee Discount

Q. Please describe the objections of ICNU-CUB, CUB and CAPO regarding the Employee Discount.

A. Parties' objections can be summarized as follows: 1) the employee discount is discriminatory; 2) it should have been a part of PGE's cost of service study; 3) the cost of the plan is hidden; 4) it is not a reasonable and necessary cost for providing service to customers; 5) the discount partially insulates PGE employees from the impacts of PGE's rate increases; 6) it does not promote conservation; 7) there is an income imbalance between customers providing the discount and the employees receiving it; 8) the discount requires customers to subsidize unregulated activities; 9) discounts for regulated utilities are different than discounts to employees working for an 'economically-regulated' company, and 10) shareholders should pay for the discount.

Q. Is PGE's employee discount discriminatory as ICNU-CUB and CUB suggest?

A. No. Similar to many of PGE's benefits, the employee discount is available for PGE's employees based on individual choice by the employee. For example, PGE offers employees partial reimbursement for health club memberships. The employee's choice to join or not to join a health club dictates whether they receive the benefit. Similarly, if an employee chooses to live outside of PGE's service territory, then the employee chooses not to avail him/herself of this benefit. This is not discrimination by the utility.

Q. Does ICNU-CUB support its argument that the employee discount should be included in PGE's cost of service study as a separate customer class (ICNU-CUB Exhibit 100, pg. 14)?

A. No. The employee discount is a revenue requirement adjustment so it is unnecessary to include it as a separate customer class in PGE's cost of service study.

Q. Has the amount of the employee discount been transparent in this and past rate cases?

A. Yes. PGE has identified the cost of the employee discount in UE-197 (PGE Exhibit 1204), UE-188 (PGE Exhibit 403), UE-180 (PGE Exhibit 1303), and UE-115 (PGE Exhibit 1609).

Q. What is the cost of the employee discount?

A. The cost of the employee discount in 2009 identified in PGE's filing is $885,846. Table 7 is the actual 2007 employee discount cost with an estimate of the breakdown by active and non-active (retiree and surviving spouse) employees.

Table 7
Estimated Active & Non-Active
Employee Discount Participants

	2007 Actual	
Active	$518,616	67.6%
Non-active	$248,790	32.4%
Total	**$767,406**	**100%**

Q. Why is the employee discount a reasonable and necessary cost of providing service to customers?

A. The employee discount has been an important part of PGE's total compensation package for over 40 years. With other utilities in the Pacific Northwest providing an employee discount (ex: PacifiCorp, NW Natural, etc.) and vying for the same qualified individuals, applicants and employees expect PGE to provide a similar benefit.

Q. Are employee discounts prevalent in other industries?

A. Yes. Numerous other industries (apparel, telecom, automotive, etc.) routinely provide their employees with a discount on their goods or services. Providing this type of discount is relatively low cost compared to other means of compensation.

Q. Can an equivalent be provided?

A. Yes. PGE could replace the discount with an equivalent benefit, but it would be more expensive for customers.

Q. What would be the cost of replacing the employee discount with equivalent compensation such as wages and salaries?

A. Using the 2007 allocation of 67.6% and applying this ratio to the $885,846 cost in 2009, the cost for active employees is $598,832. If, for instance, PGE were to replace the employee discount with additional wages and salaries, we would need to gross-up that additional amount for Federal tax (25%), State tax (9%), Social Security (6.2%) and Medicare (1.45%). The result would be:

Table 8
Active Employee Discount Gross-up

	2009
Employee Discount	$598,832
divided by	
Gross up factor	58.35%
results in	
Wages and salaries	**$1,026,276**

This analysis does not include those employees currently not receiving the employee discount, nor does it account for incremental labor-related costs such as incentives, payroll taxes, etc., which would further increase the cost. Providing PGE employees with an equivalent level of compensation to that of the employee discount would be more costly.

Q. Would anyone be harmed if PGE eliminated the employee discount and provided employees with an equivalent amount of compensation?

A. Yes. As shown in PGE Exhibit 1505, ceasing to provide an employee discount would result in a loss of benefit to an estimated 710 retirees who have already provided service to customers and 193 surviving spouses.

Q. Is there any legal requirement that PGE replace this compensation?

A. Yes. For our union employees, removal of this benefit can only be done through collective bargaining, which is likely to require some type of alternative compensation.

Q. Does the employee discount insulate PGE employees from rate increases or reduce conservation by employee receiving the discount?

A. No. The employee discount does not insulate PGE employees from rate increases. A 5% increase to one of PGE's residential customers is also a 5% increase to PGE's employees, regardless of whether or not they receive the discount. While the absolute dollar impact may be less, the actual impact depends entirely on the consumption habits of both customers and employees, and both are motivated to adjust their habits through conservation or other means based on the increase in their individual costs.

Q. CUB and CAPO suggest that the employee discount "represents a transfer of money from PGE customers to employees many of whom already earn more in wages" (CAPO-OECA Exhibit 100, pg. 3) and that this "makes little economic sense" (CUB Exhibit 100, pg. 43). Are these points valid?

A. No. It is necessary that PGE employ highly-skilled, highly-experienced, and in many cases highly specialized employees for our complex business. These positions are paid market-based wages and salaries. Competing for these employees, especially in tight labor markets, requires that PGE's total compensation, including benefits, be at market for those jobs. Gearing total compensation to the level of the average wage-earner in Oregon would not allow PGE to attract and retain the necessary skilled employees to provide the safe and reliable service that customers require.

Q. Does PGE provide the employee discount to employees performing activities that are not funded through rates?

A. As discussed in PGE's Response to CUB Data Request No. 080 and 082 (PGE Exhibits 1506 and 1507), PGE does not distinguish between so-called above and below the line activities for purposes of the employee discount. However, based on operations payroll totals for 2009, only 1.2% of PGE's operations are below the line. Using this percentage, only approximately $6,200 of the requested 2009 employee discount funds would be provided to employees performing below the line activities.

Q. CUB states that "a non-regulated company…charges prices that are generally set by the market. This means that…having or not having an employee discount will have no impact on prices" (CUB Exhibit 100, pg. 44). Is this economic analysis based on relevant criteria?

A. No. These statements are non-sequitur. Regulation is based on the prudently incurred cost of service. By CUB's argument, none of PGE's costs should be allowed in rates because in a non-regulated business "prices are set by the market." In a regulated company, all aspects of employee compensation have an effect on prices, but that doesn't mean one should eliminate as much compensation as possible. Compensation must be aimed at attracting, retaining and motivating qualified employees to work hard to provide safe, reliable service to customers.

Q. Should shareholders pay for the employee discount?

A. The employee discount is an important part of PGE's total compensation package, and is a relatively inexpensive benefit. Customers benefit both directly and indirectly from PGE being able to compete effectively in the market for highly skilled and experienced workers. Thus, it is reasonable for PGE to expect to include the employee discount component of compensation in its rates.

Q. Are there any other items mentioned by any of the parties that should be addressed?

A. Yes. CAPO calculates a ratio comparing the employee discount to "total Administrative and General expenses" (CAPO-OECA Exhibit 100, pg. 2). However, CAPO uses an Administrative and General expense figure from PGE testimony (PGE Exhibit 800, pg. 6,

Table 3) that applies only to Total Wages and Salaries. Table 9 demonstrates the correct calculation:

Table 9
Employee Discount as a Percentage of Total A&G

	2009
Employee Discount	$885,846
divided by	
Total A&G (PGE/200, Tooman – Tinker/4)	$120,522,000
results in	
Percent of Total A&G	**0.7%**

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
1501	Forecast Pay Increases for 2009. Source: Economic Research Institute
1502C	**Copy of PGE's Response to ICNU Data Request No. 265**
1503	Copy of PGE's Response to OPUC Data Request No. 300
1504C	**2009 Flex Dollar Allocation**
1505	Copy of PGE's Response to CUB Data Request No. 081
1506	Copy of PGE's Response to CUB Data Request No. 080
1507	Copy of PGE's Response to CUB Data Request No. 082

Forecast Pay Increases for 2009

	Budgeted Last Year	Projected Next Year
All employees	4.1%	4.0%
Executive	4.4%	4.3%
Middle management	4.4%	4.3%
Professional	4.4%	4.3%
Technician	4.4%	4.3%
General/nonunion	4.4%	4.3%

(Source: ERI Economic Research Institute)

May 19, 2008

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to OPUC Data Request
Dated May 1, 2008
Question No. 300

Request:

Please identify the 2007 actual and forecasted 2009 weighted average Health and Dental program premiums, as discussed in UE 197/PGE 800, Barnett – Bell/14, without factoring in any employer/employee sharing. Please also provide a breakdown of the weighted average Health and Dental program premiums between union and non-union.

Response:

There are seven separate coverage options under the Health and Dental active non-union plans. 1,785 employees were eligible for this coverage in June 2007. Total premium costs in 2007 were $19,041,514 for employer and employee shares. Using the 1,785 employee count, the 2007 total average premium cost for this group was approximately $10,668. PGE's forecasted contribution to these coverage options in 2009 is $19,042,599 (employer only share). PGE targets an 85/15 employer/employee sharing of health and dental premium costs; consequently, PGE's 2009 total program premium costs would be approximately $22,403,058 (employer and employee share).

For employees in the main bargaining unit, PGE only knows the amount it pays and is not able to calculate a weighted average cost. PGE contributes a fixed amount per hour for bargaining employees to an Employee Beneficial Association Trust as described in PGE's response to OPUC Data Request No. 255. PGE's total contribution for 2007 active and retiree health and welfare costs was $10,056,070 (see OPUC Data Request No. 256). These costs are broken down between active ($9,244,620) and retiree ($811,450) costs. PGE had 843 active union and 528 retiree union employees as of Jun 30, 2007. Using these employee counts, PGE's total weighted average contribution to active union employees was $10,966 and to union retirees was $1,537 per employee

July 10, 2008

TO: Lowrey Brown
Citizens' Utility Board

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to CUB Data Request
Dated June 25, 2008
Question No. 081

Request:

Please provide a table – with a row for each category, 79(a) through 79(g) – showing the number of individuals receiving the employee discount in that category and the forecast amount, in dollars, for each category included in the 2009 test year.

Response:

The table below provides, by category, an estimate of the number of individuals receiving the employee discount in December 2007. PGE does not forecast the employee discount by category. PGE's estimate for the total 2009 employee discount is approximately $885,000 (refer to PGE/1204/Kuns-Cody/2).

		# of individuals
a.	Officers	0 (not eligible)
b.	Directors	0 (not eligible)
c.	Non-union	1,166
d.	Union	452
e.	Spouse	193
f.	Retiree	710
g.	Family	See category (e)

Regarding categories (a) and (b), Officers and Directors are not eligible for the employee discount. Regarding category (g), only a surviving spouse of a deceased employee (either employed or retired) is eligible.

July 2, 2008

TO: Lowrey Brown
Citizens' Utility Board

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to CUB Data Request
Dated June 25, 2008
Question No. 080

Request:

Are PGE employees who perform unregulated activities eligible for the employee discount? If so, is the cost of this employee discount included in the UE 197 test year?

Response:

Those PGE employees meeting the eligibility requirements as defined in PGE's Response to CUB Data Request No. 079, Attachment 079-A, are eligible for the employee discount. This includes employees who may be conducting unregulated activities.

Yes, the cost of the employee discount is included in the UE 197 test year. As described in PGE's Response to OPUC Data Request No. 377, PGE's regulated operations payroll totals $222.5 million for the 2009 test year (as provided in work papers to PGE Exhibit 800). PGE's total operations payroll forecast for 2009 is $225.2 million. Thus, on this basis, PGE non-regulated operations are 1.2% of total operations.

July 2, 2008

TO: Lowrey Brown
Citizens' Utility Board

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to CUB Data Request
Dated June 25, 2008
Question No. 082

Request:

If applicable, please provide the same information as in data request 81, but only for those employees who perform unregulated activities.

Response:

Refer to PGE's Response to CUB Data Request No. 080. PGE does not distinguish between regulated and unregulated activities for purposes of the employee discount.

Table of Contents

I. Introduction

Q. What is your name and position with PGE?

A. My name is Stephen Hawke. I am Senior Vice President of Customer Service and Delivery. My qualifications appear in Section IV of PGE Exhibit 600.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to issues discussed by other parties' regarding transmission and distribution O&M costs.

Q. How is your testimony organized?

A. In Section II, I discuss other proposed adjustments to transmission and distribution O&M costs. Specifically, I rebut other parties' proposed adjustments for professional services, the porcelain insulator program, locating expenses, arc-flash mitigation, EMS development costs, tree trimming, FITNES, and miscellaneous O&M costs. In Section III, I discuss the basis for the increase in FTEs in the transmission and distribution areas. In Section IV, I rebut proposed adjustments to test year helicopter costs. Finally, in Section V, I discuss Distribution Services.

II. Other Adjustments

A. Professional Services

Q. Does PGE agree with OPUC Staff's adjustment allowing $250,000 for PGE's membership in the Northern Tier Transmission Group?

A. Yes. Since submitting our response to OPUC Staff Data Request No. 084, PGE has learned that our membership cost in 2009 will be approximately $200,000, as originally estimated in our initial filing. The remaining $50,000 for professional services is needed to prepare an economic study, as part of our Attachment K obligations on file with FERC.

Q. Why is an economic study necessary and what is its purpose?

A. We have an obligation under PGE's Open Access Transmission Tariff Attachment K to complete an economic (congestion) study on an annual basis as part of our local transmission planning. The economic study's purpose is to test the congestion of the transmission system in PGE's territory and determine if there are economic impacts due to congestion on the system. The study then helps facilitate ways to resolve constraints on the system and relieve economic impacts.

Q. Is PGE making any other adjustments to its Transmission O&M costs?

A. Yes. PGE is proposing two additional adjustments to Transmission O&M. The first adjustment removes $100,000 related to Unscheduled Flow Mitigation as identified in OPUC Staff's adjustment S10. PGE agrees these costs will not be incurred in the 2009 test year. The second adjustment is to remove our request for 7.5 FTEs associated with FERC Order 890-A. PGE agreed to remove these costs if we received an exemption from the FERC order, which FERC allowed by order on May 8, 2008. This represents approximately $776,000.

B. Porcelain Insulators

Q. What is PGE proposing for the Porcelain Insulator Project for 2009?

A. We are proposing approximately $684,000 in the 2009 forecast.

Q. How does this compare to prior years spending on this project?

A. In 2006 and 2007, PGE spent $791,894 and $525,789.

Q. What mix of resources do you use to perform the work?

A. PGE uses a combination of PGE labor and contract labor. The historical numbers reflect the total costs for both PGE and contract labor. However, PGE's 2009 forecast reflects only contract labor.

Q. What is the basis for OPUC Staff's adjustment?

A. Staff focused only on the contract labor component for this project by escalating 2007 non-labor costs to 2009. This is inappropriate because it isn't the <u>mix</u> of resources that is relevant, but rather, the <u>total</u> <u>costs</u> to accomplish the work in each given year.

Q. If OPUC Staff's adjustment was implemented, what is the impact to the Porcelain Insulator Project?

A. It would significantly extend the length of time needed to complete this project, which PGE does not believe is appropriate, given the safety and reliability concerns.

C. Locating Expenses

Q. Please summarize OPUC Staff's recommended adjustment to 2009 test year locating costs.

A. Staff states that "PGE submitted a UE 197 increase in locating costs due to higher contract costs of $688,548. Staff recommends an increase in locating costs due to higher contract costs of $417,413" (Staff/300, Ball-Dougherty/18, Lines 4-6). Staff's recommendation results in a decrease in test year locating costs of approximately $270,000.

Q. Do you agree with this approach?

A. No, for two reasons. First, the amount requested in PGE's initial filing for locating costs was developed through careful consideration and analysis of locating work that is necessary in 2009. Staff ignores this information. Second, Staff's approach is formulaic and based on assumptions that are not valid for the 2009 test year.

Q. What factors did you consider in developing the 2009 locating cost forecast?

A. As noted in my direct testimony, we considered service territory growth, road construction and widening, and Verizon's activities (PGE/600, Hawke/14). An additional factor is increased customer awareness through the "811—call before you dig" announcements. This has increased the number of locating requests, thereby increasing costs. These are factors that have increased over time and we expect to continue through 2009 and beyond.

Q. Please summarize why any decrease to the amount requested for locating costs in PGE's initial filing would be inappropriate?

A. PGE's locate function is demand driven and a service PGE is required by law to provide. Our request is based on the forecasted costs required in 2009 to meet legal requirements. Underfunding legal requirements would unfairly penalize shareholders.

Q. You disagree with Staff's formulaic approach in general. Do you also disagree with Staff's implementation of such an approach?

A. Yes.

Q. What are the problems with Staff's specific formulaic approach?

A. Staff's approach has two major problems. First, PGE submitted a test year increase in contract locating costs of approximately $480,000, not $688,548. Staff's error is based on an incomplete measure of 2007 costs that only considered the non-labor component of locating costs; thus Staff's calculation of approximately $1.3 million is too low. Second, Staff's recommended figure does not consider the increased number of locate requests in 2009 compared to 2007.

Q. Have you reevaluated Staff's approach, using corrected 2007 cost figures and an estimate of 2009 locates?

A. Yes. This reevaluation is a work paper included in this rebuttal testimony filing.

Q. Does the corrected implementation of Staff's formulaic approach support the amount requested in PGE's initial filing?

A. Yes. Correct implementation of the formulaic approach would result in an <u>increase</u> to PGE's initial filing request of approximately $160,000.

Q. Please summarize why PGE's initial filing request for locating costs should not be decreased.

A. We developed our test year request based on increased needs and work that will need to be done in 2009.

D. Arc-Flash Mitigation

Q. Is OPUC Staff's proposal to spread the 2009 costs for Arc-Flash Mitigation ($360,000) over four years adequate?

A. No. Arc-flash mitigation will become a requirement of OSHA in 2009. The $360,000 is the initial cost to purchase personal protective equipment (PPE) for all affected employees in

2009 in order to comply with the new requirement. Staff's proposal would only be enough to protect a quarter of the affected employees in 2009.

Q. What will the ongoing costs of Arc-Flash Mitigation be?

A. Based on discussions with a peer utility that has used PPE for a number of years, PGE believes that the ongoing costs for arc-flash mitigation will be approximately $55,000 a year due to turnover and replacement of worn PPE.

Q. What method does PGE propose for recovery of ongoing costs for Arc-Flash Mitigation?

A. PGE proposes that in years subsequent to this rate case, we will defer the difference between the $360,000 forecast and actual expenditures. This deferral would end at the next general rate case and be held in a balancing account for future refund to customers.

E. EMS Development Costs

Q. Does OPUC Staff recommend a reduction in the test year revenue requirement related to Energy Management System (EMS) development costs?

A. Yes. Staff recommends a reduction of approximately $174,000 because it alleges the costs are "one time" in nature (Staff/300, Ball-Dougherty/19, Line 16).

Q. Is this reduction appropriate?

A. No. As discussed in PGE Exhibit 1300, Section IV (B), although these might appear to be one-time costs, they are performed in the normal course of business. The EMS development costs represent PGE labor that was redeployed to a new IT project upon completion of the EMS project. The new IT project could have been a capital job or O&M, but would have been part of ordinary IT activity. Because PGE's IT activities involve specific areas (e.g., software applications, communication networks, and hardware), particular projects such as

EMS represent distinct but continuous efforts of those areas. This is true for a large portion of PGE's costs that relate to a continuous series of projects that are ordinary and part of normal business. In that sense, Staff's adjustment involves the arbitrary rejection of certain legitimate costs without considering how they fit into the normal level of activity for the respective operations.

F. Tree Trimming

Q. What is OPUC Staff's recommendation for tree trimming expenses in the 2009 test year?

A. Staff recommends a reduction of approximately $1.3 million from the $12.3 million requested in PGE's initial filing.

Q. Is this reduction reasonable?

A. No. We base the $12.3 million requested in PGE's initial filing on work that must be done in 2009 to meet service quality measures (SQMs) that are set by the OPUC. It is not reasonable to underfund activities needed to meet OPUC standards. PGE is willing to discuss SQM changes, but, given current SQMs, we anticipate a cost of $12.3 million for tree trimming in 2009.

Q. Please explain in more detail why the $12.3 million is needed.

A. The full $12.3 million is required to fund the current Vegetation Management Program through 2009. This provides 38 two-person bucket crews, 3 three-person climbing crews, and 12 full-time flagging crews to complete scheduled trimming along approximately 4,500 distribution line miles, at a cost of $2,100 per line mile. It also funds 2 high-lift tree crews and 1 three-person right-of-way crew to perform vegetation maintenance along PGE's roadside and cross-country transmission lines. In addition, the $12.3 million figure includes

2 one-person tree crews that respond to more than 3,400 customer requests per year for assistance with trees near power lines.

Q. What problems would result with funding at the level Staff proposes?

A. Staff recommends a decrease of approximately $1.3 million. One way to reduce costs by $1.3 million would be to not trim more than 600 miles of lines otherwise scheduled for trimming in 2009. This would increase the possibility of tree contacts in violation of OAR 860-024-0016 and increase the likelihood of not meeting required SQMs.

Q. What is the basis for Staff's recommendation of only approximately $11.0 million for tree trimming costs in the test year revenue requirement?

A. Again, Staff used a formulaic approach. Specifically, Staff calculated their estimate by simply multiplying by three a measure of tree trimming costs for the first four months of 2008 ($3.7 million).

Q. Do you agree with Staff's approach as a primary analysis tool?

A. No. The 2009 test year tree trimming-related revenue requirement should be based on the costs of work that must be performed to meet existing SQMs. A formulaic approach should only serve as a check.

Q. Are there specific problems with Staff's approach?

A. Yes. Staff did not escalate its $11.0 million figure to 2009, even though Staff itself mentions the possible use of an 8 percent escalation rate "because PGE's budgeted tree trimming expense has increased an average of 7.97 percent per year for the time period of 2003 to 2007." (Staff/300, Ball-Doughterty/20, Lines 4-6). Also, more recent information is available to calculate a 2008 estimate. Specifically, Asplundh Tree Expert Company, PGE's contractor, performed work billed at approximately $5.7 million during the first six months of 2008, or an annualized figure of $11.4 million.

Q. Does Staff's approach, more appropriately implemented with an $11.4 million estimate for 2008 and 8% escalation, support PGE's request?

A. Yes. The $11.4 million, escalated by 8%, results in a 2009 forecast of $12.3 million, which is the amount of PGE's initial filing request.

Q. Please summarize why PGE's initial filing request for tree trimming costs should not be decreased.

A. The test year request is based on work that will need to be done in 2009 to meet SQMs. Correct implementation of Staff's formulaic approach also supports PGE's requested amount.

G. FITNES

Q. What is OPUC Staff's recommendation concerning FITNES program costs included in PGE's 2009 test year revenue requirement?

A. Staff recommends elimination of the approximately $900,000 increase from 2007 to 2009 that "is due to the early completion of the FITNES program in 2007, which lowered the costs for 2007" (UE 197/PGE/600, Hawke/12, Lines 19-20).

Q. Did this "early completion" primarily affect the underground or the overhead component of the FITNES program?

A. The lower 2007 base costs were primarily associated with the underground program, which is on a four-year cycle.

Q. Staff's recommendation effectively assumes that these "early completion" benefits will occur in the 2009, thereby lowering costs in that year. Is this appropriate?

A. No. We began a new four-year underground cycle in 2008. It is unclear whether there will be any similar benefits at the end of this cycle, but in any case, this would not occur until 2011.

Q. If 2009 expenditures for the underground portion of the FITNES program were reduced to the level proposed by Staff, would PGE be able to meet the Service Quality Measures, which currently require a four-year cycle for underground equipment?

A. No.

Q. Could a change in SQMs for PGE's underground equipment result in significantly lower costs?

A. Yes. Division 024 Rules allow for a 10-year cycle. This is the standard for other electric utilities in Oregon, and the Commission could make this the standard for PGE. Doing so would decrease the 2009 costs of the underground equipment-related portion of PGE's FITNES program by approximately 60% or $900,000. PGE fully supports this change and requests that the Commission find that a 10-year cycle is appropriate and thus also reduce our underground FITNES cost to $600,000 in 2009.

H. Miscellaneous O&M

Q. Does OPUC Staff propose eliminating the cost of a contract forester from the 2009 test year revenue requirement?

A. Yes.

Q. What is Staff's rationale for this decrease?

A. Staff notes that the contract forester works on tree trimming, and claims that PGE has added an FTE for tree trimming, but has not made a corresponding decrease in contract labor. (Staff/300, Ball-Dougherty/21).

Q. Is this correct?

A. No. PGE does make a corresponding decrease in contract labor. We will replace one of two contract foresters currently working in the Vegetation Management program with PGE labor.

Q. What is the second reason that Staff's adjustment is not reasonable?

A. The second reason is that Staff is already proposing an adjustment to PGE's tree trimming costs and they are also proposing to remove all of PGE's incremental FTEs from 2007 to 2009. The additional adjustment for the contract forester would result in double counting.

Q. Do you conclude that the cost of the contract forester should remain in the 2009 test year revenue requirement?

A. Yes.

III. FTEs

Q. Please summarize PGE's request in its initial filing for additional FTEs in the Distribution area.

A. In our initial filing, we requested 32 additional FTEs for 2009. However, we realized that these were difficult to fill positions and therefore included a credit for approximately 20 positions, leaving only 12 new positions for 2009.

Q. Are the 12 FTEs still necessary for 2009?

A. Yes. These additional 12 FTEs are part of the process to develop journeymen linemen. PGE will need to hire these FTEs to begin the process of apprenticeship, which will eventually lead to journeymen. While these new linemen are entry level and apprentices, their productivity as well as that of journeymen linemen training them, will be lower than normal. Consequently, for a while, more than one FTE per position will be required to perform the necessary work.

Q. Why is it important to hire and train these 12 additional FTEs?

A. The process to transition from entry level FTE to journeyman, currently takes approximately five years. With such a lengthy process, a current shortage of skilled line workers, and the retirement of more and more skilled linemen, it is crucial for PGE to focus on hiring and training the next generation of line workers.

IV. Helicopter

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

A. I respond to the Citizens' Utility Board (CUB) regarding the purchase of a new single-turbine engine Eurocopter helicopter to replace PGE's existing twin-turbine engine helicopter, which we purchased in 1980.

Q. Why does PGE plan to purchase a new helicopter?

A. Our existing helicopter is 28 years old and approaching the end of its useful life. It has had reliability issues, and we are concerned about its safety. We have experienced increased maintenance costs, declining availability of spare parts, and increased downtime due to maintenance needs. PGE must inspect transmission lines according to Western States Coordinating Council and North American Electric Reliability Corporation standards. Use of the helicopter is one of the means by which PGE performs these inspections. Our economic and non-economic analyses show that it is better to purchase a helicopter than to outsource one.

Q. CUB believes PGE should outsource helicopter services. Do you agree?

A. No. CUB's analysis is based on incorrect assumptions regarding usage hours and costs. Further, CUB neglects to consider important non-economic factors such as pilot turnover, availability and experience, outsourced aircraft availability, safety, maintenance costs, and parts availability. Finally, CUB fails to recognize the importance of terrain, weather, and topography in the benchmarking analysis.

Q. How is the remainder of the testimony on this issue organized?

A. First, I describe why CUB's assumption that the helicopter will be used only 150 hours per year is incorrect. Second, I have provided a revised economic analysis that shows even if

CUB's erroneous assumption were made, the current decision would still be to purchase the Eurocopter. Third, I describe some of the non-economic factors that make outsourcing helicopter operations more challenging. Finally, I respond to CUB's criticism of PGE's benchmarking efforts.

A. CUB's Assertions Regarding Helicopter Usage are Flawed

Q. You mentioned that CUB has performed an economic analysis regarding outsourcing the helicopter. Can you summarize the analysis?

A. CUB first calculated PGE's average helicopter usage by averaging 2006 and 2007 usage data and then subtracting 10 percent for maintenance flights to arrive at 145 hours per year. CUB used this adjusted average to justify reducing PGE's forecast of helicopter usage from 250 hours to 150 hours. Finally, using its forecast of a "more realistic 150 hours" per year, CUB concluded that outsourcing has a net present value benefit of $1.2 million over 22 years.

Q. Is 2006 and 2007 usage data representative of expected helicopter usage in 2009?

A. No. The usage hours in 2006 and 2007 were significantly lower than expected due to unusual circumstances such as increased maintenance hours of an aging aircraft, atypical pilot hours due to illness, and difficulty in contracting experienced pilots. These events are not representative of the expected operation of the helicopter on a going-forward basis. This was explained in PGE's Response to CUB Data Request No. 091 (provided as PGE Exhibit 1601). For example, in June 2008, our existing helicopter flew approximately 98 hours and we expect to fly a total of 225-250 hours this year, assuming the helicopter does not require unexpected maintenance.

Q. Please describe further how the maintenance of an aged helicopter led to reduced operating hours in 2006 and 2007.

A. PGE is required to perform various routine inspections, maintenance, and if necessary, repairs of our helicopter, based on aircraft time flown, age of parts, and condition of parts. The purpose of the routine activities is to complete scheduled work such as oil changes, lubrication, and identify through inspections the need to replace any parts. During inspections, unforeseen issues can be identified and they must be addressed. As an aircraft ages, these issues are more common and, at times, can lead to unexpected down-time of the helicopter.

Q. Does the declining availability of parts for the aged helicopter also result in less availability?

A. Yes. In August 2007, PGE delivered our helicopter to Cascade Airframe for the annual inspection. The inspection revealed critical and substantial cracks in the structural support of the engine floor and cargo area. The aircraft was grounded until repairs could be made. Unfortunately, parts were not immediately available and had to be manufactured.

Q. Does PGE expect about 250 usage hours for the 2009 test year?

A. Yes. We expect to use the helicopter for 250 hours including infrared inspections in 2009, as we will explain in more detail below. With a new helicopter and pilot, and the increased number of infrared inspections, we expect 2009 usage hours to be up substantially from 2007, with 250 hours being a reasonable estimate of total usage.

Q. Please describe the infrared inspection process, which will lead to additional operational hours in 2009 and beyond?

A. First, an infrared camera is mounted to the front of the helicopter. The helicopter then flies over specified transmission lines and if the camera detects a “hot spot,” it glows. An item that emits heat is a sign of a potential failure. These infrared inspections can help facilitate earlier detection of failing cable elbows and connections as well as overloaded transformers.

Q. What is the benefit of an infrared inspection?

A. The benefit of infrared inspections is that it will lessen the impact of outages due to equipment failure by finding potential trouble spots before the equipment fails and before the damage is visible to the human eye. For example, one infrared inspection revealed that the Grizzly Malin line, which is a 500-kV high-voltage intertie line, was energized from the tower to the ground. We were able to repair the tower without a costly and unexpected outage.

Q. Why can’t inspections be done on the ground?

A. Our transmission lines are located in geographic areas ranging from high density areas to extremely mountainous and high desert terrain. In many areas the terrain and vegetation make it difficult and at times, impossible, to patrol these lines from the ground. Also, some lines are not accessible by ground during colder seasons, because of snow.

Q. How many infrared patrol hours do we expect in the 2009 test year?

A. PGE expects to conduct about 50 hours of infrared inspection in the 2009 test year. We hired a pilot who is becoming more familiar with our environment, so we expect to conduct significantly more infrared patrols than in the past.

B. An Economic Analysis Assuming 150 hours per year Would Still Lead to Purchasing, not Outsourcing

Q. Does outsourcing lead to a NPV benefit of $1.2 million relative to purchase under the assumption of 150 hours of usage per year as CUB asserts?

A. No. CUB's model assumes that all outsourcing costs are variable when they are not. The formula used by CUB is too simplistic and fails to take into consideration the rigidity of the fixed costs involved in outsourcing a helicopter.

Q. Did you perform a revised economic analysis under the assumption that 150 hours is representative of ongoing operations?

A. Yes. Our economic analysis, whether its 150 or 250 hours, shows that the lowest-cost option is to purchase the Eurocopter AS 350B3 helicopter. Summarized below is the net present value of the option to purchase and the two options to outsource at 150 and 250 hours. Confidential PGE Exhibit 1602 shows the economic analysis of the helicopter acquisition and net present value over 22 years in more detail.

PGE Helicopter Economic Summary – Net Present Value Over 22 Years			
	Purchase Eurocopter	Outsource Rogers	Outsource Haverfield
150 hours	$7,521,626	$9,703,346	$11,311,367
250 hours	$8,219,068	$9,703,346	$11,311,367

Q. Please explain why the costs to outsource are the same irrespective of usage hours.

A. Rogers Helicopter and Haverfield Corp. provided an annual outsourced fixed bid, which is based on annual availability of an aircraft and pilot; this is comparable to what we have with our in-house operation. These costs are fixed and do not vary with usage hours as CUB assumed in its analysis. Annual fixed bid costs for Rogers Helicopter were approximately $562,000 plus $203,000 for additional fixed costs (hanger costs, crew per diem, overtime costs, ferry costs, and infrared costs), totaling $765,000. Annual fixed bid costs for Haverfield Corporation were $725,000 plus about $167,857, totaling $892,857. Confidential PGE Exhibit 1603 is Haverfield Corporation pricing estimate and confidential PGE Exhibit 1604 is Rogers Helicopters pricing estimate.

C. Outsourcing Limitations

Q. What non-economic factors make outsourcing more challenging?

A. Outsourcing helicopter operations raises concerns regarding safety, pilot familiarity with PGE's assets, and flexibility.

Q. Is it common to see turnover in pilots and crew staff when outsourcing?

A. Yes. Pilot availability can be challenging during fire and storm seasons because charter helicopter crew and pilot turnover is common.

Q. It is preferable to have pilots who are familiar with our T&D system?

A. Yes. Many charter operators hire pilots with less experience, pay lower salaries, and train pilots on the job. The potential for a different pilot and crew each time increases the potential for accidents due to the unfamiliarity with our T&D system. Safely flying a utility helicopter in the wire zone requires more training and experience than that needed to just fly a helicopter. [1]

Q. When are utility line patrol accidents more likely to occur?

A. One study showed that nearly 90% of accidents were by utilities that used contractors or charter operators as opposed to companies who had their own in-house operations. [2]

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[1] *Transmission & Distribution World*. "Utility Helicopter Operations" April 1, 2005. Authors Terry Herring and Bob Feerst are experts in the utility industry. Bob Feerst is president of Utilities/Aviation Specialist Inc. and Terry Herring is manager of helicopter operations for the Tennessee Valley Authority.

[2] Email from Bob Feerst on 12/11/2002. The subject line of the email was "In-House Flight Operations vs. Contractors." In addition, the article, "Flying Down in the WireZone" by John Philpot and David Comstock published in *Transmission & Distribution World* on July 1, 2005 further supports accident prevention.

Q. Do local charters have limited resources during wildfire and storm seasons?

A. Yes. Many clients of helicopter charter operators are in need of helicopters for aerial reconnaissance of storm damage. Since aircraft are only available on a first come, first served basis, there is no guarantee that PGE can secure a helicopter during storm season.

Q. Are there many aircraft available for use during summer wildfire season?

A. No. Local charter operators have limited resources and there are very few aircraft available during the summer wildfire season, from May to October each year, for charter use. Also, these helicopters may not be acceptable for most missions that PGE flies due to mission limitations and safety concerns flying in our range of operations. See PGE Exhibit 1605 for a list of local aircraft available for consideration to fly PGE missions.

Q. What other issues exist with outsourcing?

A. Weather is also a big factor in outsourcing because PGE faces wind restrictions, low visibility, high temperatures and dense fog that restrict the use of a helicopter. In-house helicopter operations provide greater flexibility to wait out poor weather and return to line patrols when the weather clears.

D. Response to CUB Criticism of PGE Benchmarking

Q. CUB claims PGE did not consider other utilities' need for a helicopter as compared to its own helicopter usage (CUB/100, Jenks/18, lines 17-18). Do you agree?

A. No. PGE interviewed personnel of Southern California Edison (SCE), Bonneville Power Administration (BPA), Pacific Power, and Avista Power. PGE benchmarked its operations with utilities that conduct aerial patrols in topographical environments similar to PGE. We examined characteristics more relevant than just service miles such as: patrol area; the location of our assets; what we are required to patrol; topography; terrain; and weather conditions. Each utility that we interviewed has unique circumstances, and benchmarking acts as flag post, not an absolute determinant.

Q. What is the topographical environment in which PGE must conduct aerial-patrols?

A. We must inspect our transmission lines and generation assets. These areas include the Willamette Valley floor from Portland to Salem, Oregon, a portion of the Pacific Coast Range, the Cascade Mountain Range, and remote high desert in Central and South Central Oregon to the California border, and the Boardman / Arlington area.

Q. Will PGE need a helicopter to inspect Biglow Canyon?

A. Yes. Biglow Canyon is located about eight miles south of the Columbia River near Wasco, Oregon. The wind farm is being built in three phases and with the addition of our Biglow 2 and 3 wind farm, we will need to inspect these generation and distribution assets.

Q. CUB claims, "While environment certainly might play a role in the type of helicopter to use, it would seem the miles of transmission lines and geographic extent would be more relevant…," (CUB/100, Jenks/20, lines 14-17). Were those factors ignored as CUB suggests?

A. Absolutely not. CUB suggests Bonneville Power Authority (BPA) and Southern California Edison do not have similar needs as PGE, because SCE has millions of customers and BPA has 15,000 circuit miles of transmission system. CUB fails to recognize that BPA has 4 helicopters and Southern California Edison has 5 or more to serve their customers and areas, whereas PGE has one helicopter.

Q. Do you conclude that purchasing a helicopter is the best option?

A. Yes. We believe the best option is to purchase a new helicopter to replace our existing one rather than outsourcing. After performing an economic analysis using 250 hours and then performing a revised analysis using 150 hours, we still conclude the best option is to purchase a helicopter. Beyond the economic analysis, the non-economic issues with outsourcing limitations, safety, and pilot/patrolman familiarity with the T&D system also provide compelling reasons to continue an in-house operation.

V. Distribution Services

Q. Staff has suggested that "Distribution Services" should remain "below-the-line" because "PGE's customers should not have to subsidize electrical services provided for or to facilities owned by PGE customers." Does PGE agree?

A. PGE does agree that our customers should not have to subsidize electrical services provided for or to facilities owned by PGE customers. And PGE, in its proposal to move Distribution Services above-the-line, certainly did not mean to suggest that our customers should subsidize the provision of those services to others' equipment.

In fact, when PGE began providing these types of services to our customers, at their request, over fifteen years ago, they were provided after ensuring that the recipient would pay the fully loaded and allocated costs, including overheads, plus a margin. Prior to implementing Schedule 715 and OAR 860-038-0500(8)(b), all revenue gained from these types of services was used to offset PGE's Distribution O&M costs and help mitigate rate increases. PGE's intent in proposing to now move Distribution Service above-the-line was to return to the way it used to be, and use any revenue generated through the provision of Distribution Services to help offset PGE's Distribution O&M expenses.

Q. Given Staff's concerns, is PGE willing to keep Distribution Services below-the-line?

A. Yes, at this time.

List of Exhibits

PGE Exhibit	Description
1601	Copy of PGE's Response to CUB Data Request No. 091
1602C	**Economic analysis of purchasing helicopter v. outsourcing**
1603C	**Haverfield Corporation Annual Fixed Bid Costs**
1604C	**Rogers Helicopter Annual Fixed Bid Costs**
1605	List of local aircraft availability for consideration of PGE missions

July 7, 2008

TO: Lowrey Brown
Citizens' Utility Board

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to CUB Data Request
Dated June 27, 2008
Question No. 091

Request:

For PGE's helicopter, please provide the hours of operation for regulated operations for each of the years 2003 through 2005.

Response:

PGE's helicopter operated approximately 158 hours in 2003, 111 hours in 2004, and 140 hours in 2005. However, this period reflects unusual circumstances that are not representative of the expected operation of the helicopter on a going-forward basis.

During this period, PGE's pilot missed significant amounts of time due to a long-term illness, the helicopter spent significant time in maintenance, and the availability of contract pilots was limited due to severe fire seasons in the state. As indicated in the project profile provided in PGE's response to CUB Data Request No. 050, the risk of availability of contract pilots and helicopters was a factor in the decision to own a helicopter and maintain in-house operations of the helicopter. Also, the age (28 years) and recent maintenance history of the helicopter were factors in the decision to purchase a new helicopter. Thus, for 2009 we would expect the new helicopter to operate 250 hours.

For 2008 YTD, the helicopter has flown approximately 98 hours and we expect to fly approximately 225-250 hours for the year, assuming the helicopter does not require unexpected maintenance.

Local Aircraft Available for consideration of PGE Missions:

Bell 203 B3
Bell 206 L3
Bell 206 L4
Bell 205

Charter Limitations and Usage Restrictions

Bell 206 B3	Lack of High Altitude / High Temp Power, Tail Rotor Effectiveness, Type of Tail Rotor System No High Altitude Rotor System available for this aircraft **Result:** Decreased/Limited Maneuverability and Tail Rotor Response at High Altitude **Not an acceptable option for certain weather conditions based on safety requirements.**
Bell 206 L3	Lack of High Altitude / High Temp Power, Tail Rotor Effectiveness, Type of Tail Rotor System No High Altitude Rotor System available for this aircraft Larger engine size and 65" Tail Rotor allow flights at high altitudes on cooler days only. **Result:** Decreased/Limited Maneuverability and Tail Rotor Response at High Altitude **Not an acceptable option for certain weather conditions based on safety requirements.**
Bell 206 L4	Lack of High Altitude / High Temp Power, Tail Rotor Effectiveness, Type of Tail Rotor System Must have a High Altitude Tail Rotor System to be acceptable **Result:** Decreased/Limited Maneuverability and Tail Rotor Response at High Altitude **Not an acceptable option for certain weather conditions based on safety requirements.**
Bell 205	Sufficient for High Altitude / High Temp Power, Tail Rotor Effectiveness, Type of Tail Rotor System. Limited Pilots available to fly aircraft, limiting availability. PGE would have to pay the monthly insurance costs for off season flights October - April. Aircraft unavailable during summer months due to Fire Season. **Result:** Cost of flights not economically feasible outside of emergency situations and call outs.

Table of Contents

I. Introduction

Q. Please state your name and position with PGE.

A. My name is Stephen Hawke. I am Senior Vice President of Customer Service and Delivery. My qualifications appear in Section IV of PGE Exhibit 600.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to issues raised by other parties regarding customer accounting and other programs and service option costs.

Q. How is your testimony organized?

A. In Section II, I rebut adjustments to high-bill inquiry field check costs that Staff refers to as “energy audit” costs. In Section III, I discuss the increase in customer service FTEs. In Section IV, I rebut proposed adjustments to the Customer Focus Initiative. In Section V, I rebut adjustments to PGE’s uncollectibles rate.

II. Energy Audits

Q. In its support of Adjustment S-19, Staff contends that PGE performs energy audits. Is this true?

A. No. PGE does not perform energy audits. We refer our customers to the Energy Trust of Oregon (ETO).

Q. If PGE does not perform energy audits, why did Staff propose the S-19 Adjustment?

A. KATU News mislabeled PGE's customer service investigations of high bill inquiries as "energy audits." Consequently, OPUC Staff, based on a two-minute KATU news segment, made the determination that PGE's customer service activity that investigates high-bill inquiries is similar to the free energy audit services provided by the (ETO). PGE Exhibit 1701 is a transcript of the news segment.

Q. Did OPUC Staff perform any analysis that compared PGE's high-bill inquiry investigation with the free energy audits performed by the ETO?

A. No. Staff's Response to PGE's Data Request No. 041 states: "Staff has no study or analysis illustrating that the energy audit provided by the Energy Trust is similar in scope and cost to the high-bill field check request performed by PGE." Instead, Staff states: "Staff believes…" that the activity performed by PGE employees in the KATU segment is "similar in scope." Staff's Response to PGE's Data Request No. 041 is PGE Exhibit 1702.

Q. What was the purpose of the KATU news segment?

A. KATU News approached PGE asking for assistance in identifying appliances that contribute to "phantom load." It was not initiated by PGE. The use of the term "energy audit" was the choice of the reporter, not PGE. Before a "high-bill" season (winter or summer), it is not uncommon for news organizations to approach PGE and ask for assistance in energy cost related stories. In this particular case, it was a great opportunity to communicate regarding "phantom loads" with little to no cost.

Q. Does PGE perform high-bill field investigations?

A. Yes. PGE has performed high-bill investigations for over thirty years. This activity is part of PGE's customer service. The majority of customer inquiries are resolved over the phone. Prior to a field visit by PGE's customer service representative, the customer's inquiry goes through two reviews. The first review occurs during the original phone call. The second review also occurs over the phone. If the customer's inquiry cannot be resolved during the second phone call, we then determine if a field visit is required.

Q. How many high-bill field visits did PGE complete in 2007?

A. In 2007, PGE completed 1,108 high-bill field check requests (high-bill FCRs) in response to high-bill inquiries from PGE customers.

Q. Please comment on Staff's statement that: "Staff believes that the number of high-bill field checks appears to be excessive, and as such should not be included in PGE's cost of service rates." (Staff/100, Owings/29, lines 19-21).

A. PGE has over 800,000 customers. In 2007, PGE's Customer Service Representatives responded to almost 1.4 million customer inquiries. Considering the large customer base and large volume of calls that PGE responded to in 2007, the 1,108 field visits to resolve high-bill inquiries is not excessive. PGE's Data Request No. 042 to OPUC Staff asked Staff to provide the number of high-bill field check requests per year that PGE could perform without being excessive. Staff replied that "…it does not have an estimate, nor has it performed the analysis on the number of high-bill field check requests per year that PGE should perform." PGE Exhibit 1703 is Staff's Response to PGE's Data Request No. 042.

Q. Are PGE's high-bill field visits similar to the energy audits offered by ETO?

A. No. The purpose of the ETO's energy audit[1] is to educate the customer about energy efficiency opportunities that involve a customized action plan prepared by the ETO's representative as well as the distribution of free energy saving products such as CFL light bulbs, water saving shower heads and water saving faucet aerators. The sole purpose of PGE's high-bill field visits is to help resolve customer bill inquiries. During this process, PGE representatives often refer customers to the ETO and inform customers about the ETO's available programs.

Q. Should the Commission reject Staff's proposed Adjustment S-19?

A. Yes. Staff's proposal is not based on facts but on a two-minute news segment that was taken out of context. PGE's high-bill inquiry resolution practice has been in place for at least 30 years and has effectively served as a valuable tool for customers, PGE, and the Commission.

[1] See PGE Exhibit 1702, Staff's Response to PGE's Data Request No. 041, Attachment A

III. FTEs

Q. Please explain PGE's need for 14 additional FTEs in the Customer Accounts area of Customer Service.

A. After PGE's adjustment in direct testimony to eliminate 10 unfilled positions, PGE is proposing an increase of 14 additional FTEs in Customer Accounting (Meter, Bill, Collect, and Respond) because the activities in this area are directly related to the growth in customers.

Q. Are the additional FTEs necessary to maintain current levels of customer service?

A. Yes. We are providing our customers the means to conduct business on their terms. As we open up more and more channels of communication with our customers via the Web and through e-mail communications, our contact and interaction with customers continues to grow. This increased communication, along with the growth in the number of customers, requires more FTEs to just maintain the current level of service.

Q. Please describe the need for two additional FTEs in the Other Programs and Service Options area of Customer Service.

A. As an outgrowth of our IRP process, and as part of the commitment we made for the AMI stipulation, we are developing Demand Response and Critical Peak Pricing programs. We are hiring two additional FTEs to support these activities.

Q. What activities or job duties will these FTEs perform?

A. Job duties will include planning, organizing, scheduling, identifying and coordinating operating departments in preparation for Demand Response; preparing internal systems for enrollment, billing, data collection, research design, impact verification, data analysis, and customer web interface.

IV. Customer Focus Initiative

Q. What is the Customer Focus Initiative?

A. The Customer Focus Initiative is a company-wide, long-term initiative dedicated to developing cost efficient, customer-focused practices at PGE. This initiative is supplemental to existing efforts at PGE to improve our business processes, and is designed to provide employees with the tools and structure to better serve our customers. These improvements will result in better communication among PGE's various departments and will create synergies as best practices and other improvements are shared across departments. The ultimate outcome will be improved reliability, service, and cost efficiency.

Q. How is PGE implementing the Customer Focus Initiative?

A. The Customer Focus Initiative requires company-wide involvement in order to be successful and thus the initiative is being implemented in phases. PGE kicked off the initiative in 2007, holding a series of training sessions for employees. The intent of this training was to educate and motivate PGE employees to support the Customer Focus Initiative. Once employees understand the initiative, they begin thinking about how they can improve their work with customers or support the work of others who do. PGE departments were then asked to develop ways that they could improve their processes to provide benefit to customers. These process improvements come in two different forms as I explain below.

First, 'quick hits' are developed by each department and are improvements that the department can make on its own or in collaboration with other departments. Quick hit improvements are to be made using existing resources. Several examples were provided in PGE's Response to CUB Data Request No. 062 (PGE Exhibit 1704). Second, improvements may take the form of projects that require broader support within PGE. These projects develop the infrastructure at PGE such that we are better aware and more responsive to the needs and desires of customers.

As departments make progress in identifying and implementing process improvements, it is expected that these successes will lead to further improvements. These successes will be shared and implemented in departments throughout PGE. This iterative process is expected to yield favorable results, and though some areas of PGE will likely move through these phases more quickly than others, the outcome will be improved reliability, service, and cost efficiency.

Q. What are some examples of these projects?

A. PGE is currently developing several projects to create support mechanisms and infrastructure that will improve PGE's value to customers. It is foundational projects such as these that create a platform from which PGE can share knowledge and ideas, and improve cost effectiveness.

- Customer Interaction Skills Training provides employees throughout the company with training on how to effectively listen and respond to customers' needs. Improving the quality of our interactions with customers will enable us to better understand the needs and desires of our customers, and respond in ways that improve and enhance the quality and efficiency of our service.
- Touchpoint Customer Feedback seeks immediate customer feedback on an individual and/or project. We are developing key transactional customer feedback metrics and operational reporting procedures to collect and react to customers' feedback. This will allow us to respond much more quickly and

precisely to customers' feedback than our current processes allow and serves as a basis for 21st Century Service Quality Metrics.

- Line of Sight Metrics is a progressive planning tool that is being designed to help employees and departments cost-effectively align their performance and allocate resources to efficiently meet customers' needs and increase PGE's value to them.
- Customer Feedback System provides all employees with a mechanism to share unsolicited feedback they have received from customers. Systematically capturing, centralizing, analyzing and sharing unsolicited feedback enables PGE to better understand and respond to customers.

Q. Please describe CUB's position on the topic of the Customer Focus Initiative.

A. CUB proposes to disallow the entire program cost, approximately $300,000. CUB asserts that the program lacks a focus on cost control, cost efficiency, or minimizing customers' rates. (CUB/100, Jenks/24-26).

Q. Has CUB mischaracterized the intent of the Customer Focus Initiative?

A. Yes. CUB implies that short-term cost efficiency should be the focal point for the Customer Focus Initiative. While we expect the Customer Focus Initiative will lead to some short-term cost efficiencies, the program is designed to foster durable and sustainable improvements that will enhance reliability, service, and cost efficiency company-wide and over the long term. Cost efficiency is part of the basis for Customer Focus Initiative, but it is not the entire justification.

Q. CUB claims that the Customer Focus Initiative does not once mention minimizing rates, cost efficiency or cost control (CUB/100, Jenks/25, lines 6-11). Is this correct?

A. No. CUB ignored the 'Facilitator's Guide,' which was also provided in PGE's Response to CUB Data Request No. 029 (PGE Exhibit 1705). The Facilitator's Guide reminds the trainers about cost efficiency. It says:

"Let's, every division, group and individual in the organization, step up to the challenge to <u>add</u> <u>greater</u> <u>value</u> to customers. Let's distinguish ourselves through great quality and service and <u>to containing price</u>" (*emphasis added*).

And, in the context of line of sight between PGE employees and customers: "Frontstage work makes direct impacts on customers, through reliability, service, <u>price</u>, or reputation" (*emphasis added*).

The Facilitator's Guide was used during preliminary Customer Focus Initiative training and all participating PGE employees were reminded about price containment.

Q. Does PGE expect to realize cost efficiencies from the Customer Focus Initiative?

A. Yes. However, the initiative is still in its infancy and many of PGE's current efforts are focused on reminding all employees to be more intentional and more collaborative in understanding customers and how their work impacts customers. We believe focusing on customers will lead to cost savings, and at this early phase of the initiative we are implementing programs and systems to further develop and support a culture that focuses on customers. For example, we are developing programs to collect additional customer feedback. This additional information that PGE gathers will enable us to make more informed, customer-focused decisions on how to best improve our business processes. We have every expectation that those improvements will result in cost efficiencies, cost savings, and cost avoidance, and the result for customers will be a better product at a better price.

Q. Does PGE intend to track the direct and indirect benefits resulting from the Customer Focus Initiative?

A. Yes. PGE employees have been working on 'quick hits' since 2007 and each department has been tracking their progress. The tracking system is evolving but does serve as a mechanism for sharing innovative ideas company-wide. We currently gather qualitative information regarding the outcomes of quick hits and are in the process of revamping our collection system to include quantitative tracking of cost efficiencies and savings. We expect to have such a mechanism in place in the third quarter of 2008.

Q. Could the Customer Focus Initiative result in actions that have additional costs?

A. Yes. However, any such proposal will be evaluated to determine if the benefit to customers supports the cost. Economic benefit will be a prime consideration.

VI. Uncollectibles

Q. Please summarize OPUC Staff's recommended adjustment to the 2009 uncollectibles rate?

A. Staff correlates PGE's uncollectibles rate with unemployment rates and argues that since unemployment rates are expected to remain steady in 2008 and 2009, so, too, should PGE's uncollectibles rate.

Q. Are unemployment rates expected to remain steady in 2008 and 2009?

A. No. The State of Oregon Department of Consumer and Business Services has revised its unemployment forecasts. For 2008, the forecast for Oregon unemployment has increased from 5.6% to 5.8%, and in 2009, the forecast for Oregon unemployment has increased from 5.6% to 6.2%.

Q. Did OPUC Staff perform an analysis that shows there is a correlation between PGE's uncollectibles rate and the Oregon unemployment rates?

A. No. In OPUC Staff's Response to PGE's Data Request No. 009, Staff states they did not perform a study or an analysis. Staff cites sources from 2004 and 2005, but these sources do not demonstrate any relationship between unemployment and uncollectibles,[2] and these sources do not apply to Oregon or the Northwest region. See PGE Exhibit 1706, which is a copy of OPUC Staff's Response to PGE Data Request No. 009.

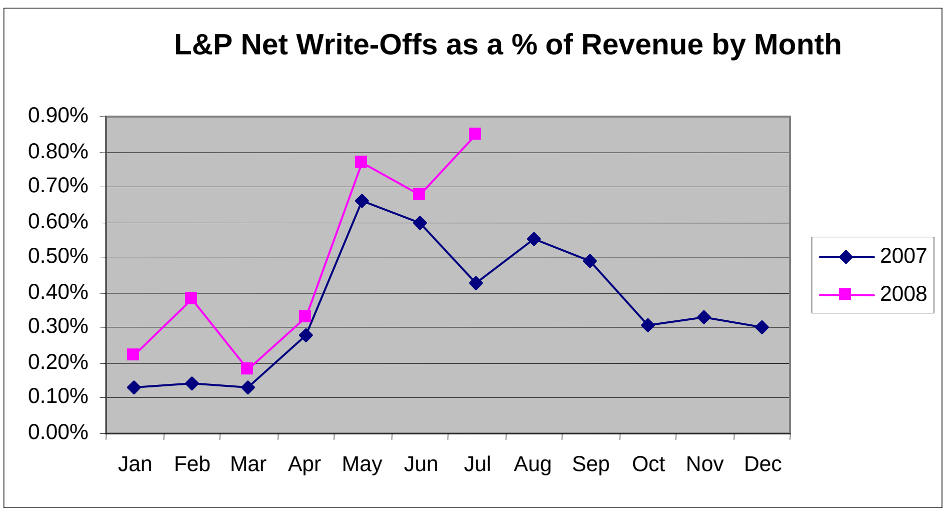
Q. Does PGE believe there may be a correlation between the uncollectibles rate and the Oregon unemployment rate?

[2] The one exception to this is Staff's Response to PGE Data Request No. 009, Attachment A. The Corning Metro Gas Corp of New York attributed the increase in uncollectibles to a significant layoff within the gas company service territory. This does not demonstrate any correlation between regional or national unemployment rates and uncollectibles, but is only an isolated incident that is related to that local economy only.

A. Yes. There may be a correlation between the uncollectibles rate and the unemployment rate, but it is not the only driver of the uncollectibles rate, as Staff implies. There are other factors that contribute to write-offs of uncollectible accounts, such as higher gasoline prices, the resetting of adjustable rate mortgages, and higher food expenses that affect not only the unemployed, but the economy as a whole.

Q. Is PGE's current uncollectibles rate approximately the 0.38% that OPUC Staff recommends?

A. No. The graph below shows how PGE's uncollectibles rate continues to increase in a worsening economy. PGE's uncollectibles rate for July 2008 is 0.85% for the light and power (L&P) portion alone.



Q. Please summarize CUB's adjustment to the uncollectibles rate.

A. On January 1, 2008, in accordance with Section 1(7)(b) of State Senate Bill 461, PGE and Pacific Power began collecting low income energy assistance funding in the amount of $0.50 per residential meter and up to a maximum of $500 per commercial meter (based on usage).

CUB notes that the Oregon Legislature increased state energy assistance funds by approximately $5.0 million dollars per year, of which PGE's portion is approximately $2.9 million dollars per year. CUB then states that regardless of this increase in energy assistance, "PGE has failed to show a need to increase the uncollectible expense." Thus, CUB reasons, that "the Commission disallow the proposed $2 million increase in uncollectible accounts" (CUB/100, Jenks/40, lines 8-11).

Q. Is this a reasonable recommendation?

A. No, for three reasons. The first reason is that PGE's year-to-date uncollectibles rate demonstrates a need for increased uncollectible expense. I discussed how we calculated our uncollectibles rate in my direct testimony (PGE Exhibit 700, Section III) and we responded to data requests from OPUC and CAPO/OECA, including OPUC Data Request No. 293, which specifically discusses uncollectibles. Thus, CUB's claim that we failed to show a need for an increase is unfounded.

Q. What is the second reason?

A. CUB implies that due to an increase in energy assistance, PGE's increase in uncollectible accounts of approximately $2.0 million is not warranted.

Q. Would an increase in energy assistance offset increases in PGE's uncollectible account expenses?

A. Not necessarily. There is not a 1:1 relationship with the amount of increased energy assistance and the amount of increased funding that PGE receives from the various agencies. Administrative fees from the various agencies reduce the amount of funds PGE receives. On a monthly basis, PGE forwards funds billed in the previous month to the Oregon Housing and Community Services Department (OHCS). OHCS deducts administrative fees

(2.5%), and then distributes the balance to the Community Action Partnership of Oregon (CAPO) agencies on a quarterly basis. In turn, CAPO agencies deduct their share of administrative fees (7.5%) and program delivery fees (12.4% on average), and then distribute the remaining Oregon Energy Assistance Program (OEAP) funds to PGE and Pacific Power. In Multnomah County only, sub-agencies distribute the OEAP funds, which add another layer of administrative fees to the mix. Depending on how the funds are distributed, PGE does not know the exact dollar amount it will receive in energy assistance.

Q. What is the third reason?

A. The third reason is that an increase in energy assistance is not a dollar-for-dollar credit to our net write-offs. The current level of energy assistance funding is estimated to cover only a portion of the existing need. Therefore, when additional funding becomes available it is committed on a first-come first-serve basis and does not necessarily apply only to uncollectible accounts.

Q. Are there other factors that offset the increase in energy assistance?

A. Yes. In 2006-2007, PGE received additional funding from the Duke El Paso and Williams Settlements. This additional funding was distributed by OHCS and Oregon HEAT to provide additional energy assistance to our customers. PGE received approximately $1.9 million from these funds. However, this funding is almost depleted for 2008.

Q. Has a relationship been determined between energy assistance funding and the uncollectibles rate?

A. No, not that we are aware. While one can theorize that there should be some relationship, it has not been quantified. It is unclear how many customers receiving assistance would not otherwise pay their electric bills. Certainly energy assistance is improving the quality of life of some of our customers, but the direct impact on uncollectibles is undetermined.

Q. What uncollectibles rate do you recommend the Commission adopt in this case?

A. I recommend the Commission adopt the overall rate of 0.48%, as filed by PGE.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1701	Transcript of the KATU News segment
1702	Copy of OPUC Staff's Response to PGE Data Request No. 041
1703	Copy of OPUC Staff's Response to PGE Data Request No. 042
1704	Copy of PGE's Response to CUB Data Request No. 062
1705	Copy of PGE's Response to CUB Data Request No. 029, Attachments 029-A and 029-B
1706	Copy of OPUC Staff's Response to PGE Data Request No. 009

July 31, 2008

TO: Patrick G. Hager
Manager, Regulatory Affairs

FROM: Judy Johnson
Program Manager, Rates and Regulation

OREGON PUBLIC UTILITY COMMISSION
UE 197
PGE's Second Set of Data Requests to OPUC
Dated July 17, 2008
Question No. 041

Request:

41. In reference to Staff Exhibit 100, Adjustment S-19, please provide studies or analysis illustrating that energy audit activity provided by the Energy Trust is similar in scope and cost to the high bill field check requests performed by PGE customer service representatives. Please provide the workpapers and analysis for the estimate.

Response:

Staff has no study or analysis illustrating that the energy audit provided by the Energy Trust is similar in scope and cost to the high bill field check requests performed by PGE. However, please see Staff's Attachment 41-A for a copy of the Residential Audit performed by the Energy Trust.

Staff believes that the "Energy Audit" performed by the PGE employee in the KATU news story in May of 2008, is similar in scope and cost to the audits performed by the Energy Trust of Oregon. Staff believes that if PGE is unable to satisfy its customers during the inquiry and interview process that takes place at the Customer Service Representative level when a customer calls into the utility company due to a high bill, then PGE should be referring these customers to the Energy Trust for a free Energy Audit rather than performing "high bill field checks". The business of helping a customer to "pinpoint possible causes for the customer's high bill"[1] and "educating the customer on ways to save on their electric bill"[2] should, for the most part, be performed by the Energy Trust.

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[1] *See* PGE's response to Staff's Data Request No. 402, i.
[2] *Id.*

Smart Energy Investments Start with a FREE Home Energy Review

Up to 60 percent of energy used to heat and cool homes is lost due to leaky ducts, inefficient equipment, poor insulation and air leaks.

Increase your home's energy efficiency with help from Energy Trust and save money.

Start with a FREE Home Energy Review. You'll learn how to use less energy while making your home more comfortable, healthier and safer. Plus, receive a customized action plan and cash incentives for qualifying, energy-saving home improvements!

Schedule a FREE Home Energy Review

Call 1-866-368-7878 or **schedule your Home Energy Review online**. An Energy Advisor will conduct a one-hour walkthrough of your home, visually assessing the following typical areas of energy loss:

- Insulation levels in the attic, ceiling, walls, floors and ducts
- Heating system
- Air sealing and windows
- Ventilation
- Moisture problems

You will also receive the following free, instant energy-saving products to immediately start on the path to home energy efficiency (eligibility requirements apply):

- ENERGY STAR® qualified compact fluorescent light bulbs (up to 10, a $50 value)
- Water-saving showerheads
- Water-saving faucet aerators

Learn more about Home Energy Reviews:

- **Energy-saving home improvements**
- **Cash back for completed home improvements**
- **Take the next step with Home Performance with ENERGY STAR**
- **Go Solar**
- **Eligibility**
- **Oil-heated homes**

Energy-saving home improvements
With your energy-saving action plan, you will have all the information to make your upgrades. To install energy-efficient upgrades, contact an **Energy Trust trade ally contractor**, or any other licensed and bonded contractor, to discuss and schedule installation of eligible energy-saving measures for your home.

Cash back for completed home improvements
After your contractor installs your energy-saving improvements and within 120 days of measure installation, simply submit a copy of the contractor's invoice with Energy Trust Incentive **Form 300A**, confirming that your home improvements were completed. (You or your contractor can submit both materials.)

If you plan to install your own insulation (excluding duct and wall insulation), or work with an Oregon Construction Contractors Board (CCB)-licensed contractor who is not an Energy Trust trade ally, call us at 1-866-368-7878 before beginning work to receive pre-approval. *Attic or floor insulation can be self-installed with pre-approval from Energy Trust.*

Mail the completed form and invoice to:
Home Energy Solutions
P.O. Box 847
Portland, Oregon 97207
Or, fax to: 1-866-516-7592

You will receive your incentive check six to eight weeks after we receive your invoice and completed form.

You can also receive cash incentives when you purchase featured **ENERGY STAR qualified products**, such as clothes washers, refrigerators and compact fluorescent light bulbs (CFL).

Take the next step with Home Performance with ENERGY STAR

Your Energy Advisor may suggest that you consider scheduling a **Home Performance with ENERGY STAR** comprehensive home assessment.

Assessments take three to four hours and are performed by a certified contractor who evaluates every component of your home's interior and exterior.

Go Solar

Today's solar energy systems are reliable, attractive and affordable with Energy Trust incentives and Oregon Residential Energy Tax Credits.

If you are interested in installing **solar electric** or **water heating**, your Advisor can evaluate your home, explain how solar systems work, and inform you about Energy Trust solar incentives.

Eligibility

Homeowners who are Oregon customers using heat provided by Portland General Electric, Pacific Power, NW Natural or Cascade Natural Gas are eligible to participate in Energy Trust programs.

Owners and renters are eligible. Most improvements require the permission of the landlord to install.

Oil-heated homes

Oregon customers of PGE and Pacific Power living in homes heated with oil, propane, kerosene, butane or wood may be eligible for weatherization incentives through the **Oregon Department of Energy's SHOW Program.**

[1]Energy Trust maintains a network of trade ally contractors. Contractors who are not participating in Energy Trust's Trade Ally Network are eligible to install recommended measures if they are licensed by the Oregon Construction Contractors Board.

[2]Financing is available to help you install recommended measures. You can choose between cash incentives and 100% financing of qualifying measures. Home Performance with ENERGY STAR jobs are eligible for a lower interest rate. Participants may not receive both cash incentives and a loan for standard measures; however, participants may be eligible to receive a cash bonus for installing multiple qualifying measures.

[3]Energy Trust provides technical assistance and financial incentives but does not develop, sell or install energy systems or equipment. This work is done by independent businesses that are solely responsible for the quality and performance of their installations.

July 31, 2008

TO: Patrick G. Hager
Manager, Regulatory Affairs

FROM: Judy Johnson
Program Manager, Rates and Regulation

OREGON PUBLIC UTILITY COMMISSION
UE 197
PGE's Second Set of Data Requests to OPUC
Dated July 17, 2008
Question No. 042

Request:

42. In reference to Staff Exhibit 100, Owing/29, lines 19-21, Staff states: "Staff believes that the number of high bill field checks appears to be excessive and such, should not be included in PGE's cost of service rates." Please provide the number of high bill field check requests per year that PGE should perform without being excessive.

Response:

Staff does not have an estimate, nor has it performed an analysis on the number of high bill field check requests per year that PGE should perform.

June 26, 2008

TO: Lowrey Brown
Citizens' Utility Board

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to CUB Data Request
Dated June 11, 2008
Question No. 062

Request:

What is the cost of The Customer Focus Initiative in the UE 197 test year?

Response:

The cost associated with the Customer Focus Initiative (CFI) in 2009 is approximately $300,000. This includes the cost of the Program Manager, contract labor, materials, equipment, etc. The costs associated with the initial company-wide training were incurred in 2007.

Overview

PGE determined that a long-term cultural change to become more customer-focused was needed. Overall, each employee and department is asked to consider how their work directly or indirectly impacts the customer and what changes the employee or department can make to improve the cost effectiveness or service that PGE provides to its customers. Improvements are to be done with existing resources rather than requiring large expenditures. Should an improvement require additional resources, a business case would have to be made.

The program launched in 2007 with company-wide training. Each of PGE's employees was required to take part in this four hour training session or a modified shorter version of it. The CFI has now been incorporated into the existing orientation program and does not require additional hours of training time. New employees will receive information on the CFI during their orientation.

The primary objective for the CFI is to increase PGE's level of service to customers. Though cost efficiency is one of the original long-term objectives of the CFI, it is not used as a primary motivator for employees. Instead, we have asked employees to consider how service can be improved using existing resources.

Attachment 062-A is a summary of several Quick Hits demonstrating the types of efficiencies and savings PGE has captured thus far, less than one year into the program. PGE expects to continue to capture cost savings and efficiencies; however, much of the benefit of the CFI cannot be easily quantified in dollar terms.

UE 197
Attachment 062-A

Quick Hits

Customer Focus Quick Hit Improvement Examples

Storeroom Collaboration Quick Hit

The storeroom collaborated with line crews to improve efficiencies in outfitting and stocking the trucks with the proper equipment to complete jobs without additional trips. Storeroom management and General Line Foremen meet regularly to look for ways to improve procedures and communications. Crews are using new procedures now to ensure that they request the specific equipment, parts and quantities for each job. This requires a thorough review of the work requirements prior to arriving on site as well as a review of the materials stocked on the trucks. Conservative estimates are that we are saving at least two 20 mile round trips per day (probably more) which equates to an annual savings of 10,400 miles or $5,252 (at the IRS reimbursement rate of .505 per mile). This also represents a reduction of approximately 693 gallons of diesel fuel used.

IVR Quick Hit

Customers had reported that the IVR system playback of confirmation numbers was too fast for some alpha-numeric characters and difficult to differentiate. We updated the programming in the IVR to slow down the confirmation numbers playback and we re-recorded applicable prompts to over-enunciate problematic alpha-numeric characters. These changes, implemented in the summer of 2007, impact approximately 250,000 customer transactions annually. Since implementing, we have not received any comments that the playback is too fast. Complaints about difficulty differentiating specific alpha characters have decreased by approximately 75% (falling from approximately one complaint per week to one complaint per month.)

Distribution Communications Quick Hit

Created a simple one-sheet laminated bi-lingual sheet to help linemen and other field personnel better communicate to our Spanish-speaking customers about equipment repairs/outages affecting them. The intention is to reduce the number of calls to the contact center to speak with a Spanish-speaking representative to understand what is going on and any required action on their part. Communicating with this simple tool reduces calls to the Contact Center, better informs our Spanish-speaking customers, reduces the need for crews to double back and start/finish work they could not do until appropriate action was taken, and provides better customer service because our customers do not need to call customer service and wait in a queue to speak with a translator.

Distribution Services Location Efficiency Quick Hit

To reduce the number of times a PGE crew could not find a light or tree locations reported by a customer, Distribution Services began using Google Maps in complement with PGE’s mapping program when speaking with customers that were reporting locations without specific ID numbers. The original intention was to provide a less frustrating experience for the customer and to reduce wasted trips by crews. Using Google Maps allows PGE to visually confirm the customer's instructions and ask clarifying questions if needed. Additional benefits included providing first call resolution and shorter calls. Since implementing this approach at the beginning of 2008, our accessibility to customers that call in (answering the phone in person) to this department has increased from 51 percent in 2007 to 71 percent through June of 2008. Off phone work productivity has also benefited. Goals are to accomplish work tasks (managed through the Work Management System) within 24 hours of receiving. Last year we completed this type of off-phone work within 24 hours, 65 percent of the time. That compares to 90 percent YTD through June 2008.

Table of Contents

I. Introduction

Q. Please state your name and position.

A. My name is Stephen Quennoz. My position at PGE is Vice President, Supply. I am responsible for all aspects of PGE's power supply generation and for decommissioning the Trojan nuclear plant. My qualifications are listed in Section V of PGE Exhibit 400.

Q. What is the purpose of your testimony?

A. The purpose of my rebuttal testimony is to address issues raised by other parties relating to five areas:

- Generation Excellence: I discuss the costs and associated benefits of this Initiative.
- FTEs: I discuss the need for and update the hiring status of additional generation FTEs.
- Fixed Plant O&M: I discuss alternative proposals for appropriate collection of test year O&M costs at three plants that are higher than 2003-2008 averages.
- General Production: I provide more detailed information about the costs requested in this area.
- Hydro Relicensing Project Closure Dates: I provide test year expense and rate base changes associated with more recent estimates of closure dates.

Q. How is your testimony organized?

A. In addition to this introduction section, there are five additional sections, one for each area mentioned above.

II. Generation Excellence

Q. What is CUB's summary recommendation for PGE's Generation Excellence Initiative?

A. CUB recommends that Generation Excellence costs not be included in retail rates because PGE did not perform any comprehensive cost-benefit analyses for the program. (CUB/100, Jenks/30, Lines 1-5)

Q. Do you agree with CUB's recommendation?

A. No. CUB is under the mistaken belief that all initiatives or projects must have a formal cost benefit analysis even if the primary motivation is another reason, such as reliability, or if the benefits are obvious. In the case of Generation Excellence, the primary motivation is two-fold: safety and reliability. This initiative, though, has small costs and mostly serves as an umbrella to centralize several programs that focus on plant safety and reliability.

Q. What is the focus of Generation Excellence?

A. Generation Excellence is essentially an investment in our people. PGE has historically benefited from the pool of talented, highly qualified personnel from Trojan. However, that group has all but disappeared. Additionally, the retirement of many very experienced engineers and power plant employees is imminent, and the availability of critical technical specialties in the electric utility industry is diminishing.

In order to keep the generating plants operating with consistent performance during this transition period, a concerted investment in people is needed to mitigate the succession issues discussed above. Generation Excellence is a crucial endeavor and certainly not a discretionary effort.

There are four cornerstones of Generation Excellence: Safety, Process Improvement, Human Performance and Plant Reliability.

1. Personnel Safety: Increased productivity (and reduced costs) by reducing on-the-job injuries and related employee medical expenses.
2. Process Improvements: In maintenance work management, this allows more work to be accomplished. In operations, the process improvements decrease the potential for errors. From both the operations and maintenance perspectives, the process improvement focus increases plant reliability. Concurrently, an emphasis on problem solving effectively prevents recurrence of issues, leading to progressively higher levels of plant performance than otherwise.
3. Human Performance: This results in a more highly trained and capable workforce, enabling a desired trend of improved plant operations and maintenance. It likewise facilitates the expeditious training of new personnel replacing retiring employees, thereby ensuring continuity of operations.
4. Plant Reliability: Implementation of industry best practices and reliability-centered maintenance techniques will improve both asset management and dependable operations.

Q. Was a cost-benefit analysis performed for Generation Excellence initiative?

A. The initiative was developed by a Delphi panel of senior plant managers, a common technique used in problem solving that emphasizes experience and collaboration to find practical and effective outcomes. Financial analysis is one of many criteria considered by this process. For example, when considering training programs, a dedicated training staff was eschewed in favor of an evolutionary and less costly process to first build on a standardized "best practices" qualification program, and to develop plant specific state-of-the-art training materials and human-factor procedures.

Similarly, while a training simulator was desired for all of the plants and projects, it was determined through the process that it would be more cost effective to first develop and implement a simulator only for Boardman so that other simulators, if it is determined that they are needed, could be implemented in the most efficient and cost effective manner. The Delphi panel placed priority on ensuring that the initiatives selected delivered tangible and predictable results in the most economical manner. In some cases, the economic benefits were difficult to quantify. However, no proposal was selected if it was collectively judged that the benefits to safety and reliable operations did not outweigh the expenses involved.

Q. How much of the Generation Excellence costs are incremental from 2008 in the 2009 test year?

A. Less than 10% of the costs are incremental. The total cost in the test year is $1.2 million, and only $0.1 million of that is incremental from 2008 to 2009. PGE Exhibit 1801 is a copy of Attachment 048 Supp 1-D, to PGE's Response to CUB Data Request No. 048, which shows these totals and the breakdown between incremental and non-incremental costs from 2007 to 2009. In other words, PGE strongly believes in this initiative and that it provides benefits to customers. Therefore, we are currently spending dollars not anticipated in the 2007 UE 180 authorized revenue requirement to support the initiative.

Q. What comprises the total $1.2 million in cost for Generation Excellence in the 2009 test year?

A. $0.3 million is for training and software for various plants, including Port Westward, Beaver, West Side Hydro, and Pelton Round Butte. $0.9 million is for seven FTEs at Boardman and general plant support.

Q. How many of the seven FTEs are incremental from 2008 in the 2009 test year?

A. None. Again, these positions will be filled by the end of 2008. Three FTEs, now the Reliability Centered Maintenance (RCM) group, were included in PGE's last general rate case, UE 180. As mentioned on page 17 of PGE Exhibit 400, the RCM group is made up of existing employees. The other four FTEs have been hired or are expected to be hired in 2008 and, therefore, are not incremental from 2008 to 2009.

Q. Please describe the work performed by these seven FTEs and whether they have been hired.

A. Table 1 below lists the employees and whether they have currently been hired.

Table 1
FTEs Hired

Job Description	FTE	Hired?
RCM Group	3	Yes
Boardman Control Operator	1	No
Boardman Assistant Control Operator	1	No
Boardman Simulator Supervisor	1	Yes
Hydro Trainer	1	Yes
Port Westward Technician	1	Yes

The descriptions of the seven FTEs are as follows[1]:

- RCM group (three FTEs): The RCM group provides expertise in Root Cause Analysis, Failure Modes and Effects Analysis, Reliability Centered Maintenance and other reliability based improvement programs. The group analyzes problems that affect plant reliability and implements corrective action plans. The output of the group is measured in reduced life cycle costs and higher plant production, thus having direct fiscal impact.
- One Control Operator and One Assistant Control Operator: These employees are at the controls, monitoring and conducting plant operations. They make the

[1] At Port Westward a technician was hired in April 2008 to meet an enterprise zone requirement. This employee works primarily on Generation Excellence and is not included in the 2009 test year revenue requirement.

decisions to start, stop, and change output levels. Without these two new employees, Boardman would not have sufficient employees to both train and operate the plant. Training will now be available quarterly, instead of annually or bi-annually as occurred in the past. Without the additional employees, the full benefit of the simulator will not be realized since the needed training could not be scheduled without excessive overtime and fatigue.

- One Simulator Trainer Supervisor: This FTE is required to develop the Boardman-specific training scenarios and to then train plant operations personnel (both Control Operators and Equipment Operators). This position was budgeted prior to the Generation Excellence program. However, Generation Excellence raised the priority of the training function. We have already filled this position.
- One Hydro Trainer: This FTE is responsible for the overall development and implementation of training programs for the hydro plants to ensure that personnel are properly trained and qualified to complete their assigned activities. The increased controls placed on the operations of the river systems subsequent to relicensing has required increased training; conversely, not receiving such training would leave PGE exposed to possible FERC violations and penalties.

Q. What is CUB's position on the Boardman Simulator?

A. CUB states that the company did not provide any cost benefit analysis after revision two of the project profile and that the project profile should have been approved based on calculations demonstrating that the "projected replacement power cost savings from a reduced forced-outage rate due to a simulator, as opposed to off-site training" should "outweigh the increased cost of the simulator with its associated construction and personnel." (CUB/100, Jenks/18, Lines 7-9) CUB believes that the cost above $1.5 million in revision two should be disallowed because there is no economic evaluation beyond this point.

Q. Were any versions of the Boardman simulator profile approved on the basis of economic valuation?

A. No. The original version and the subsequent revisions of the project profile for the simulator at Boardman have always been approved on the basis of reliability. An economic valuation was performed in the original version of the project profile and subsequently updated in revision one of the project to understand what benefits in addition to reliability would be obtained from the simulator at that point; however, the project was always pursued on the basis of reliability.

Q. Please explain the additional $1.0 million in revisions two and three for the simulator project.

A. The additional $1.0 million for the Simulator project is primarily related to three items:

- $0.4 million - increased building and construction costs: This includes two major elements. First, space was doubled to 3,200 square feet. The increased space will provide additional offices for increased operational personnel and the Regional Haze Best Available Retro-fit Technology (BART) process. The additional space will also provide for computer-based training, which will be offered to plant personnel through 18 computer work stations. Given these functions, the additional space requires additional furniture and network connectivity. Second, since the initial request, concrete and steel prices have increased, as have earthquake-related building requirements.

- $0.4 million – high fidelity simulator: It costs more to have a simulator that more closely resembles the control room at Boardman, rather than one that is fairly close. This is an improvement over the outside training our operators currently receive, which is on simulators that only approximately replicate Boardman. Better replication results in better training and decreased chance of operator errors.
- $0.2 million - additional start up costs: This includes costs for increased training and interfacing for Boardman personnel, additional installation factory acceptance testing, and overtime to complete installation of the simulator.

Q. Why is increased training at Boardman important?

A. It is now more important to have more simulator training for two reasons. First, the cost of an outage is higher than in the past. Second, equipment is becoming more sophisticated over time. Previously, we sent employees to simulator training off-site and only during planned maintenance outages. As a result, operators received training once every two years. We believe the training is necessary once every quarter, which we will be able to do with our own simulator (and the new control operator and assistant control operator discussed above). The fact that Boardman is complex and is dispatched as a base-load resource disadvantages the operating staff since they do not get routine experience in starting up, shutting down, and maneuvering the plant, which is essential in controlling the unit during challenging conditions. A control room simulator provides this practical experience in diagnosing problems and following off-normal and emergency procedures. This provides benefits through the safe operation of a valuable asset and we consider it to be a best practice.

Q. Is it appropriate to approve the simulator and not approve the employees to run it or coordinate training?

A. No. The simulator provides training for the employees at Boardman and requires one training supervisor to run the simulator, as well as two additional employees (the new assistant control operator and new control operator) to provide the necessary back up to allow employees, otherwise on shift, to participate in training, as well as succession planning. If the new employees are not authorized, we will have to do the training during planned maintenance outages and this would jeopardize receiving full benefit from the investment.

Q. Please summarize PGE's position on Generation Excellence and the Boardman Simulator.

A. Generation Excellence is an important initiative for PGE and our customers. The focus on safety, process improvements, training and reliability will benefit customers through improved plant operations and reliability. The simulator and its associated additional staff are critical to maximizing the value of the initiative's training component. The entirety of Generation Excellence and the simulator should be included in PGE's 2009 test year revenue requirement.

III. FTEs

Q. PGE Exhibit 400 (PGE/400, Quennoz-Lobdell/18, Table 2) shows a forecasted increase of 21 general plant FTEs from 2007 to 2009. These are positions in the generation function that are not assigned to specific generation units. PGE Exhibit 400 also includes a discussion of this increase (PGE/400, Quennoz-Lobdell/18-19). Can you provide more detail on this FTE increase?

A. Yes. Our forecasted increase of general plant FTEs from 2007 to 2009 remains at 21. The discussion below reflects the fact that the composition and/or focus of the FTEs within the overall increase has evolved. We have already filled 13 of these positions and we expect to fill the remaining eight by the start of 2009 test year.

Q. Please summarize the 13 positions that you have already filled.

A. We have filled the following 13 positions:

- Generation projects group: five employees – director, two project managers, budget analyst, and scheduling/support person.
- Hydro and wind operation support group: six employees – general manager, safety coordinator, procedures and training coordinator, maintenance engineer, budget analyst, and support person.
- Civil engineer.
- Geographic Information System (GIS) specialist.

Q. What does the generation projects group do?

A. The group is currently examining options for the Best Available Retrofit Technology (BART) to bring our Boardman plant into compliance with environment standards, providing benchmark resource cost estimates to support our Integrated Resource Plan (IRP) and future Request for Proposal (RFP) processes, and supporting the scoring of bids recently submitted in our current RFP. This group also provides all project management for the Biglow Canyon wind farm construction as well as any other future generation projects.

Q. Please summarize why the generation projects group is needed.

A. Given PGE's need for power supply resources in the near future, the planning and project management functions performed by this group are critical to meet customer load requirements in a cost-effective way.

Q. What does the hydro and wind operation support group do?

A. This group provides the safety, training, and maintenance engineering functions for PGE's Pelton Round Butte, Willamette Falls, and Clackamas (four separate plants) hydro facilities, and for the Biglow Canyon wind farm. Biglow Canyon is a new resource and PGE expertise is needed to support this new technology and maintain the value of this expensive asset. More training is needed at the hydro facilities for new people who are replacing retiring plant personnel. The hydro plants are also aging, making maintenance more difficult, as "off the shelf" solutions generally do not exist.

Q. Please summarize why the hydro and wind operation support group is needed.

A. The hydro and wind operation support group ensures the reliability of our low-cost hydro and wind resources, which in turn reduces variable power costs and contributes towards meeting renewable resource goals. Not having these personnel would jeopardize plant performance due to a lack of experienced technical support.

Q. What are the duties of the civil engineer?

A. The civil engineer focuses on generating plants, particularly the oversight necessary to complete and support capital modifications required by the new long-term licenses for our hydro facilities, as well as providing dam safety reviews and assessments.

Q. Why is this position needed?

A. Not having the civil engineer would decrease the ability of PGE's power supply engineering services organization to provide continuity of expertise in monitoring dam safety and support for the design and construction of FERC-ordered re-licensing modifications of our Pelton Round Butte and Clackamas hydro facilities.

Q. What are the responsibilities of the GIS specialist?

A. The GIS specialist develops and maintains maps of our generating facilities, which show features such as site boundaries, flood inundation levels, and geomorphic and terrestrial data necessary to establish baselines and trends.

Q. Why are these maps necessary?

A. These maps are needed for applications including emergency response preparation and, in the case of hydro facilities, compliance with licensing requirements. With more plants and requirements, we have a greater need for GIS support, particularly at the Biglow Canyon, Pelton Round Butte, and Clackamas project sites.

Q. Please summarize the eight positions you plan to fill.

A. We plan to fill the following positions prior to the start of the 2009 test year:

- Construction specialist.
- Project scheduler.
- Compliance specialist.
- Non-destructive engineering examiner.

- Mechanical engineer.
- Electrical engineer.
- Project manager for generation-related projects.
- Distributed generation and solar project technical support person.

Q. What are the responsibilities of the construction specialist?

A. The construction specialist, along with one of the project managers in the generation projects group discussed above, will focus on completion of the Biglow Canyon Wind Farm, Phases 2 and 3. They will work specifically on the Siemens SWT2.3-93 technology and monitor construction of 141 wind turbines. We are currently in the process of hiring for the construction specialist position.

Q. What benefits will the construction specialist provide?

A. The specialist will ensure that we make use of all development potential at the high capacity factor Biglow site, which will help PGE to cost-effectively meet renewable targets.

Q. Please discuss the project scheduler position and why it is needed.

A. PGE engineering manages many capital projects, each of which requires design, material ordering, hiring of contractors, working with plants to prepare for project implementation, and contract administration. The scheduler develops a schedule and timeline for each capital project so that critical tasks are coordinated and completed on time. This work is currently performed by a contractor, who will be replaced by the PGE scheduler.

Q. What are the responsibilities of the compliance specialist?

A. The compliance specialist will provide additional support for PGE compliance with North American Reliability Corporation (NERC) and Western Electric Coordinating Council (WECC) Reliability Standards and Critical Infrastructure Protection Systems (CIPS) standards. The specialist will interpret standards, write procedures, and develop training to ensure compliance. The specialist will also document and monitor compliance, and keep PGE's compliance current by changing policy and procedures as NERC/WECC standards change.

Q. Why is the compliance specialist position necessary?

A. This position is necessary to help with the significant workload increase created by mandatory compliance with the evolving NERC/WECC standards.

Q. Why is the non-destructive engineering examiner needed?

A. This position represents an addition to our one current examiner. The new person will help with additional work at Port Westward and Biglow Canyon. Not having a second engineering examiner would limit the ability of PGE's power supply engineering organization to resolve complex issues inherent to piping systems, heat exchangers, and mechanical components found in power plants.

Q. Why are the mechanical and electrical engineer positions necessary?

A. Both engineers will focus on wind and other renewable technologies. They are needed to support PGE's development of resources to meet renewable targets.

Q. What are the responsibilities of the project manager?

A. The project manager will ensure completion of generation-related projects other than Biglow Canyon. These other projects may include development of a capacity resource needed to integrate wind energy and an energy resource needed to maintain load-resource balance in the near future.

Q. Why is this position necessary?

A. The project manager is needed to ensure both the permitting and the engineering-procurement-construction (EPC) of these facilities and other project management efforts.

Q. What will be the focus of the technical support person?

A. This person will provide technical support for distributed stand-by resources and for solar projects.

Q. Why is this position needed?

A. We need this additional person to support an increase in distributed stand-by resources and a possible new solar initiative. Distributed stand-by resources diversify our resource portfolio and provide operating reserves (PGE/400, Quennoz-Lobdell/4). Solar projects support development of a diversified renewable resource portfolio.

Q. Did PGE consider redeploying current staff to fill any of these positions?

A. Yes. PGE carefully reviewed the needs of the company and determined that the current staffing level could not support the critical work associated with these additional positions.

IV. Fixed Plant O&M

Q. What is Staff's summary recommendation for fixed plant O&M costs in the 2009 test year?

A. Staff proposes an "adjustment to PGE's filed Fixed Plant O&M costs to disallow one time excess maintenance costs, including $2.2 million for Beaver, $3.2 million for Colstrip and $3.0 million for Boardman" (Staff/400, Durrenberger/7, Lines 7-9).

Q. Is "excess" an accurate characterization of these costs?

A. No. The costs Staff refers to are those for specific plant O&M procedures that are not performed annually. These procedures are necessary to keep our plants in good working order. The related costs are not excessive or extraordinary, but rather are required to provide reliable power to customers.

Q. Do you agree with Staff's assertion that these "nonrecurring expenses for Beaver, Colstrip, and Boardman should be disallowed because they distort the test period revenue requirement and result in incorrect rate setting?" (Staff/400, Durrenberger/6, Lines 8-10)

A. No. Under Staff's proposal, PGE would never recover $8.4 million in necessary costs that will occur in the 2009 test year. The test year revenue requirement should include costs that are expected to be incurred. If the test year-based rates remain in effect in future years, some costs actually incurred in the future years will be lower than what is included in the test year (Staff's concern) and some will be higher. Staff's approach is one-sided.

Q. Does Staff mention another approach that might be used for large expenditures that do not occur every year?

A. Yes. Staff states that "[a]lternately, the Commission may choose to allow an amortizing adjustment whereby the nonrecurring excess cost is spread over a number of years so that the test period included only a portion of the expense" (Staff/400, Durrenberger/6, Lines 17-20).

Q. Would you support this general approach for the O&M expenses at Boardman, Colstrip, and Beaver in the 2009 test year?

A. Yes.

Q. Is this approach similar to the treatment of existing long term service agreements at Coyote Springs and Port Westward?

A. Yes, it is conceptually similar, but has some practical differences. For example, the approach discussed here concerns costs in one test year that will be spread over five years, whereas the other two agreements are on-going contracts with service providers.

Q. What elements does a specific approach to these O&M expenses need to include?

A. A structure for recovering these costs should include:

- A comparison of overall 2009 test year O&M costs for Boardman, Colstrip, and Beaver with an average of these costs in recent years.
- Reasonable recovery period.
- Appropriate "return on" component.

Q. Please discuss these features in more detail.

A. Staff focuses on certain statements in PGE Exhibit 400 that discuss only changes in specific plant O&M expenses and make comparisons with 2007 and 2008. The more appropriate question is: How do overall forecasted 2009 O&M costs compare with those incurred in recent years? The overall 2009 test year O&M forecasts for these plants must be compared to an average of several preceding years, on an inflation-adjusted basis.

A regulatory asset should then be established in the amount of the difference between the 2009 test year plant O&M cost forecasts and the relevant averages. This will provide PGE cost recovery, with appropriate interest.

The recovery period for the regulatory asset must be set to balance Staff's objective that base rates be lower with the desire to recover costs over a reasonable period of time.

Q. What is your specific proposal?

A. We propose to first compare forecasted 2009 O&M expenses, as measured by the sum of preventive and corrective maintenance, for Boardman, Beaver, and Colstrip with the 2003-2008 averages of these same expenses. The averages include actual expenses for 2003-2007 and budgeted amounts for 2008, all adjusted for actual or projected inflation to 2009 dollars. The summary comparisons are in Table 2 below:

Table 2
Plant O&M Cost Comparison
($000,000)

Plant	2009 Forecast	2003-2008 Average	Variance
Boardman	$ 5.0	$ 3.5	$ 1.5
Colstrip	$11.0	$ 7.5	$ 3.5
Beaver	$15.0	$13.2	$ 1.8
Total	$31.0	$24.2	$ 6.8

The $6.8 million summary figure is a measure of above average O&M expenditures for the three plants in 2009. Five years is a reasonable period over which to recover this amount. Therefore, we propose to establish a $6.8 million regulatory asset, to be collected over a five-year period, beginning January 1, 2009. PGE Exhibit 1802 provides detail on the regulatory asset balance through the end of 2013, at which point it will be zero, given the annual collection amount of $1.4 million.

For the 2009 test year, both the O&M expenses and rate base proposed by PGE in its initial February 27, 2008, filing must be revised. $6.8 million is a measure of "higher than average" O&M expenses for the three plants in the test year and $1.4 million is the annual collection amount associated with the regulatory asset. The net of these figures, approximately $5.5 million, is the reduction in 2009 test year O&M expenses relative to the initial filing. The average balance of the regulatory asset in the 2009 test year is approximately $6.2 million (or 90% of the January 1, 2009, starting balance, given the five-year collection period and average test year rate base construct). This $6.2 million figure is then added to the rate base included in the initial filing.

Q. Staff recommends that all costs associated with the Boardman stator rewind be capitalized. (Staff/400, Durrenberger/6, Line 23). Do you agree with this approach?

A. Yes. We used this approach in our original filing for our test year revenue requirement.

Q. Are any of the forecasted stator rewind costs included in the regulatory asset you propose above?

A. No. Factors which contribute to the higher than average forecasted test year Boardman O&M costs are tasks such as a boiler acid cleaning and work on the pulverizer pivot brackets.

V. General Production

Q. What is Staff's recommendation for the $0.5 million requested for General Production?

A. Staff recommends rejecting these costs because they are either one time or speculative costs.

Q. Are these costs one-time or speculative?

A. No.

Q. Please explain the $0.5 million in general production costs.

A. $0.1 million is for the RCM group, to aid in plant reliability. The $0.1 million is an increase from 2007 to 2008, with escalation to 2009. The increase is related to two additional plants, Port Westward and Biglow Canyon, coming on-line in 2007 and 2008. These are ongoing costs for reliability consultants to aid implementation of the RCM program and analysis of plant systems and components.

$0.1 million is for miscellaneous software purchases and upgrades. Every year there are many different software packages for which there are license renewals. In 2008, the budget is higher due to license purchases for additional employees. These are expected to be ongoing costs.

$0.3 million is for contract labor for two areas:

- $0.1 million is related to contract labor for civil, mechanical and electrical engineering to cover non-job work. This is required due to the high number of engineering labor hours budgeted to capital jobs.
- $0.2 million is for consultants and outside services, primarily for NERC/WECC compliance procedure development. There is a growing list of NERC compliance guidelines that are approved by FERC with which PGE must comply. These

guidelines are constantly revised, and PGE has to hire contractors to develop procedures to meet these guidelines and document PGE's compliance. It is mandatory to be in compliance; there are civil penalties for non-compliance.

Q. Are these $0.5 million in general production costs unique to 2009?

A. No. Support of the Port Westward and Biglow Canyon facilities will be ongoing. We will continue to have a high number of capital jobs, resulting in a need for some contract engineering to cover non-job work. NERC and WECC requirements will remain mandatory and will continue to change, resulting in an ongoing need to hire consultants to document compliance with existing requirements and develop procedures to meet new requirements. We will also continue to need more software, both new programs and additional licenses for additional employees.

VI. Hydro Relicensing-Related Capital Additions

Q. In PGE Exhibit 400 you took the position that FERC would likely issue a new license for the Clackamas project late in 2009. This was the basis for the initial February 27, 2008, filing assumption that costs incurred to obtain the license would close to book at the end of 2009. However, Staff expresses the view that FERC will not issue a new long-term license for the Clackamas Project until after the 2009 test year. (Staff/100, Owings/21-22). Have you reconsidered the position taken in PGE Exhibit 400?

A. Yes. We are now willing to assume that costs incurred to obtain the license will not close to book until sometime after the end of 2009.

Q. What effect does this have on the test year rate base?

A. Given the "average of averages" methodology used to calculate the test year rate base, the rate base impact is 1/24 of the $65.2 million figure, or approximately $2.7 million. There is no impact on depreciation because none was assumed in PGE's initial February 27, 2008, filing, given the end of 2009 assumption for closure to book.

Q. In PGE's Response to CUB Data Request No. 053, PGE revised its estimated closure date for the Selective Water Withdrawal Structure (SWW), which is a requirement of the new long-term license for the Pelton Round Butte Project. The expected closure date was revised from the end of March 2009 to the end of April 2009. What impact does this change have on rate base and depreciation in the test year?

A. The rate base impact is a decrease of 1/12 of the $80.8 million amount forecasted to close to book, or approximately $6.7 million. The depreciation impact is a decrease of approximately $0.2 million.

Q. Is April 30, 2009 still a reasonable closure date?

A. Yes. We are making good progress on the SWW structure. Erection of the bottom structure component is nearing completion and its placement is scheduled to start in early September and be completed in early November. We expect that the overall SWW structure will be completed prior to April 30, 2009.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1801C	**Copy of Confidential Attachment 048 Supp 1-D, to PGE's Response to CUB Data Request No. 048**
1802	Regulatory Asset Balance and Revenue Requirement Effects

Regulatory Asset (Related to Higher than Average Plant O&M Costs)

Date		Balance		Average Balance For Year	Year
1/1/2009	$	6,844,920			
12/31/2009	$	5,475,936	$	6,160,428	2009
12/31/2010	$	4,106,952	$	4,791,444	2010
12/31/2011	$	2,737,968	$	3,422,460	2011
12/31/2012	$	1,368,984	$	2,053,476	2012
12/31/2013	$	-	$	684,492	2013

2009 Test Year Revenue Requirement Effects

Table of Contents

I. Introduction

Q. What is your name and position with PGE?

A. My name is James J. Piro. I am the Executive Vice President and Chief Financial Officer for PGE. My qualifications appear in PGE Exhibit 100, Section VIII.

My name is Alex Tooman. I am a Project Manager for Regulatory Affairs at PGE. My qualifications appear in PGE Exhibit 200, Section IX.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address the issues raised by other parties related to PGE's administrative and general (A&G) costs.

Q. How is your testimony organized?

A. In the next section, we address Staff's and other parties' concerns regarding the increase in full time equivalent employees (FTEs), specifically as they pertain to A&G. We then respond to issues raised regarding the increase in research and development (R&D) costs. Next, we include a discussion on cost of capital witness fees. We follow with a response to Staff's proposed adjustment to PGE's forecasted insurance expense and uninsured losses. We then provide detail regarding Staff's proposed adjustment related to miscellaneous actual charges in 2007. We conclude with a reply to CUB's concerns regarding Sherman County cost classification.

II. FTEs

Q. By how much do you forecast FTEs to increase for the A&G area.

A. PGE Exhibit 501 identifies a 26 FTE increase for the A&G area (including IT) between 2007 and 2009.

Q. Have you previously provided an explanation for these increases?

A. Yes. In PGE Exhibit 500, we discussed the primary drivers of the cost increases from 2007 to 2009. Consequently, we addressed the larger aspects of these increases as follows:

- Five FTEs in IT are needed to support PGE's customer information system, Banner. PGE discontinued the vendor's maintenance agreement for Banner in April 2007, after determining that it was more cost effective to bring the system expertise in-house. This change produced a savings for PGE by reducing the annual maintenance costs by approximately $650,000, net of the increase in FTEs. More detail on this cost saving can be found in PGE Exhibit 500, Section H.
- Two FTEs in IT to support the WebSphere technology, which provides an integration framework to share data across applications and to ultimately reduce the development and on-going maintenance costs that are otherwise incurred to interface applications directly with one another. More detail on WebSphere can be found in PGE Exhibit 500, Section H.
- 3.5 FTEs for the Business Continuity and Emergency Management Department, which was established to support on-going evaluation, mitigation and response to significant events that may adversely affect service to customers, company assets, and employees. More detail on Business Continuity and Emergency Management can be found in PGE Exhibit 500, Section F.

Q. Can you provide support for the remaining increase of 15 FTEs?

A. Yes. Most of this increase occurs in three functional areas: three FTEs in the Legal Department, five FTEs in IT, and 3.5 positions in Environmental Services. We discuss these in detail below.

Q. What FTEs have been added to the Legal Department?

A. PGE has added FTEs to date to fill the following positions:

- Two attorney positions that were temporarily unfilled in 2007. One of these positions was filled in January 2008 and the other was filled in July 2008.
- One legal assistant position that was temporarily open in 2007 but filled late that year.
- One attorney position filled by an individual with whom PGE previously contracted for outside legal services.

PGE has simply filled temporarily-open positions and replaced one outside contractor with an FTE, keeping legal costs relatively flat as shown in PGE Exhibit 501.

Q. Please explain the five FTEs increase in IT starting with First Position.

A. The first position is central to managing all business application change requests (from inception to delivery) for PGE's Power Supply operations. This position also acts as a subject matter expert guiding business process reengineering efforts and business case development in support of any new and changing business needs. In addition, this position collaborates closely with our applications maintenance team members to ensure our legacy trading applications continue to function according to operation requirements.

Q. What would be the consequences of not hiring this FTE?

A. Not filling this position would have a direct impact on PGE's ability to ensure that all functionality change requests are completed in a timely manner and meet various regulatory requirements, such as those supporting FERC and Reliability Standards. In addition, PGE needs to keep application and infrastructure upgrades current with the technical requirements.

Q. Please discuss the second IT position.

A. This position is for energy management system (EMS) support and is central to managing all System Control Center (SCC) business application change requests from inception to delivery. The position also supports the day-to-day operations of EMS and other ancillary systems for the SCC with any issues that would affect EMS's proper operation. Due to the NERC cyber security constraints and the complexity of the system, remote support is not an option.

Q. What would be the consequences of not hiring this position?

A. Not filling this position could result in untimely response to operational issues, which could adversely impact PGE’s ability to deliver safe, reliable energy. This would also create critical regulatory exposure in not meeting NERC expectations regarding system reliability.

Q. Please explain the third IT position.

A. Not filling this position would have a direct impact on PGE’s ability to ensure that all functionality change requests are done in a timely manner and meet various regulatory requirements, such as those supporting safety, reliability and rate and tariff changes. In addition, PGE also needs to keep application and infrastructure upgrades current with technology versioning requirements. These upgrades require functionality changes in order to support efficient work processes and to perform critical application break-fix and maintenance work.

Q. What would be the consequences of continuing to use a contractor for the work described?

A. This position requires a long-term commitment due to the nature of the work. Currently, the contractor continually improves their skills and gains knowledge from the work they perform. PGE would have a better chance of retaining those skills and knowledge through a regular employee rather than a contractor. In addition, there are some cost savings (approximately $50,000) in hiring an employee versus using a contractor.

Q. Please explain the fourth IT position.

A. This position is responsible for coordinating the completion of all new functionality changes among the approximately 50 software applications used by the Distribution function[1] and is central to managing all Distribution business client-originated functionality change requests from inception to delivery. The position also acts as a subject matter expert guiding business process reengineering efforts and Distribution business case development. In addition, the position collaborates closely with our applications maintenance team to ensure our Legacy distribution applications continue to function as required by Distribution operations.

Q. What would be the consequences of not hiring this position?

A. Not filling this position would have a direct impact on PGE's ability to ensure that all functionality change requests are done in a timely manner and meet various regulatory requirements, such as those supporting safety, reliability and rate and tariff changes. In

[1] For example, in 2008 alone, PGE projects that there are roughly 8,000 hours of work to complete the functional changes in the applications.

addition, PGE also needs to keep application and infrastructure upgrades current with technology versioning requirements. These upgrades require functionality changes in order to support efficient work processes and to perform critical application break-fix and maintenance work.

Q. Please explain the fifth IT position.

A. The final position is a Senior Application Developer. The purpose of this position is to provide on-going technical analysis and support for the Masterpiece software. Masterpiece is PGE's financial enterprise resource planning (ERP) application, which includes Accounts Payable, Accounts Receivable, General Ledger, Purchasing and Inventory Control. This position works closely with our financial business clients to provide systems analysis and technical guidance in response to unusual or complex problems. Additionally, this position provides operational support for the financial applications, which includes on-call support available 24 hours a day, 7 days a week. Finally, this position is responsible for developing, modifying, or enhancing Masterpiece's application functionality, as required, to respond to regulatory, legal, or business needs. These duties were previously performed by a contractor. PGE hired the FTE because of total job requirements and the need to have a long-term dedicated resource to perform these duties.

Q. What would be the consequences of not hiring this position?

A. Not filling this position would have direct impact on PGE's ability to respond to technical/operational issues for our financial system, which could impact PGE's financial closing cycle and regulatory reporting. Additionally, there would be a direct impact on our ability to ensure timely application modifications to address new or changed compliance or legal requirements.

Q. How do you explain the 3.5 FTE increase for Environmental Services starting with the First FTE position?

A. The first position was filled in September 2007 and represents the one-half FTE. The purpose of that position was to provide administrative support for approximately 12 Environmental Services employees stationed at the Pelton Round Butte Project. This position enhances efficiency at the site by performing necessary administrative functions, which allows the biologists, technicians, and supervisor at the Pelton Round Butte Project to concentrate on their primary duties.

Q. Please discuss the second position for Environmental Services.

A. There are two positions for Assistant Fish Biologists. These new positions are an addition to the Native Fish Studies Team at the Pelton Round Butte Project. PGE filled one position in January 2008 and we expect to fill the other position in October 2008. Their primary duties are to assist the Native Fish Studies Team with the implementation of certain required studies. The FERC license requires PGE to conduct native fish monitoring to evaluate effects of reintroducing anadromous fish on resident fish populations in the Deschutes Basin. In addition, studies are required to evaluate the effectiveness of fish passage facilities in achieving fish passage goals. All this work requires year-round biological/technical support, involving field work, data analysis, work planning, and reporting.

Q. What would be the consequences of not hiring for these positions?

A. Without the Assistant Fish Biologists, it is highly unlikely that PGE could complete these activities and thus fulfill or fully comply with our FERC license requirement for the Pelton Round Butte Project.

Q. Please discuss the remaining position you propose for Environmental Services?

A. The third position is an Assistant Wildlife Biologist and was filled in April 2008. Its primary duties are to provide biological support for various terrestrial resource programs throughout PGE, including the Pelton Round Butte Project, Clackamas Hydro Project, Boardman Plant, Biglow Canyon wind farm, Port Westward Generation Project, Bull Run decommissioning, and an avian protection program. In addition, the Clackamas Hydro FERC license, now expected in early 2010, will include additional workload.

Q. What would be the consequences of not hiring for this position?

A. Without this position, it would be extremely difficult for the existing Wildlife Biologists to complete all the requirements throughout PGE. The major terrestrial resource programs are long-term, and it is essential that PGE conform with the FERC license and EFSC site certificate requirements.

Q. How do you justify the remaining four FTEs?

A. We project one FTE in each of four functional areas, including Governmental Affairs, Contract Service/Purchasing, Human Resources, and Facilities and General Plant maintenance. Combined, these functional areas total 151 FTEs and the four incremental FTEs represent an annual 1.4% increase for a general growth of business requirements.

Q. Pleas describe the Governmental Affairs position.

A. The Government Affairs position was vacant through mid-2008. During that time, the environmental policy work was completed by hiring outside consultants. Given the recent increase in environmental policy and sustainability issues at both the state and federal level, PGE believed it was critical to fill this position rather than rely on outside consulting and we have done so.

Q. Please discuss the Contract Service/Purchasing position.

A. This position is for a Buyer whose duties were previously performed by a contractor. PGE made this change because the requirements for this position require experience and training so that the individual can develop long-term effective relationships with qualified reliable suppliers from whom we purchase. Contractors do not receive this training and are a more temporary resource, which can be effective in accommodating growth but only up to a certain point. Finally, PGE filled this position internally, thereby creating an added benefit of hiring someone with working knowledge of PGE.

Q. Please describe the Human Resources position.

A. This position is for a Staffing Specialist to perform the functions of a recruiter, who identifies candidates, assists managers in hiring activities, and assists with employees leaving PGE (exit interviews, separation notices, etc.). This position also administers PGE's corporate-wide summer hire program, which is seasonal, but the work occurs throughout the year. This position is especially relevant because approximately 40% of PGE's workforce is eligible for retirement over the next several years so that there will continue to be an increasing need for hiring and job placement activities. Therefore, assistance to managers is critical so that they can focus on their departmental duties rather than hiring activities.

Q. How do you justify the Facilities and General Plant maintenance position.

A. The facilities position monitors and documents space planning and floor plans using electronic drafting software (AutoCAD). This position interfaces with all levels of PGE employees to determine specific space needs for effective and efficient utilization of office space. In addition, this position develops short and long-term capital, site maintenance, and O&M budgets. We anticipate that the person in this position will be able to purchase commercial real estate and will have property management and leasing experience.

III. R&D

Q. What adjustment have other parties proposed regarding R&D costs?

A. Staff and CUB propose a $1.7 million disallowance for R&D costs in the 2009 test year forecast.

Q. What is their basis for this adjustment?

A. Their basis is to calculate the escalated average of PGE's actual expenditure between 2002 and 2007 (approximately $312,000), and compare this amount to $1,995,000.

Q. Is this reasonable?

A. No, for two reasons. First, their basic calculation is in error because PGE has not requested $2.0 million in R&D costs. Rather, we proposed $1.0 million for R&D as described in PGE Exhibit 500 and listed in PGE Exhibit 501.

Q. How did Staff and CUB arrive at the $2.0 million estimate for R&D?

A. This amount was provided in Attachment 269-B-2 as part of PGE's Response to OPUC Data Request No. 269 (provided as PGE Exhibit 1901). This response, however, shows how much PGE <u>could</u> spend on R&D in 2009 based on all the projects currently identified for potential funding. Attachment 269-B-2 also noted that a number of the amounts listed represent <u>multiple year</u> expenditures. We responded this way for other parties to see the importance of PGE's proposed R&D program and emphasize the nature and magnitude of the programs available. Unfortunately, Staff and CUB have focused on the $2 million to the exclusion of the actual amount requested in the revenue requirement and ignored PGE's explanations that they continue to use an erroneous number.

Q. Is Staff consistent in their use of the $2.0 million reference to PGE's 2009 R&D forecast?

A. No. Staff references the $1.0 million R&D total listed in PGE Exhibit 500 and uses it to calculate their "demonstration of … proposed increase measured from PGE's UE 180 rates" (Staff/100, Owings/6, lines 10-18).

Q. If the Commission were to decide that Staff's basic approach is appropriate, what should be the adjustment to PGE's revenue requirement for R&D costs?

A. Based on Staff's method of escalating the average of historical costs, the maximum reduction of R&D costs would be $678,000 ($1 million – $312,000) and not $1,678,000 ($2 million – $312,000). An adjustment to PGE's costs should **not** be greater than the amount we are actually requesting for those costs.

Q. Does PGE propose any adjustments to the forecast for R&D costs?

A. Yes. Based on the other parties' comments that they do not approve of PGE's R&D forecast and are more interested in cost reductions, PGE proposes that we reduce the R&D forecast from $1.0 million to $500,000.

Q. What is the second reason that PGE believes Staff's and CUB's adjustment is excessive?

A. The second reason is that the projects that PGE has identified for 2009 are important in the long-term for customers and the environment. Ultimately, with PGE's proposed $500,000 forecast for R&D, reduced funding and impacts will occur in the following areas:

Distributed Standby Generation:

Funding would be reduced to 20% of projected effort (i.e., $250,000 to $50,000). PGE would focus on the use of cleaner fuels and introduction of renewable fuels such as biodiesel for amenable generators. R&D would decline for: 1) further testing of dual fuel applications, 2) network optimization for increasing units coming on line, and 3) improved control systems for integration of distributed generation.

Distributed Energy Storage:

Funding would be reduced to 40% of projected effort (i.e., $250,000 to $100,000). PGE would focus on the use of rapidly evolving plug-in electric vehicles and high power density, deep cycle, advanced batteries. EPRI research in this area – especially in compressed air storage – would be reduced as would efforts around energy storage in ice. The overall impact involves deriving less understanding and capability in using distributed energy storage opportunities to help with peak shaving and the intermittency associated with renewable power resources such as wind and solar.

Highly Efficient Community Scale Infrastructure:

Funding would be reduced to 20% of projected effort (i.e., $285,000 to $60,000). PGE would focus on small demonstration projects to the extent they can be leveraged with interested partners. It would be unlikely that any sizable demonstration would be initiated at this level of funding. Costlier, but highly efficient and versatile technologies such as geothermal heat pump community loops would not be pursued. The overall impact would be to lose impetus in this arena of community scale space heating and cooling and local renewable power generation that involves low to no carbon emissions.

Infrastructure Reliability, Maintenance, Sustainability:

Funding would be reduced to 67% of projected effort (i.e., $150,000 to $100,000). PGE would focus on continued work on system security improvements and any efforts that could reduce system faults and outages and/or improve efficiency.

Anticipating Carbon / Greenhouse Gas Regulation:

Funding would be reduced to 17% of projected effort (i.e., $750,000 to $125,000). Ultimately, PGE would be contributing not much more than token support in the areas around carbon emission mitigation as manifested in imminent greenhouse gas regulation. Control and reduction of these emissions will have a large impact on PGE and its customers especially in helping determine the viability of a power generation and base load mix that has sufficient fuel diversity for reliability and economic purposes. R&D efforts supporting carbon offset opportunities, such as tree planting and other ecological services monetization, would decline.

Renewable Power or Highly Efficient Generation:

Funding would be reduced to 30% of projected effort (i.e., $150,000 to $50,000). PGE would focus only on projects that have received support in the past (e.g. wave power) and perhaps one or two smaller efforts. Research into efficient, reliable, and safe integration of many small scale wind and solar applications to the grid would be significantly reduced.

IV. Cost of Capital Witness

Q. Please summarize CUB's recommendation regarding PGE's requested ROE increase and the cost of PGE's cost of capital witness.

A. CUB believes that PGE's request for an increased ROE was "inappropriate and unnecessary" (CUB/100, Jenks/40) and believes the cost associated with PGE's use of an outside cost of capital witness should be removed from the revenue requirement. (CUB/100, Jenks/42)

Q. Why did PGE use an outside cost of capital witness?

A. PGE last used a cost of capital witness in UE 180, which was filed in 2006. In UE 188, PGE did not use a cost of capital witness. Therefore, it had been two years since PGE had performed a study to evaluate the need to request a change in its cost of capital.[2] Since Commission Order No. 07-015 in January 2007 (UE 180), financial markets became more volatile, making the required ROE determination more complex and difficult. PGE hired an outside expert that was familiar with such complexity and based our initial estimate of PGE's cost of capital on the expert's results.

What CUB fails to mention is that there is more to PGE's required cost of capital than just the return on equity. We also filed with a different cost of debt and evaluated our capital structure because the 2009 forecasted equity had declined from 2007.

Q. Was PGE's request for an increased ROE "inappropriate and unnecessary"?

A. No. CUB's complaint seems to imply that had we not settled at the currently authorized ROE in UE 197, the expenditures would then be prudent. This is not logical and is based entirely on hindsight.

[2] In UE 180 and UE 115, cost of capital was a highly contested issue that was decided by the Commission.

Q. CUB also implies that PGE assumed the continuation of the UE 180 capital cost and structure by referencing that PGE held these constant in its financial projections for S&P in December 2007. (CUB/100, Jenks/41, Lines 7-9) Why did PGE make this assumption?

A. As we noted in PGE's Response to CUB Data Request No. 030 (provided as Exhibit 1902) our financial forecasts assume annual regulation, which normally includes our currently authorized return on equity and capital structure. Consequently, not only did PGE's financial projections for S&P in December 2007 include the UE 180 capital structure and ROE, but subsequent projections would continue to do so until the next general rate case and associated Commission order. This, however, is not an indication of PGE's projections for a general rate case.

Q. Should CUB's recommended adjustment be made to the 2009 test year?

A. No. PGE's expenses for a cost of capital witness measured in 2007 and 2008 should not be removed from the 2009 test period.

V. Insurance and Losses

Q. What adjustments does Staff recommend on insurance expense?

A. Staff recommends an adjustment of $2.1 million to insurance premiums and a $1.8 million adjustment to uninsured losses.

Q. Do you agree with these adjustments?

A. No. I will first discuss the insurance premiums followed by the uninsured losses.

A. Insurance Premiums

Q. Please explain Staff's adjustment to Insurance Premiums.

A. Staff adjusted the Supplemental Director's and Officer's (D&O) Liability Insurance, citing two studies that found shareholders' claims are the largest source of the D&O risk and that 50% of the claims against such policies are from shareholders.

Q. Is this adjustment reasonable?

A. No. The D&O insurance provides adequate protection for frivolous lawsuits brought against a company's directors and officers. Consequently, it is part of a complete benefits package that attracts highly qualified directors and officers to PGE. Without adequate coverage, PGE would not be able to attract the executives needed to effectively guide PGE. As a necessary cost of a regulated utility, the D&O insurance coverage should be included in PGE's 2009 test year forecast.

Q. What are the consequences of such an adjustment?

A. If Staff's adjustment were approved by the Commission, PGE would have no alternative but to continue to provide the D&O insurance to directors and officers. By not allowing full cost recovery of D&O insurance premiums, the Commission would essentially not be providing PGE with the opportunity to earn its authorized rate of return. In addition, if the SB 408 taxes-paid ratios are not adjusted, customers will actually receive an SB 408 refund because PGE had to incur these costs.

Q. Do you have further comments regarding the insurance premiums?

A. Yes. PGE has recently renewed several of its property insurance policies and we have updated information regarding our premiums. These premiums have been reduced to a significant extent due to PGE's good operations and our efforts to: 1) utilize a variety of means to manage the cost of our insurance expenses, and 2) negotiate the best terms and conditions to reduce insurance premiums, including maximizing the use of industry mutual companies. Table 1 below reflects those policy renewals and calculates a revision to Staff's adjustment based on those updates.

Table 1

PGE Insurance Adjustment for 2009 Test Year

Insurance Premium	Updated Forecast	UE 197 Original Forecast
Property	4,235,989	4,363,269
Worker's Comp	279,985	282,613
Liability	3,867,062	4,343,835
Credit	(220,000)	
Totals	8,163,036	8,989,717
PGE's Proposed Adjustment	(826,681)	

Q. What is the last issue related to Insurance Premiums?

A. Staff used a Utility Allocation Factor to adjust the insurance premium costs. However, this allocation is redundant given that PGE already applies a Corporate Governance allocation and labor loadings to adjust the relevant A&G costs to capital and "below the line." Therefore, Staff's Utility Allocation factor is inappropriate.

Q. How do all these factors change Staff's adjustment?

A. Staff's total adjustment is a $2.1 million reduction to PGE's insurance costs. By adding back Staff's D&O adjustment, updating the property insurance policies, and deleting the use of the allocation factor, the adjustment to PGE's insurance costs should be a reduction of $0.8 million.

B. Uninsured Losses

Q. Please describe Staff's adjustment for Uninsured Losses.

A. Staff escalated five years of PGE's historical losses (2003 through 2007) to 2008 dollars and then averaged the total. Staff then escalated this average to 2009 dollars to calculate a $2.3 million proposal for PGE's 2009 Uninsured Losses.

Q. Do you agree with Staff's methodology?

A. Not entirely. We do not agree that the formulaic approach is an appropriate basis for determining future Uninsured Losses given our actuarial studies, but we acknowledge Staff's and other parties' concerns regarding increasing costs. Consequently, we accept Staff's approach in this instance with two qualifiers.

Q. What is your first qualifier?

A. Staff used the Consumer Price Index for all Urban Consumers (CPI-U) calculated by the Bureau of Labor Statistics. While we agree with the use of the CPI-U, Staff did not apply the correct CPI to the respective uninsured losses and is off by one year in their calculations.

Q. How has Staff misapplied the CPI-U?

A. Staff applied the 2003 amounts to the 2003 CPI-U. This is incorrect since the effects of the 2003 CPI-U are already included in the 2003 amounts. For data represented in 2003 dollars, the CPI-U for 2004 should be applied to the 2003 amount to arrive at 2004 dollars. Staff has this error in each year's calculation.

Q. Is there anything else you wish to discuss regarding Staff's analysis?

A. Yes. PGE Exhibit 1903, (which provides the US Economic Outlooks from 2004 through 2008) shows the CPI-U from 2004 through 2007. For the 2008 and 2009 forecast, we used 4.8% and 2.3% escalators, as listed in the most current publication on U.S. Economic Outlook by Global Insight, which was issued in June 2008.

Q. What is the result of PGE's analysis compared to Staff?

A. Staff adjustment was $1,798,860 and PGE's recommended adjustment is slightly less at $1,738,579.

VI. Miscellaneous Charges

Q. What adjustments has Staff proposed for miscellaneous costs?

A. Staff has proposed a number of adjustments to miscellaneous A&G and O&M based on their review of transaction listings from PGE's 2007 actual costs. Because of the similar nature of these adjustments, we address them all here.

Q. What is the nature of these adjustments and for what amounts are they?

A. As a result of Staff's review of PGE's 2007 transaction listings, they identified certain costs that they believed should not be included in the 2009 test year forecast. These costs encompassed several categories and can be summarized as follows:

- Catering – $173,370
- Gifts – $79,652
- Promotional – $137,460
- Civic Activities – $91,327
- Other – $277,544

Staff's rationale is that these expenses are discretionary, not core to PGE's business, and not directly related to the generation, transmission and distribution of electricity. Staff cites OPUC Order No. 87-406 and further notes that eliminating 100 percent of the expenses for civic activities is because "Commission policy does not require customers to support causes in which they do not believe" (Staff/300, Ball-Dougherty/15, lines 9-11).

Q. Are Staff's adjustments reasonable?

A. No. Staff's approach entails two fallacies: 1) they simply reviewed a listing with vendor's names, and without further review of the costs, made assumptions regarding what the costs entailed, and 2) they assumed that the same costs would apply to the 2009 forecast. Consequently, we believe Staff's adjustments are inappropriate.

Q. What is PGE's position on costs for catering and gifts?

A. We observe that catering includes costs for employee meetings, including lunch meetings, and that gifts relate to sympathy flowers (for deaths in employees' families), team days for PGE employees, and holiday supplies/activities.

Q. What is the nature of the promotional items and civic activities?

A. Promotional items include retirement gifts for many years of service as well as clothing items in lieu of cash bonuses for employees who perform significant amounts of unpaid overtime for major projects including operating telephones during major storm outages. Minor rewards for years of service or for significant unpaid overtime would seem to contradict Staff's claim that these "are not directly related to generation, transmission, and distribution of electricity" (Staff/300, Ball-Dougherty/14).

The category Staff refers to as civic activities includes costs for internships for student workers (which again relate to work performed on utility activities), service awards for PGE employees, and costs that relate to workforce development.

Q. What other adjustments has Staff proposed as miscellaneous items?

A. Staff has proposed the following adjustments with which we disagree:

- Environmental services – $49,532
- Legal costs – $66,295
- Rent Expense – $24,140
- Tree trimming – $51,356
- Non-essential activity – $13,200

Q. Why is Staff opposed to these environmental services?

A. Staff does not appear to oppose these costs although they originally classified them as Civic Activities. Staff describes them accurately but then states that "these types of costs would be more appropriately included in licensing costs" (Staff/300, Ball-Dougherty/16). Ironically, their solution to this statement is not to propose a reclassification, but to remove them from PGE's revenue requirement. PGE is willing to consider a proposal to reclassify these compliance costs. However, Staff has neither stated the costs are inappropriate nor have they provided any evidence to suggest they are inappropriate, so excluding them is not appropriate.

Q. Why does Staff propose to reduce these legal costs?

A. Staff's proposal is based on the fallacy discussed in PGE Exhibit 1300 regarding one-time costs. These specific legal costs, incurred in 2007, relate to the California refund for energy contracts. These are one-time costs in the same sense that most of PGE's legal proceedings represent one-time costs. In addition, even if these were non-recurring or extraordinary items, they occurred in 2007. Hence, they are not included in the 2009 forecast because the California issue is completely resolved. Consequently, there is no reason to exclude these costs from the 2009 forecast because there was nothing further for PGE to budget for this activity in either 2008 or 2009.

Q. What is the basis for Staff's adjustment to rent expense?

A. Similar to environmental services, above, Staff describes these costs accurately[3] and does not object to their basic nature, but then states that "The 2008 costs were removed because PGE's transaction summaries included a 2007 cost. Without further information, this would

[3] Annual rent for storage of some of PGE's underground materials and equipment.

result in double counting" (Staff/300, Ball-Dougherty/16). However, we note that this cost occurs in more than one year, so it does not violate Staff's rigid "one-time cost" parameter. Unfortunately, Staff appears to apply a very inconsistent standard by saying that if this is not a one-time cost, then it is double counted.[4] This rental is nothing more than a legitimate cost that is incurred over a period of time, but is not invalid because that period spans more than one year.

Q. Did Staff include a miscellaneous adjustment regarding tree trimming?

A. Yes. We discuss this in detail in PGE Exhibit 1600, but note that Staff is already proposing an adjustment to PGE's tree trimming costs. They are also proposing to remove all of PGE's incremental FTEs from 2007 to 2009. Consequently, the miscellaneous adjustment regarding tree trimming involves genuine double counting in Staff's adjustment.

Q. What is the basis for Staff's $13,200 adjustment described as "non-essential activity"?

A. This is another example where Staff made assumptions regarding a cost based solely on the name of the vendor, which in this case was OMSI. In reality, this cost is a rent expense that PGE pays OMSI for the use of parking spaces for the nearby Hawthorne Building. The Hawthorne Building houses the following PGE groups:

- Cash remittance
- Line center for local underground line work
- Underground materials store room
- Offices for service design consultants

[4] If both of these standards are valid, then PGE would have **no** costs that qualify for recovery.

Because the Hawthorne Building does not have any parking spaces available for the PGE employees who work there, PGE pays for the use of parking spaces at OMSI to make them available.

Q. Did Staff propose any additional adjustments to the Other category?

A. Yes. Staff also proposed an additional adjustment for approximately $73,000 for four other items that Staff characterizes as political activity, corporate image, and other non-essential costs. We disagree with these adjustments because they represent 2007 actual costs that are not included in the 2009 forecast.

VII. Sherman County Cost Classification

Q. What adjustment has CUB proposed regarding the Sherman County Strategic Investment Program (SIP) Payments?

A. CUB has proposed that these costs be functionalized to generation based on cost causation rather than be allocated as a support cost typical of other A&G.

Q. What is PGE's response to CUB's proposal?

A. PGE believes CUB's proposal is reasonable and we will make this correction to our unbundled revenue requirement.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1901	PGE Response to OPUC Data Request No. 269
1902	PGE Response to CUB Data Request No. 030
1903	US Economic Outlooks from 2004 through 2008

May 8, 2008

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to OPUC Data Request
Dated April 21, 2008
Question No. 269

Request:

Please provide a summary for each year of the amount PGE has spent on Research and Development for the years 2002 through 2007.

a. Please provide a breakout for each year identifying the major projects PGE researched and the amount spent in that category for the time period between 2002 and 2007.

b. Please identify the amount budgeted for 2008 and 2009 for in each major category PGE identifies as projects for research and development.

Response:

See Attachment 269-A that provides annual R&D projects and amounts spent for the years 2002 through 2007.

PGE did not conduct R&D projects in 2003. Company-wide efforts at cost containment were the driving factor in this decision. In the period 1994 to present, this was the only time where R&D, as a corporate function, was not pursued.

See Attachment 269-B which provides 2008 and 2009 budgets for R&D projects.

UE 197
Attachment 269-A

Research and Development Projects

See Excel File
(Projects 2002 through 2007)

UE 197
Attachment 269-B

Research and Development Budgets
For years 2008 and 2009

UE-197
PGE Responses to OPUC Data Request No. 269
Attachment 269-B -1(2008)

Funded Research Projects in 2008 – To Date (April / 2008) *

Project	Approved Funding	
N44706 Corporate R&D, Supply Energy		
OSU Wave Energy Research	20,000	
Finite Element Modeling to Decrease Repair Costs and Increase Reliability at PGE Hydro & Thermal Plants	25,000	
Canemah Bluffs Micro-Hydroelectric Feasibility Study	10,000	
Geothermal Investigation of PGE Leased Lands NE of Mt. Hood	15,000	
Boiler Life and Availability Improvement EPRI Target 63	29,882	
Collaborative Analysis of CO2 Policy Impacts on Western Power Markets EPRI tailored collaboration	5,000	
Development and Evaluation of Grid-Support Infrastructure Application for PHEVs – EPRI Target 18.012	8,564	
Multi-pollutant Technology Evaluations and Databases – EPRI Target P75.001	12,630	
Subtotal		121,076
N44707 Corporate R&D, Delivery System		
PNNL Real-Time Appliance Load Modulation **	25,000	
Exacter Outage Avoidance System	15,000	
Subtotal		40,000
N44708 Corporate R&D, Serve Customers		
Community Geothermal & Municipal Water Heat Exchange Program	35,000	
Plug-in Electric Vehicle Initiative – Charging Station Pilot Project **	10,000	
Subtotal		45,000
N44799 Corporate Membership		
GRIDAPP Utility Consortium Membership	50,000	
Subtotal		50,000
Total	**$256,076**	$256,076

* Approximately $40,000 remains in the $304,000 2008 R&D budget at this point in time

** Also funded at this level into 2009

UE-197
PGE Response to OPUC Data Request No. 269
Attachment 269-B-2 (2009)

Summation of Specific Topical Research Areas For 2009

R & D Research Area*	Sub-Total Cost	Total Cost ($)
Distributed Standby Generation		275,000
• Testing fuel additives to extend biodiesel shelf life in support of diesel applications		
• Testing of evolving IEEE standards for DSG applications on localized electrical networks		
• Protocol development and testing of DSG with AMI		
• PNNL Real-Time Appliance Load Modulation		
Distributed Energy Storage		
Plug-in Electric Hybrid Vehicles		
• Plug-in Electric Vehicle Initiative – Charging Station Pilot Project	10,000	
• Conversion of two hybrids w/ advanced battery	75,000	
• New EV with advanced battery	75,000	
• Joint Partnership w/ manufacturer	100,000	
Sub-total	260,000	260,000
Ice Storage demonstration	125,000	125,000
Highly Efficient Community-Scale Infrastructure		
• Solar-Ready Homes	50,000	
• Geothermal Heat Pump Community Loop	50,000	
• Municipal Water Coupled Heat Pump	125,000	
• Ductless Mini-Split Applications	60,000	
Sub-total	285,000	285,000
Infrastructure Reliability, Maintenance, Sustainability		150,000
• Extending power pole life through in-field inspection and treatment		
• Specific university level research into mechanisms that decrease pole life		

* Some of these projects will undoubtedly be funded on a multi-year basis (beginning 2009 and ending in 2010)

UE-197
PGE Response to OPUC Data Request No. 269
Attachment 269-B-2 (2009)

R & D Research Area*	Sub-Total Cost	Total Cost ($)
• Continuing research in minimizing our system infrastructure impacts on wildlife and local ecology		
• Updating PGE's very progressive forest management plan to include the latest management thinking		
• Testing and demonstrations for transmission and distribution upgrades that allow early failure detection and prevention		
Anticipating Carbon / Greenhouse Gas Regulation		
• Carbon Capture from Flue Gas	225,000	
• Biotic Capture & Storage from Flue Gas	75,000	
• Geologic Carbon Storage from Flue Gas	150,000	
• Other Biotic Carbon Storage Opportunities	150,000	
• Capture or mitigation of other GHGs	100,000	
• Tree Planting as an Ecological Service	50,000	
Sub-total	750,000	750,000
Renewable Power Or Highly Efficient Generation		150,000
• Testing "drop-off" sensitivity to grid frequency variation for solar photovoltaic inverters		
• Test and demonstration of various solar array, environmental conditions and energy storage combinations		
• Complimentarity assessments for co-located wind and solar powered resources		
• Compatibility and complimentarity studies of co-located eco-roofs and solar PV installations		
• Formal studies of physical and infrastructural limitations for large scale solar PV and solar hot water penetration in PGE's service territory		
Total		**$1,995,000**

May 02, 2008

TO: Lowrey Brown
Citizens' Utility Board

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to CUB Data Request
Dated April 23, 2008
Question No. 030

Request:

(The original request from CUB was marked Confidential, however upon review, PGE has determined that the request does not need to be confidential.)

In PGE's confidential presentation to S&P of December 2007, (Staff DR_18 Attach B, *Annual Review S&P 12-07*, page 62), the Company projects new rates from general rate cases ("general price increases") going into effect both in 2009 (UE 197) and 2010 (next year). Please list the factors that make the Company project another general rate increase next year (with rates going into effect in 2010).

Response:

For the purpose of these projections we assumed annual regulation at our currently allowed ROE (50/50 capital structure) for 2009 and 2010 since the decision had not yet been made regarding the need for a general rate case in those years. In general, in PGE's extended forecasts (beyond one year), annual regulation is assumed. At this time, PGE has not determined whether to pursue a general rate increase in 2010.

file

U.S. ECONOMIC OUTLOOK

JUNE 2008

GLOBAL INSIGHT
www.globalinsight.com

TABLE 1
Prices and Wages

	2007:4	2008:1	2008:2	2008:3	2008:4	2009:1	2007	2008	2009	2010	2011	2012	2013
Indexes													
Employment Costs (Dec 2005=1.000)	1.065	1.073	1.082	1.091	1.100	1.108	1.052	1.087	1.120	1.150	1.185	1.224	1.264
Wages & Salaries	1.067	1.076	1.083	1.092	1.100	1.107	1.055	1.088	1.118	1.147	1.179	1.214	1.249
Benefits	1.058	1.064	1.077	1.088	1.099	1.109	1.045	1.082	1.122	1.158	1.198	1.245	1.296
Health Insurance	1.100	1.101	1.113	1.127	1.135	1.146	1.074	1.119	1.162	1.215	1.278	1.347	1.419
Consumer Prices (1982-84=1.000)													
All-Urban	2.106	2.128	2.154	2.197	2.213	2.218	2.073	2.173	2.223	2.252	2.290	2.329	2.368
Core (excl. Food & Energy)	2.126	2.139	2.149	2.164	2.179	2.192	2.107	2.158	2.210	2.257	2.304	2.353	2.402
Commodities	1.401	1.403	1.404	1.411	1.419	1.425	1.401	1.409	1.433	1.451	1.468	1.485	1.498
Nonenergy Services	2.561	2.582	2.599	2.617	2.635	2.651	2.531	2.608	2.675	2.739	2.802	2.870	2.938
Food	2.062	2.087	2.121	2.151	2.176	2.195	2.029	2.134	2.213	2.246	2.285	2.333	2.383
Energy	2.217	2.313	2.457	2.727	2.746	2.672	2.077	2.561	2.553	2.442	2.410	2.373	2.321
Energy Commodities	2.677	2.843	3.015	3.446	3.458	3.316	2.410	3.190	3.107	2.894	2.812	2.735	2.638
Energy Services	1.880	1.908	2.030	2.147	2.174	2.168	1.863	2.065	2.140	2.129	2.149	2.152	2.145
Producer Prices, Stage of Processing (1982=1.000)													
Finished Goods	1.705	1.743	1.794	1.853	1.869	1.871	1.666	1.815	1.865	1.866	1.875	1.885	1.890
Core (excl. Food & Energy)	1.629	1.646	1.664	1.684	1.705	1.719	1.617	1.675	1.732	1.760	1.786	1.811	1.832
Food	1.705	1.749	1.769	1.791	1.805	1.809	1.670	1.778	1.812	1.808	1.811	1.829	1.852
Energy	1.677	1.758	1.916	2.105	2.108	2.074	1.563	1.972	2.011	1.944	1.912	1.874	1.821
Consumer Goods	1.785	1.832	1.896	1.972	1.986	1.984	1.735	1.922	1.972	1.963	1.967	1.974	1.977
Core Consumer Goods	1.715	1.735	1.757	1.781	1.803	1.818	1.700	1.769	1.831	1.860	1.889	1.918	1.945
Producer Goods	1.502	1.515	1.528	1.544	1.563	1.575	1.495	1.538	1.588	1.615	1.637	1.655	1.669
Intermediate Materials	1.753	1.815	1.904	1.979	1.997	1.988	1.707	1.924	1.974	1.968	1.984	1.992	1.987
Crude Materials	2.228	2.499	2.796	2.914	2.762	2.719	2.071	2.743	2.671	2.614	2.558	2.514	2.454
Percent Change, SAAR													
Employment Costs	3.5	3.0	3.4	3.5	3.4	3.0	3.1	3.3	3.1	2.7	3.0	3.3	3.3
Wages & Salaries	3.1	3.4	2.8	3.2	3.0	2.6	3.4	3.1	2.8	2.5	2.8	3.0	2.9
Benefits	3.1	2.3	4.8	4.2	4.1	3.8	2.4	3.5	3.7	3.2	3.5	3.9	4.1
Health Insurance	7.6	0.5	4.1	5.3	3.0	3.8	4.8	4.2	3.8	4.5	5.2	5.4	5.4
Consumer Prices													
All-Urban	5.0	4.3	5.1	8.1	3.0	1.0	2.9	4.8	2.3	1.3	1.7	1.7	1.6
Core (excl. Food & Energy)	2.5	2.5	1.9	2.8	2.7	2.4	2.3	2.4	2.4	2.1	2.1	2.1	2.1
Commodities'	0.4	0.5	0.2	2.2	2.1	1.8	-0.4	0.6	1.7	1.3	1.2	1.1	0.9
Nonenergy Services	3.3	3.3	2.6	2.9	2.7	2.5	3.4	3.1	2.6	2.4	2.3	2.4	2.4
Food	3.8	4.9	6.7	5.8	4.7	3.5	4.0	5.2	3.7	1.5	1.7	2.1	2.1
Energy	29.3	18.5	27.4	51.7	2.8	-10.4	5.6	23.3	-0.3	-4.4	-1.3	-1.5	-2.2
Energy Commodities	50.5	27.2	26.6	70.6	1.4	-15.4	8.3	32.4	-2.6	-6.9	-2.8	-2.7	-3.6
Energy Services	4.6	6.2	28.2	25.0	5.2	-1.2	2.3	10.8	3.6	-0.5	0.9	0.1	-0.3
Producer Prices, Stage of Processing													
Finished Goods	9.1	9.2	12.1	13.9	3.4	0.4	3.9	8.9	2.8	0.1	0.5	0.5	0.3
Core (excl. Food & Energy)	1.7	4.4	4.4	4.9	5.0	3.3	1.9	3.6	3.4	1.6	1.4	1.4	1.2
Food	9.7	10.6	4.6	5.2	3.0	1.0	6.5	6.5	1.9	-0.2	0.2	1.0	1.2
Energy	31.0	20.9	40.9	45.7	0.6	-6.2	7.2	26.2	2.0	-3.3	-1.6	-2.0	-2.8
Consumer Goods	11.4	10.9	14.8	16.9	3.0	-0.5	4.5	10.8	2.6	-0.4	0.2	0.4	0.1
Core Consumer Goods	2.0	4.8	5.2	5.5	5.0	3.3	2.0	4.0	3.5	1.6	1.5	1.6	1.4
Producer Goods	1.3	3.6	3.6	4.2	4.8	3.3	1.8	2.9	3.3	1.7	1.3	1.1	0.8
Intermediate Materials	9.4	14.9	20.9	16.9	3.5	-1.6	4.1	12.7	2.6	-0.3	0.8	0.4	-0.3
Crude Materials	39.9	58.2	56.7	17.9	-19.3	-6.0	12.1	32.5	-2.6	-2.2	-2.1	-1.7	-2.4

UE 197 / PGE Exibit / 1903
Piro - Tooman / 3

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U.S. ECONOMIC OUTLOOK

SEPTEMBER 2007

GLOBALINSIGHT
www.globalinsight.com

UE 197 / PGE Exibit / 1903
Piro - Tooman / 4

TABLE 1
Prices and Wages

	2007:1	2007:2	2007:3	2007:4	2008:1	2008:2	2006	2007	2008	2009	2010	2011	2012
Indexes													
Employment Costs (Dec 2005=1.000)	1.039	1.048	1.056	1.065	1.073	1.080	1.021	1.052	1.084	1.116	1.151	1.188	1.228
Wages & Salaries	1.043	1.051	1.059	1.066	1.073	1.080	1.020	1.055	1.083	1.113	1.146	1.180	1.215
Benefits	1.031	1.042	1.052	1.063	1.073	1.082	1.021	1.047	1.086	1.122	1.163	1.209	1.259
Health Insurance	1.053	1.066	1.081	1.095	1.105	1.115	1.025	1.074	1.120	1.162	1.215	1.278	1.347
Consumer Prices (1982-84=1.000)													
All-Urban	2.041	2.071	2.079	2.082	2.092	2.102	2.016	2.068	2.106	2.145	2.186	2.225	2.264
Core (excl. Food & Energy)	2.090	2.100	2.113	2.122	2.132	2.141	2.059	2.106	2.145	2.185	2.227	2.271	2.316
Commodities	1.403	1.399	1.401	1.403	1.406	1.408	1.406	1.401	1.410	1.424	1.434	1.443	1.452
Nonenergy Services	2.501	2.520	2.539	2.553	2.566	2.579	2.447	2.528	2.585	2.639	2.701	2.765	2.831
Food	1.994	2.019	2.041	2.054	2.063	2.073	1.952	2.027	2.076	2.115	2.154	2.193	2.232
Energy	1.922	2.120	2.076	2.014	2.033	2.050	1.967	2.033	2.054	2.094	2.126	2.130	2.128
Energy Commodities	2.099	2.486	2.418	2.281	2.260	2.264	2.227	2.321	2.264	2.288	2.325	2.328	2.319
Energy Services	1.857	1.874	1.856	1.872	1.934	1.967	1.821	1.865	1.974	2.036	2.063	2.069	2.074
Producer Prices, Stage of Processing (1982=1.000)													
Finished Goods	1.625	1.664	1.670	1.673	1.695	1.706	1.603	1.658	1.709	1.744	1.768	1.783	1.796
Core (excl. Food & Energy)	1.606	1.613	1.622	1.630	1.644	1.655	1.587	1.618	1.659	1.691	1.715	1.735	1.754
Food	1.641	1.669	1.686	1.674	1.671	1.682	1.567	1.668	1.680	1.704	1.728	1.748	1.768
Energy	1.433	1.567	1.558	1.558	1.620	1.631	1.458	1.529	1.638	1.683	1.705	1.698	1.689
Consumer Goods	1.681	1.733	1.739	1.740	1.765	1.777	1.660	1.723	1.781	1.818	1.844	1.859	1.873
Core Consumer Goods	1.685	1.693	1.704	1.714	1.728	1.740	1.666	1.699	1.745	1.780	1.808	1.833	1.856
Producer Goods	1.488	1.494	1.502	1.509	1.521	1.530	1.469	1.498	1.534	1.562	1.580	1.595	1.607
Intermediate Materials	1.654	1.703	1.714	1.724	1.741	1.747	1.639	1.699	1.749	1.771	1.787	1.797	1.802
Crude Materials	1.934	2.065	2.045	2.030	2.167	2.129	1.848	2.018	2.136	2.180	2.178	2.156	2.135
Percent Change, SAAR													
Employment Costs	2.3	3.5	3.3	3.2	3.0	2.7	2.9	3.1	3.0	2.9	3.2	3.2	3.3
Wages & Salaries	4.3	3.1	3.0	2.7	2.6	2.6	2.9	3.4	2.7	2.8	2.9	2.9	3.0
Benefits	-1.2	4.3	4.0	4.2	3.9	3.1	2.9	2.6	3.7	3.3	3.7	3.9	4.1
Health Insurance	1.7	4.7	5.9	5.2	3.7	3.8	4.9	4.8	4.3	3.7	4.5	5.2	5.4
Consumer Prices													
All-Urban	3.8	6.0	1.6	0.6	2.0	1.9	3.2	2.6	1.9	1.8	1.9	1.8	1.7
Core (excl. Food & Energy)	2.3	1.9	2.4	1.8	1.8	1.7	2.5	2.3	1.9	1.8	2.0	2.0	2.0
Commodities'	-0.1	-1.0	0.5	0.6	0.8	0.8	0.2	-0.4	0.6	1.0	0.8	0.6	0.6
Nonenergy Services	3.3	3.1	3.1	2.2	2.1	2.0	3.4	3.3	2.3	2.1	2.3	2.4	2.4
Food	5.2	5.1	4.5	2.4	1.9	1.9	2.3	3.8	2.4	1.8	1.9	1.8	1.8
Energy	16.0	48.1	-8.1	-11.3	3.8	3.4	11.1	3.4	1.0	2.0	1.5	0.2	-0.1
Energy Commodities	17.7	96.7	-10.5	-20.8	-3.5	0.7	12.8	4.2	-2.5	1.1	1.6	0.1	-0.4
Energy Services	13.9	3.7	-3.7	3.3	14.0	7.0	9.4	2.4	5.9	3.1	1.3	0.3	0.3
Producer Prices, Stage of Processing													
Finished Goods	6.7	10.0	1.6	0.7	5.2	2.7	2.9	3.4	3.1	2.0	1.4	0.8	0.7
Core (excl. Food & Energy)	3.1	1.7	2.3	2.1	3.3	2.7	1.5	2.0	2.5	1.9	1.4	1.2	1.1
Food	14.8	7.0	4.1	-2.8	-0.7	2.6	0.6	6.4	0.7	1.5	1.4	1.2	1.1
Energy	9.2	43.0	-2.4	0.0	16.9	2.8	10.0	4.9	7.1	2.8	1.3	-0.4	-0.6
Consumer Goods	7.8	12.8	1.5	0.3	5.9	2.8	3.4	3.8	3.3	2.1	1.4	0.8	0.7
Core Consumer Goods	3.2	1.8	2.6	2.4	3.4	2.8	1.5	2.0	2.7	2.0	1.6	1.4	1.3
Producer Goods	2.6	1.6	2.1	2.0	3.1	2.5	1.5	2.0	2.4	1.8	1.2	0.9	0.7
Intermediate Materials	4.2	12.4	2.4	2.4	4.0	1.5	6.4	3.6	3.0	1.3	0.9	0.6	0.3
Crude Materials	28.7	30.0	-3.9	-2.8	29.9	-6.8	1.4	9.2	5.8	2.1	-0.1	-1.0	-1.0

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U.S. ECONOMIC OUTLOOK

OCTOBER 2006

GLOBALINSIGHT
www.globalinsight.com

TABLE 1
Prices and Wages

	2006:1	2006:2	2006:3	2006:4	2007:1	2007:2	2005	2006	2007	2008	2009	2010	2011
Indexes													
Employment Costs (June 1989=1.000)	1.811	1.825	1.840	1.853	1.866	1.880	1.782	1.832	1.887	1.948	2.014	2.084	2.157
Wages & Salaries	1.720	1.736	1.749	1.761	1.770	1.782	1.692	1.742	1.788	1.842	1.903	1.965	2.027
Benefits	2.056	2.070	2.087	2.103	2.126	2.145	2.023	2.079	2.155	2.234	2.315	2.406	2.507
Health Insurance	2.869	2.905	2.942	2.979	3.016	3.053	2.790	2.924	3.072	3.201	3.320	3.471	3.651
Consumer Prices (1982-84=1.000)													
All-Urban	1.993	2.017	2.031	2.024	2.043	2.055	1.953	2.016	2.060	2.102	2.139	2.177	2.217
Core (excl. Food & Energy)	2.036	2.054	2.069	2.082	2.095	2.107	2.009	2.060	2.112	2.157	2.201	2.246	2.294
Commodities	1.405	1.409	1.409	1.407	1.409	1.414	1.403	1.408	1.416	1.429	1.439	1.447	1.457
Nonenergy Services	2.410	2.436	2.460	2.483	2.502	2.518	2.366	2.447	2.526	2.590	2.655	2.722	2.794
Food	1.938	1.942	1.958	1.966	1.973	1.985	1.907	1.951	1.990	2.032	2.066	2.101	2.140
Energy	1.928	2.038	2.043	1.859	1.940	1.955	1.770	1.967	1.965	1.980	1.977	1.973	1.955
Energy Commodities	2.095	2.383	2.420	2.055	2.147	2.105	1.973	2.238	2.130	2.116	2.103	2.098	2.087
Energy Services	1.874	1.810	1.784	1.783	1.856	1.933	1.665	1.813	1.928	1.974	1.983	1.979	1.954
Producer Prices, Stage of Processing (1982=1.000)													
Finished Goods	1.593	1.610	1.602	1.592	1.624	1.646	1.557	1.599	1.649	1.679	1.690	1.696	1.700
Core (excl. Food & Energy)	1.579	1.588	1.585	1.590	1.604	1.617	1.564	1.586	1.620	1.651	1.667	1.679	1.692
Food	1.555	1.550	1.581	1.567	1.564	1.576	1.557	1.563	1.575	1.597	1.609	1.623	1.641
Energy	1.441	1.498	1.443	1.401	1.504	1.560	1.325	1.446	1.565	1.596	1.589	1.573	1.538
Consumer Goods	1.648	1.669	1.658	1.643	1.681	1.708	1.604	1.655	1.711	1.742	1.752	1.758	1.761
Core Consumer Goods	1.661	1.670	1.666	1.669	1.684	1.698	1.643	1.666	1.702	1.735	1.755	1.770	1.787
Producer Goods	1.459	1.468	1.467	1.473	1.486	1.497	1.446	1.467	1.500	1.526	1.539	1.546	1.554
Intermediate Materials	1.615	1.643	1.655	1.653	1.680	1.699	1.540	1.642	1.701	1.715	1.712	1.702	1.694
Crude Materials	1.870	1.828	1.868	1.780	1.930	1.950	1.822	1.836	1.983	2.029	1.998	1.964	1.896
Percent Change, SAAR													
Employment Costs	2.4	3.2	3.3	2.8	2.8	3.0	3.1	2.8	3.0	3.2	3.4	3.5	3.5
Wages & Salaries	2.8	3.6	3.2	2.7	2.1	2.7	2.5	2.9	2.7	3.0	3.3	3.3	3.2
Benefits	1.6	2.8	3.4	3.1	4.3	3.8	4.6	2.8	3.7	3.7	3.6	3.9	4.2
Health Insurance	1.7	5.1	5.1	5.2	5.0	5.0	6.7	4.8	5.0	4.2	3.7	4.5	5.2
Consumer Prices													
All-Urban	2.2	5.0	2.8	-1.3	3.7	2.3	3.4	3.3	2.2	2.0	1.8	1.8	1.8
Core (excl. Food & Energy)	2.4	3.5	2.9	2.6	2.5	2.2	2.2	2.6	2.5	2.1	2.0	2.0	2.1
Commodities'	0.8	1.1	0.1	-0.7	0.7	1.2	0.5	0.3	0.6	1.0	0.7	0.5	0.6
Nonenergy Services	3.2	4.3	4.0	3.8	3.1	2.6	2.8	3.4	3.2	2.5	2.5	2.5	2.6
Food	2.9	1.0	3.2	1.6	1.5	2.3	2.4	2.3	2.0	2.1	1.7	1.7	1.9
Energy	0.5	25.0	0.9	-31.5	18.6	3.2	16.9	11.2	-0.1	0.7	-0.1	-0.2	-0.9
Energy Commodities	-6.3	67.3	6.4	-48.0	19.1	-7.5	22.5	13.4	-4.8	-0.6	-0.6	-0.2	-0.5
Energy Services	10.0	-13.0	-5.7	-0.2	17.4	17.7	10.5	8.9	6.4	2.4	0.5	-0.2	-1.2
Producer Prices, Stage of Processing													
Finished Goods	-0.4	4.4	-1.9	-2.4	8.1	5.6	4.9	2.7	3.1	1.8	0.7	0.4	0.2
Core (excl. Food & Energy)	3.1	2.3	-0.7	1.2	3.6	3.1	2.4	1.4	2.2	1.9	1.0	0.7	0.8
Food	-3.3	-1.1	8.1	-3.5	-0.6	2.9	2.0	0.4	0.8	1.3	0.8	0.9	1.1
Energy	-7.3	16.7	-13.8	-11.4	33.0	15.7	17.3	9.1	8.2	2.0	-0.5	-1.0	-2.2
Consumer Goods	-1.4	5.0	-2.4	-3.7	9.6	6.5	5.8	3.1	3.4	1.8	0.6	0.3	0.1
Core Consumer Goods	3.5	2.2	-1.1	0.9	3.6	3.2	2.5	1.4	2.1	2.0	1.2	0.8	1.0
Producer Goods	2.6	2.5	-0.3	1.6	3.6	3.0	2.3	1.4	2.3	1.7	0.8	0.4	0.5
Intermediate Materials	1.9	7.2	2.9	-0.4	6.7	4.5	8.0	6.6	3.6	0.8	-0.2	-0.5	-0.5
Crude Materials	-33.7	-8.8	9.0	-17.5	38.2	4.3	14.6	0.8	8.0	2.3	-1.5	-1.7	-3.5

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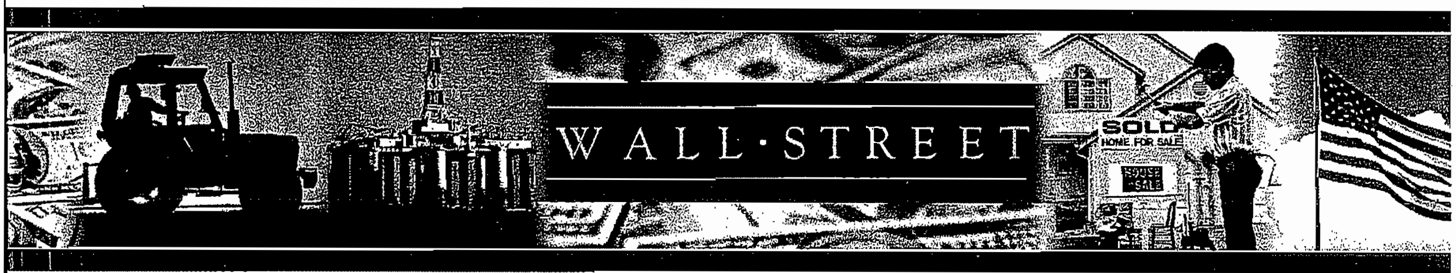
U.S. ECONOMIC OUTLOOK

OCTOBER 2005



GLOBALINSIGHT
www.globalinsight.com

TABLE 1
Prices and Wages

	2005:1	2005:2	2005:3	2005:4	2006:1	2006:2	2004	2005	2006	2007	2008	2009	2010
Indexes													
Employment Costs (June 1989=1.000)	1.773	1.784	1.801	1.819	1.838	1.857	1.739	1.794	1.867	1.940	2.016	2.092	2.170
Wages & Salaries	1.674	1.684	1.695	1.708	1.723	1.740	1.650	1.690	1.748	1.811	1.878	1.946	2.012
Benefits	2.020	2.036	2.064	2.093	2.123	2.149	1.954	2.053	2.162	2.260	2.359	2.458	2.564
Health Insurance	2.744	2.780	2.831	2.882	2.924	2.961	2.619	2.809	2.980	3.093	3.223	3.343	3.495
Consumer Prices (1982-84=1.000)													
All-Urban	1.922	1.941	1.965	1.989	2.001	2.001	1.889	1.954	2.006	2.035	2.072	2.116	2.162
Core (excl. Food & Energy)	1.995	2.005	2.013	2.026	2.040	2.054	1.966	2.010	2.060	2.111	2.163	2.217	2.272
Commodities	1.404	1.404	1.401	1.405	1.410	1.415	1.396	1.404	1.416	1.428	1.443	1.457	1.471
Nonenergy Services	2.342	2.359	2.375	2.392	2.412	2.432	2.302	2.367	2.441	2.516	2.591	2.669	2.750
Food	1.888	1.905	1.910	1.923	1.936	1.948	1.862	1.906	1.953	1.989	2.026	2.065	2.104
Energy	1.593	1.694	1.862	1.989	1.992	1.862	1.513	1.784	1.861	1.710	1.636	1.621	1.610
Energy Commodities	1.718	1.877	2.173	2.259	2.148	1.978	1.610	2.007	1.982	1.828	1.721	1.707	1.687
Energy Services	1.561	1.605	1.647	1.827	1.953	1.857	1.506	1.660	1.851	1.692	1.651	1.632	1.631
Producer Prices, Stage of Processing (1982=1.000)													
Finished Goods	1.527	1.538	1.569	1.630	1.634	1.614	1.485	1.566	1.615	1.593	1.591	1.600	1.611
Core (excl. Food & Energy)	1.555	1.561	1.566	1.585	1.599	1.610	1.527	1.567	1.613	1.633	1.652	1.672	1.691
Food	1.558	1.557	1.537	1.551	1.555	1.554	1.527	1.550	1.557	1.563	1.574	1.589	1.605
Energy	1.213	1.247	1.388	1.600	1.573	1.456	1.130	1.362	1.454	1.293	1.224	1.198	1.182
Consumer Goods	1.565	1.579	1.619	1.699	1.700	1.669	1.517	1.615	1.670	1.631	1.623	1.631	1.641
Core Consumer Goods	1.634	1.641	1.646	1.669	1.686	1.698	1.603	1.648	1.700	1.721	1.742	1.767	1.791
Producer Goods	1.439	1.445	1.450	1.462	1.473	1.483	1.414	1.449	1.486	1.505	1.521	1.535	1.546
Intermediate Materials	1.493	1.511	1.550	1.623	1.629	1.605	1.426	1.544	1.600	1.546	1.527	1.521	1.517
Crude Materials	1.658	1.699	1.881	2.227	2.160	1.966	1.591	1.866	1.987	1.741	1.649	1.610	1.590
Percent Change, SAAR													
Employment Costs	2.5	2.5	3.8	4.0	4.2	4.4	3.9	3.2	4.0	3.9	3.9	3.8	3.7
Wages & Salaries	2.4	2.4	2.6	3.2	3.4	4.0	2.5	2.4	3.4	3.6	3.7	3.6	3.4
Benefits	4.3	3.2	5.6	5.7	5.9	5.0	7.1	5.1	5.3	4.6	4.3	4.2	4.3
Health Insurance	7.0	5.4	7.6	7.3	6.0	5.1	8.3	7.2	6.1	3.8	4.2	3.7	4.5
Consumer Prices													
All-Urban	2.4	4.2	5.0	4.9	2.6	-0.1	2.7	3.5	2.7	1.4	1.8	2.1	2.2
Core (excl. Food & Energy)	2.6	2.0	1.7	2.5	2.8	2.8	1.8	2.2	2.5	2.5	2.4	2.5	2.5
Commodities'	1.3	0.0	-0.9	1.3	1.4	1.2	-0.9	0.6	0.9	0.9	1.0	1.0	1.0
Nonenergy Services	3.1	2.8	2.7	3.0	3.3	3.3	2.8	2.8	3.1	3.1	3.0	3.0	3.0
Food	1.1	3.7	1.1	2.7	2.9	2.5	3.4	2.4	2.5	1.9	1.8	1.9	1.9
Energy	3.9	27.8	46.1	30.3	0.6	-23.7	10.9	17.9	4.3	-8.1	-4.3	-0.9	-0.7
Energy Commodities	1.6	42.6	79.4	16.8	-18.2	-28.0	17.8	24.6	-1.2	-7.7	-5.9	-0.8	-1.2
Energy Services	6.8	11.8	10.9	51.4	30.5	-18.2	3.8	10.2	11.5	-8.6	-2.4	-1.1	-0.1
Producer Prices, Stage of Processing													
Finished Goods	2.8	2.9	8.2	16.6	0.9	-4.8	3.6	5.4	3.2	-1.4	-0.1	0.6	0.7
Core (excl. Food & Energy)	3.9	1.6	1.3	4.7	3.7	2.8	1.5	2.6	2.9	1.2	1.2	1.2	1.1
Food	1.6	-0.2	-5.1	3.7	1.3	-0.3	4.6	1.6	0.4	0.4	0.7	1.0	1.0
Energy	2.0	11.6	53.6	76.6	-6.7	-26.6	10.6	20.5	6.7	-11.1	-5.3	-2.2	-1.3
Consumer Goods	2.9	3.5	10.5	21.3	0.2	-7.1	4.4	6.5	3.4	-2.3	-0.5	0.5	0.7
Core Consumer Goods	4.4	1.6	1.1	5.8	4.2	2.8	1.6	2.8	3.2	1.2	1.2	1.5	1.4
Producer Goods	2.9	1.7	1.6	3.2	3.1	2.8	1.4	2.5	2.5	1.3	1.0	0.9	0.8
Intermediate Materials	5.4	4.8	10.7	20.5	1.4	-5.9	6.6	8.3	3.6	-3.4	-1.2	-0.4	-0.3
Crude Materials	-3.2	10.4	50.1	96.5	-11.5	-31.3	17.5	17.3	6.5	-12.4	-5.2	-2.4	-1.3

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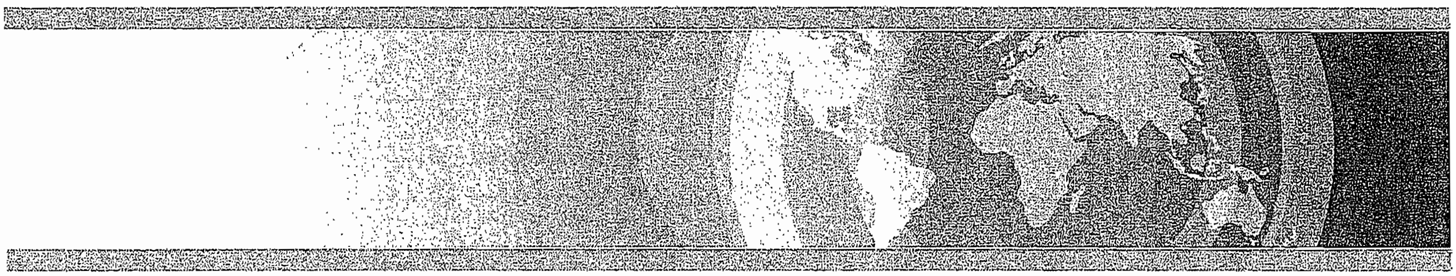
U.S. ECONOMIC OUTLOOK

SEPTEMBER 2004



GLOBAL INSIGHT

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TABLE 1
Prices and Wages

	2004:1	2004:2	2004:3	2004:4	2005:1	2005:2	2003	2004	2005	2006	2007	2008	2009
Indexes													
Employment Costs (June 1989=1.000)	1.713	1.730	1.746	1.761	1.777	1.791	1.673	1.737	1.800	1.865	1.933	2.002	2.072
Wages & Salaries	1.635	1.644	1.654	1.666	1.678	1.691	1.610	1.650	1.698	1.752	1.812	1.872	1.932
Benefits	1.912	1.945	1.971	1.995	2.019	2.040	1.825	1.956	2.052	2.146	2.233	2.327	2.422
Health Insurance	2.542	2.593	2.644	2.697	2.744	2.780	2.419	2.619	2.809	2.980	3.093	3.223	3.343
Consumer Prices (1982-84=1.000)													
All-Urban	1.864	1.886	1.895	1.905	1.914	1.921	1.840	1.888	1.924	1.952	1.986	2.025	2.067
Core (excl. Food & Energy)	1.949	1.963	1.972	1.984	1.996	2.007	1.932	1.967	2.011	2.050	2.093	2.140	2.188
Commodities	1.394	1.397	1.394	1.396	1.399	1.400	1.409	1.395	1.400	1.404	1.411	1.422	1.433
Nonenergy Services	2.275	2.296	2.312	2.331	2.348	2.365	2.238	2.303	2.372	2.432	2.496	2.566	2.637
Food	1.838	1.856	1.865	1.868	1.875	1.879	1.800	1.857	1.880	1.902	1.934	1.969	2.003
Energy	1.429	1.515	1.522	1.536	1.521	1.506	1.365	1.500	1.497	1.461	1.435	1.422	1.435
Energy Commodities	1.472	1.624	1.617	1.631	1.588	1.564	1.367	1.586	1.551	1.496	1.477	1.469	1.482
Energy Services	1.475	1.494	1.517	1.532	1.546	1.540	1.451	1.504	1.536	1.518	1.482	1.462	1.477
Producer Prices, Stage of Processing (1982=1.000)													
Finished Goods	1.461	1.483	1.491	1.497	1.503	1.503	1.433	1.483	1.501	1.497	1.499	1.507	1.522
Core (excl. Food & Energy)	1.516	1.525	1.533	1.542	1.550	1.554	1.505	1.529	1.554	1.563	1.577	1.594	1.612
Food	1.495	1.541	1.513	1.497	1.506	1.506	1.459	1.512	1.503	1.496	1.503	1.512	1.523
Energy	1.083	1.111	1.152	1.169	1.170	1.156	1.021	1.129	1.150	1.117	1.080	1.062	1.071
Consumer Goods	1.489	1.514	1.523	1.528	1.535	1.532	1.453	1.514	1.530	1.523	1.521	1.528	1.544
Core Consumer Goods	1.593	1.601	1.611	1.620	1.628	1.632	1.579	1.606	1.633	1.644	1.661	1.683	1.704
Producer Goods	1.402	1.413	1.419	1.428	1.435	1.439	1.395	1.415	1.438	1.443	1.453	1.466	1.477
Intermediate Materials	1.373	1.414	1.443	1.457	1.459	1.454	1.337	1.422	1.449	1.427	1.423	1.425	1.432
Crude Materials	1.507	1.581	1.627	1.587	1.594	1.558	1.353	1.576	1.551	1.476	1.418	1.398	1.405
Percent Change, SAAR													
Employment Costs	4.3	4.0	3.7	3.5	3.6	3.4	4.0	3.9	3.6	3.6	3.6	3.6	3.5
Wages & Salaries	2.5	2.2	2.5	2.9	3.0	3.1	2.9	2.5	2.9	3.2	3.4	3.3	3.2
Benefits	10.9	7.1	5.5	4.8	5.0	4.2	6.3	7.2	4.9	4.6	4.1	4.2	4.1
Health Insurance	7.3	8.3	8.1	8.3	7.0	5.4	10.2	8.3	7.2	6.1	3.8	4.2	3.7
Consumer Prices													
All-Urban	3.6	4.7	1.9	2.3	1.8	1.5	2.3	2.6	1.9	1.5	1.7	2.0	2.1
Core (excl. Food & Energy)	1.8	3.0	1.8	2.5	2.4	2.2	1.5	1.8	2.2	1.9	2.1	2.2	2.3
Commodities	0.0	0.9	-0.7	0.6	0.8	0.4	-2.0	-0.9	0.3	0.3	0.6	0.8	0.8
Nonenergy Services	2.5	3.8	2.8	3.2	3.0	2.8	2.9	2.9	3.0	2.5	2.6	2.8	2.8
Food	2.6	4.0	2.0	0.6	1.4	0.8	2.1	3.2	1.3	1.2	1.7	1.8	1.7
Energy	24.8	26.3	1.8	3.7	-3.8	-3.8	12.2	9.9	-0.2	-2.4	-1.8	-0.9	0.9
Energy Commodities	45.3	48.1	-1.8	3.4	-10.1	-5.8	16.8	16.0	-2.2	-3.5	-1.2	-0.5	0.8
Energy Services	6.9	5.4	6.1	4.1	3.9	-1.5	7.9	3.7	2.1	-1.2	-2.4	-1.3	1.0
Producer Prices, Stage of Processing													
Finished Goods	3.9	6.2	2.3	1.6	1.8	-0.2	3.2	3.5	1.2	-0.2	0.1	0.6	1.0
Core (excl. Food & Energy)	1.2	2.6	2.1	2.4	1.9	1.1	0.2	1.6	1.6	0.5	0.9	1.1	1.1
Food	-2.1	12.9	-7.2	-4.1	2.6	-0.2	4.2	3.6	-0.6	-0.4	0.5	0.6	0.7
Energy	25.1	10.7	15.7	5.9	0.3	-4.6	15.0	10.6	1.9	-2.8	-3.3	-1.7	0.9
Consumer Goods	5.2	7.1	2.4	1.3	1.7	-0.6	4.3	4.2	1.1	-0.4	-0.1	0.5	1.0
Core Consumer Goods	1.5	2.2	2.3	2.3	2.0	1.1	0.2	1.7	1.7	0.7	1.0	1.3	1.3
Producer Goods	0.5	3.2	1.9	2.5	1.9	1.1	0.3	1.5	1.6	0.3	0.7	0.9	0.8
Intermediate Materials	8.5	12.4	8.6	3.9	0.6	-1.4	4.7	6.3	1.9	-1.6	-0.3	0.1	0.5
Crude Materials	36.4	21.1	12.2	-9.6	1.8	-8.8	25.1	16.5	-1.5	-4.9	-4.0	-1.4	0.5

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I. Introduction

Q. Please state your name and positions.

A. My name is Doug Kuns. I am the Manager of the Pricing and Tariffs Department within the Rates & Regulatory Affairs Department.

My name is Marc Cody. I am a Senior Pricing Analyst in the Pricing and Tariffs Department.

My name is Michaela Lynn. I am the Manager of Receivables, Billing and Low Income Operations.

Q. Have you previously testified in this proceeding?

A. The direct testimony and qualifications of Messrs. Kuns and Cody are provided in PGE Exhibit 1200. The qualifications of Ms. Lynn appear at the end of this testimony.

Q. What is the purpose of this rebuttal testimony?

A. The purpose of this rebuttal testimony is to address the issues identified by Commission Staff (separately two portions of testimony, Staff/500 and Staff/600), the issues identified by ICNU, Kroger, CAPO, and the price elasticity comments of CUB. Issues identified in Staff/600 regarding decoupling are discussed in the testimony of Mr. Cavanagh.

II. OPUC Staff 500

Q. Please summarize the issues identified by Staff in Staff 500.

A. Staff states that they do not support PGE's Schedule 125 proposal to include a true-up of the fixed generation cost contributions of customers either returning to or departing from Cost of Service (COS) energy pricing. Staff also proposes to introduce seasonal energy pricing for all of PGE's major nonresidential rate schedules such that energy prices are higher in the months of July through September, and to introduce a third higher-priced energy block for Schedule 7 Residential Service during these summer months. In addition to the seasonally differentiated energy prices, Staff proposes to add a third super-peak energy price block to Schedule 89 in the summer months.

Q. Why does Staff not support PGE's proposal to true-up fixed generation revenue requirement through Schedule 125?

A. Staff states the following:

> A key principle that guided Staff in reviewing direct access concepts is that actions by direct access customers, either departing or returning to PGE, should not affect non-direct access customers--at least not outside of a general rate case, where various offsetting considerations will be brought to bear. PGE's proposal is inconsistent with this principle. (See Staff 500, page 5 lines 14-19.)

Q. Can you propose an alternative true-up mechanism that does not impact non-direct access eligible customers?

A. Yes. PGE agrees to remove the proposed true-up language from its Schedule 125 and instead incorporate the same principles but on a limited scale within a Special Condition of Schedule 129 Long-Term Transition Adjustment. By limiting the true-up impacts to the system usage charge for Schedules 83, 89, 483, 489, 583, and 589, PGE believes that it can address Staff's concerns regarding non-direct access customers. PGE Exhibit 2001 contains the proposed changes to Schedules 125 and 129 in redline format.

Q. With respect to Staff's seasonal pricing proposal do you agree that Staff's analysis demonstrates that PGE's 2009 marginal energy costs on a per unit basis are higher in the summer months than the average of the other nine months of the year?

A. Yes, but we point out that according to Staff's own analysis, based on a projection of PGE loads and a snapshot of a 2009 forward price curve (see Staff Exhibit 502), PGE's per unit costs of meeting load with market purchases are similarly high in the winter months of November, December, January, and February. Therefore, one could alternatively make a case that PGE should have higher winter energy prices than in the other months of the year, or that energy prices should be lower in the spring. Additionally, PGE typically incurs its highest peak on a weather-normalized basis during the winter, not the summer and its heaviest loads occur during the winter. Ultimately, the analysis demonstrates that projected market prices are lower in the spring during the peak hydro season and in the fall when loads are typically lower. Thus, we conclude that the imposition of seasonal pricing and an additional summer on-peak block price are not warranted.

Q. Do you have additional concerns regarding Staff's commercial and industrial customer summer energy pricing proposals?

A. Yes. We are concerned about the effect that this differential pricing may have on the pricing of PGE's Schedule 128 Short-Term Transition Adjustment. Currently PGE calculates one Schedule 128 annual transition adjustment for all direct access eligible schedules other than Schedule 89 for whom it calculates two transition adjustments (on- and off-peak). PGE is concerned that the summer-differentiated pricing and the inclusion of three peak periods for

Schedule 89 will introduce unnecessary confusion to potential direct access customers. In order to accommodate the proposals of Staff, PGE may have to resort to monthly Schedule 128 transition adjustments with each delivery voltage of Schedule 589 having as many as 36 different annual transition adjustments (12 months times the three peak periods). This would be in addition to the plethora of quarterly transition adjustments we currently prepare to support direct access. These quarterly transition adjustments will also have to be modified to accommodate the Staff proposal. Finally, we are concerned with the effect that Staff's proposal may have on seasonal agricultural customers and other customers such as water providers who provide critical services and who typically consume at a much heavier level during the summer than during other months of the year. These customers can legitimately argue that on a cost-causation basis, peak pricing should occur during the winter months instead of the summer months.

Q. Please state your concerns regarding Staff's Schedule 7 Residential Service blocking proposal.

A. Our concerns are similar to our concerns regarding commercial and industrial customers. Staff has only shown that a projection of wholesale market prices are lower in the spring months and in October than they are the other eight months of the year. We do not feel that this provides a sufficient basis for a third, higher priced energy block for the summer months.

PGE prefers to have only one breakpoint (therefore two energy blocks) on a year-round basis. We suggest that this breakpoint remain at the current level of 250 kWh. We believe that our simpler two-block Schedule 7 pricing proposal also provides for more consistent transparent Schedule 7 Time of Use (TOU) pricing. Furthermore, the Staff proposal conflicts with the current seasonal definitions contained in both the Schedule 7 and Schedule 32 TOU pricing. This suggests that the TOU prices will need to change even more frequently than the standard tariff prices due to the conflicting seasonal definitions. Additionally, we are aware of at least one utility with three price blocks that has negative off-peak energy prices in order to avoid unwarranted incentives to enroll in TOU pricing. PGE strongly recommends avoiding this type of price design.

Q. Why do you believe that your Schedule 7 Residential Service proposal is preferable to that of Staff?

A. Our proposal to maintain the current pricing structure provides for bill stability, it avoids the two additional price changes that occur each year along with the associated prorated bill calculations and, as mentioned above, it more easily accommodates the Schedule 7 TOU pricing.

Q. Are there operational issues associated with implementing Staff's seasonal pricing proposals?

A. Of course. While none are insurmountable, they will divert employees from other important tasks. For example, to implement the changes PGE would need to reprogram its billing system to accept the seasonal differentials and perform more maintenance and testing to insure that the larger price matrix is accurate. The metering department would need to reprogram some meters for the new Schedule 89 super-peak price. The Network Data Operations department would have to program additional fields for the seasonal super-peak. Perhaps most importantly, the timing will impact the resources from departments dedicated to develop system changes for the AMI project. Additionally, we anticipate that each year the Customer Contact Center would have to provide additional training to enable it to field more calls due to the additional amount of prorated bills.

Q. Do you have any final comments on Staff's seasonal energy pricing?

A. Yes. We advocate continuation of our current and proposed practice of having the same energy prices during the year. Staff has not convinced us that the seasonal energy prices they propose are warranted and in fact the seasonal pricing may prove detrimental to some customers who consume at a much heavier level in the summer than in the winter when market prices are equally high. PGE believes that it is more appropriate to attempt to implement changes in commercial and industrial energy pricing after the implementation of AMI has occurred. In this manner PGE and its customers would not have to incur potentially costly and confusing changes in 2009 and then again several years later to accommodate the post-AMI implementation changes. PGE is interested in the opinions of ICNU, CUB, and Kroger regarding Staff's proposals as well as PGE's response to these proposals. PGE believes that ultimately customers should help determine what type of differentiated energy pricing structure is adopted and when this should occur.

III. OPUC Staff 600

Q. Please summarize the marginal cost study issues identified by Staff.

A. Staff takes issue with how PGE calculates the marginal cost of meter reading, how PGE calculates the marginal cost of a certain line item within the functional category Other Consumer Service, and how PGE estimates the marginal cost of generation. Staff also "strongly recommends the Commission direct PGE to emulate the Pacific Power approach to customer cost allocations in its next general rate application." (See Staff/600 page 6, lines 14-16.) Staff further recommends the Commission "direct PGE to hold workshops for the purpose of considering whether to revise the Company's basis for developing marginal cost estimates." (See Staff/600 page 6, lines 16-18.) Staff does not adequately specify whether this recommendation is for generation marginal costs only or for any other marginal cost estimate produced in this case.

Q. What does Staff recommend with respect to the marginal cost estimates?

A. Staff recommends the Commission accept PGE's cost studies because they find the overall results to be reasonable.

Q. Staff asserts that another utility weights its industrial customers meter reading expense at over ten times the cost of reading residential meters and, therefore, PGE is somehow lacking when it assigns an equivalent weight of one. Is Staff's criticism reasonable?

A. No. Our marginal customer costs are prepared by surveying the functional areas such as meter reading, credit and collections, and billing. We provide the managers with the results of our prior rate case surveys and ask them to update for any changes between the residential and non-residential allocations of costs. As with both UE 115 and UE 180, the meter reading marginal cost estimates in this proceeding reflect the results of this process, a process that yielded the same results in all three dockets. In the two prior dockets, Staff had no issue with the results. Regarding the Staff proposed meter reading weights we note that when asked for the basis of the weighting factors, Staff responded that they did not have the information readily available.

Q. Please describe the meter reading arrangements for Schedule 89.

A. Currently more than half of the meters of PGE's Schedule 89 customers are read and billed from remotely read data. Additionally, PGE attempts to reduce potential meter reading costs by requiring that customers make the meter location more accessible to meter readers. Within its Rules at M-4, PGE specifies the following:

> C. **Inaccessible Meters**
>
> When in the Company's opinion a meter is inaccessible, the Company may:
>
> 1) Permit the Customer to read the meter and supply meter readings to the Company, subject to actual verification by the Company, not less than once every four months; or
>
> 2) Require the Customer, at the Customer's expense, to locate the meter socket to an accessible location satisfactory to the Company.

In short, when weighing factors such as those above, PGE believes that its marginal cost of meter reading calculation provides for reasonable results. PGE cannot comment on the policies, practices and service territory characteristics of other companies as they relate to meter reading.

Q. What are Staff's stated concerns about the Other Consumer Service marginal cost estimates?

A. Staff claims that PGE’s marginal cost estimates do not adequately reflect the extent to which customers in individual rate schedules impose a burden or receive a benefit in relation to residential rate schedules. Staff states the following: “But in general I would draw attention to and commend the much more granular approach of Pacific Power, whereby the number of customers in the rate schedules are differentially weighted (with a weight of one being equivalent to the residential customer weighting) so as to reflect the extent to which customers impose a burden or receive a benefit that is greater than that imposed upon/received by the average customer.” (See Staff/600 page 5, lines 7-12.)

Q. Please evaluate Staff’s assertions.

A. In this proceeding, PGE’s ratio of the Other Consumer Service marginal cost difference between industrial customers and residential customers is 27.3 ($1,061.45 to $38.84) while in the UE 179 Pacific Power docket that Staff commends, the resulting Other Consumer Service ratio differential is much smaller, 19.0 ($254.44 to $13.38). In short, while PGE may not use the explicit weights that Staff seems to prefer, PGE’s methodology provides for more robust Other Consumer Service marginal cost differentials than the study Staff commends. Additionally, we point out that Staff in both UE 115 and UE 180 had no issue with how PGE reflected the allocation of costs within the line item referenced.

Q. Please comment on the “granularity” that Staff references.

A. While we can only guess what Staff means by “granularity”, we note that within the three functional customer service categories PGE has evaluated 29 different accounts while in Staff Exhibit 602 only 12 separate accounts are presented. In general, we believe that the reason our Other Consumer Service marginal cost methodology provides more robust results than the Staff methodology is because it examines many more accounts than just the standard FERC accounts. Thus, it is important for reviewers to not focus on one line item, ignoring the relative overall results.

Q. Does Staff have specific actionable issues with PGE's marginal cost of generation estimates?

A. No. Staff only makes general comments and provides no analysis whatsoever. Their comments on Staff/600 page 5 of their testimony imply that they wish to see an explicit acknowledgement of generation capacity costs. As justification for this implication Staff states on page 6 of their testimony that PGE has recently constructed Port Westward "and is currently building significant wind resources." We address generation allocation issues later in this testimony.

Q. Please discuss Staff's recommendation that the Commission direct PGE to hold workshops for the purpose of considering whether to revise the Company's basis for marginal cost estimates.

A. PGE is willing to meet with interested parties to discuss marginal cost issues and only a request, not a Commission Order, is needed.

Q. Regarding marginal cost estimation in general, do you have any final comments?

A. Yes. We find the UM 827 Order No. 98-374, page 12, instructive:

> <u>Commission Decision</u>
>
> We will not require a single marginal cost approach for all utilities. Calculating marginal costs is as much of an art as it is a science. Allowing utilities to address the issue of calculating marginal costs in different ways has led to significant and productive new approaches to efficient pricing and costing of electrical service. We do not believe that mandating a single approach will advance the art of marginal cost analysis, and it could significantly impede progress.

Furthermore, utilities should be allowed to choose approaches that best fit the particular circumstances of their systems and nature of their customers. We do not believe that we are capable of identifying a single approach that will satisfy the needs of every utility and its respective customers.

IV. ICNU

Q. What rate spread issue does ICNU identify?

A. ICNU's testimony addresses PGE's estimates of the marginal cost of generation and the subsequent allocation to the individual rate schedules of the $1.165 billion generation revenue requirement presented in PGE's direct testimony. Specifically, ICNU states that PGE's marginal cost of generation suffers from four deficiencies. These are: 1) PGE's method is too broad brushed and therefore loses or ignores a lot of information. 2) PGE's method neglects the role of capacity or reliability in the electrical planning process and cost causation. 3) PGE fails to distinguish between fixed costs and variable costs. 4) PGE's cost allocation shortsightedly focuses on short-run marginal costs instead of long-run marginal costs. As we explain later in testimony we do not agree with ICNU, but we do present an alternative allocation method to address their concerns.

Q. Do you agree with ICNU's first assertion that PGE's marginal cost of generation estimate is too broad brushed?

A. In part, yes, but not to the extent that we would propose to change our generation allocations on this basis alone. This is because we believe that the generation allocation results likely would not deviate significantly even if PGE were to use estimates of the hourly load shape of every individual rate schedule combined with the hourly energy prices provided in PGE's power cost model MONET. ICNU asserts that because PGE uses monthly on- and off-peak differentiated energy combined with the monthly load shapes of each individual rate schedule, PGE misses the cost causation responsibility attributable to the large price fluctuations that can occur on an hourly basis. However, the ratio of the highest to the lowest hourly price within MONET is approximately 5.3 ($97.40 to $18.50), hardly the 100 to 1 ratio that ICNU states (See ICNU/200 page 4, lines 6-7). In short, significant hourly price and load deviations do not occur when hourly prices are appropriately constrained by the monthly forward curve values, and the loads in a test period are appropriately temperature adjusted.

Q. Do you agree with ICNU's second assertion that PGE's generation cost of service estimates neglect the role of reliability and capacity in the electrical planning process and cost causation?

A. No. We agree that PGE's planning process includes capacity resources and that NERC imposes reserve requirements. Currently, however, market purchases of energy contain operating reserves and, thus, they are included in prices charged.

Q. How does ICNU attempt to support their third assertion?

A. ICNU cites the PGE decomposition of generation revenue requirement into two categories, Net Variable Power Costs (NVPC) and fixed costs, as evidence that PGE has fixed generation costs. The fixed portion of the generation revenue requirement consists of all portions of the generation revenue requirement that are not included in the NVPC. ICNU also claims that the results of a regression analysis performed on PGE's allocation methodology produced "simply unrealistic" results.

Q. Are there problems with ICNU's analysis?

A. Yes. The objective of an allocation methodology is to reflect cost-causation in pricing. Our methodology clearly reflects test-period marginal cost causation based on projected market prices applied to each rate schedule's load shape. ICNU's assertion that historical fixed costs and variable costs are not reflected adequately is simply not consistent with marginal cost-based pricing because ICNU focuses on historical fixed costs.

PGE is aware that portions of our generation revenue requirements are related to fixed plant and other support items. The ratios cited by ICNU of fixed and variable generation revenue requirement are projected figures for the 2009 test period, but a large portion of the costs are based on historical contract provisions or historical investment. These types of costs are simply not marginal generation costs and are not useful for a marginal cost-based allocation process.

Consistent with Commission policy, we are estimating PGE's marginal generation costs for purposes of allocating the generation revenue requirements; we are not attempting to conduct an embedded cost study. Therefore, for PGE, the near-term marginal generation costs are based on monthly on- and off-peak forward market prices.

Q. Briefly comment on ICNU's regression analysis and its importance.

A. We performed a regression analysis similar to ICNU's on the results of ICNU's recommended alternative to PGE's allocation methodology and discovered similar results; the R-squared value was 0.997857. It seems that by ICNU's criteria, their own recommendations could also be thought of as "simply unrealistic."

We believe that any valid allocation method will demonstrate a high correlation with energy consumption. To use a blunt instrument such as the summary statistic from a simple regression analysis to evaluate the efficacy of a production allocation method seems too simplistic and arbitrary to us.

Q. How does ICNU attempt to justify their fourth assertion?

A. ICNU's fourth assertion is similar to their first in that they claim that it is unreasonable to assume that PGE's long-term fixed production capital costs recovery is fully reflected in short-term, on-peak energy prices. They further state that some fixed cost recovery may be embedded in on-peak energy prices, but only for a relatively brief period of time.

Q. Do you agree with ICNU's assertions?

A. We neither agree nor disagree because ICNU's assertions are too unsubstantiated to formulate a basis for agreement or disagreement. Furthermore, PGE has made no claim in its direct testimony that the 2009 projected market prices recover long-term fixed production capacity costs. We simply assert that these provide a reasonable method to allocate production costs, both fixed and variable.

Q. Please summarize ICNU's alternate allocation of generation revenue requirement.

A. ICNU proposes to decompose PGE's generation revenue requirement into two portions, the NVPC portion and the remaining amount that both ICNU and PGE called "fixed." This fixed component includes the return on and of generation plant, allocated Administrative & General expense (A&G), fixed and variable Operations and Maintenance (O&M), and other allocated items such as taxes and other revenue sensitive costs. From this decomposition of generation revenue requirement, ICNU proposes to allocate the NVPC on the same marginal cost basis as PGE and to allocate the fixed portion on an embedded cost basis using a weighted five coincident peak as the allocator. ICNU then proposes to weigh its methodology and the methodology proposed by PGE equally for purposes of allocating the generation revenue requirement. To further support their analysis, ICNU performs a second analysis, this one marginal cost based, that employs a proxy gas peaker plant in combination with PGE's marginal cost analysis. ICNU uses the single coincident peak occurring in January as the capacity billing determinant for the proxy peak analysis.

Q. Please evaluate ICNU's proposed generation revenue requirement allocation.

A. We find ICNU's proposed allocation deficient for the following reasons:

- The fixed cost allocation is done on an embedded cost basis that ignores past Commission precedent of using marginal cost.
- The weighted five coincident peaks used by ICNU do not necessarily reflect the periods during which PGE may need capacity the most.
- Some of the allocated costs within the fixed generation revenue requirements such as A&G and revenue sensitive costs support operations related to NVPC rather than to generation plant.
- By allocating the NVPC in the same manner as PGE, ICNU in effect captures any capacity cost recovery inherent in the diurnal forward curves and then again captures capacity in their embedded cost allocation methodology.

Q. Please explain the first problem, that ICNU employs an embedded cost methodology rather than a marginal cost methodology.

A. Since 1974, the OPUC has specified the use of marginal costs as one of the principal factors for spreading revenue requirement among customer classes. ICNU proposes to ignore this precedent by spreading a portion of generation revenue requirements on an embedded cost basis. We believe that in order to send a more correct price signal it is more appropriate to continue to use marginal costs, however determined, to spread generation revenue requirement.

Q. Please elaborate on the second problem with the ICNU methodology, that the five weighted coincident peaks does not necessarily reflect the periods during which PGE may need capacity the most.

A. The ICNU methodology employs the highest projected 100 hours of PGE load and uses the months in which these highest 100 hours occur to proportionately weight each month. The fixed generation revenue requirement is then allocated to each individual rate schedule on the basis of this weighted five coincident peak (CP) method. This weighting is problematic because it narrowly focuses on PGE peak loads only and ignores regional peak loads. In other words, it is possible that PGE may need capacity during more of the summer hours than the winter hours due to regional peak load consumption. In fact, the highest prices cited by ICNU on page five of their testimony occur in months other than in the winter. The ICNU weighting methodology completely ignores this and narrowly focuses on PGE peak loads only. This results in the winter months receiving 96% of the weights and the summer months only 4%.

Q. Why is it inappropriate to allocate the entire fixed generation revenue requirement on a weighted five CP basis?

A. Leaving aside the other problems with the ICNU methodology, as mentioned above, some of the costs included in this category are allocated costs such as A&G and revenue sensitive costs. These costs also either support the NVPC or are a derived function of the NVPC. The ICNU methodology completely ignores this cost causation and lumps these costs in with the embedded costs of plant-related revenue requirement.

Q. Why is it inappropriate to continue to use the monthly on- and off-peak price curves in conjunction with an embedded capacity cost allocation methodology as proposed by ICNU?

A The ICNU methodology in effect captures elements of capacity more than once; once by using an embedded cost coincident peak methodology for the fixed generation revenue requirement and again by using diurnally differentiated market prices as a basis to allocate the NVPC. A proper long-run cost of service analysis that intends to separately differentiate capacity costs from energy would use annual energy consumption coupled with flat energy prices so as to remove the extent to which the diurnally differentiated prices reflect recovery of capacity costs.

Q. Please briefly evaluate the ICNU marginal cost approach that uses a proxy peaker plant as the basis for estimating marginal capacity costs.

A. The ICNU methodology in this instance provides reasonable estimates of the marginal cost of capacity with some exceptions. Briefly, its shortcomings include the following:

- ICNU inconsistently uses a single coincident peak methodology (January) instead of the five months it identified in its embedded cost methodology. This exacerbates the problems discussed above and effectively assumes that PGE has need of capacity in January only.
- As discussed above, ICNU continues to use the diurnally differentiated forward prices in conjunction with an explicit capacity calculation, in effect capturing recovery of capacity costs more than once.

Q. Regarding the estimation of marginal generation costs, has the ICNU testimony or any other developments persuaded you that PGE should change its marginal cost of generation methodology?

A. No. We continue to support our original methodology for the following reasons:

- PGE is and will continue to be highly dependent upon short-term wholesale market purchases that are priced either flat or on- and off-peak differentiated on a monthly, seasonal, or annual basis.

- Due to PGE's projected investments such as hydro relicensing costs and pollution control issues at Boardman, PGE anticipates frequent rate filings; therefore the marginal cost methodology presented in our opening testimony is consistent with the period during which the energy prices are anticipated to be in effect.
- The marginal cost methodology presented in our opening testimony has been used in our two prior rate case dockets and was used to allocate the revenue requirements of PGE's most recent generating station, Port Westward.

Q. Ultimately, what is the generation revenue requirement allocation issue in this docket?

A. Narrowly defined, the issue is whether to continue to use estimates of short-run marginal costs as presented by PGE in this docket and used in the two previous general rate cases or whether to use a hybrid embedded cost methodology as advocated by ICNU.

However, in broader terms, PGE believes that the Commission should be presented a third option, one that both employs marginal cost methodology and is long-run in nature.

Q. What do you recommend if the Commission decides to use a long-run methodology?

A. Notwithstanding our recommendations, PGE has identified a future need for capacity resources and we understand that other parties believe it appropriate to explicitly recognize capacity costs in calculating our marginal cost of generation. The proxy peaker plant analysis presented by ICNU is a reasonable method by which to accomplish this, but the ICNU analysis as presented is inadequate for the reasons mentioned above. Below we present our interpretation of how to more correctly implement a long-run marginal cost methodology that explicitly includes capacity costs. Should the Commission decide to implement a long-run marginal cost methodology that more explicitly recognizes capacity costs, we recommend they choose to implement our methodology along with the appropriate rate design and gradualism constraints we propose.

V. PGE Long-run Marginal Cost Methodology

Q. Please describe how to more correctly implement a long-run marginal cost of generation methodology that employs separate calculations of generation capacity and energy.

A. We first define the long-run resource as a combined cycle combustion turbine (CCCT) used for baseload purposes and separately estimate the capacity and energy components. We then estimate the fixed cost of a simple cycle combustion turbine (SCCT), which is usually built as a capacity resource and use these fixed costs as the portion of the fixed cost of a CCCT that is assigned to capacity with the remaining costs assigned to energy. Finally, we express these values in real levelized terms. PGE Exhibit 2002, page one, presents the summary of these calculations.

Q. How do you apply this methodology for purposes of spreading the generation revenue requirement?

A. We use the annual energy rate grossed up for the line losses of each rate schedule and multiply this by the annual energy consumption of each schedule. We then use the capacity portion expressed on a dollars per kW basis and multiply this by each rate schedules average monthly peak (12-CP). Finally, we sum these two components to arrive at each rate schedule's marginal cost of generation. This calculation is presented on page two of PGE Exhibit 2002.

Q. Please show why it is appropriate for PGE to use the 12-CP for the capacity portion of marginal generation costs.

A. To verify that the 12-CP methodology is correct for PGE we applied tests used by the Federal Energy Regulatory Commission (FERC) to help determine whether or not a utility experiences a pronounced peak during a particular period. To determine if PGE is a 12-CP company, we performed three tests used by FERC in prior proceedings:

- Test 1 compares the average of PGE's twelve monthly peaks to its highest monthly peak. If this ratio is greater than 84% the Commission has adopted 12-CP.
- Test 2 compares the average of the system peaks during the seasonal peak period as a percentage of the annual peak to the average of the system peaks during the off-peak months as a percentage of the annual peak. For PGE, the peak period occurs during the months of November through February and again in July and August. Generally, large differences between the two percentages lends support to something other than 12-CP.
- Test 3 calculates the lowest monthly peak as a percentage of the annual peak. Higher percentages support using the 12-CP methodology.

Q. Please provide the results of the tests you performed.

A. The three 12-CP tests produced the results below:

Test 1	3,187 MW/3,762 MW	84.7%	
Test 2	3,442 MW/3,762 MW	91.5%	On-peak (Nov-Feb, Jul-Aug)
	2,932 MW/3,762 MW	77.9%	Off-peak (Mar-Jun, Sep-Oct)
	Difference	13.6%	
Test 3	2,808 MW/3,762 MW	74.6%	

The results are within the parameters used historically by FERC to determine 12-CP companies: the ratio of the twelve average peaks to the annual peak is greater than approximately 84%, and the ratio of the lowest monthly peak to the highest is greater than approximately 71%. We therefore conclude that PGE is a 12-CP company.

Q. Can you offer some guidance on how to implement this long-run marginal cost methodology should the Commission decide that this is a more appropriate method to estimate generation marginal costs?

A. Yes. We believe that any change in methodology should be implemented gradually and with discretion. We therefore have the following specific recommendations:

- For this proceeding, if the Commission determines that a long-run approach is warranted, we recommend the generation revenue requirement allocations be equally weighted between the methodology proposed by PGE in its direct testimony and the methodology above. This gradualism helps to mitigate large deviations in rate impacts between the rate schedules and the weighting is consistent with the ICNU recommendation.
- For Schedules 83 and 89, the delivery voltage differences in the energy charges should reflect the line loss differentials adjusted for the ratio of generation revenue requirements to marginal energy costs.
- The Schedule 128 Short-Term Transition Adjustment calculations should continue to be based upon the methodology employed by PGE in its direct testimony.
- The results for special schedules such as Schedule 38 should not unduly influence migrations to these schedules. We therefore suggest that the flat Schedule 38 energy charge be set equal to the energy charge of Schedule 83-S with the

resulting difference used to offset the Customer Impact Offset (CIO) for all schedules not receiving a CIO credit.

- The CIO should be capped at 30 mills/kWh and the floor should be set such that no schedule receives less than 25% of the base rate change. This helps to mitigate CIO subsidies in the event that the proposed overall base rate change is markedly different from that presented here. It also helps assure that no rate schedule receives a relative change markedly different from that proposed in our original filing.

Q. Please provide the results of this marginal cost and ratespread methodology after applying the suggestions above and compare it to the methodology employed by PGE in its direct testimony.

A. From the revenue requirements discussed in PGE Exhibit 1400, we present in PGE Exhibit 2003 the impacts by rate schedule using the currently proposed PGE marginal cost methodology and the long-run methodology discussed above with and without our specific recommendations. We believe that the blended approach we present provides a sound basis which the Commission may rely upon should it decide to rule in favor of using long-run marginal cost as opposed to the short-run marginal cost methodology used by PGE in its last two general rate cases.

Below we present a brief summary comparison of the price change impacts for the major rate schedules:

Schedule	Direct Testimony Method	Blended Method
7	12.9%	13.9%
32	11.2%	10.1%
83	12.1%	11.8%
89	15.6%	13.7%
Overall	12.9%	12.9%

VI. Kroger

Q. Please summarize the pricing issue identified by Kroger.

A. Kroger specifically claims the following:

> PGE has proposed an overall increase of 7.7 percent for Schedule 83. However, the proposed rate increase for 83-S is 7.6 percent and the proposed rate increase for 83-P is 9.1 percent. The higher rate increase for 83-P occurs because PGE's rate design shifts some of the costs associated with providing distribution service for 83-S onto 83-P. This cost shift is unreasonable and should be corrected. If this correction is made, Schedule 83-S and 83-P would receive approximately the same percentage rate increase.

Q. Please state why Kroger's claims are incorrect.

A. First, the Kroger claim that the 1.5% price change difference between 83-S and 83-P is attributable to PGE's rate design shifting distribution costs is erroneous. As demonstrated in our Pricing work papers, of the 1.5% difference, 1.45% is attributable to changes in energy and system usage charges. On a cost causation basis, PGE has continued to reflect the cost differences between secondary and primary voltage customers for the average size Schedule 83 customer at the appropriate point in the distribution system within the distribution facilities charge. This appropriate point is the difference in costs to provide customers with a line transformer and service (both secondary voltage service) as well as the service design costs incurred to energize the customer. To this cost difference PGE adds the difference in feeder costs attributable to the fact that some secondary voltage customers will be served at single-phase rather than three-phase.

Q. Please substantiate this last statement that you continue to reflect the cost differences for the average size Schedule 83 customer through the distribution facilities charge.

A. PGE Exhibit 2004 contains the UE 180 compliance work papers that demonstrate a facilities marginal cost difference between 83-S and 83-P of 31 cents per kW that is reflected in the current facilities charges for 83-S and 83-P and the same distribution demand charge basis of $2.27 per kW. For 83-S, this $2.27 was blocked in order to effect an easier migration for Schedule 32 customers whose demand exceeded 30 kW.

In the opening testimony of this docket we calculated a facilities marginal cost difference of 31 cents per kW, the same as in UE 180, and a distribution demand charge value of $2.10 for both 83-S and 83-P. This amount was increased to $2.13 to account for the under-recovery of customer charges. In this docket we chose to block the distribution facilities charge instead of the distribution demand charge to effect the Schedule 32 migration and in part to make it easier to incorporate on- and off-peak differentiated Schedule 83 distribution demand charges in the future. The blocking of the 83-S facilities charge is why the second 83-S facilities charge block is 53 cents higher instead of 31 cents higher than the 83-P facilities charge.

Q. Kroger has provided analysis in support of its claim. Could you please evaluate this analysis?

A. Yes. The Kroger analysis evaluates one aspect of embedded cost differential; the cost to connect a primary and a secondary service customer but ignores other aspects of cost differentials. Contrary to what Kroger implies, this cost is recovered through PGE's facilities charge, not the distribution demand charge. Furthermore, the Kroger analysis does not reflect the cost differentials to serve the average size Schedule 83 customer, but rather reflects the fact that the average Schedule 83-P customer is larger than the average Schedule 83-S customer. PGE believes its methodology that captures the price differentials where they occur at the appropriate point on the distribution system for similar size customers is superior and reflects true marginal cost pricing.

Q. How would you calculate the appropriate delivery price differential for a customer approximating the average size of a PGE Schedule 83-P customer?

A. The average size Schedule 83-P customer is about 470 kW facility capacity. We would therefore calculate the delivery voltage cost difference by estimating the cost of providing a 500 kVa transformer and service for a secondary voltage customer compared to the cost of providing primary voltage service.

Q. Have you performed this calculation?

A. Yes. Our work papers contain a calculation that demonstrates on a marginal cost basis the appropriate price differential would be about 25 cents per kW, less than the amount we proposed for Schedule 83 in our initial filing.

Q. What are the delivery voltage price differentials for other regional investor-owned electric utilities in the region in whose ratemaking dockets Kroger intervenes?

A. We calculated base rate annual bills for the prices proposed by PGE in its direct testimony, the relevant comparable schedule for Pacific Power in Oregon as well as the comparable proposed prices for Puget Sound Energy in its current rate case. For a 470 kW customer, PGE’s difference between secondary and primary voltage was the highest of the three utilities. Specifically, PGE’s differential was 0.32 cents per kWh while the differences for Puget and Pacific Power were 0.16 and 0.11 cents per kWh respectively. Measured on a percent basis, PGE’s secondary voltage bills were 4.2% higher than for primary service, while for Puget and PacifiCorp, the percent differences were 2.1% and 2.2% respectively. The rate design recommended by Kroger yields differences of 0.42 cents per kWh and 5.5%. This tells us that regarding delivery voltage differentials, our pricing proposals are, contrary to Kroger’s assertions, perhaps too generous relative to other regional utilities. The Kroger rate design recommendations would unwarrantedly accentuate this. We have included the details behind these calculations in our work papers.

Q. What do you recommend regarding Kroger's distribution demand charge issue?

A. We recommend that the Commission reject Kroger's proposals because the assertion that the differential rate change impact between 83-S and 83-P is caused by PGE shifting costs in its distribution charges is incorrect; we have shown that the reason for the rate impact differential is due to changes in energy-related charges. Furthermore, PGE has demonstrated that there has been no change in cost causation principles since UE 180 as Kroger implies, but rather a simple change in how PGE effects the migration of Schedule 32 customers to Schedule 83-S. Additionally, we have amply demonstrated in both UE 180 and in this docket the basis for the differential facilities charges. Finally, we have surveyed two other regional investor-owned utilities that serve Kroger stores and in whose ratemaking dockets Kroger intervenes and determined that PGE's differential is greater than these other utilities.

VII. CUB's Elasticity

Q. Please state the CUB issue you are addressing.

A. We address CUB's comments regarding price elasticity found on pages 6 and 34 of their Exhibit 100 testimony. Specifically, we address CUB's statements that PGE has removed a disincentive to increase prices because it includes estimates of price elasticity of demand in its load forecasts.

Q. Should PGE include estimates of price elasticity of demand in its load forecasts?

A. Yes. PGE believes that it is important to produce the best possible load forecast at all times. An estimate of price elasticity, similar to the other inputs in the load forecast, helps provide a more accurate load forecast that helps to set appropriate test period prices.

Q. Are there instances where including estimates of price elasticity in the load forecast benefit customers?

A. Yes. In PGE's Annual Update Tariff (AUT) proceedings, PGE includes estimates of price elasticity even though the marginal cost of energy is considerably higher than the embedded cost of energy. In other words, were PGE not to include estimates of price elasticity in its AUT load forecast, it would project higher loads resulting in higher unit costs to the detriment of customers.

Q. What do you conclude about CUB's statements regarding price elasticity?

A. We conclude that, contrary to CUB's assertions, both PGE and customers benefit from including price elasticity of demand in test period load forecasts.

VIII. CAPO/OECA

Q. Please summarize issues identified by CAPO/OECA.

A. CAPO/OECA discusses PGE's collection practices and the impacts they have on PGE's low-income customers, the impacts of rising energy costs, PGE's decoupling proposal and PGE's Tariff related to Basic Charge (Rule F, Section 1, Paragraph (C)). In order to mitigate potential rate impacts on low income customers, CAPO/OECA proposes to freeze Schedule 7 first block energy rates (applicable to consumption of 250 kWh or less) at UE-180 levels. CAPO/OECA further proposes to exempt low-income customers from payment of late-pay charges, disapproval of the increase in PGE's proposed field collection and reconnection fees, exemption of low-income customers from PGE's proposed field collection and reconnection fees and disapproval of PGE Tariff language in Rule F, Section 1, Paragraph (C).

Q. Prior to addressing CAPO/OECA's specific recommendations, please describe the current efforts of PGE customers to help low-income customers.

A. Although not discussed by CAPO/OECA, PGE customers already provide over $16 million annually to low-income customers living in PGE's service territory. In 2008, PGE residential and non-residential customers will pay approximately $9 million to Oregon Energy Assistance Program (OEAP) through PGE's Low Income Assistance Charge (PGE Tariff Schedule 115) and approximately $7.6 million through Public Purpose Charge (PGE Tariff Schedule 108) funds for low-income weatherization and low-income housing purposes.

Q. Please describe PGE's current and past actions that facilitate low-income customers' access to resources to help pay their bills and manage their energy costs.

A. In its day to day activities, PGE seeks opportunities to work collaboratively with agencies and community partners to develop solutions, create efficiencies and enable existing resources to serve more customers. The following represents some of PGE's on-going and past activities supporting PGE's commitment to low-income customers:

- Since 1989, PGE has provided office, administrative and monetary support to Oregon HEAT. Semi-annually PGE solicits donations to Oregon HEAT from its customers to help fund energy assistance to low-income households.
- PGE provides on-going support to various Community based organizations either through employee involvement (i.e. Take the Chill Out) or through grants.
- Annually, through the PGE newsletter and through bill inserts, PGE informs customers about the Earned Income Tax Credit (EITC) and energy assistance and low-income weatherization programs. Energy assistance information is also included in past due notices and is available on PGE's website.
- Between September 2006 and February 2008, PGE piloted the New Start Arrearage Forgiveness program, in collaboration with seven community action agencies. The pilot's goals were to help low income customers reduce their past due balances, provide low income customers with energy education to help them manage their energy use and help low income customers improve their payment behavior long-term. A final report on the pilot program was filed with the OPUC on May 7, 2008.
- PGE has participated in LIHEAP Action Day in Washington D.C. to urge the Oregon congressional delegation to advocate for additional federal low income support for the state of Oregon.

- In 2007, the BPA residential exchange credit was suspended by the 9th Circuit Court. Recognizing the potential impact this loss of credit would have on our low income customers, PGE proactively enacted a series of measures to help mitigate the impact. These measures included making extended time payment agreements available, making an additional donation of $50,000 to Oregon HEAT, and conducting a series of 19 workshops on energy saving tips targeted to renters conducted in community locations such as affordable housing complexes, Head Start centers and churches.
- PGE has begun work on an online portal to facilitate interaction between PGE and low income agencies making financial commitments of energy assistance to our customers. When complete, the portal is expected to streamline and automate procedures for both PGE and the agencies eliminating many phone calls, faxes and manual system entries and improving service to low income customers.

Q. How do these actions impact energy affordability in Oregon?

A. While CAPO/OECA extensively used Home Energy Gap statistics in their testimony, CAPO/OECA failed to mention that in 2007 Oregon had the most affordable Home Energy Affordability Gap in the nation. Home Energy Affordability Gap is calculated by Fisher, Sheehan & Colton Law and Economic Consulting firm. Excerpts from CAPO/OECA Response to a PGE's Data Request No. 009 are included in PGE Exhibit 2005.

Q. Please evaluate CAPO/OECA's proposal to freeze the first residential block energy rate at the UE-180 level of 4.429 cents per kWh, and its effect on low-income customers?

A. CAPO/OECA's analysis supporting the proposal is incorrect. First, CAPO/OECA fails to show the correlation between low use (250 kWh per month and less) and income levels of residential customers living in PGE's service territory. The average consumption of a PGE residential customer is about 900 kWh per month. While econometric analyses typically show a positive relationship between income and energy usage, the energy usage of individual customers vary widely from the average. Some low-income customers use more than the system average especially if they live in older, inefficient, electrically heated homes. Homes of high-income customers can use significantly less electricity than the system average, especially if the homes are newly built condos or homes that have natural gas furnaces, water-heaters and ranges. Thus, there is no guarantee (and no analysis) that CAPO/OECA's proposal will help low income customers. It will likely hurt some low-income customers and help some high-income customers. Second, the transfer payment from the first consumption block to the second block would be approximately $13 million versus the $750,000 as calculated by CAPO/OECA. In calculating the $750,000, CAPO/OECA only summed up the consumption of customers that use 250 kWh or less year round, not the actual usage that "passes through" the first block. In addition, CAPO/OECA used a 13-month data set rather than a 12-month data set to calculate the transfer payment. CAPO/OECA did not take into consideration that, a residential customer using on average more than 250 kWh per month would also be impacted by the rate freeze proposal. In order to calculate the transfer payment correctly, CAPO/OECA should have used all the energy (i.e. kWh) that "passes through" the first consumption block; not just the usage up to the first block threshold. So instead of using 118,012,931 kWh, CAPO/OECA should have used 2,042,532,552 kWh. This yields a transfer payment of approximately $13 million. Please see PGE Exhibit 2006 for a correct analysis of what the transfer would be should the first block rate freeze proposal be implemented.

Q. Should the Commission adopt CAPO/OECA's proposal to freeze the first block residential energy rate?

A. No. As we discussed above, CAPO/OECA made a significant error in calculating the transfer payment from block 1 to block 2 customers and did not present studies specific to low-income customers living in PGE's service territory that correlate customer income levels to consumption. Proposing a freeze on the first block residential energy rate without correctly establishing the impacts on all PGE customers including low-income is not prudent and, therefore, CAPO/OECA's proposal should be rejected.

Q. Do PGE's collection practices unfairly burden low-income customers relative to other customers?

A. Absolutely not. PGE's collection practices are governed by Division 21 Rules of Oregon Administrative Rules (OAR). They are applied on an equal basis regardless of customers' income level.

Q. Please describe PGE's collection practices.

A. PGE services are rendered on a credit basis and payment for services is not required until after the electric service has been used. Customer bills are due approximately 15 days after bill presentment as prescribed in OAR 860-021-0125. If PGE does not receive payment by the requested due date, a 15-day notice is mailed, and a subsequent 5-day notice is then mailed in accordance with OAR 860-021-045. Although not required by OARs, prior to disconnection of service, PGE makes additional attempts to contact the customer through automated phone calls Further, PGE's current threshold to initiate collection activity is a

$100 past due amount. With an average monthly bill of $87.85 per month, a typical customer would have at least two billing cycles to make a payment or enter into a payment arrangement prior to having service scheduled for disconnection. If a customer does not make a payment or does not enter into a payment arrangement on or before the due date of the 5-day notice, electric service could be disconnected for non-payment. Disconnection of service is a collection effort of last resort and an activity that PGE does not take lightly. PGE does not disconnect service for credit related purposes on Fridays, holidays, or during inclement weather.

Q. Does PGE work with its customers that fall behind on their electric bill?

A. Yes. PGE offers interest-free time payment agreements (TPAs), under which a customer can pay off their past due account balance in 12 monthly installments. Further, PGE's customer service representatives (CSRs) are empowered to make reasonable payment arrangements with customers to help with their immediate needs while minimizing the risk of disconnection of service. Furthermore, PGE will stop collection activity for customers who secured energy assistance from a low income agency with a promised dollar amount, even though PGE has not received the energy assistance funds, only the promise of payment.

Q. Could you provide an example of the options PGE offers when a customer is scheduled for disconnection?

A. Yes. For example, if a customer has a total account balance of $225, and $150 of the $225 is past due and subject to disconnection and the customer calls PGE in response to the notice(s) received, the following process is typical. The CSR will offer two types of TPAs. Under both TPAs the customer would be required to pay only $18.75 (1/12 of $225) to enter into a TPA, thereby averting disconnection of service. The balance is then placed on an interest free installment plan to be paid off in 11 months. If the customer is already on a TPA with no means of payment, the customer is referred to energy assistance for help. If agency assistance is not available, a reasonable partial payment may be accepted. It is PGE's aim to work with its customer rather than disconnect their service. Disconnection is a tool that PGE utilizes as a last resort. Reasonable partial payment is considered by PGE so long as there is no history of broken arrangements or fraud.

Q. What is the purpose of the fees associated with PGE's credit activity (late fees, field visit fees and reconnection fees)?

A. The purpose of PGE's credit-related fees is to recover at least a portion of the costs that PGE incurs to provide these services during its normal course of business. The field visit fee is charged if a customer has failed to make a payment or enter into a payment arrangement with PGE and a PGE field representative has had to personally visit the customer's premises to collect past due amounts. The reconnect fee is assessed when a customer's service has been disconnected for non-payment and the same customer is requesting that service be re-established in their name. As described in prior sections, before PGE's initiates credit related activities, the customer has multiple opportunities to either make a payment or enter into a payment arrangement with PGE. Aside from recovering costs, these charges provide customers with important price signals. The late payment fee places the bill for electric service on par with other bills that have similar charges. As such, there is not a subtle message that the electric bill is somehow less important to pay in a timely fashion. The field visit fee signals that it is "not ok" to just wait until the last minute and make a payment at the door, thus saving the cost of a stamp while forcing the utility to incur substantial costs to collect for electric service.

Q. Historically, what has been the Commission's stance on late fees, field visit fees and reconnection fees?

A. It has been a long standing Commission and utility practice not to unfairly burden customers that either make timely payments or take the opportunity to engage PGE and make payment arrangements for past due balances. Reconnection fees and field visit fees are explicitly allowed by OARs 860-021-0330 and 860-021-0420, respectively. PGE's late payment fees are determined by the Commission's Staff and prescribed by OAR 860-021-0126. In its most recent Order (No. 07-514), the Commission ruled that the 1.7% charge is "reasonably consistent with the practices of other commercial enterprises."

Q. Please address CAPO/OECA's claim that PGE's late fees are charged at annual rates of 242%, 85% and 51% (CAPO Exhibit 200/page 24/lines 17-19).

A. CAPO/OECA's assertion is misleading. The effective interest rate as calculated by Staff and approved in the OPUC Order 07-514, attached in PGE Exhibit 2007, is 20.1% CAPO/OECA did not take into consideration OAR 860-021-0126 and PGE's business practices. According to OAR 860-021-0126, PGE can only impose late fees if the customer's account balance has been carried forward for two consecutive months. Consequently a customer would have to be late by two months and 5 days in order to be assessed a late fee. As such, in accordance with PGE's current collection practices if a customer does not make a payment for two months the annual interest charged, is actually less than 10%.

Q. Please discuss how charges for credit related field visits and reconnections are determined?

A. PGE developed its credit related field visit charges using a bottom-up approach, with the basic premise that on average it takes 33 minutes to perform a field activity. The methodology has not changed since the last time the Commission approved changes to Schedule 300 charges on March 2, 2004. The methodology includes overhead loadings associated with the activity and vehicle. PGE found that 33 minutes is a reasonable time considering that a field representative has to drive and interact with the customer, which could involve negotiating with the customer or allow the customer call the contact center to make payment arrangements, performing the field activity and the administrative tasks associated with the activity.

Q. What is the revenue impact of late-fees and credit collection charges?

A. Revenues associated with credit and collection activities are part of PGE's Other Revenues and are deducted from PGE's overall revenue requirement reducing all customers' rates.

Q. Will PGE's late fees and credit related fees increase as a result of the UE 197 proposal?

A. No. As part of a stipulation regarding certain revenue requirement issues filed with the Commission on August 5, 2008, PGE has agreed not to seek an increase in its credit related fees at this time. Please see Staff-CUB-PGE/Exhibit 100/page 3.

Q. In its testimony, CAPO/OECA's makes a claim that PGE's Budget Billing options are not available to PGE's low-income customers. Please state why this claim is false.

A. In Exhibit 200/page 28/lines 10-12, CAPO/OECA claims that PGE's budget billing options (PGE offers two, equal pay and average pay) are not available to low-income customers. This is not true. PGE's business practices are provided on the same basis regardless of a household's size or income level. In fact, PGE has not received a single customer complaint or an at fault violation from the OPUC Consumer Staff in which the Company was found to not have allowed a customer to sign up for budget pay because of income levels. All customers are eligible on the same terms for budget pay or levelized time payment agreements that provide PGE customers with equalized monthly bills for a twelve month period. When PGE asked CAPO/OECA to provide the number of low-income customers that CAPO/OECA are aware of that were denied access to PGE's budget billing or levelized billing programs during the 2004 to present time-period, CAPO/OECA replied that it did not possess such data. PGE Exhibit 2008 contains a copy of CAPO/OECA's response.

Q. Should the Commission adopt CAPO/OECA's proposal to exempt low-income customers from paying late fees, and credit related field visit and reconnection fees?

A. No. Exempting low-income customers from late-fees and credit related field visit and reconnection fees would send the wrong price signal to customers that their electric bill is not as important to pay as other bills. In addition, the administrative challenges of implementing the proposal could be very expensive as PGE's billing systems are not set up to track and verify the income status of its residential customers. Moreover, PGE's current business practices and Division 21 rules approved by the Commission already provide sufficient protection for all customers, low-income and non-low income in assessing only those fees that are applicable and where such fee is appropriate. Customers, regardless of income levels, are provided with multiple opportunities to enter into arrangements on past due balances long before disconnection of electric service or application of credit related fees occurs. Low-income customers' ability to pay is not related to a single commodity or a single utility's service territory. Low income customers unable to afford their electric bill need to receive assistance prior to having their service disconnected. There is significant assistance available. In 2007, PGE customers received a little over $10 million[1] in various direct energy assistance funds. In total, PGE received 41,426 agency payments on behalf of customers, averaging slightly over $240 per payment. In 2008, the Oregon Legislature increased funding from PGE and PacifiCorp customers dedicated to OEAP from $10 million to $15 million per year. If more assistance is needed (and PGE does not dispute that this may be the case), funding for additional assistance should be addressed through the Oregon Legislature.

Q. Should the Commission adopt CAPO/OECA's proposal that asks the Commission to dedicate late-fee revenues for low-income purposes?

A. No. As mentioned above, PGE believes that issues related to additional energy assistance, poverty and energy affordability should be addressed comprehensively in the Oregon legislature. Also the Commission should consider that late-fee revenues are part of "Other Revenues" and are deducted from PGE's overall test-year revenue requirement reducing all customers' retail rates. The parties to this rate case have stipulated to the level of "Other Revenues" in their stipulation submitted on August 5, 2008. Should the Commission adopt CAPO/OECA's recommendation, a portion of late fee revenues will have to be removed from "Other Revenues" category, decreasing the overall deduction to PGE's retail revenue requirement and increasing all other customers' retail rates.

Q. Please discuss how PGE applies the monthly Basic Charge to customers that were disconnected for non-payment of electric service.

[1] Total funds received in 2007 from LIEAP, OEAP, Oregon Heat, and other agencies.

A. There is a misconception by CAPO/OECA (Exhibit 200/page 48/ lines 9-11) that PGE continues to charge the monthly Basic Charge to customers whose service has been disconnected for credit-related reasons. The reference in Rule F, Continuing Nature of Charges, under Section 1, Subsection C, was put into place to prevent customers from voluntarily closing their service and months later re-establishing service at the same address (i.e., seasonal homes) in order to avoid payment of the monthly Basic Charge. For customers who are disconnected for credit related reasons, the Basic Charge is charged only for the period for which service was available prior to the disconnection and again when service is re-established in the customer/applicant's name. The Basic Charge is prorated upon bill issuance should the subsequent bill period be less than 27 days following the re-establishment of service. In conclusion, Rule F, Section 1, Paragraph (C) does not pertain to customers whose service has been involuntarily disconnected.

Q. Please summarize your response to CAPO/OECA's testimony.

A. We believe that while CAPO/OECA seeks to help low-income customers, the proposals and the basis for the proposals are not reasonable and should not be adopted by the Commission. PGE supplies residential electric service and charges for all of its customers on equal basis. PGE's current credit practices and Division 21 rules provide protection for all customers, low-income and non-low income in assessing only those fees that are applicable and where such fees are appropriate.

IX. Qualifications of Michaela Lynn

Q. Ms. Lynn, please state your educational background and qualifications.

A. I received a Bachelor of Science degree in Human Development from Colorado State University. Since joining PGE in 1997, I have held various management positions within the customer service and delivery areas. My current position is Manager of Receivables, Billing and Low Income Operations.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
2001	Redline of Schedules 125 and 129
2002	Long-run Generation Marginal Cost Estimate
2003	Comparative Bill Impacts from PGE Long-run Marginal Cost Methodology
2004	Schedule 83 Delivery Voltage Differentials
2005	Oregon Energy Gap Rankings
2006	Analysis of CAPO/OECA First Block Rate Freeze Proposal
2007	Late Payment Interest Rate Order
2008	CAPO/OECA Budget and Levelized Payment Program Data Response

SCHEDULE 125
ANNUAL POWER COST UPDATE

PURPOSE

The purpose of this adjustment schedule is to define procedures for annual rate revisions due to changes in the Company's projected Net Variable Power Costs (the Annual Power Cost Update). This schedule is an "automatic adjustment clause" as defined in ORS 757.210(1), and is subject to review by the Commission at least once every two years.

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.

NET VARIABLE POWER COSTS

Net Variable Power Costs (NVPC) are the power costs for energy generated and purchased. NVPC are the net cost of fuel, fuel transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load.

RATES

This adjustment rate is subject to increases or decreases, which may be made without prior hearing, to reflect increases or decreases, or both, in NVPC.

ANNUAL UPDATES

The following updates will be made in each of the Annual Power Cost Update filings:

- Forced Outage Rates based on a four-year rolling average.
- Projected planned plant outages.
- Forward market prices for both gas and electricity.
- Projected loads.
- Contracts for the purchase or sale of power and fuel.
- Changes in hedges, options, and other financial instruments used to serve retail load.
- Transportation contracts and other fixed transportation costs.
- No other changes or updates will be made in the annual filings under this schedule.

~~ADJUSTED~~ CHANGES IN NET VARIABLE POWER COSTS

Changes in ~~Adjusted Net Variable Power Costs~~NVPC for purposes of rate determination under this schedule are the projected NVPC as determined in the Annual Power Cost Update ~~plus~~ less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case~~changes in fixed generation revenues caused by the net change in Cost of Service loads resulting from either return to or departures from Cost of Service pricing by Schedule 483 and 489 customers relative to the Company's most recent general rate case~~, adjusted for a revenue sensitive cost factor of 1.0342.

SCHEDULE 125 (Continued)

FILING AND EFFECTIVE DATE

On or before April 1st of each calendar year, the Company will file estimates of the adjustments to its NVPC to be effective on January 1st of the following calendar year.

On or before October 1st of each calendar year, the Company will file updated estimates with final planned maintenance outages, final load forecast, updated projections of gas and electric prices, power, and fuel contracts.

On November 15th, the Company will file the final estimate of NVPC and will calculate and file the final ~~unit~~ change in NVPC to be effective on the next January 1st with: 1) projected market electric and fuel prices based on the average of the Company's internally generated projections made during the period November 1st through November 7th, 2) load reductions from the October update resulting from additional participation in the Company's Long-Term Cost of Service Opt-out that occurs in September, 3) new market power and fuel contracts entered into since the previous updates, and 4) the final planned maintenance outages and load forecast from the October 1st filing.

RATE ADJUSTMENT

The rate adjustment will be based on the Adjusted NVPC less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case applied to forecast loads used to determine ~~Adjusted~~ Changes in Net Variable Power Costs. NVPC prices are defined as the price component that recovers the level of NVPC from the Company's most recent general rate case contained in each Schedule's Cost of Service energy prices.

ADJUSTMENT RATES

Schedule		Part A ¢ per kWh
7		0.000
15		0.000
32		0.000
38	Large Nonresidential	0.000
47		0.000
49		0.000
75	Secondary	0.000 (1)
	Primary	0.000 (1)
	Subtransmission	0.000 (1)
83	Secondary	0.000
	Primary	0.000
87	Secondary	0.000
	Primary	0.000
	Subtransmission	0.000

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 125 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule		Part A ¢ per kWh
89	Secondary	0.000
	Primary	0.000
	Subtransmission	0.000
91		0.000
92		0.000
93		0.000
94		0.000

SPECIAL CONDITIONS

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

~~2. In determining changes in fixed generation revenues from movement to or from Schedules 483 and 489, the following factors will be used:~~

~~Schedule~~		~~¢ per kWh~~
~~83~~	~~Secondary~~	~~1.942~~
	~~Primary~~	~~1.879~~
~~89~~	~~Secondary~~	~~1.950~~
	~~Primary~~	~~1.860~~
	~~Subtransmission~~	~~1.818~~

SCHEDULE 129 (Concluded)

TRANSITION COST ADJUSTMENT (Continued)
Three Year Opt-Out

For Enrollment Period F (2007), the Transition Cost Adjustment will be:

(1.250) ¢ per kWh	January 1, 2008 through December 31, 2008
(1.434) ¢ per kWh	January 1, 2009 through December 31, 2009
(1.248) ¢ per kWh	January 1, 2010 through December 31, 2010

SPECIAL CONDITIONS

1. Annually, the total amount paid in Schedule 129 Long-Term Transition Cost Adjustment will be collected through applicable Large Nonresidential rate schedules (Schedules 75, 76R, 83, 89, 483, 489, 575, 576R, 583, 589), through either the System Usage or Distribution Charges. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year.

2. Changes in fixed generation revenues resulting from either return to or departure from Cost of Service pricing by Schedule 483 and 489 customers relative to the company's most recent general rate case will be incorporated into the System Usage Charges of the applicable Large Nonresidential rate schedules (Schedules 75, 76R, 83, 89, 483, 489, 575, 576R, 583, 589). The changes in fixed generation revenues will be adjusted to account for a revenue sensitive cost factor of 1.0342. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year.

3. In determining changes in fixed generation revenues from movement to or from Schedules 483 and 489, the following factors will be used:

Schedule		¢ per kWh
83	Secondary	x.xxx
	Primary	x.xxx
89	Secondary	x.xxx
	Primary	x.xxx
	Subtransmission	x.xxx

TERM

The term of applicability under this schedule will correspond to a Customer's term of service under Schedule 483 or 489.

PORTLAND GENERAL ELECTRIC
Marginal Cost Estimate of Generation Resource
Nominal Dollars

Year	Marginal Cost mills/kWh	Energy mills/kWh	Capacity mills/kWh
1	94.96	77.13	17.83
2	91.53	73.29	18.24
3	89.76	71.10	18.66
4	87.34	68.30	19.04
5	85.07	65.54	19.53
6	82.48	62.50	19.98
7	85.12	64.68	20.44
8	88.78	67.92	20.85
9	94.05	72.66	21.39
10	100.76	78.87	21.88
11	104.25	81.87	22.39
12	108.06	85.23	22.84
13	110.60	87.17	23.43
14	113.14	89.17	23.97
15	115.74	91.22	24.52
16	118.34	93.33	25.01
17	121.12	95.46	25.66
18	123.90	97.65	26.25
19	126.75	99.89	26.85
20	129.60	102.21	27.39
Real Levelized Cost	82.80	64.98	17.82
Capacity $/kW (mills per kWh times 93% capacity factor times 8.766)			$145.28

PORTLAND GENERAL ELECTRIC
ALLOCATION OF PRODUCTION COSTS TO COS CUSTOMERS
2009

Grouping	COS Calendar Energy	Annual Energy Price	Marginal Energy Costs ($000)	12 CP	Marginal Capacity Costs ($000)	Total Marginal Costs ($000)	Allocation Percent	Allocated Production Costs ($000)	Cycle Basis Costs ($000)
Schedule 7	7,723,589	$70.40	$543,736	1,506.6	$218,882	$762,618	42.74%	$541,109	$540,973
Schedule 15	23,853	$70.40	$1,679	2.4	$344	$2,023	0.11%	$1,435	$1,435
Schedule 32	1,526,672	$70.40	$107,477	233.9	$33,975	$141,452	7.93%	$100,366	$100,321
Schedule 38	74,427	$70.40	$5,240	4.4	$633	$5,873	0.33%	$4,167	$4,174
Schedule 47	22,468	$70.40	$1,582	3.9	$565	$2,147	0.12%	$1,523	$1,507
Schedule 49	66,181	$70.40	$4,659	11.5	$1,663	$6,323	0.35%	$4,486	$4,502
Schedule 83-S	5,333,978	$70.40	$375,508	878.8	$127,679	$503,188	28.20%	$357,033	$356,563
Schedule 89-S 1-4 MW	645,468	$70.40	$45,441	106.2	$15,428	$60,868	3.41%	$43,189	$43,455
Schedule 89-S GT 4 MW	26,311	$70.40	$1,852	3.4	$488	$2,340	0.13%	$1,660	$1,652
Schedule 83-P	297,123	$68.15	$20,249	45.1	$6,546	$26,795	1.50%	$19,013	$18,818
Schedule 89-P 1-4 MW	642,716	$68.15	$43,802	97.1	$14,101	$57,903	3.25%	$41,085	$41,276
Schedule 89-P GT 4 MW	1,150,411	$68.15	$78,402	140.6	$20,422	$98,823	5.54%	$70,119	$69,746
Schedule 89-T	1,249,068	$67.17	$83,900	142.0	$20,625	$104,525	5.86%	$74,165	$74,172
Schedule 91	104,956	$70.40	$7,389	10.6	$1,540	$8,929	0.50%	$6,335	$6,335
Schedule 92/94	5,097	$70.40	$359	0.6	$87	$446	0.02%	$316	$316
Schedule 93	566	$70.40	$40	0.1	$12	$52	0.00%	$37	$37
TOTAL	18,892,884		$1,321,313	3,186.9	$462,992	$1,784,305	100.00%	$1,266,039	$1,265,284
Simple Cycle Proxy Plant $/kW					$145.28		TARGET	$1,266,039	
Marginal Energy Price		$64.98							

PORTLAND GENERAL ELECTRIC
Comparative Generation Allocations and Relative Price Impacts

Grouping	Cycle MWH	Current Revenues	Method 1 Proposed Revenues	Method 1 Percent Change	Method 2 Proposed Revenues	Method 2 Percent Change	Blended Proposed Revenues	Blended Percent Change
Schedule 7	7,721,634	$764,344	$863,152	12.9%	$878,594	14.9%	$870,719	13.9%
Schedule 15	23,853	$4,323	$4,517	4.5%	$4,443	2.8%	$4,480	3.6%
Schedule 32	1,525,992	$143,924	$160,095	11.2%	$156,962	9.1%	$158,498	10.1%
Schedule 38	74,559	$7,103	$8,099	14.0%	$7,283	2.5%	$8,111	14.2%
Schedule 47	22,224	$2,253	$2,831	25.6%	$2,831	25.6%	$2,831	25.6%
Schedule 49	66,419	$4,821	$6,057	25.6%	$6,057	25.6%	$6,057	25.6%
Schedule 83-S	5,326,952	$411,732	$461,137	12.0%	$459,305	11.6%	$460,021	11.7%
Schedule 83-P	294,088	$21,052	$23,965	13.8%	$23,646	12.3%	$23,920	13.6%
Schedule 89-S	675,632	$49,228	$56,058	13.9%	$55,638	13.0%	$55,380	12.5%
Schedule 89-P	1,789,998	$117,427	$135,558	15.4%	$131,086	11.6%	$133,562	13.7%
Schedule 89-T	1,249,192	$74,757	$87,469	17.0%	$83,371	11.5%	$85,575	14.5%
Schedule 91	104,956	$16,968	$17,869	5.3%	$17,562	3.5%	$17,713	4.4%
Schedule 92	5,001	$365	$446	22.4%	$426	16.7%	$436	19.5%
Schedule 93	566	$86	$97	12.8%	$97	12.1%	$97	12.4%
Schedule 94	96	$7	$9	22.4%	$8	15.3%	$8	18.8%
Totals	18,881,162	$1,618,388	$1,827,359	12.9%	$1,827,307	12.9%	$1,827,408	12.9%

Notes: Method 1 is PGE's proposed methodology in direct testimony
Method 2 is PGE's long-run marginal cost estimates prior to blending and rate design
Blended is Method 1 and Method 2 equally weighted with rate design considerations

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2007

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 83						
General Service 31-1,000 kW						
Theoretic						
Functional Costs						
Basic Charge						
Single-Phase Secondary	$303	750	Customers	$33.65	per cust, per mo.	$303
Three-Phase Secondary	$4,816	11,105	Customers	$36.14	per cust, per mo.	$4,816
Primary	$237	145	Customers	$136.38	per cust, per mo.	$237
Transmission & Related Service Charge	$8,798	14,921,244	kW demand	$0.59	per kW demand	$8,804
Distribution Charges						
13 kV Facilities	$23,425	17,039,584	kW faccap	$1.37	per kW faccap	$23,344
Connect Charge	$12,584	17,039,584	kW faccap	$0.74	per kW faccap	$12,609
Subtransmission Charge	$16,619	14,921,244	kW demand	$1.11	per kW demand	$16,563
Substation Charge	$17,278	14,921,244	kW demand	$1.16	per kW demand	$17,309
Secondary Franchise Fees & Other	$22,303	5,366,608	MWh	4.16	mills/kWh	$22,325
Primary Franchise Fees & Other	$1,206	299,879	MWh	4.02	mills/kWh	$1,206
Secondary COS Energy Charge	$292,042	5,359,462	MWh	54.49	mills/kWh	$292,037
Primary COS Energy Charge	$15,730	299,879	MWh	52.46	mills/kWh	$15,732
Subtotal	$415,342					$415,283
Proposed						
Functional Costs						
Basic Charge						
Secondary Single-Phase		750	Customers	$20.00	per cust, per mo.	$180
Secondary Three-Phase		11,105	Customers	$25.00	per cust, per mo.	$3,331
Primary		145	Customers	$90.00	per cust, per mo.	$156
Trans. & Rel. Serv. Charge						
First 30 kW		4,233,895	kW demand	$0.61	per kW demand	$2,583
Over 30 kW		10,687,349	kW demand	$0.61	per kW demand	$6,519
Distribution Charges						
Secondary Facilities Charge						
First 30 kW		4,267,524	kW faccap	$2.12	<= 30 kW faccap	$9,047
Over 30 kW		11,965,408	kW faccap	$2.12	> 30 kW faccap	$25,367
Primary Facilities Charge						
First 30 kW		52,080	kW faccap	$1.81	<= 30 kW faccap	$94
Over 30 kW		754,572	kW faccap	$1.81	> 30 kW faccap	$1,366
Secondary Demand Charge						
First 30 kW		4,181,815	kW demand	$1.41	per kW demand	$5,896
Over 30 kW		10,048,441	kW demand	$2.70	per kW demand	$27,131
Primary Demand Charge						
First 30 kW		52,080	kW demand	$2.27	per kW demand	$118
Over 30 kW		638,908	kW demand	$2.27	per kW demand	$1,450
Secondary System Usage Charge Calc						
Franchise Fees & Other		5,366,608	MWh	4.16	mills/kWh	$22,325
Cust Impact Offset		5,366,608	MWh	0.22	mills/kWh	$1,181
System Usage Charge		5,366,608	MWh	4.38	mills/kWh	$23,506
Primary System Usage Charge Calc						
Franchise Fees & Other		299,879	MWh	4.02	mills/kWh	$1,206
Cust Impact Offset		299,879	MWh	(0.31)	mills/kWh	($93)
System Usage Charge		299,879	MWh	3.71	mills/kWh	$1,113
Secondary COS Energy Charge		5,359,462	MWh	54.49	mills/kWh	$292,037
Primary COS Energy Charge		299,879	MWh	52.46	mills/kWh	$15,732
Reactive Demand Charge		1,697,722	kVar	$0.50	kVar	$849
Subtotal						$416,475
					w/o CIO	$415,387

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2007

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
Theoretic Facilities Charge Differential between Schedule 83 Secondary and Primary Voltage Service						
Secondary Three Phase Connect Marginal Costs	$1,115.54					
Primary Three Phase Connect Marginal Costs	$863.63					
Delta	$251.91					
Distribution Equal Percent	98%					
Equal Percent Difference	$247.04					
Average Annual Facilities Billing Determinant	1,420					
Facilities Charge Delta per Faccap	$0.17					
Secondary 13 kV Costs	Marg. Cost	NCP				
Single phase	$27.70	19,724	$546,345			
Three phase	$19.43	1,144,722	$22,241,952			
Weighted	$19.57	1,164,446	$22,788,296			
Primary 13 kV Costs	$19.43					
Delta 13 kV Costs	$0.14					
Equal Percent Difference	$0.14					
Total Schedule 83 Facilities Delta	$0.31					
Theoretic Facilities Charge Differential between Schedule 89 Secondary and Primary Voltage Service						
Billing Demand of 1,000 to 4,000 kW						
Secondary Three Phase Connect Marginal Costs	$4,526.14					
Primary Three Phase Connect Marginal Costs	$863.63					
Delta	$3,662.51					
Distribution Equal Percent	98%					
Equal Percent Difference	$3,591.65					
Average Annual Facilities Billing Determinant	20,659					
Facilities Charge Delta per Faccap	$0.17					
Theoretic Facilities Charge Differential between Schedule 89 Secondary and Primary Voltage Service						
Billing Demand greater than 4,000 kW						
Secondary Three Phase Connect Marginal Costs	$20,823.37					
Primary Three Phase Connect Marginal Costs	$3,068.13					
Delta	$17,755.24					
Distribution Equal Percent	98%					
Equal Percent Difference	$17,411.74					
Average Annual Facilities Billing Determinant	136,723					
Facilities Charge Delta per Faccap	$0.13					
Weighted Average Schedule 89 Difference	$0.13					
Theoretic Facilities Charge Differential between Schedule 89 Primary and Subtransmission Voltage Service						
Billing Demand greater than 4,000 kW						
Primary Connect & 13 kV Marginal Costs	$45,909					
Subtransmission Connect Marginal Costs	$56,755					
Delta	($10,846)					
Distribution Equal Percent	98%					
Equal Percent Difference	($10,636)					
Average Annual Facilities Billing Determinant	179,716					
Facilities Charge Delta per Faccap	($0.06)					
Subtransmission Facilities Billing Determinants	2,458,092					
Dollars to Demand Charge ($000)	$145					

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2009

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 83						
General Service 31-1,000 kW						
Theoretic						
Functional Costs				68%		
Basic Charge						
Single-Phase Secondary	$325	801	Customers	$33.77	per cust, per mo.	$325
Three-Phase Secondary	$5,233	11,808	Customers	$36.93	per cust, per mo.	$5,233
Primary	$195	143	Customers	$114.04	per cust, per mo.	$195
Transmission & Related Service Charge	$11,012	15,495,047	kW demand	$0.71	per kW demand	$11,001
Distribution Charges						
13 kV Facilities	$25,343	18,548,463	kW faccap	$1.37	per kW faccap	$25,411
Connect Charge	$13,993	18,548,463	kW faccap	$0.75	per kW faccap	$13,911
Subtransmission Charge	$13,122	15,575,321	kW demand	$0.84	per kW demand	$13,083
Substation Charge	$19,586	15,575,321	kW demand	$1.26	per kW demand	$19,625
Secondary Franchise Fees & Other	$22,311	5,481,948	MWh	4.07	mills/kWh	$22,312
Primary Franchise Fees & Other	$1,080	275,761	MWh	3.91	mills/kWh	$1,078
Secondary COS Energy Charge	$343,603	5,442,588	MWh	63.13	mills/kWh	$343,591
Primary COS Energy Charge	$16,839	275,761	MWh	61.06	mills/kWh	$16,838
Subtotal	$472,642					$472,603
Proposed						
Functional Costs						
Basic Charge						
Secondary Single-Phase		801	Customers	$20.00	per cust, per mo.	$192
Secondary Three-Phase		11,808	Customers	$25.00	per cust, per mo.	$3,542
Primary		143	Customers	$80.00	per cust, per mo.	$137
Trans. & Rel. Serv. Charge						
First 30 kW		4,410,599	kW demand	$0.75	per kW demand	$3,308
Over 30 kW		11,084,448	kW demand	$0.75	per kW demand	$8,313
Distribution Charges						
Secondary Facilities Charge						
First 30 kW		4,539,432	kW faccap	$1.54	<= 30 kW faccap	$6,991
Over 30 kW		13,229,074	kW faccap	$2.34	> 30 kW faccap	$30,956
Primary Facilities Charge						
First 30 kW		51,360	kW faccap	$1.81	<= 30 kW faccap	$93
Over 30 kW		728,598	kW faccap	$1.81	> 30 kW faccap	$1,319
Secondary Demand Charge						
First 30 kW		4,363,870	kW demand	$2.13	per kW demand	$9,295
Over 30 kW		10,561,013	kW demand	$2.13	per kW demand	$22,495
Primary Demand Charge						
First 30 kW		51,261	kW demand	$2.13	per kW demand	$109
Over 30 kW		599,177	kW demand	$2.13	per kW demand	$1,276
Secondary System Usage Charge Calc						
Franchise Fees & Other		5,481,948	MWh	4.07	mills/kWh	$22,312
Cust Impact Offset		5,481,948	MWh	0.12	mills/kWh	$658
System Usage Charge		5,481,948	MWh	4.19	mills/kWh	$22,969
Primary System Usage Charge Calc						
Franchise Fees & Other		275,761	MWh	3.91	mills/kWh	$1,078
Cust Impact Offset		275,761	MWh	0.12	mills/kWh	$33
System Usage Charge		275,761	MWh	4.03	mills/kWh	$1,111
Secondary COS Energy Charge		5,442,588	MWh	63.13	mills/kWh	$343,591
Primary COS Energy Charge		275,761	MWh	61.06	mills/kWh	$16,838
Reactive Demand Charge		1,739,215	kVar	$0.50	kVar	$870
Subtotal						$473,406
					w/o CIO	$472,715

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2009

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
Theoretic Facilities Charge Differential between Schedule 83 Secondary and Primary Voltage Service						
Secondary Connect Marginal Costs		Customers				
Single phase	$461.49	801				
Three phase	$1,224.35	11,808				
Weighted	$1,175.87	12,609				
Primary Three Phase Connect Marginal Costs	$958.67					
Delta	$217.20					
Distribution Equal Percent	94%					
Equal Percent Difference	$203.12					
Average Annual Facilities Billing Determinant	1,455					
Facilities Charge Delta per Faccap	$0.14					
Secondary 13 kV Costs	Marg. Cost	NCP				
Single phase	$31.03	23,283	$722,483			
Three phase	$22.02	1,146,923	$25,255,247			
Weighted	$22.20	1,170,206	$25,977,730			
Primary 13 kV Costs	$22.02					
Delta 13 kV Costs	$0.18					
Equal Percent Difference	$0.17					
Total Schedule 83 Facilities Delta	$0.31					

Theoretic Facilities Charge Differential between Schedule 89 Secondary and Primary Voltage Service
Billing Demand of 1,000 to 4,000 kW

Secondary Three Phase Connect Marginal Costs	$6,591.78
Primary Three Phase Connect Marginal Costs	$958.67
Delta	$5,633.11
Distribution Equal Percent	94%
Equal Percent Difference	$5,267.84
Average Annual Facilities Billing Determinant	19,856
Facilities Charge Delta per Faccap	$0.27

Theoretic Facilities Charge Differential between Schedule 89 Secondary and Primary Voltage Service
Billing Demand greater than 4,000 kW

Secondary Three Phase Connect Marginal Costs	$33,743.42
Primary Three Phase Connect Marginal Costs	$3,806.65
Delta	$29,936.77
Distribution Equal Percent	94%
Equal Percent Difference	$27,995.54
Average Annual Facilities Billing Determinant	128,193
Facilities Charge Delta per Faccap	$0.22
Weighted Average Schedule 89 Difference	$0.22

Theoretic Facilities Charge Differential between Schedule 89 Primary and Subtransmission Voltage Service
Billing Demand greater than 4,000 kW

Primary Connect & 13 kV Marginal Costs	$50,690
Subtransmission Connect Marginal Costs	$74,730
Delta	($24,040)
Distribution Equal Percent	94%
Equal Percent Difference	($22,481)
Average Annual Facilities Billing Determinant	167,664
Facilities Charge Delta per Faccap	($0.13)
Subtransmission Facilities Billing Determinants	2,763,937
Dollars to Demand Charge ($000)	$371

Oregon Energy Gap Rankings (scale of 1-51)

A higher ranking indicates better conditions while a lower ranking indicates worse conditions relative to other states.

AVERAGE DOLLAR AMOUNT BY WHICH ACTUAL HOME ENERGY BILLS EXCEEDED AFFORDABLE HOME ENERGY BILLS FOR HOUSEHOLDS BELOW 185% OF POVERTY LEVEL. **$744 per household** **RANK: #1**	AVERAGE TOTAL HOME ENERGY BURDEN FOR HOUSEHOLDS BELOW 50% OF POVERTY LEVEL. **44.2% of household income** **RANK: #2**
PERCENT OF INDIVIDUALS BELOW 100% OF POVERTY LEVEL. **11.6% of all individuals** **RANK: #27**	PORTION OF HEATING/COOLING AFFORDABILITY GAP COVERED BY FEDERAL HOME ENERGY ASSISTANCE. **10.4% of gap is covered** **RANK: #26**

DEFINITIONS AND EXPLANATIONS

Each state (along with the District of Columbia) has been ranked (from 1 to 51) in terms of four separate measures of the extent of the energy affordability gap facing its low-income customers:

(1) The percent of individuals with annual incomes at or below 100% of the Federal Poverty Level. This data is obtained directly from the 2000 U.S. Census.

(2) The average total home energy burden for households with income at or below 50% of the Federal Poverty Level shows the percentage of income that households with these incomes spend on home energy. "Total home energy" includes all energy usage, not merely heating and cooling. A home energy bill is calculated on a county-by-county basis. The statewide average is a population-weighted average of county-by-county data.

(3) The average affordability gap (in dollars per household) for all households with income at or below 185% of Poverty is the dollar difference between actual total home energy bills and bills that are set equal to an affordable percentage of income. Affordability for total home energy bills is set at 6% of household income.

(4) The extent to which federal energy assistance covers the combined heating/cooling affordability gap for each state. The combined heating/cooling affordability gap is the difference between actual heating/cooling bills and bills that are set equal to an affordable percentage of income. Affordability for combined heating/cooling bills is set at 2% of income. This measure thus examines the proportion of the heating/cooling gap that is covered by the gross federal Low-Income Home Energy Assistance Program (LIHEAP) allocation to the state assuming that the entire LIHEAP allocation is used for cash benefits.

In the state's rankings, a higher ranking indicates better conditions while a lower ranking indicates worse conditions relative to other states. Thus, for example:

(1) The state with the rank of #1 has the lowest percentage of individuals living in households with income at or below 100% of the Federal Poverty Level while the state with the rank of #51 has the highest percentage.

(2) The state with the rank of #1 has the lowest average home energy burden for households with income below 50% of the Federal Poverty Level while the state with the rank of #51 has the highest average home energy burden.

(3) The state with the rank of #1 has the lowest average affordability gap (dollars per household) while the state with the rank of #51 has the highest dollar gap.

(4) The state with the rank of #1 has the highest percentage of its heating/cooling affordability gap covered by federal energy assistance while the state with the rank of #51 has the lowest percentage of its heating/cooling gap covered.

All references to "states" include the District of Columbia as a "state." Low-income home energy bills are calculated using average residential revenues per unit of energy. State financial resources and utility-specific discounts are not considered.

LIHEAP comparisons use gross allotments from the baseline LIHEAP appropriation; they do not reflect supplemental appropriations or the release of other emergency funds. For example, the 2006 Home Energy Affordability Gap (issued in April 2007) analysis does not reflect the supplemental appropriation bill enacted in March 2006.

Energy bills are a function of the following primary factors:

- Tenure of household (owner/renter)
- Housing unit size (by tenure)
- Heating Degree Days (HDDs) and Cooling Degree Days (CDDs) (by county)
- Household size (by tenure)
- Heating fuel mix (by tenure)
- Energy use intensities (by fuel and end use)

Bills are estimated using the U.S. Department of Energy's "energy intensities" published in the most recent DOE Residential Energy Consumption Survey (RECS). The energy intensities used for each state are those published for the Census Division in which the state is located. State-specific demographic data is obtained from the most recent Decennial Census of the U.S. Census Bureau. Heating Degree-Days (HDDs) and Cooling Degree-Days (CDDs) are obtained from the National Weather Service's Climate Prediction Center on a county-by-county basis for the entire country. State price data for each end-use is obtained from the Energy Information Administration's (EIA) fuel-specific price reports (e.g., Natural Gas Monthly, Electric Power Monthly).

Each state's Home Energy Affordability Gap is calculated on a county-by-county basis. Once total energy bills are estimated for each county, each county bill is weighted by the percentage of persons below 185% of the Federal Poverty Level in each county to the total statewide population below 185% of the Federal Poverty Level to derive a statewide result.

The Home Energy Affordability Gap Index uses 2002 as its base year. In that year, the Index was set equal to 100. A current year Index of more than 100 thus indicates that the Home Energy Affordability Gap has increased since 2002. A current year Index of less than 100 indicates that the Home Energy Affordability Gap has decreased since 2002.

The Home Energy Affordability Gap is a function of many variables. Increases in income, for example, result in decreases in the Gap while increases in energy prices result in an increase in the Gap. The Home Energy Affordability Gap Index allows the reader to determine the cumulative impact of these variables. Since the Gap is calculated assuming normal Heating Degree Days (HDDs) and Cooling Degree Days (CDDs), temperatures do not have an impact on the Affordability Gap or the Affordability Gap Index.

Price data for the various fuels underlying the calculation of the 2007 Home Energy Affordability Gap was used from the following time periods:

Heating prices	
Natural gas	February 2007
Fuel oil	February 2007
Liquefied petroleum gas (LPG)	February 2007
Electricity	February 2007
Cooling prices	August 2007
Non-heating prices	
Natural gas	May 2007
Fuel oil	May 2007
Liquefied petroleum gas (LPG)	May 2007
Electricity	May 2007

ANALYSIS OF CAPO'S FIRST BLOCK ENERGY RATE FREEZE PROPOSAL

	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Total
1-35	24,392,420	24,398,934	24,411,147	24,431,321	24,441,801	24,475,415	24,526,039	24,574,209	24,615,088	24,677,435	24,729,391	24,728,328	294,401,528
36-50	10,430,687	10,425,456	10,427,100	10,441,658	10,444,205	10,459,038	10,477,742	10,500,134	10,526,527	10,555,804	10,577,373	10,575,405	125,841,129
51-100	34,536,492	34,476,362	34,444,732	34,505,889	34,517,070	34,573,954	34,629,129	34,766,525	34,928,615	35,044,363	35,105,224	35,065,875	416,594,230
101-200	67,443,031	67,002,010	66,657,594	66,691,592	66,766,035	66,830,619	67,184,868	67,982,675	68,800,692	69,190,697	69,238,548	68,820,949	812,609,310
201-225	16,431,686	16,243,943	16,099,209	16,067,621	16,086,457	16,097,006	16,255,795	16,598,398	16,937,806	17,075,836	17,066,657	16,880,310	197,840,724
226-250	16,222,942	15,991,396	15,815,521	15,776,091	15,788,829	15,784,108	15,975,837	16,416,378	16,821,785	16,972,172	16,949,557	16,731,015	195,245,631
Total B1	169,457,258	168,538,101	167,855,303	167,914,172	168,044,397	168,220,140	169,049,410	170,838,319	172,630,513	173,516,307	173,666,750	172,801,882	2,042,532,552
Total kWh	598,771,427	547,643,933	522,865,546	541,437,522	551,003,540	533,243,932	529,461,025	629,723,028	802,792,248	908,137,769	830,898,042	721,804,219	7,717,782,231
>250	429,314,169	379,105,832	355,010,243	373,523,350	382,959,143	365,023,792	360,411,615	458,884,709	630,161,735	734,621,462	657,231,292	549,002,337	5,675,249,679

Block 1 (12 months Mar-08 - Apr 07)	2,042,533	MWh
Block 2 (12 months Mar-08 - Apr 07)	5,675,250	MWh
Total (12 months Mar-08 - Apr 07)	7,717,782	MWh

	mills/kWh	MWh	('000)
Rate frozen at UE-180 levels (mills/kWh)	44.29	2,042,533	$90,463.77
Proposed UE-197 first block rate (mills/kW	50.66	2,042,533	$103,474.70
			($13,010.93)

ORDER NO. 07-514

ENTERED 11/26/07

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 779

In the Matter of	)	
	)	ORDER
Public Utility Commission of Oregon	)	
Determination of Late-Payment Rate and	)	
Interest Accrued on Customer Deposits.	)	

DISPOSITION: CURRENT LATE PAYMENT RATE CONTINUED; CUSTOMER DEPOSIT INTEREST ACCRUAL RATE CHANGED

At its public meeting on November 20, 2007, the Public Utility Commission of Oregon (Commission) adopted Staff's recommendation that the Commission continue the current maximum 1.7 percent monthly rate which utilities may charge customers on overdue accounts. Staff also recommends that the current 5 percent annual rate at which utilities must credit customer deposit accounts be changed to 4 percent. Staff's recommendation, submitted pursuant to OAR 860-21-0126(3), is attached as Appendix A and incorporated by reference.

ORDER

IT IS ORDERED that effective January 1, 2008:

1. The monthly late-payment rate which utilities may charge customers on overdue accounts shall continue at 1.7 percent.

2. The customer deposit interest accrual rate is changed from 5 percent to 4 percent.

3. These rates shall remain in effect until further notice.

Made, entered, and effective NOV 26 2007.

BY THE COMMISSION:

Becky L Beier

Becky L. Beier
Commission Secretary

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

ORDER NO. 07-514

ITEM NO. CA6

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: November 20, 2007

REGULAR ____ **CONSENT** X **EFFECTIVE DATE** January 1, 2008

DATE: November 1, 2007

TO: Public Utility Commission

FROM: Ming Peng mp

THROUGH: Lee Sparling, Marc Hellman, and Bryan Conway

SUBJECT: OREGON PUBLIC UTILITY COMMISSION STAFF: (Docket No. UM 779) Commission determination of late-payment rate and interest accrued on customer deposits.

STAFF RECOMMENDATION:

Staff recommends no change in the current maximum late-payment charge of 1.7% monthly (20.1% Annual Percentage Rate). The late-payment rate is the fee utilities may charge customers on overdue accounts. Staff also recommends that, beginning January 1, 2008, the annualized interest rate at which utilities must credit customers for deposits be changed to 4%, from the current 5%.

DISCUSSION:

Late-Payment Rate: Oregon Administrative Rules (OAR) 860-21-0126(3), 860-34-0120(2), and 860-036-0130(1) specify that "The Commission will determine the late-payment rate based on a survey of prevailing market rates for late-payment charges of commercial enterprises and will advise all utilities of the changes in the rate they may use to determine late-payment charges on overdue customer accounts as needed. The current late-payment rate and the conditions for its application to customer accounts shall be specified on the utility bill."

Staff surveyed 30 commercial accounts that reasonably represent the general range of businesses likely to be patronized by most utility consumers, such as department stores (including furniture), gasoline dealer, air travel, tire retailer, home improvement warehouse, hardware store, water and sewer systems, recycling and disposal firms, electricity, and telephone companies as well as insurance companies.

The survey indicated that a maximum monthly rate of 1.7% is applied by a few businesses for late payments. Most businesses (commercial enterprises), however, charge a flat fee for late payments (for example, $10 up to $39) in addition to a finance charge of 1.4% to 2.1% per month. Some publicly owned utilities (water/sewer and electricity) and insurance companies do not charge a late-payment fee. Past due accounts are subject to cancellation of the services or policies.

Across the country, many utility companies set the late-payment fees at a certain percentage point per month to ensure that the cost of not paying a utility bill is roughly equal to the cost of not paying a credit card. Staff recommends no change in the current maximum late-payment charge of 1.7% monthly. It is reasonably consistent with the practices of commercial enterprises.

Interest Paid on Customer Deposits: OAR 860-21-0210(1), 860-34-0160(1), and 860-036-0050(1) state that "Each year, the Commission shall establish an annual interest rate that must be paid on customer deposits. The Commission will base the rate upon consideration of the effective interest rate for new issues of one-year Treasury Bills issued during the last week of October, the interest rate on the most recent issuance of one-year Treasury Bills, or the effective interest rate for the average yield of Treasury Bills of the closest term issued during the last week of October. This interest rate, rounded to the nearest one-half of one percent, shall apply to deposits held during January 1 through December 31 of the subsequent year."

No new issues of 52-week Treasury bills were issued during the last week of October 2007. Staff used the average yields of Treasury bills of the closest term issued during the last week of October. From October 25 to 31, 2007, the Wall Street Journal reported that the Treasury bill maturing on May 1, 2008, (177-183 days to maturity) had asking yields that had an average of 4.018%. As specified in the administrative rules, the annual interest rate is rounded to 4.0%.

PROPOSED COMMISSION MOTION:

Staff's recommendation to continue the current maximum late-payment rate of 1.7% monthly on overdue customer accounts, and change the annual interest rate to 4.0% on customer deposits for the calendar year 2008, be adopted.

UM 779 - 2008

PORTLAND GENERAL ELECTRIC
UE 197
PGE's Second Set of Data Requests to CAPO
Dated July 16, 2008
Question Nos. 002-057

34. In reference to CAPO/OECA Colton page 28, lines 3-5, please list the number of low-income customers that CAPO/OECA are aware of, that were denied access to PGE's budget billing or levelized time payment programs during the 2004 to present time-period.

Response

CAPO/OECA does not possess such data.

Table of Contents

I. Background and Qualifications

Q. Please state your name, address, and employment.

A. My name is Ralph Cavanagh. I am the Energy Program Co-Director for the Natural Resources Defense Council, 111 Sutter Street, 20th Floor, San Francisco, CA 94104.

Q. Please outline your educational background and professional experience.

A. I am a graduate of Yale College and Yale Law School, and I joined NRDC in 1979. I am a member of the faculty of the University of Idaho's Utility Executive Course, and I have been a Visiting Professor of Law at Stanford and UC Berkeley (Boalt Hall). From 1993-2003 I served as a member of the U.S. Secretary of Energy's Advisory Board, and in March of 2008 I was appointed to serve on the U.S. Department of Energy's Electricity Advisory Committee. My current board memberships include the Bonneville Environmental Foundation, the Center for Energy Efficiency and Renewable Technologies, the California Clean Energy Fund, the Northwest Energy Coalition, and the Renewable Northwest Project. I have received the Heinz Award for Public Policy (1996) and the Bonneville Power Administration's Award for Exceptional Public Service (1986). In April 2008, I agreed to serve as a member of the Executive Committee of the Northwest Energy Efficiency Taskforce (NEET), whose deliberations are ongoing.

Q. On whose behalf are you testifying?

A. I am testifying at the request of the Portland General Electric Company (PGE) as an expert on mechanisms for "decoupling" utilities' fixed-cost revenue recovery from their retail energy sales.

Q. Is Portland General compensating you in any way for this testimony?

A. No.

Q. Have you ever received any compensation from Portland General Electric for any purpose?

A. No.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony reviews the decoupling proposal that PGE has advanced in this proceeding, along with responses of other parties to that proposal, and recommends acceptance of the PGE proposal with certain modifications.

Q. What materials have you reviewed in preparation for this testimony?

A. I have reviewed the company's Direct Testimony in support of its decoupling proposal (PGE/100 & 1200), along with Staff Exhibit 600, the Direct Testimony of the Citizens' Utility Board of Oregon, the Direct Testimony of Kevin C. Higgins on behalf of Fred Meyer Stores (FM Exhibit 100), and the Direct Testimony and Exhibits of Roger D. Colton (CAPO-OECA Exhibit 200).

II. Summary of Conclusions and Recommendations

Q. Summarize your conclusions and recommendations.

A. One of the company's most important responsibilities involves "integrated resource planning" (IRP): assembling a diversified mix of demand- and supply-side resources designed to minimize the societal costs of reliable electricity supplies. The company is effectively a resource portfolio manager for its customers, and in the volatile financial markets of the early twenty-first century, the stakes and challenges have never been more daunting. Yet the regulatory status quo undercuts sound portfolio management by penalizing utility shareholders for reductions in electricity throughput over the distribution system, regardless of the cost-effectiveness of any contributing energy-efficiency, distributed-generation or fuel substitution measures. From customers' perspective, increases in throughput (above those contemplated when rates were established) result inappropriately in an uncompensated over-recovery of fixed costs by their utility. And from a least-cost planning perspective, a grave if unintended pathology of such ratemaking practices is the linkage of utilities' financial health to retail electricity throughput. Increased retail electricity sales produce higher fixed cost recovery and reduced sales have the opposite effect. My testimony includes a demonstration, based on unchallenged elements of the record in this proceeding, that reasonably aggressive five-year energy efficiency investment programs throughout its service territory in the residential sector alone would automatically inflict some $60 million in cumulative losses on PGE's shareholders (notwithstanding full recovery of program costs) regardless of the cost-effectiveness of the resulting electricity savings.

To address all these problems, I recommend that the Commission accept PGE's proposal to adopt a simple system of periodic true-ups in electric rates, designed to correct for disparities between the company's actual fixed cost recovery and the revenue requirement approved by the Commission in this proceeding. The true-ups would either restore to the company or give back to customers the dollars that were under- or over-recovered as a result of fluctuations in retail electricity sales. My recommendations build on precedents established earlier by this Commission. In response to concerns raised by other parties, I recommend several adjustments in the PGE proposal, which would ensure an opportunity for the Commission to revisit key elements of the decoupling mechanism within five years, create benchmarks for evaluating progress, and substitute what PGE calls a "load-based" decoupling adjustment for the lost revenue recovery mechanism that the company recommends for Schedule 123 (PGE/1200, Kuns-Cody/29-30).

III. PGE's Proposed Decoupling Mechanism

Q. Why do you support the restoration of electricity-sector decoupling in Oregon?

A. Oregon has a longstanding commitment, as a matter of both law and policy, to pursue all cost-effective electricity savings and avoid unnecessary expenditure on generation and grid additions. The state also promotes customer-installed solar generation through energy tax credits and net metering. In addition to encouraging greater efforts and investment in energy efficiency and on-site solar power, the Oregon PUC has an opportunity in this proceeding to continue its longstanding efforts to align shareholder and customer interests in reduced electricity needs. Commissioner Beyer represented Oregon at the July 2006 NARUC ceremony marking the release of the National Energy Efficiency Action Plan; among the Plan's core objectives is "modify policies to align utility incentives with the delivery of cost-effective energy efficiency," by "addressing the typical utility throughput incentive and removing other regulatory and management disincentives to energy efficiency."[1]

Like most utilities, PGE recovers most of its fixed costs through the rates it charges per kilowatt-hour. In other words, a part of the cost of every kWh represents the system's fixed costs of existing plant and equipment (4.6 – 5.1 cents/kWh for most customers, according to data cited in Staff/600, Storm/10), while the rest of the charge per kWh collects the variable cost of producing that kilowatt-hour. After approving a fixed-cost revenue requirement, the Commission sets rates based on assumptions about annual kilowatt-hour sales. If sales lag below those assumptions, the company will not recover its approved fixed-cost revenue requirement. By contrast, if the company were successful in promoting consumption increases above regulators' expectations, its shareholders would earn a windfall in the form

[1] National Action Plan for Energy Efficiency (July 2006), p. 8 (Recommendations); the NARUC ceremony occurred on July 31, 2006, the opening day of the organization's annual summer meeting.

of cost recovery that exceeded the approved revenue requirement. And whether consumption ends up above or below regulators' expectations, every reduction in sales from efficiency improvements yields a corresponding reduction in cost recovery, to the detriment of shareholders.

Q. Why not solve the problem by recovering utilities' fixed costs in fixed charges to customers?

A. This would require radical changes in rate design and would dramatically reduce customers' rewards for saving energy at the very time they should be encouraged to do more. The rationale for integrated resource planning rests in part on the conclusion that extensive market failures continue to block energy savings that are much cheaper than additional energy production at <u>today's</u> electricity prices. We would make a bad situation worse by reducing customers' rewards for conserving electricity, which is precisely what would happen if the Company shifted costs from volumetric to fixed charges.

Q. What's the best alternative?

A. As PGE proposes in this proceeding, the Commission should put in place for electricity sales the policy it already applies to Oregon's natural gas utilities: the use of modest, regular true-ups in rates to ensure that any fixed costs recovered in kilowatt-hour charges are not held hostage to sales volumes. The state regulatory community has more than two decades of experience with such mechanisms, which involve a simple comparison of actual fixed cost revenues to authorized revenues, followed by an equally simple true-up calculation to reconcile the difference. The result is then either refunded to customers or restored to the Company. Note that the true-up can go in either direction, depending on whether actual fixed-cost revenues are above or below the authorized level.

Q. What is the magnitude of the financial disincentives that decoupling aims to remove?

A. To illustrate the potential importance of such true-ups for PGE, witness Piro (PGE/100, Piro/19) notes without contradiction elsewhere in the record that "if PGE's residential customers reduce loads by just 0.5% per year, we estimate lost margins of approximately $2 million in the first year." For purposes of meeting Oregon's long-term electricity needs, I believe that savings of at least one percent of systemwide consumption will be needed. Based on witness Piro's estimate, every one percent reduction in residential electricity use on the company's system would cut annual fixed-cost recovery totals by about $4 million; every one percent increase would have the opposite effect. Since many efficiency measures last ten years or more, these one-year impacts only just begin to address the impact on shareholder interests.

And the losses get much worse in the context of multi-year programs initiated under a long-term resource plan. Consider a five-year program that pursues annual savings equivalent to one percent of residential load in the initial year, with each year adding new savings equivalent to the savings achieved during the previous year, and all savings persisting for at least five years. The first year impact on fixed cost recovery is then about $4 million, followed by $8 million dollars in the second year (as an equal amount of savings is added), and so on: **the automatic cumulative five-year loss to shareholders from this steady-state residential initiative would be some $60 million**,[2] with shareholder losses continuing to escalate in succeeding years as initial electricity savings persisted (with some gradual erosion) and more savings were added. Note that the shareholders would be absorbing these losses even as customers gained from substituting less costly energy

[2] The minimum loss figure is the sum of $3.74 million + $7.48m + $11.22m + $14.96m + 18.7m = $56.1m.

efficiency for more costly generation. Even if PGE were to respond by filing more frequent rate cases, it could not recoup losses incurred in the interval between OPUC decisions, and the stream of losses would recommence as soon as each rate case order were issued.

Q. Are adverse effects of this kind limited to cost-effective energy efficiency improvements?

A. No. Substituting efficient gas applications for electricity, or adding distributed generation such as solar PV on the customer's side of the meter, reduces retail kilowatt-hour sales and has adverse effects on fixed-cost recovery that are identical (per kWh of lost retail sales) to those described above.

Q. What makes you think energy efficiency programs can save one percent of system-wide consumption per year?

A. The Northwest Power Planning Council reports that the region very nearly did, despite widely varying levels of effort in 2007.[3] Also, based in part on a finding that each dollar spent on energy efficiency provides about two dollars in net benefits, California's PUC pushed its statewide savings targets above one percent of utilities' annual electricity sales in 2005 and again in 2008.[4] And in Wisconsin, as reported by the Public Service Commission, statewide savings have reached as much as 1.2 percent of statewide electricity use.[5]

Q. Summerize Oregon's experience with the type of decoupling mechanism that you are recommending.

[3] See http://www.nwcouncil.org/library/releases/2008/0514.htm for the Northwest Power and Conservation Council's press release on the savings data (2007 Savings were 203 aMW @ busbar, 2007 consumption @ busbar 20,825 aMW = 0.97% of regionwide consumption).

[4] See California PUC, Decision No. 08-07-047, Decision Adopting Interim Energy Efficiency Savings Goals for 2012 Through 2020, and Defining Energy Efficiency Savings Goals for 2009 through 2011 (July 31, 2008).

[5] That occurred in 1993, based on PSC-reported savings in Wisconsin's Environmental Decade Institute, Energy Efficiency Crisis Report, p. 1 (1999); statewide electricity consumption data for 1993 are from State of Wisconsin, Department of Administration, Wisconsin Energy Statistics 2004, p. 46.

A. Oregon has ample experience. "[T]he Commission first considered decoupling over ten years ago as a means to make regulatory policy more compatible with least-cost planning," and moved to "fully decouple PGE in the mid-1990s."[6] The Commission went on to "adop[t] a revenue cap mechanism for PacifiCorp's distribution revenues in 1998."[7] Initial rate impacts of PacifiCorp's "Alternative Form of Regulation" were extremely modest for all classes, and (as predicted) adjustments went in both directions; the largest annual rate increase for any class was 1.9%, the largest annual rate reduction was 0.83%, and out of a total of fifteen true-ups from 1999 – 2001, seven resulted in rate reductions and eight resulted in rate increases.

More recently (in 2002), the Oregon PUC also adopted a modified true-up mechanism for Northwest Natural Gas Co.; an independent evaluation concluded, in March 2005, that the mechanism was "effective in altering Northwest Natural's incentives to promote energy efficiency" and should be retained, although the authors recommended removing some rather complex features that were not relevant to the mechanism's primary purpose.[8] The Commission issued an order in August 2005 adopting a stipulation that simplified the mechanism and extended it for another four years.[9] The State's other major gas distributor, Cascade Natural Gas, secured its own decoupling mechanism when the Oregon Commission approved its May 18, 2006 tariff filing.[10]

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[6] Oregon PUC, Order No. 02-633 (Sept. 12, 2002), p. 5.
[7] See id. and Oregon PUC, Order No. 98-191 (May 5, 1998) (covering 1998 – 2001). Rate impact data were supplied to me by PacifiCorp's Paul Wrigley and initially published in Direct Testimony of Ralph Cavanagh, Washington UTC Docket No. UE-050684 (Nov. 2, 2005), p. 13.
[8] D. Hansen & S. Braithwait, A Review of Distribution Margin Normalization as Approved by the Oregon Public Utilities Commission for Northwest Natural (March 2005), pp. 67-68.
[9] Oregon PUC, Order No. 05-934 (UG 163, August 25, 2005).
[10] The filing, numbered CNG/O05-10-01, was approved by the Commission on May 23, 2006

Q. What happened when the Commission last considered a decoupling mechanism for PGE?

A. In 2001, PGE sought restoration of its true-up mechanism in UE 126, with support from NRDC and others. The Commission rejected the proposal, citing skepticism that such mechanisms would in fact yield any change in utilities' motivation to support and fund expanded conservation efforts.[11] Subsequent experience with Northwest Natural Gas's mechanism certainly shows otherwise, and the Commission should use this proceeding to indicate that Order No. 02-633 is no barrier to reinstituting decoupling for Oregon's retail electric utilities. As suggested in Oregon CUB's testimony, the Commission also should make clear that the mechanism's success will be judged in substantial part on the emergence of material benefits to Oregon customers in the form of substantially increased conservation investment and results.

Q. Are you suggesting that PGE should supplant the Energy Trust of Oregon as a delivery mechanism for energy efficiency services?

A. No. I am not suggesting that PGE or any other electric utility should substitute for the Oregon Energy Trust as the state's primary energy-efficiency delivery mechanism. For purposes of increased energy efficiency investment and results, I have in mind a partnership between utilities and the Trust, not any kind of displacement of Trust responsibilities. I am mindful also of the fact that PGE can influence the pace of efficiency improvements, for good or ill, in many ways that are unrelated to delivering energy efficiency services directly. Its potential role in shaping state and federal efficiency standards and tax credits comes instantly to mind, as do its numerous opportunities to shape customers' attitudes about and

[11] Oregon PUC, Order No. UE 126, pp. 5-7 (2001).

openness to efficiency investments of their own. To that list can be added development of "non-wires" alternatives to costly grid enhancements and the integration of cost-effective "distributed" generation on customers' premises. I know from much personal experience that utilities can make both positive and negative differences from the perspective of energy efficiency progress, and it is long past time to remove a significant disincentive to a host of utility efforts that would reduce costs for all PGE customers.

Q. Has any other northwest state adopted a per-customer decoupling mechanism for an electric utility?

A. Washington's UTC adopted such a mechanism for Puget Power in the early 1991, and in 2007 the Idaho PUC approved a per-customer decoupling mechanism proposed by the Idaho Power Company. The Washington Commission implemented Puget's revenue-per-customer cap by "set[ting] up a deferred account allowing a reconciliation of revenue and expenses that would be subject to hearing and review."[12] In its initial review of the mechanism that it had adopted two years earlier, the Commission in 1993 "accept[ed] the parties representations" that the revenue-per-customer cap had "achieved its primary goal – the removal of disincentives to conservation investment," and concluded that "Puget has developed a distinguished reputation because of its conservation programs and is now considered a national leader in this area."[13] Based on these findings, the Commission granted a three-year extension of the revenue-per-customer cap.[14] In 1995, as part of a litigation settlement proposal intended to create no precedent, Puget and several other parties filed a request with the Commission to terminate a complex system of rate adjustment

[12] Id., at p. 10.
[13] See Washington UTC, Eleventh Supplemental Order, Docket No. UE-920433, p. 10 (September 21, 1993).
[14] See id. , p. 10 (concluding that "the PRAM/decoupling experiment should continue for at least another three-year cycle").

mechanisms that included the revenue-per-customer cap (along with, e.g., a controversial approach to allocating risks of hydropower fluctuations). The Commission approved that request, but the proposal itself expressly reserved the right of all parties to bring forward in the future "other rate adjustment mechanisms, including decoupling mechanisms, lost revenue calculations, [and] similar methods for removing or reducing utility disincentives to acquire conservation resources."[15]

The Idaho Commission's March 2007 order establishing per-customer decoupling for Idaho Power included a finding that "[p]romotion of cost-effective energy efficiency and demand-side management (DSM) . . . is an integral part of least-cost electric service," along with the Commission's expectation that, in the aftermath of decoupling, "the Company is expected to demonstrate an enhanced commitment to energy efficiency and DSM. Evidence of enhanced commitment will include, but not be limited to, . . . efforts to improve and enforce state building codes and appliance efficiency standards, as well as expansions and improvements to its load efficiency, load management and DSM programs."[16]

Q. What if any modifications do you recommend in PGE's proposal?

A. I recommend three modifications, which reflect issues raised in the testimony of other parties (reviewed more fully below). First, I agree with Staff that approval of the mechanism should be conditioned on PGE's agreement to file a new rate case within five years, to allow for midcourse corrections in the mechanism and a review of all relevant financial issues. Second, based on considerations raised in CUB's testimony, I recommend that the Commission make clear that its willingness to renew the mechanism over time will depend on PGE's ability to demonstrate increases in energy efficiency benefits delivered to

[15] Docket No. UE-921262, Joint Report and Proposal Regarding Termination of the Periodic Rate Adjustment Mechanism (April 20, 1995).
[16] Idaho PUC, Order No. 30267, pp. 13-14 (March 2007).

its system in partnership with the Energy Trust and others. Finally, for Large Nonresidential customers, I recommend that the Commission select the second of the two approaches proposed by the Company (a "load based" decoupling mechanism, as opposed to a "Lost Revenue Recovery" mechanism). See PGE/100, pp. 21-22.

Q. Why do you recommend these modifications?

A. I think that Staff is reasonable in wanting to revisit the mechanism and the underlying financial assumptions within five years (Exh. 600, p. 23). CUB makes the point forcefully that decoupling should result in demonstrated benefits to customers in the form of cost-effective energy efficiency results, and I agree.

Q. What accounts for your preference for a load-based decoupling mechanism over lost revenue recovery, for large users?

A. In my judgment, the load-based mechanism would be easier to administer, and it would avoid the perverse incentives associated with any lost revenue recovery system (where the most lucrative energy efficiency measures to utilities are those that look good on paper and save little or nothing in practice). Moreover, as the Massachusetts Department of Public Utilities recently noted in a critique of lost revenue recovery, "a shortcoming . . . is that distribution companies will continue to face financial disincentives for those demand resource activities that are not specifically identified in the mechanism and, thus, will focus only on the identified activities and will be reluctant to seek or support a broader range of demand resource activities."[17]

By contrast, PGE's proposed load-based mechanism would involve a simple comparison of IRP-based load forecasts with actual consumption; "[a]ny difference between

[17] Massachusetts Department of Public Utilities, D.P.U. 07-50-A (July 16, 2008), p. 29).

[the IRP] baseline and actual loads for a given year would be applied to a fixed cost per kWh rate determined in the rate case to determine an adjustment amount." (PGE/100, p. 22). This avoids the necessity to adjudicate savings from individual programs or to deal with the layering of adjudicated savings from multiple programs over multiple years, with escalating rate impacts. Under the load-based mechanism, like the per-customer mechanism proposed for other customer classes, modest annual rate adjustments could go either up or down, with no need to layer on compensation for cumulative program savings over multiple years.

Q. What should the Commission do if it agrees with your recommendation regarding a load-based decoupling mechanism for large users?

A. The Commission should direct PGE to propose specific tariff language implementing its proposed "load-based" decoupling mechanism for large users, based on the description provided at PGE/1200, pp. 30-31.

IV. Responses to Other Parties' Testimony

A. OPUC Staff

Q. Respond to the PUC Staff's analysis of PGE's decoupling proposal.

A. In Exhibit 600, Staff witness Steve Storm begins with an overview of the structure and rationale for PGE's decoupling proposal (pp. 7-16). He then raises five objections to the proposal (p. 17): (1) it is excessively favorable to shareholders in light of PGE's "demographic environment;" (2) it shifts the "burden of regulatory lag from shareholders to ratepayers;" (3) it is insufficiently supported by evidence of impacts of the disincentives that decoupling would remove; (4) it disregards "near-term AMI deployment and approaching imposition of carbon tax (or cap and trade)"; and (5) it shifts risk from shareholders to ratepayers. I disagree on all counts, as explained below.

Q. Why do you disagree with Staff's contention that PGE will over-collect its fixed costs due to the manner with which the proposed decoupling mechanism deals with customer growth?

A. In essence, this argument boils down to the contention that changes in the customer count do not correlate perfectly with changes in the company's fixed costs of serving customers; while indisputably true, it is equally obvious that the status quo is vulnerable to the same objection. Changes in retail sales do not correlate perfectly with cost of service changes, and yet without decoupling PGE keeps the fixed-cost revenues associated with increased retail sales. In rejecting an analogous objection to a per-customer decoupling proposal in Washington State, the UTC observed more than a decade ago that "even under the current system of ratemaking, costs and rates will diverge immediately following implementation of a rate change."[18]

Note also that the staff's example of potential "over-collection" seems implausible in the extreme: a recession in which customer growth continues while electricity usage per customer drops significantly (p. 21). In the hypothetical example, PGE adds customers at a rate of 1.2 percent per year and customers reduce their usage by 4 percent per year (p. 21) – and even then, as staff acknowledges, rate impacts are capped at two percent. And nothing short of the extraordinary events of 2000-2001 seems consistent with the staff scenario.[19] Recessions would be likely to affect customer growth along with usage per customer, and even if they did not, PGE could reasonably point out that additional customers bring with them additional fixed-cost revenue needs, regardless of overall economic conditions.

Q. What about Staff's concern about the shift in the burden of regulatory lag?

A. This might have some merit if decoupling resulted uniformly in rate increases and shareholder benefits; as noted above, decoupling adjustments go both ways, and in the history of the electric utility industry regulatory shareholders have both benefited and lost from regulatory lag. The one consistent loser has been energy efficiency, given the strong linkage that status quo regulation creates between retail sales and shareholder benefits. But there is no need to contest the point at length, because staff's proposed remedy is entirely reasonable; I agree with the recommendation that any Commission order adopting a decoupling mechanism "be accompanied by a requirement that general rate cases will be filed on a basis that is no less frequent than every five years (p. 23)."

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[18] Washington UTC, Docket No. UE-901183-T, Third Supplemental Order (April 10, 1991), p. 10.
[19] For a review of these events, see R. Cavanagh, Revisiting "the Genius of the Marketplace": Cures for the Western Electricity and Natural Gas Crisis, The Electricity Journal (June 2001); and R. Cavanagh, California Overcomes an Electricity Crisis, The Electricity Journal (January/February 2002).

Q. Respond to Staff's contention that decreasing disincentives to efficiency doesn't matter much, given the establishment of the Energy Trust of Oregon in 2002, and PGE's diminished responsibility for achieving energy efficiency results.

A. But Staff itself recognizes the importance of "[a] quality hand-off or referral from PGE personnel to ETO of customers seeking energy efficiency (p. 24)," and staff would surely acknowledge also the potential importance of PGE advocacy in promoting more rigorous efficiency standards for equipment and buildings at both state and federal levels. Strong public advocacy for energy efficiency was among the benefits cited prominently in the first independent audit of Northwest Natural Gas's decoupling mechanism.[20] I count myself a long-time admirer and supporter of the Energy Trust, and as noted earlier my support for decoupling in Oregon reflects a hope for expanded Trust efforts and resources in partnership with PGE.

Q. But Staff points out that PGE has identified no energy efficiency efforts that were not pursued as a result of current financial disincentives (p. 24).

A. It really isn't an argument against more rational incentives to say that a party subject to irrational incentives can't describe specifically how its behavior would change if the problem were fixed. The whole point of decoupling is to help unleash management talent and creativity that are underutilized in the current environment, and to respond creatively to opportunities in a rapidly shifting energy policy arena that cannot be predicted today. And certainly the Commission should not draw adverse inferences from PGE's recent willingness to increase energy efficiency funding significantly in advance of any OPUC decision on

[20] See D. Hansen & S. Braithwait, note 7 above, pp. 46-48 (reviewing "steps to publicly support energy efficiency and conservation" taken by Northwest Natural Gas in the aftermath of decoupling, and concluding that "Northwest Natural takes its commitment to promoting energy efficiency seriously").

decoupling, in cooperation with the many other parties involved in Advice No. 07-25 and the Company's supplemental filings.

Q. Address Staff's fourth contention, which as stated initially involves concerns about AMI and imminent government responses to climate change.

A. The summary of Exhibit 600 includes that statement in a summary of staff's five principal concerns (p. 17), but staff's subsequent explication of the point (p. 24) addresses a different issue altogether, which is the "questionable efficacy of PGE's objective to 'maintain existing pricing structures for customers, which give price signals that support energy efficiency efforts.'" But I strongly concur with PGE's belief that its rate structures should not change in ways that reduce customers' rewards for reducing consumption; decoupling achieves this objective. Staff responds that estimates of price elasticity in the short-term are relatively modest for both residential and nonresidential customers; I don't disagree, but staff surely does not contend that reducing customers' reward for conserving by raising fixed charges would be an appropriate alternative to decoupling. And I don't see what any of this has to do with staff's initial references to carbon policy or AMI issues, which to my mind are wholly consistent with the energy efficiency priorities that underpin PGE's decoupling proposal.

Q. What about Staff's final point, regarding allocation of risks of potential under-recovery of costs between rate cases?

A. Staff sees "an obvious shift of risk from shareholders to ratepayers" (p. 27) in the way PGE's proposed decoupling mechanism would restore losses in recoveries of authorized fixed costs following a decline in usage per customer. But of course the mechanism also would erase gains from any increases in usage per customer. As staff concedes (pp. 26-27), there is no evidence in this proceeding that "usage per customer is in fact declining for the residential and small nonresidential customer classes," and indeed there is no visible "downward trend in usage per customer over the 2004 through 2007 period." On this evidence, there is no basis for prejudging the issue of which way risks will shift under the PGE decoupling proposal.

B. Community Action Partnership of Oregon, Oregon Energy Coordinators Association

Q. Please respond to witness Colton's contention that decoupling will disadvantage low-income customers.

A. Witness Colton argues that low-income customers have relatively little if any access to energy efficiency opportunities and contribute (in relative terms) less than other customers to PGE's fixed cost revenue requirements. Accordingly, on his view, decoupling adjustments will disproportionately burden low-income customers collectively. I disagree strongly with Mr. Colton's first contention, which may reflect a lack of familiarity with PGE's and Oregon's history of support for low-income energy efficiency programs.

Q. How do you respond to witness Colton's assertion that "the Energy Trust of Oregon offers no specific low-income programs?"

A. He may not realize that the agency primarily responsible for low-income energy efficiency services in Oregon is the Department of Housing and Community Services, not the Energy Trust of Oregon, or that PGE customers provide millions of dollars annually of dedicated support for these programs through a statutory public purpose charge. As a longtime supporter of these programs with my colleagues in the Northwest Energy Coalition, I am proud of Oregon's regional and national leadership on low-income issues, and I also appreciate and commend PGE's record of voluntary assistance to the Community Energy Project and Oregon HEAT (including both cash donations and volunteer efforts by PGE employees).

Q. Why don't you agree with witness Colton that any decoupling-linked rate increases will fall disproportionately on low-income customers?

A. Witness Colton himself presents extensive evidence that low-income households "use less electricity than do their higher income counterparts" (Exh. 200, p. 55), and contends specifically that "consumption for households with annual incomes higher than $50,000 is more than 60% higher than consumption for households with income below Poverty Level" (id., pp. 55-56). Since any decoupling adjustments under PGE's proposal will be made on a volumetric basis, the very consumption patterns cited by Mr. Colton himself will help insulate low-income customers from disproportionate impacts, on those occasions when decoupling adjustments actually do raise rates (of course, decoupling adjustments can go in either direction, depending on whether system-wide electricity use is trending up or down). Also mitigating against any disproportionate rate impacts are Oregon's targeted low-income weatherization programs, as noted earlier. Finally, it bears emphasis that annual rate impacts on all customers are capped at 2 percent under PGE's proposal for increases, and uncapped for decreases (PGE/1200, Kuns – Cody, p. 29).

C. Fred Meyer Stores

Q. Address witness Higgins's concern that decoupling is "a hazardous undertaking that is akin to single-issue ratemaking," in that it could create rate increases at times when rates might actually deserve to be reduced if all relevant variables were considered (Fred Meyer/ p. 12).

A. Traditional ratemaking makes ample provision for "trackers" and/or true-ups associated with, e.g., weather and fuel costs; the Company's proposal is no different in its "single issue" implications, and the public interest justification is at least as compelling. Ken Costello of the National Regulatory Research Institute has investigated whether decoupling mechanisms meet the traditional tests justifying state utility regulators' use of "tracking mechanisms that adjust rates and revenues whenever sales deviate from their targeted level," and has concluded that "[u]nless a state commission faces legal restrictions in implementing a 'sales tracker' or has a built-in policy of limiting trackers in general, [revenue decoupling] would seem to meet the regulatory threshold for a tracker."[21] I agree. See also Washington UTC v. Puget Sound Power and Light Co., Docket No. UE-901183-T, Third Supplemental Order, p. 10 (April 10, 1991): "The decoupling mechanism does not involve retroactive ratemaking. It is similar to the prior ECAC mechanism in that it sets up a deferred account allowing a reconciliation of revenue and expenses that would be subject to hearing and review."

D. Citizens' Utility Board of Oregon

Q. CUB says that "decoupling is a way to ensure that utility profits do not decline when there are changes in load," and that decoupling surcharges during economic downturns "would ensure that utilities earned the same profit they would have earned if loads hadn't declined".(CUB/100, Jenks/46). What's your response?

[21] Ken Costello, Briefing Paper: Revenue Decoupling for Natural Gas Utilities, p. 9 (National Regulatory Research Institute, April 2006).

A. Decoupling does not guarantee any particular level of "profit," or in any way insulate PGE against the risk that internal inefficiencies will prevent management from achieving profitability objectives. With or without decoupling, the company keeps any operating savings that it achieves between rate cases and absorbs any cost overruns. Decoupling merely assures that PGE's opportunity to recover the overall fixed cost revenue requirement *authorized by the Commission* will not be affected by fluctuations in electricity use that the Commission did not anticipate when it set the company's rates. It is hard to see a pro-shareholder bias in that common sense proposition.

Q. Do you agree with CUB's view (CUB/100, Jenks/46) that decoupling "insulates the utilities from the effect of an economic downturn, but raises cutomers' rates at a time when customers can least afford it"?

A. No. First, recognize that a mechanism tied to revenues per customer leaves utilities fully exposed to reductions in customer growth associated with economic downturns. As the Washington Commission found in similar circumstances:

> [T]he revenue per customer mechanism does not insulate the company from fluctuations in economic conditions, because a robust economy would create additional customers and hence, additional revenue. Furthermore, the Commission believes that a mechanism that attempts to identify and correct only for sales reductions associated with company-sponsored conservation programs may be unduly difficult to implement and monitor. The company would have an incentive to artificially inflate estimates of sales reductions while actually achieving little conservation.[22]

Moreover, in or out of recessions, decoupling will only raise <u>rates</u> at a time when <u>bills</u> are declining as consumption drops; it is of course utility bills, not rates, that matter to customers. And of course the best way to protect customers from unaffordable bills is to maximize cost-effective energy efficiency investment, which decoupling promotes and its

[22] Docket No. UE-901183-T, Third Supplemental Order (April 10, 1991), p. 10.

absence discourages. The potential economic benefits to customers from cost-effective energy efficiency measures dwarf the two percent maximum annual rate increases that PGE's decoupling mechanism could produce.

Q. What about CUB's assertion (CUB/100, Jenks/46) that we tried decoupling with electric utilities in the 1990's, and energy efficiency programs were cut anyway?

A. Cuts in energy efficiency programs during the 1990s largely reflected a regionwide (and indeed nationwide) response to the prospect of radical industry restructuring, which would have ousted utilities from their role in electric resource portfolio management; the wholly predictable result was cutbacks in all forms of resource investment, including but emphatically not limited to energy efficiency. The more recent revival of decoupling on the natural gas side, with CUB's invaluable support, has been strongly and gratifyingly linked to energy efficiency progress in Oregon. There is no reason to expect a different result on the electricity side.

Q. Do you share CUB's view that the case for decoupling must be directly linked with energy efficiency progress?

A. Yes.

Q. Then how do you respond to CUB's statement that "in the case of PGE, there is no proposal for any new programs that provide benefit to customers" (CUB/100, Jenks/47)?

A. This is not a convincing argument against removing significant financial obstacles to cost-effective savings, which serve in my experience to strangle management initiative and creativity. Let's give PGE a chance to show what it can do when the barriers are removed, and hold the company accountable if it fails, by making the extension of the mechanism contingent in part on energy efficiency results. I note that PGE has recently requested, and the Commission has approved, significant supplemental funding for the Energy Trust of Oregon. This is a positive first step, but I hope that CUB would agree with me that it falls well short of tapping the full cost-effective potential identified by the Trust and others.[23] NRDC is committed to work with the Trust, CUB, PGE and other interested parties to find additional savings, and as already indicated I agree that the future of the decoupling mechanism should hinge in part on demonstrated success. It is important to recognize that no one can identify or predict in advance all the opportunities that PGE will have to influence energy efficiency progress, including but not limited to advocacy opportunities at the state and federal level linked to policy and regulatory actions with strong efficiency implications. I encourage the Commission to act now to get the incentives right and then to monitor and evaluate the results, a policy that the Commission has already adopted with great success for Northwest Natural Gas.

Q. Address CUB's concern that "the economy is heading into a recession," and that "now is not a good time to shift the risk and cost of a recession onto customers."

A. I have already noted my reasons for disagreeing that PGE's proposal "shifts the risk and cost of a recession onto customers." Moreover, among the best antidotes to recessions is the substitution of less costly energy efficiency for more costly electricity production, which is also among the best antidotes to the global warming challenge on which CUB has been a consistent regional leader. If the Commission concludes, as I do, that decoupling is crucial

[23] See, e.g., Public Utility Commission of Oregon, Staff Report from Lori Koho to PUC (May 12, 2008) (Item No. 2, Public Meeting Date: May 20, 2008), pp. 3-4 (reviewing estimates by the Trust of "achievable energy efficiency acquisition potential," and noting that "[t]he proposed acquisition target [using the proposed incremental PGE funding] is less than the identified gap.")

to a sustained ramp-up of energy efficiency for the PGE service territory, there is no better time to approve PGE's proposal, with the modifications noted earlier in this testimony.

KATU 2

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Unplugging some appliances could save you cash

YouNewsTV™

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By Angelica Thornton

Video

With everything from the price of rice to the price of gas going up, many people are looking for ways to cut costs. We came up with a few simple things you can do around the house that could have a big impact on your bottom line.

With the help of Portland General Electric, we did an energy audit, looking for home appliances and electronics that waste energy. What we found will surprise you.

We'll begin with the biggest energy offenders, furnaces and refrigerators. To soften the blow to your budget, turn the thermostat down when you are gone and turn your refrigerator and freezer to a slightly warmer setting.

But there are other not so obvious appliances using energy, even when they're off. PGE Residential Energy Expert Garrett Harris calls them a phantom load

"Cell phone chargers, TV's, dishwashers, microwaves, a lot of the things you think are off are in fact on," he said.

To measure the phantom load, PGE uses a device called the "Watt's Up Pro." We measured the microwave and the coffee maker. Both were plugged in and sucking power just to run the clock - not to mention we already had an oven doing that. So we were keeping the time three times. That is a little redundant.

The biggest power sucker was the entertainment center, which according to Harris was using between 45 and 50 watts while it was off! The cell phone charger actually used the least amount of power.

In all we measured eight appliances, none of which needed to be plugged in. They all added up to about 60 watts of energy, equaling over 525 watts a year, for doing nothing.

According to PGE's calculations we could save more than $50 a year just by unplugging.

PGE's energy audit service is free but only customers who have abnormally high bills can use it.

If you want to test things out yourself, you can buy a similar device online. We bought the "Kill-A-Watt" for about $25 including shipping, and the results were almost identical to PGE's.

You can't unplug all your appliances, but the ones you can, could end up saving you a lot of money.

For more energy saving tips, click here for Green Power Oregon or click here for PGE.

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http://www.katu.com/news/problemsolver/19085034.html

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Dated at Portland, Oregon, this 15th day of August 2008.

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