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July 9, 2008

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
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RE: **Docket No. UE197 – In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a general rate revision.**

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

/s/ Kay Barnes
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c: UE 197 Service List (parties)

PUBLIC UTILITY COMMISSION OF OREGON

UE 197

STAFF DIRECT TESTIMONY OF

Carla Owings
Paul Rossow
Dustin Ball/Michael Dougherty
Ed Durrenberger
George R. Compton
Steve Storm

In the Matter of
PORTLAND GENERAL ELECTRIC COMPANY
Request for a General Rate Revision.

REDACTED

July 9, 2008

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Direct Testimony

July 9, 2008

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

A. My name is Carla Owings. I am a Senior Revenue Requirements analyst employed by the Public Utility Commission. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. As the Revenue Requirement Summary Witness for this proceeding, I will explain the overall impact to PGE's requested revenue requirement per Staff's recommendation for an increase of approximately $79 million in revenues, as well as introduce adjustments, sponsored by other Staff members, that are not included in a partial stipulation that has been reached. I will also testify to the adjustments proposed by Commission Staff (Staff) to Portland General Electric Company's (PGE's) application as agreed upon in the stipulated agreement filed in this docket, and finally, I will sponsor testimony as evidence to support six adjustments that I propose in this case:

S-2 Research and Development;
S-3 Workforce Adjustment;
S-4 Corporate Incentives Adjustment;
S-5 Capital Expenditures Adjustment;
S-16 Revenue Sensitive Costs Adjustment; and
S-19 Energy Audits.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared several exhibits:

Exhibit Staff/101, Witness Qualifications, consisting of 1 page
Exhibit Staff/102, Summary of PGE's Results of Operations Report consisting of 5 pages
Exhibit Staff/103, Revenue Requirement, consisting of 10 pages
Exhibit Staff/104, S-2, Research and Development, consisting of 1 page
Exhibit Staff/105, S-3, Workforce Adjustment, consisting of 2 pages
Exhibit Staff/106, S-4, Corporate Incentives, consisting of 2 pages
Exhibit Staff/107, Confidential
Exhibit Staff/108, S-5, Capital Expenditures, consisting of 1 page
Exhibit Staff/109, PGE's Quarterly Hydro Report, consisting of 14 pages
Exhibit Staff/110, PGE Errata Filing, consisting of 10 pages
Exhibit Staff/111, Data Request No. 105 consisting of 2 pages
Exhibit Staff/112, Data Request No. 402 consisting of 10 pages
Exhibit Staff/113, S-19, Energy Audits, consisting of 1 page

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into four parts:

Part I of my testimony summarizes PGE's application for a general rate increase, the revenue requirement impact and generally addresses Staff's findings as well as providing a summary of Staff's remaining adjustments and identifies the pertinent testimony where each Staff witness will discuss their adjustment.

Part II explains the revenue requirement model and all exhibits submitted in support of the model adjustments.

Part III summarizes the Partial Stipulation agreed upon by Staff, PGE, the Citizens' Utility Board (CUB), The Oregon Department of Energy, Fred Meyer Stores, Quality Food Centers Division of Kroger, and the Industrial Customers of Northwest Utilities (ICNU) and summarizes the adjustments agreed upon by all Parties to the Stipulation.

Part IV of my testimony provides support for each adjustment that I am proposing as a Staff Witness.

Part I

Case Summary

Q. PLEASE SUMMARIZE THE COMPANY'S RATE REQUEST.

A. On February 27, 2008, PGE filed an application for a general rate increase pursuant to ORS 757.205 and ORS 757.220 to become effective January 1, 2009, docketed as UE 197. The original application proposed to increase PGE's revenues by $145.9 million on an annual basis an overall increase of approximately 8.9%. This request included the annual filing required by PGE's annual update tariff (Schedule 125), as well as other proposed changes related to net variable power costs and the annual update process that may only be made in a general rate proceeding. On March 23, 2008, a prehearing conference was held. During the conference, the parties agreed to bifurcate docket UE 197 and create a separate docket to address all of the issues related to PGE's net variable power costs (*See* docket UE 198). Although PGE's annual update filings are usually limited to updating only those items listed in Schedule 125, docket UE 198 is not so limited. All issues related to PGE's net variable power costs are addressed in docket UE 198. All other issues related to PGE's general rate revision are addressed in docket UE 197.

On April 3, 2008, PGE filed an amended application revising its request in the general portion of the case and on April 4, 2008, PGE provided its quarterly update estimate pertaining to its forecasted power costs. In order to summarize the basis of this case as of the writing of this testimony, Staff submits Table I demonstrating the requested increases as they relate to the amended filing dates for both the general portion of the rate proceeding (UE 197) and the power cost portion of this case (UE 198).

Table I

Date of filing	Requested Increase ($000)	Pertinent Docket	Overall Percentage Change	Brief Description
February 3, 2008	92,900	UE 197	5.78%	Hydro & General
February 3, 2008	53,000	UE 198	3.30%	NVPC
April 3, 2008	1,340	UE 197	0.08%	General
April 4, 2008	10,100	UE 198	0.62%	NVPC
TOTAL INCREASE	**157,340**		**9.78%**	
STIPULATION	-5,058	UE 198	**-0.31%**	NVPC
STIPULATION	-14,000	UE 197	**-0.87%**	General
REMAINING REQUEST	138,282		8.60%	
STAFF PROPOSED ADJUSTMENTS	-59,280		-3.69%	
STAFF-PROPOSED INCREASE & NVPC Update (to date)	**79,002**		**4.91%**	

Q. HAS STAFF INCLUDED PGE'S REQUEST FOR INCREASED POWER COSTS IN ITS REVENUE REQUIREMENT MODELING?

A. Yes, in its revenue requirement model Staff has included both PGE's original request of approximately $53 million and the updated power cost estimate filed April 4, 2008, resulting in an additional increase of approximately $9.7 million. As of the time of this writing, Staff expects that PGE will update its estimate of power costs again on July 11, 2008, and on subsequent dates as provided in docket UE 198.

Q. DOES STAFF HAVE AN EXPECTATION OF HOW MUCH THE POWER COST ESTIMATE OF JULY 11TH WILL BE?

A. No. Staff can only estimate that PGE's updated forecast of power costs on July 11th will be in the range of an additional $50 to $70 million based on the unprecedented increases in gas and electricity market prices. However, these forecasts will be solidified in PGE's July 11, 2008, updated forecast and Staff expects they will be included in PGE's rebuttal testimony of August 15, 2008.

<u>Staff Findings</u>

Q. PLEASE DESCRIBE STAFF'S OBSERVATIONS REGARDING PGE'S UE 197 APPLICATION.

A. Other than the increasing power costs and the proposed changes to Hydro costs, in many cases Staff found it very difficult to support the basis of PGE's request for an increase for the general, non-power cost portion of the rate proceeding. While the rate request presented by the Company in its application for UE 197 purported to identify new programs and other changes as justification for its rate request, Staff's review did not verify those assertions. In the UE 180 application, PGE clearly identified its need to bring new generation (Port Westward) into ratebase. However, in this application the sustenance of its request for general costs seemed to be based on one-time events or replacing aging equipment (*See, e.g.,* Exhibit Staff/Durrenberger/400).

Q. WHAT ARE STAFF'S FINDINGS REGARDING THE 2009 TEST PERIOD PRESENTED IN PGE'S APPLICATION?

A. Staff acknowledges that future test periods, by nature, must be based on estimates. Staff believes the test period is expected to represent the Company's best estimate of future normal operations and cost of service. However, Staff believes that the Company should clearly identify expenses and revenues of reasonable certainty and definite character that reflect the actual operating experience in order to arrive a 12-month period which represents normal or average operating conditions. In this application PGE seeks increases that far exceed average or normal operating conditions. Following is a demonstration of cost increases requested in this application and proposed increase measured from PGE's UE 180 rates (based on a 2007 test period):

Hydro Projects O&M	Exhibit PGE/400/ 10&13	34%
Coal	Exhibit PGE/400/ 10&13	17%
General Plant O&M	Exhibit PGE/400/ 10&13	21%
HR/Employee Support	Exhibit PGE/500/2	32%
Corporate R&D	Exhibit PGE/500/2[1]	70%
Hydro Projects A&G	Exhibit PGE/500/2	67%

Staff acknowledges that these requests represent only a portion of PGE's application; however, overall Staff believes that its request related to the general portion of the application does not represent an expected *normal* cost of service. Given the recent rate increases for Port Westward (June of 2007), Biglow Canyon and implementation of the AUT (January of 2008) (*See* UE 180, UE 181, UE 184, UE 188 and UE 192) Staff believes that PGE should

[1] Also see PGE's response to Staff's Data Request No. 279.

have used its actual results in 2007[2] as a base year, adjust out non-recurring events, and normalize for weather and other regulatory adjustments to demonstrate its *normal* operations. Rather, PGE's application uses a 2007 forecast as a base year and states that its 2009 test period is not based on applying typical escalators, but created through bottom-up forecasts.

Introduction of Staff Adjustments

Staff originally identified eighteen adjustments that impact the revenue requirement request in the Company's application for the general rate proceeding and four issues not impacting revenue requirement. Due to late information, as a part of Staff's testimony here, Staff proposes one additional adjustment listed as S-19, Energy Audits and is supported in testimony in Part IV of this testimony.

As a result of two settlement conferences held June 12, 2008, and June 19, 2008, PGE, Staff and the intervening parties were able to come to an agreement on nine revenue requirement issues identified in Part III of this testimony. These issues are supported in the stipulated agreement and supporting joint testimony to be filed in this proceeding in early to mid-July. Based on the stipulated agreement and Staff's analysis of the remaining issues below, Table II summarizes the remaining proposed Staff Adjustments and identifies the pertinent testimony where each Staff adjustment is discussed:

[2] Staff notes that on June 3, 2008, PGE filed its Results of Operation report for 2007, demonstrating a Return on Equity (ROE) of 10.59 percent before Type I or Type II adjustments normalizing adjustments. ROE after Type I and Type II adjustments were reported to be 11.58 and 7.28 percent, respectively (See Exhibit Staff/102/Owings/1-5).

Table II

Issue	Description	Amount ($000)	Pertinent Exhibit
S-2	Research and Development	(1,752)	Staff/Owings/100
S-3	Workforce Adjustment	(11,414)	Staff/Owings/100
S-4	Corp Incentives	(7,017)	Staff/Owings/100
S-5	Cap Ex	(12,438)	Staff/Owings/100
S-9	A&G and O&M	(10,557)	Staff/Ball_Dougherty/300
S-10	WECC, RTP & flow mitigation	(156)	Staff/Durrenberger/400
S-11	Fixed Plant Costs	(8,743)	Staff/Durrenberger/400
S-13	NERC/WECC, RCM, Misc	(520)	Staff/Durrenberger/400
S-14	Property Tax Adjustment	(4,416)	Staff/Ball_Dougherty/300
S-16	Revenue Sensitive Costs	(1,805)	Staff/Owings/100 Staff/Rossow/200
S-19	Energy Audits	(287)	Staff/Owings/100
S*	Rounding	(116)	
	Total Revenue Requirement Impact	**(59,221)**	

Part II

Revenue Requirement Model

Q. CAN YOU PLEASE EXPLAIN THE REVENUE REQUIREMENT MODEL?

A. Yes. Staff Exhibit/103/Owings is a series of interlinked spreadsheets that contain ten separate elements that, together, summarize Staff's position on the revenue requirement adjustments for UE 197 and UE 198. The models are formatted into two phases. The first phase is the portion of the case containing the Company's general rate increase request submitted in docket UE 197 as well as forecasted updates for power costs submitted in docket UE 198. The second phase is the Company's request to increase operations and maintenance expenses and add costs to rate base to reflect the capital expenditures proposed for 2008 and the 2009 test period. The spreadsheets are formatted as follows:

1. Pages 1 and 2 are narrative summary that begins with the Company's original revenue requirement request for the general proceeding and includes the April update to power costs submitted in docket UE 198. Staff provides a short description of each of the proposed adjustments. The first column indicates an item number assigned to the adjustment. The second column indicates the Staff Witness sponsoring the adjustment and the far right column indicates the revenue requirement impact of the proposed adjustment. Staff's proposed overall revenue requirement for the portion of the proceeding can be found on the bottom of page 2, in the far right column.

2. Page 3 is a summary showing the changes to revenues, expenses and rate base and ends with the percentage change from current rates. Column (1) represents the Company's results of operations per the Company's application for the test period. Column (2) shows an aggregate of the adjustments proposed by Staff and the adjustments that would be adopted if the Commission were to adopt the proposed stipulated agreements. Column (3) shows the results of the adjustments proposed in Column (2). Column (4) shows the revenue requirement change required to meet the proposed cost of

capital, and Column (5) shows the results of operations per all adjustments proposed by Staff and agreed upon in the proposed stipulated agreements. (Note that the overall revenue requirement change is subject to the final NVPC update late this year in docket UE 198.)

3. Page 4 contains the income tax calculations for the results of operations.

4. Pages 5 and 6 show the specific adjustments; those that are agreed to in the stipulations, the additional adjustments proposed by Staff for the revenue requirement per the Staff recommendation, and the most recent (April 2008) NVPC update.

5. Pages 7 and 8 show the tax calculations associated with the adjustments shown on pages 5 and 6.

6. Page 9 shows the revenue sensitive costs associated with the revenue requirement calculation. The first column shows the revenue sensitive costs per the Company's application and the second column shows Staff's proposed revenue sensitive costs.

7. Page 10 shows a summary of the cost of capital proposed by Staff, consistent with the partial stipulation on non-power cost issues.

Part III

Stipulated Agreement

Q. CAN YOU PLEASE SUMMARIZE THE ISSUES AGREED-UPON IN THE STIPULATED AGREEMENT?

A. Yes. Table III below provides a list of the issues agreed upon in the Stipulated agreement:

Table III

Issue	Description	Amount
S-0	Rate of Return	(12,906)
S-1	Other Electric Revenues	471
S-6	Lease Adjustment	0
S-7	Fuel Adjustment	0
S-8	Membership Adjustment	0
S-12	Kelso Beaver Pipeline Transmission	(1,040)
S-17	Schedule 300	(471)
S-18	Port West/Biglow Canyon True-up	(113)
	Total Revenue Requirement Impact	(14,059)

Part IV
Staff Proposed Adjustments

Q. DID YOU PREPARE STAFF ADJUSTMENTS AS A RESULT OF YOUR REVIEW IN THIS CASE?

A. Yes. I prepared six Staff proposed adjustments identified briefly in my introduction above. I will create a subsection to discuss each adjustment.

Adjustment S-2
Research and Development

Q. PLEASE DESCRIBE YOUR FIRST PROPOSED ADJUSTMENT.

A. The first adjustment that I propose is identified in Exhibit Staff /103/Owings/1 as S-2, Research and Development. At PGE/100/Piro/7, PGE requests an increase in costs due to PGE's desire to do additional research and development pursuant to new activities necessary to respond to customer and regulator environmental demands. In data request No. 269, Staff requested historic information on how much PGE spent between the years 2002 through 2007 on research and development. Additionally, Staff requested that the Company identify major projects historically researched as well as what areas the Company intends to focus on in the 2009 test period.

Q. CAN YOU PLEASE SUMMARIZE PGE'S RESPONSE TO STAFF'S DATA REQUEST?

A. Yes. Table IV below shows the historic information provided by PGE in its response to Staff's request:

Table IV

2002 Actuals	2003 Actuals	2004 Actuals	2005 Actuals	2006 Actuals	2007 Actuals
385,003	*None	219,420	338,983	167,123	307,725

Q. HOW MUCH HAD PGE INCLUDED IN THE 2009 TEST PERIOD FOR RESEARCH AND DEVELOPMENT COSTS?

A. In response to Staff's Data Request No. 269, PGE indicated that it had budgeted $1,995,000 for test period expenses and stated that for 2003, due to cost containments, PGE had no actual costs spent on research and development (R&D). The Company identified several categories it desired to research in the 2009 test period:

- Distributed Standby Generation
- Distributed Energy Storage
- Highly Efficient Community-Scale Infrastructure
- Infrastructure Reliability, Maintenance and Sustainability
- Carbon/Greenhouse Gas Regulation
- Renewable Power or Highly Efficient Generation

Q. DOES STAFF SUPPORT PGE'S DESIRE TO PERFORM R&D IN THE AREAS PGE IDENTIFIED?

A. While Staff supports PGE's desire to be on the forefront of some of the areas identified, the amounts included in the budget to do such research are somewhat lofty (particularly in consideration of its historic R& D expense) and appears to be redundant to R&D performed by other entities such as the Energy Trust of Oregon. In the area of Highly Efficient Community-Scale infrastructure, Staff believes similar research is performed by the Energy Trust. In the area of Carbon/Greenhouse Gas Regulation, Staff believes Federal Grants are available and perhaps should be pursued by the Company. Additionally, in consideration of the rising fuel costs and PGE's anticipated projection of increased fuel prices, Staff believes that these costs are largely discretionary as demonstrated in 2003 when PGE had zero expenditures for R&D. Additionally, the Company has historically only incurred a fraction of the $1.9 million R&D expense it is requesting for the 2009 test period.

Q. WHAT DOES STAFF PROPOSE AS AN ADJUSTMENT RELATED TO R&D COSTS?

A. Staff proposes using an average of PGE's past five years spending of approximately $284,000 as the base for 2007. Staff would then allow for a 5 percent per year increase bringing the 2009 test period expense to approximately $312,000 (See Exhibit Staff /104/Owings/1). This amount would allow for some of the areas PGE identified such as Infrastructure reliability, maintenance and sustainability[3], and still allow for other discrete projects.

Q. CAN YOU PLEASE IDENTIFY THE REVENUE REQUIREMENT IMPACT ASSOCIATED WITH STAFF'S PROPOSED ADJUSTMENT FOR R&D?

A. Yes. The revenue requirement impact is a reduction of approximately $1.75 million.

Adjustment S-3
Workforce Adjustment

Q. PLEASE DESCRIBE YOUR NEXT PROPOSED ADJUSTMENT.

A. The next adjustment that I propose is identified in Exhibit Staff /103/Owings/1 as S-3, Workforce Adjustment. At PGE/800/Barnett-Bell/5, PGE states that it has included additional full-time equivalents (FTE) in the test period between 2007 and 2009 to address "additional regulatory requirements, new generating

[3] PGE identified $150,000 for this area in its response to Staff's Data Request No. 269.

plants, growth in customer base, and efforts to reduce overtime." The Company reports having 2,697 FTE in the 2007 forecast and has budgeted for 2,827. Although not specified by the Company in its testimony, this request represents an increase of 130 FTE.

Q. DOES PGE IDENTIFY PRECISELY WHERE IT INTENDS TO PLACE THE REQUESTED 130 FTE?

A. Staff sent data requests[4] attempting to identify exactly what responsibility centers or major functional areas are experiencing the alleged need for new employees and to determine the relationship between the growth of customer base verses new employees. Throughout its testimony[5] PGE identifies areas where it believes additional FTE are necessary. The total number of FTE identified in Exhibits 400, 500 and 600 is approximately 74.5 FTE, many of which Staff concludes are additional FTE and redundant FTE for existing programs. Additionally, in workshops held by PGE on May 8, 2008 and again on May 14, 2008, and in data responses, Staff believes that the Company was unable to clearly demonstrate a need for 130 FTE related to new programs, new generation or additional customer growth. Staff believes the one exception to this was related to approximately 16 FTE allocated to new generation for Port Westward and Biglow Canyon.

The requested 130 FTE represents an increase of FTE of approximately 6.7 percent compared to a historic growth that averages less than half of one percent. By contrast, in response to Staff's data request no. 217, PGE

[4] See Staff Data Request Nos. 103, 203, 217, 219, 223, 224, 225, 226, 227, 274.
[5] See PGE/400/Quennoz-Lobdell/15-19; PGE/500/Piro-Tooman/13, 20-25 and PGE/600/Hawke/4, 9.

demonstrated that growth in customer base historically is approximately 1.5 percent.

Q. CAN YOU PLEASE DESCRIBE STAFF'S PROPOSED ADJUSTMENT?

A. Yes. Staff began its analysis by requesting historic information in data request no. 203-b, regarding the actual number of FTE verses the number of FTE included in PGE's budgets for the years between 2002 and 2007 and the number of FTE budgeted for 2008 and 2009. Following is PGE's response demonstrating the actual number of FTEs and the percentage of change for each year:

Table V

2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Budget	2009 Budget
2,596	2,538	2,531	2,529	2,554	2,560	2,692	2,733
Percentage Change	**-2.29%**	**-0.28%**	**-0.08%**	**0.98%**	**0.23%**	**5.16%**	**1.53%**

Over the five-year period through 2007, the average change in FTE is a reduction of approximately .29 percent; however, over the most recent three-year period the average change is an increase of FTE of approximately .38 percent. Staff believes that the decrease in FTE over the five-year period can be attributed to the final closing of the Trojan plant, however, even in consideration of such, the major closing of Trojan took place many years earlier. Additionally, during the past two years PGE has added two major generating facilities. Even during that period of time, PGE did not experience an increase in FTE equivalent to a 5 or 6 percent increase.

Staff's proposed adjustment considers PGE's historic growth in FTE by beginning with a base assumption of the actual number of straight-time FTE in 2007 of 2,560. Staff assumes a growth of .50 percent for 2008 and .50 percent for 2009, resulting in 2,586 FTE. To this amount Staff allows an additional 26 FTE to account for new generation and growth in customer base, totaling 2,612 FTE for the test period. This proposal reduces PGE's request by approximately 120 FTE.

In order to measure the financial impact of removing 120 FTE, Staff looked at the total amount of Wages and Salary budgeted for the 2009 test period. Staff adjusts this amount to include wages and salaries requested in PGE's April 3, 2008, errata filing. The total amount of wages and salaries adjusted for 2009 is approximately $211 million. To that amount Staff applies the appropriate administrative overhead[6] taken from the 2007 cost allocation manual of approximately 52.18 percent. Once Staff determined the fully-loaded cost budgeted for the test period, then that amount was divided by the total number of FTE included in the budget resulting in an approximate cost per employee. That amount was multiplied by the 121 FTE resulting in a total adjustment of approximately $14 million (*See* Exhibit Staff /105/Owings/1-2). The final step in the analysis is to determine the appropriate percentages of wages and salaries that should be attributed to capital costs and to O&M. Staff determined that in Exhibit PGE/800/workpaper 10, the percentage of corporate incentives attributable to capital costs for the 2009 test period was 26.98

[6] Administrative Overhead (referred to by PGE as PTO) includes Benefits, Payroll taxes, Incentives and Employee Support.

percent. Staff relied upon this percentage to allocate 26.98 to capital and 73.02 to O&M for both the workforce adjustment and Staff's next proposed adjustment to Corporate Incentives.

Q. CAN YOU PLEASE IDENTIFY THE REVENUE REQUIREMENT IMPACT ASSOCIATED WITH STAFF'S PROPOSED ADJUSTMENT FOR WORKFORCE?

A. Yes. The revenue requirement impact is a reduction of approximately $11.41 million.

Adjustment S-4
Corporate Incentives

Q. PLEASE DESCRIBE YOUR NEXT PROPOSED ADJUSTMENT.

A. The next adjustment that I propose is identified in Exhibit Staff/103/Owings/1 as S-4, Corporate Incentives. At PGE/800/Barnett-Bell/8, PGE states that its strategy related to providing incentives is to attract, retain and motivate employees. The Company describes in detail its Corporate Incentive Program (CIP), the Annual Cash Incentive (ACI), its Stock Incentive Program (SIP) and its Notable Achievement Awards (Notables). Previous Commission policy has not supported a charge to ratepayers for bonuses and incentives paid to Company employees that are based on the financial performance of the utility (*See* Commission Order No. 87-406). According to a recent audit performed by Staff, both CIP and ACI programs are based on the Company's growth and profitability objectives[7]. In response to ICNU's Data Request No. 262-A, PGE

[7] See OPUC Staff Audit Report, Audit 2005-002, May 2005 - September 2005, at 19.

indicates "[redacted]" Staff believes it is appropriate to remove costs associated with ACI and the Stock Option Program and proposes to allow 50% of the remaining incentive programs, due in part to the relationship to the incentives and customer satisfaction, distribution quality and reliability and plant availability described at PGE/800/Barnett-Bell/9.

Q. CAN YOU PLEASE IDENTIFY THE REVENUE REQUIREMENT IMPACT ASSOCIATED WITH STAFF'S PROPOSED ADJUSTMENT FOR THE CORPORATE INCENTIVES ADJUSTMENT?

A. Yes. The revenue requirement impact is a reduction of approximately $7.02 million (*See* Staff Exhibit/106/Owings/1-2).

Adjustment S-5
Capital Expenditures

Q. PLEASE DESCRIBE YOUR NEXT PROPOSED ADJUSTMENT.

A. The next adjustment that I propose is identified in Exhibit Staff /103/Owings/1 as S-5, Capital Expenditures. At PGE/100/Piro/1, PGE describes its request for an increase of $147 million in revenue requirement as being categorized in three major areas; one-third is the result of fuel and purchased power cost increase, one-third is due to increases in Operations and Maintenance (O&M) and Administrative and General (A&G) expenses, and one-third is related to

[8] For confidential version of testimony *See* Exhibit Staff/107/Owings 1-5.

"larger rate base (e.g., the Selective Water Withdrawal (SWW) Tower at our Pelton Round Butte Hydro Project and fuel inventories)..."[9]

At PGE/400/Quennoz-Lobdell/21, the Company describes the major capital additions that are expected to close to plant for the 2009 test period; $36 million is expected to close to plant at Boardman (including $15 million to rewind the stator and convert the cooling system and $12 million for the purchase of a spare generator rotor). $146 million is expected to close to plant for hydro relicensing ($81 million for the SWW and $65 million for hydro relicensing).

Q. DOES PGE PROVIDE AN ESTIMATE FOR A COMPLETION OF THESE PROJECTS?

A. Yes. The projects related to the Boardman improvements are forecast to close-to-books in three separate increments throughout the 2009 test period; approximately $7 million in April, approximately $17 million in July, and the remaining $12 million in December of 2009.

For the projects related to hydro facilities, the approximately $81 million related to the SWW is forecast to close-to-books in March of 2009 and approximately $65 million related to hydro relicensing is forecast to close-to-books in December of 2009.

Q. CAN PGE PROVIDE AN ASSURANCE THAT THESE PROJECTS WILL CLOSE-TO-BOOKS AS CURRENTLY FORECAST?

[9] *See* PGE/100/Piro/2, at 8.

A. No. The Company can only provide its best estimate based on the percentage of completion for each project as of the date the Company filed its application.

Q. DO THESE PROJECTS EVER FAIL TO CLOSE-TO-BOOKS AS ORIGINALLY FORECAST?

A. Yes. As we saw for the Port Westward facility, its original forecast date was scheduled for March of 2007. It did not go on-line until June of 2007.

Q. IS IT POSSIBLE SOME OF THESE PROJECTS WILL NOT CLOSE-TO-BOOKS AND THEREFORE NOT BE IN SERVICE DURING THE 2009 TEST PERIOD?

A. Absolutely. Staff believes that the Clackamas River Hydro Relicensing is highly unlikely to occur in December 2009 of the test period. As noted above, this relicensing accounts for $65 million of the capital expenditures included in PGE's 2009 rate base. PGE states in a recent quarterly hydro relicensing activity update report (*See* Exhibit Staff/109/Owings/3), that PGE expects to file a new 401 Water Quality Application for the Clackamas River Project in third quarter 2008. The agency responsible for the 401 water quality certification (401), Oregon Department of Environmental Quality (DEQ), has one year to make its decision. If the agency accepts PGE's filing, no issuance of the 401 is likely to occur until the third quarter 2009. Once the 401 is completed, PGE must seek a Biological Opinion under the Federal Endangered Species Act. The Federal Energy Regulatory Commission (FERC) must receive both the 401 and the Biological Opinion before it will issue a new long-term operating license.

Q. IS THERE ANY GUARANTEE THAT THE OREGON DEQ WILL ACCEPT THE WATER QUALITY APPLICATION THAT IT WILL RECEIVE THIS YEAR, AND ISSUE ITS DECISION?

A. No. There is no guarantee that this will occur. In fact, PGE has stated in its quarterly hydro report (*See* Exhibit Staff/109/Owings/1, at 8) that it withdrew its original 401 application in December of 2006. Its plan is to resubmit that filing in the third quarter or 2008. Still there is no guarantee that the project will comply with DEQ's water quality standard for temperature below River Mill Dam. If no feasible alternative is found, the DEQ would have to implement a rulemaking to change the temperature standard for that location. It is very possible that PGE will be required to withdraw and re-file their water quality application again.

Q. DOES STAFF HAVE CONCERNS ABOUT WHETHER OTHER CAPITAL PROJECTS WILL BE COMPLETED AND IN SERVICE PRIOR TO THE END OF THE TEST PERIOD?

A. With regard to the costs related to the SWW tower, Staff believes there is great potential for the SWW tower to be in service some time during the 2009 test period. However, if it were to close-to-books later in the year than originally forecast, ratepayers would at best be paying a higher amount for recovery in the revenue requirement due to the misaligned forecast.

For the costs associated with the Boardman plant, Staff believes that the forecast is likely to be accurate; however, these improvements are not forecast by the Company to go into ratebase until mid-year.

Q. DO RATEPAYERS BENEFIT FROM THESE PROJECTS ON JANUARY 1, 2009, OR THE DAY RATES GO INTO EFFECT?

A. No, the projects will not be in-service and benefiting customers until the completion dates. Even PGE's forecasted completion dates for these projects are subsequent to January 1, 2009.

Q. DOES PGE'S PROPOSED TREATMENT OF THESE COSTS MEAN THAT COSTS FOR THESE PROJECTS WILL BE INCLUDED IN RATES THAT ARE SCHEDULED TO BE EFFECTIVE JANUARY 1, 2009?

A. Yes. An estimate of the costs attributable to these projects is averaged into the amount included in ratebase according to the forecasted close-to-book dates in order to calculate the rates that will go into effect on January 1, 2009.

Q. EVEN IF THE TIMING OF THESE CAPITAL INVESTMENTS WERE KNOWN, DOES STAFF BELIEVE IT IS PERMISSIBLE FOR PGE TO INCLUDE ANY OF THESE COSTS IN ITS REVENUE REQUIREMENT FOR JANUARY 1, 2009?

A. No. Staff has been advised by counsel that PGE's proposal would violate the prohibition in ORS 757.355. ORS 757.355 provides that a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer.

Accordingly, under ORS 757.355, PGE cannot recover the costs associated with rewinding the stator and converting the cooling system at the Boardman plant until after these capital improvements have occurred. Similarly, PGE cannot recover the cost of the generator spare rotor prior to the time the rotor is in PGE's possession and ready to use and cannot recover the costs associated with water withdraw tower (See PGE/400, Quennoz-Lobdell/21, lines 12-20), until after it has been installed and is in use. Finally, PGE cannot recover the costs associated with the hydro relicensing until after PGE has obtained the license.

Q. WHAT DOES STAFF RECOMMEND AS AN ADJUSTMENT TO PGE'S PROPOSAL?

A. Staff recommends that the Commission exclude the costs attributable to these specific projects from PGE's rates until the projects are completed, closed-to-books and Staff has had an opportunity to review the prudence of the costs. While Staff believes that PGE has forecast its capital costs in good faith, the audit and review of these major projects must take place prior to being included in rates, and these cost not included until the next rate case. Staff proposes to work with PGE to audit these projects for cost containments, prudence and accuracy prior to allowing these costs into rates. As such, Staff proposes in its S-5, Capital Expenditures adjustment to remove these costs from ratebase (*See* Exhibit Staff/Owings/108/1).

Q. CAN YOU PLEASE SUMMARIZE THE BASIS OF YOUR ADJUSTMENT?

A. Yes. In order to calculate the amount of costs forecasted to go into ratebase during the test period, Staff based its estimates on work papers provided to Staff in response to Staff's Data Request No. 316-d. These work papers detail the estimates being closed to plant and the corresponding date estimate. Staff relied upon this information to calculate the number of months (based on costs closing-to-books on the last day of the month forecast) for plant to be in service. Staff then averaged the amounts to estimate the amount that will be added to ratebase.

For example, if the forecast is for costs to close-to-books for March of 2009, it is assumed that the costs will close on the last day of the month and plant will be in service for the remainder of the test period, or nine months. To calculate the appropriate amount, Staff took the number of months (in this scenario, nine) divided by 12 and multiplied by the cost estimate. For the SWW, Staff took the total cost estimate of $81 million times 9/12 to come up with an estimate of approximately $64 million attributable to ratebase for the 2009 test period (*See* Exhibit Staff/108/Owings/1).

The remaining piece of Staff's proposed adjustment is to estimate the impact on depreciation when removing a ratebase item. Staff submits its estimate as a global estimate on depreciation by attributing the relationship of the percentage of depreciation to total ratebase. The reason for using this method is due to the fact that the depreciation for these improvements will be based on the life estimate for each improvement and based again on the month that the asset is placed into service. For assets placed into service for the last day of the test period, there is no adjustment for depreciation until the following month which is outside of the test period.

Likewise, Staff recognizes that removing ratebase will impact accumulated depreciation and accumulated deferred taxes. Because it is difficult to develop reasonable estimates for these items, Staff will seek to acquire the proper information from PGE prior to the final order being issued in this docket.

Q. CAN YOU PLEASE IDENTIFY THE REVENUE REQUIREMENT IMPACT ASSOCIATED WITH STAFF'S PROPOSED ADJUSTMENT FOR THE CAPITAL EXPENDITURES ADJUSTMENT?

A. Yes. Excluding final figures for depreciation, accumulated depreciation and accumulated deferred taxes, the revenue requirement impact is a reduction of approximately $12.43 million.

Adjustment S-16
Revenue Sensitive Costs

Q. PLEASE DESCRIBE YOUR NEXT PROPOSED ADJUSTMENT.

A. The next adjustment that I propose is identified in Exhibit Staff /103/Owings/2 as S-16, Revenue Sensitive Costs.

Q. COULD YOU PLEASE DESCRIBE WHAT REVENUE SENSITIVE COSTS REPRESENT?

A. Yes. Some of a utility's expenses are based on the amount of revenues generated by providing electric service. Examples of these types of costs are taxes, OPUC fees, uncollectible expense, and other local fees such as franchise fees. Revenue sensitive costs are typically calculated as a percentage of overall revenues and are applied to each adjustment to assure that as the Company's revenues fluctuate from the proposed adjustments, the revenue requirement reflects the net impact to these types of expenses.

Q. WHAT DOES PGE PROPOSE AS ITS REVENUE SENSITIVE COST PERCENTAGE?

A. PGE proposed an overall Revenue Sensitive Factor of 1.68 percent. In its calculation of revenue sensitive costs, PGE included a factor of .38 percent for uncollectible expense (*See* Exhibit PGE/201/Tooman-Tinker/3) and a factor of 5.375 percent to represent its blended rate for State taxes (*See* Exhibit Staff/110/Owings/1-10).

Q. DOES STAFF PROPOSE AN ADJUSTMENT TO THESE TWO PORTIONS OF PGE'S REVENUE SENSITIVE COSTS?

A. Yes. Staff reviewed all parts of PGE's revenue sensitive costs. Originally Staff proposed to adjust the factor attributable to PGE's franchise fees as well; however, at Settlement discussions Staff was persuaded that PGE's proposed factor representing franchise fees was accurate and did not warrant an adjustment. For uncollectible expense, Staff Witness Rossow will sponsor testimony regarding Staff's proposed adjustment to that factor (*See* Exhibit Staff/200/Rossow).

Regarding the State income tax factor proposed by PGE, the Company proposes in its April 3, 2008 errata filing (*See* Exhibit Staff/110/Owings/1& 5) to modify its original factor of 5.120 percent to 5.135 percent to allow for a larger jurisdictional allocation to the State of Montana per PGE's 2006 tax return. In response to Staff's Data Request No. 105, PGE explains how the rate is derived from a blending of the allocation of state rates between Oregon and Montana. In addition, the Company applies tax credits and the impact of timing differences that result in the blended State and Federal rates (*See* Exhibit Staff/111/Owings/1).

Staff believes that the apportionment factors used to allocate revenues between states changes on an annual basis. Increasing PGE's blended State Rate for purposes of revenue sensitive costs has the impact of increasing funds attributable to state income taxes and in turn, an increasing revenue requirement. In PGE's most recent SB408 fiilng (*See* UE 178), PGE is required to refund approximately $38 million. Per a joint stipulation in that docket, PGE will refund this amount to ratepayers over a two-year period in order to off-set a potential surcharge for the 2007 SB408 filing. Staff believes that since SB408 will true-up the actual expense allocated to State taxes and because PGE still owes a large refund to ratepayers for the over-collection of taxes, increasing the amount PGE will collect in rates for taxes, does not seem necessary at this time.

Q. WHAT DOES STAFF PROPOSE AS AN ADJUSTMENT FOR THE STATE TAX RATE?

A. Staff proposes to reset the tax rate back to 5.120%. This adjustment creates a reduction to revenue requirement of approximately $.603 million (*See* Exhibit Staff/110/Owings/5).

Adjustment S-19
Energy Audits

Q. PLEASE DESCRIBE YOUR NEXT PROPOSED ADJUSTMENT.

A. The final adjustment that I propose is identified in Exhibit Staff /103/Owings/2 as S-19, Energy Audits. During the week of May 19, 2008, Staff viewed a local news segment that focused on "phantom load" or appliances that use energy by just being plugged in as opposed to being actively used. The news story referred to PGE Energy Experts (residential), energy audits performed by PGE for free (if you have abnormally high bills), provided a link to PGE's website and had no reference to calling the Energy Trust of Oregon. In response to Staff's Data Request No. 402-a, PGE states that it has three field representatives that could help customers troubleshoot high bills on site. "In 2007, PGE's three field representatives responded to 1,108 'High Bill Field Check Requests'(*See* Exhibit Staff/112/Owings/3).

Q. DOES IT SEEM UNREASONABLE FOR PGE TO PERFORM 1,108 HIGH BILL FIELD VISITS?

A. Yes. Based on a five-day work week, there are 255 work days in a one year period. To perform 1,108 "high bill field checks" is an average of approximately 4.3 audits per day. 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. Ratepayers already bear the 3 percent public purpose charge which is intended to include this type of activity. Staff believes that the costs to dispatch field representatives for energy audits should, for the most part, be borne by the Energy Trust of Oregon.

Q. WHAT DOES STAFF PROPOSE AS AN ADJUSTMENT?

A. In response to Staff's Data Request No. 402-B, PGE provided a summary of ledgers used to book the costs of customer service representatives and more specifically, for "high bill field checks" (*See* Exhibit Staff/112/Owings/10). Ledger nos. N41325 and N41326 demonstrate that PGE included $273,252 in the 2009 test period for residential high bill calls and $3,082 for non-residential high bill calls. Staff proposes to remove these costs from the 2009 test period (*See* Exhibit Staff/113/Owings/1).

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF THE PROPOSED ADJUSTMENT RELATED TO ENERGY AUDITS?

A. The revenue requirement impact is a reduction of approximately $.287 million.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

July 9, 2008

WITNESS QUALIFICATION STATEMENT

NAME:	Carla M. Owings
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst/Revenue Requirement/Rates and Regulation
ADDRESS:	550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.
EDUCATION:	Professional Accounting Degree Trend College of Business 1983

EXPERIENCE:

I have been employed by the Public Utility Commission of Oregon since April of 2001. I am the Senior Utility Analyst for revenue requirement for the Rates and Regulation Division of the Utility Program. Current responsibilities include leading research and providing technical support on a wide range of policy issues for electric and gas utilities.

From September 1994 to April 2001, I worked for the Oregon Department of Revenue as a Senior Industrial/Utility Appraiser. I was responsible for the valuation of large industrial properties as well as utility companies throughout the State of Oregon.

I have testified in behalf of the Public Utility Commission in Docket Nos. UE 177, UE 178, UG 170, UG 171, UE 180, UM 1234, UE 167, UE 180, UE 188, UM 1121, UM 1261 and UM 1271.

OTHER EXPERIENCE:

I received my certification from the National Association of State Boards of Accountancy in the Principles of Public Utilities Operations and Management in March of 1997. I have attended the Institute of Public Utilities sponsored by the National Association of Regulatory Utility Commissioners at Michigan State University in August of 2002 and the College of Business Administration and Economics at New Mexico State University's Center for Public Utilities in May of 2004.

In 2008, I attended the Energy Utility Consultants presentation on Performance Benchmarking in Denver, Colorado. In 2005, I attended the National Association of Regulatory Utility Commissioners Advanced Course at Michigan State University. I worked for seven years for the Oregon State Department of Revenue as a Senior Utility and Industrial Appraiser.

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 102

Exhibits in Support Of Direct Testimony

July 9, 2008

Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204
PortlandGeneral.com

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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PORTLAND GENERAL ELECTRIC
OPUC REGULATORY REPORTING
RESULTS OF OPERATIONS
January 1, 2007 - December 31, 2007
(Thousands of Dollars)

Regulatory adjustments based on **Docket UE-180, Order 07-015.**	Actual Financial Statements	Type I Accounting Adjustments	Regulated Utility Actuals	Type I Adjustments	Regulated Adjusted Results	Type II Adjustments	Pro Forma Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Operating Revenues							
Sales to Consumers	1,515,532	(2,831)	1,512,701	0	1,512,701	(7,565)	1,505,136
Sales for Resale	200,867	(200,867)	0	0	0	0	0
Other Operating Revenues	26,564	(6,006)	20,558	0	20,558	0	20,558
Total Operating Revenues	1,742,963	(209,704)	1,533,259	0	1,533,259	(7,565)	1,525,694
Operation & Maintenance							
Net Variable Power Cost	878,471	(180,468)	698,003	7	698,010	26,194	724,204
Total Fixed O&M	150,580	0	150,580	0	150,580	3,102	153,682
Other O&M	184,145	0	184,145	(18,781)	165,364	2,358	167,722
Total Operation & Maintenance	1,213,196	(180,468)	1,032,728	(18,774)	1,013,954	31,654	1,045,608
Depreciation & Amortization	180,931	0	180,931	0	180,931	1,619	182,550
Other Taxes / Franchise Fee	80,020	0	80,020	0	80,020	230	80,250
Income Taxes	71,498	(2,064)	69,434	8,696	78,130	(21,141)	56,989
Total Oper. Expenses & Taxes	1,545,645	(182,531)	1,363,114	(10,078)	1,353,035	12,362	1,365,397
Utility Operating Income	197,318	(27,172)	170,146	10,078	180,224	(19,927)	160,297
Rate of Return	10.17%		8.77%		9.30%		6.87%
Return on Equity	13.21%		10.59%		11.58%		7.28%
ROE based on actual capital structure.							
Average Rate Base							
Utility Plant in Service	4,447,289	0	4,447,289	(865)	4,446,424	444,770	4,891,194
Accumulated Depreciation	2,385,624	0	2,385,624	0	2,385,624	62,653	2,448,277
Accumulated Def. Income Taxes	227,374	0	227,374	1,147	228,521	695	229,216
Accumulated Def. Inv. Tax Credit	2,182	0	2,182	0	2,182	(1,185)	997
Net Utility Plant	1,832,109	0	1,832,109	(2,012)	1,830,097	382,607	2,212,704
Net Trojan Investment	0	0	0	0	0	0	0
Weatherization Investment	2	0	2	0	2	0	2
Deferred Programs & Investments	7,508	0	7,508	181	7,689	26	7,715
Operating Materials & Fuel	63,974	0	63,974	0	63,974	231	64,205
Misc. Deferred Credits	(21,768)	0	(21,768)	0	(21,768)	8,403	(13,365)
Unamortized Ratepayer Gains	0	0	0	0	0	0	0
Working Cash	57,596	1,266	58,862	(524)	58,338	2,956	61,294
Total Average Rate Base	1,939,421	1,266	1,940,687	(2,355)	1,938,332	394,223	2,332,555

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

Exhibits in Support
Of Direct Testimony

July 9, 2008

PORTLAND GENERAL ELECTRIC
UE 197/UE 198
NARRATIVE SUMMARY
TWELEVE MONTHS ENDED DECEMBER 31, 2009
(000)

Item	Staff	Issue	Revenue Requirement Effect
		Revenue Requirement on the Company's Filed Results	**$147,233**
		Proposed Staff Adjustments	
S-0	BC	**Rate of Return** Stipulated Agreement	**(12,906)**
S-1	PR	**Other Electric Revenues** Adjust Other Revenues per Stipulated Agreement to offset Schedule 300 Revenues included in test period	**$471**
S-2	CO	**Research and Development** Staff proposes to normalize the amount spent on Research and Development	**($1,752)**
S-3	CO	**Workforce Adjustment** Staff proposes to normalize workforce in accordance with historic growth plus 26 FTE	**($11,414)**
S-4	CO	**Corp Incentives** Staff proposes to remove incentives related to the financial performance of the utility including Officer Incentives	**(7,017)**
S-5	CO	**Cap Ex** Staff proposes to remove capital expenditures not known and measurable	**(12,438)**
S-6	CO	**Lease Adjustment** Stipulated Agreement	**0**
S-7	PR	**Fuel Adjustment** Stipulated Agreement	**0**
S-8	PR	**Membership Adjustment** Stipulated Agreement	**0**
S-9	DB	**A&G and O&M** Staff proposes to make adjustments to A&G and O&M based various areas. Detail can be found on workpapers provided by Staff for settlement in a separate packet.	**(10,557)**
S-10	ED	**WECC Reliability Center, Regional Trans Planning & flow mitigation**	**(156)**

PORTLAND GENERAL ELECTRIC
UE 197/UE 198
NARRATIVE SUMMARY
TWELEVE MONTHS ENDED DECEMBER 31, 2009
(000)

		Staff proposes to make adjustments T&D based on PGE's proposal to increase costs related to Regional Trans planning, WECC reliability center and unscheduled flow mitigation	
S-11	ED	**Fixed Plant Costs** Staff proposes to adjust cost increases related to Beaver, Colstrip and Boardman	**(8,743)**
S-12	ED	**Kelso Beaver Pipeline Transmission** Remove costs per Stipulated Agreement	**(1,040)**
S-13	ED	**NERC/WECC Consultant, RCM Program costs, Misc Unspecified software upgrades** Staff proposes to remove costs associated with NERC/WECC Consult., RCM Program costs and Miscellaneous software upgrades	**(520)**
S-14	DB	**Property Tax Adjustment** Staff proposes to adjust property taxes associated with Port Westward and Biglow Canyon	**(4,416)**
S-15	ED	**NVPC Adjustment** Per Stipulated Agreement	**(5,058)**
S-16	CO, DB, PR	**Revenue Sensitive Costs** Staff proposes to Adjust Franchise Fees, Uncollectibles Expense and Taxes other than Income Taxes as a percentage of overall Revenue Sensitive Costs	**(1,805)**
S-17	LG	**Schedule 300** No changes will be adopted to Schedule 300 per Stipulated Agreement	**(471)**
S-18	CO	**Port Westward and Biglow Canyon** A true-up of Cap Costs per Stipulated Agreement	**(113)**
S-19	CO	**Energy Audits** Staff proposes to remove costs associated with Energy Audits from O&M.	**(287)**
PGE - 1		**NVPC UPDATE** April 4, 2008 Update of PGE's forecasted fuel costs and power purchases	**10,106**
S*	CO	Adjustment to rounding error	(116)
		Total Staff-Proposed Adjustments (Base Rates):	(68,232)
		Staff-Calculated Revenue Requirements Change (Base Rates):	**$79,001**

PORTLAND GENERAL ELECTRIC
UE 197/198
SUMMARY OF REVENUE REQUIREMENT
TWELEVE MONTHS ENDED DECEMBER 31, 2009
(000)

		SUMMARY SHEET	2009 Results Per Company Filing (1)	Staff Proposed Adjustments and NVPC Update (2)	2009 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1		**Operating Revenues**					
2		Retail Sales	$1,586,821	$0	$1,586,821	$79,001	$1,665,822
3		Wholesale Sales	0	0	0	0	0
4		Other Revenues	19,346	0	19,346	0	19,346
5		**Total Operating Revenues**	$1,606,167	$0	$1,606,167	$79,001	$1,685,168
6		**Operating Expenses**					
7		Net Variable Power Costs	$806,699	$4,850	$811,549	$0	$811,549
8		Production	108,251	(9,900)	98,351	0	98,351
9		Other Power Supply (Trojan)	129	0	129	0	129
10		Transmission	11,937	(150)	11,787	0	11,787
11		Distribution	68,198	(20,203)	47,995	0	47,995
12		Customer Accounting	65,235	(276)	64,959	0	64,959
13		OPUC Fees	4,959	0	4,959	247	5,206
14		Uncollectibles	7,617	(1,734)	5,883	379	6,262
15		Administrative and General	115,165	(8,190)	106,975	0	106,975
16		**Total Operation & Maintenance**	$1,188,190	($35,603)	$1,152,587	$626	$1,153,213
17		Depreciation	$175,781	($3,005)	$172,776	$0	$172,776
18		Amortization	18,781	0	18,781	0	18,781
19		Taxes Other than Income	51,232	(4,244)	46,988	0	46,988
20		Income Taxes	16,718	17,566	34,284	29,258	63,542
21		Local taxes and Franchise Fees	39,893	0	39,893	1,986	41,879
22		**Total Operating Expenses**	$1,490,595	($25,286)	$1,465,309	$31,870	$1,497,179
23		**Net Operating Revenues**	$115,572	$25,286	$140,858	$46,984	$187,842
24		**Average Rate Base**					
25		Electric Plant in Service	$5,173,537	($89,244)	$5,084,293	$0	$5,084,293
26	Less:	Accumulated Depreciation & Amortization	(2,674,938)	10	(2,674,928)	0	(2,674,928)
27		Accumulated Deferred Income Taxes	(286,869)	(20)	(286,889)	0	(286,889)
28		Accumulated Deferred Inv. Tax Credit	(271)	0	(271)	0	(271)
29		**Net Utility Plant**	$2,211,458	($89,254)	$2,122,204	$0	$2,122,204
30		Plant Held for Future Use	$0	$0	$0	$0	$0
31		Acquisition Adjustments	0	0	0	0	0
32		Working Capital	77,511	(1,316)	76,195	1,657	77,852
33		Fuel Stock	67,707	0	67,707	0	67,707
34		Materials & Supplies	0	0	0	0	0
35		Customer Advances for Construction	0	0	0	0	0
36		Weatherization Loans	0	0	0	0	0
37		Prepayments	(37,755)	0	(37,755)	0	(37,755)
38		Misc. Deferred Debits	23,917	0	23,917	0	23,917
39		Misc. Rate Base Additions/(Deductions)	0	0	0	0	0
40		**Total Average Rate Base**	$2,342,838	($90,570)	$2,252,268	$1,657	$2,253,925
41		**Rate of Return**	4.93%		6.25%		**8.33%**
42		**Implied Return on Equity**	3.30%		5.94%		**10.10%**

PORTLAND GENERAL ELECTRIC
UE 197/198
TAX CALCULATION SHEET
TWELVE MONTHS ENDED DECEMBER 31, 2009
(000)

	Income Tax Calculations	2009 Per Company Filing (1)	Adjustments (2)	2009 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	Book Revenues	$1,606,167	$0	$1,606,167	$79,001	$1,685,168
2	Book Expenses Other than Depreciation	1,298,095	($39,847)	1,258,248	2,612	1,260,860
3	Depreciation	175,781	($3,005)	172,776	0	172,776
4	Interest	76,928	($2,974)	73,954	54	74,008
5 Less:	Schedule M Differences	24,431	$0	24,431	0	24,431
6	State Taxable Income	$30,933	$45,826	$76,759	$76,335	$153,094
7	Add OR Depletion Adjustment	$0	$0	$0	$0	$0
8	Total State Taxable Income	$30,933	$45,826	$76,759	$76,335	$153,094
9	State Income Tax @ 5.35%	$1,584	$2,347	$3,931	$3,908	$7,839
10	State Tax Credits	(2,084)	$0	(2,084)	0	(2,084)
11	Net State Income Tax	($500)	$2,347	$1,847	$3,908	$5,755
12	Additional Tax Depreciation	0	0	0	0	0
13 Plus:	Other Schedule M Differences	0	0	0	0	0
14	Federal Taxable Income	$31,433	43,479	$74,912	$72,427	$147,339
15	Federal Tax @ 35%	11,002	15,219	26,221	25,350	51,571
16	Federal Tax Credits	0	0	0	0	0
17	Current Federal Tax	$11,002	$15,219	$26,221	$25,350	$51,571
18	ITC Adjustment		-			
19	Deferral	(8,363)	0	(8,363)	0	(8,363)
20	Restoration	1,456	0	1,456	0	1,456
21	Total ITC Adjustment	($9,819)	$0	($9,819)	$0	($9,819)
22	Provision for Deferred Taxes	$16,036	$0	$16,036	$0	$16,036
23	Total Income Tax	$16,718	$17,566	$34,284	$29,258	$63,542

PORTLAND GENERAL ELECTRIC
UE 197/UE 198
SUMMARY OF ADJUSTMENTS
TWELEVE MONTHS ENDED DECEMBER 31, 2009
(000)

	Staff Adjustments	Other Revenues (S-1)	Research & Develop Adjust (S-2)	Workforce Adjustment (S-3)	Corp Incentives (S-4)	Cap Ex (S-5)	Lease Adjust (S-6)	M&S Fuel Adjust (S-7)	Membership Adjust (S-8)	A&G and O&M (S-9)	WECC Rel, Reg Trans Plan Flow Mitigation (S-10)	Fixed Plant Costs (S-11)	Kelso-Beaver Pipeline Transmission (S-12)
1	**Operating Revenues**												
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Wholesale Sales	0	0	0	0	0	0	0	0	0	0	0	0
4	Other Revenues	(455)	0	0	0	0	0	0	0	0	0	0	0
5	**Total Operating Revenues**	**($455)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
6	**Operating Expenses**												
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	$0
8	Production	0	0	0	0	0	0	0	0	0	0	(8,400)	(1,000)
9	Other Power Supply (Trojan)	0	0	0	0	0	0	0	0	0	0	0	0
10	Transmission	0	0	0	0	0	0	0	0	0	(150)	0	0
11	Distribution	0	0	(10,396)	(6,392)	0	0	0	0	(3,415)	0	0	0
12	Customer Accounting	0	0	0	0	0	0	0	0	0	0	0	0
13	OPUC Fees	0	0	0	0	0	0	0	0	0	0	0	0
14	Uncollectibles	0	0	0	0	0	0	0	0	0	0	0	0
15	Administrative and General	0	(1,683)	0	0	0	0	0	0	(6,507)	0	0	0
16	**Total Operation & Maintenance**	**$0**	**($1,683)**	**($10,396)**	**($6,392)**	**$0**	**$0**	**$0**	**$0**	**($9,922)**	**($150)**	**($8,400)**	**($1,000)**
17	Depreciation	0	0	(131)	(80)	(2,719)	0	0	0	(51)	0	0	0
18	Amortization	0	0	0	0	0	0	0	0	0	0	0	0
19	Taxes Other than Income	0	0	0	0	0	0	0	0	0	0	0	0
20	Income Taxes	(174)	646	4,087	2,513	2,060	0	0	0	3,846	58	3,223	384
21	Local Taxes and Franchise Fees	0	0	0	0	0	0	0	0	0	0	0	0
22	**Total Operating Expenses**	($174)	($1,037)	($6,440)	($3,959)	($659)	$0	$0	$0	($6,127)	($92)	($5,177)	($616)
23	**Net Operating Revenues**	**($281)**	**$1,037**	**$6,440**	**$3,959**	**$659**	**$0**	**$0**	**$0**	**$6,127**	**$92**	**$5,177**	**$616**
24	**Average Rate Base**												
25	Electric Plant in Service	0	0	(3,841)	(2,362)	(80,816)	0	0	0	(1,500)	0	0	0
26	Accumulated Depreciation & Amortization	0	0	0	0	0	0	0	0	0	0	0	0
27	Accumulated Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0
28	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0
29	**Net Utility Plant**	$0	$0	($3,841)	($2,362)	($80,816)	$0	$0	$0	($1,500)	$0	$0	$0
30	Plant Held for Future Use	0	0	0	0	0	0	0	0	0	0	0	0
31	Acquisition Adjustments	0	0	0	0	0	0	0	0	0	0	0	0
32	Working Capital	(9)	(54)	(335)	(206)	(34)	0	0	0	(319)	(5)	(269)	(32)
33	Fuel Stock	0	0	0	0	0	0	0	0	0	0	0	0
34	Materials & Supplies	0	0	0	0	0	0	0	0	0	0	0	0
35	Customer Advances for Construction	0	0	0	0	0	0	0	0	0	0	0	0
36	Weatherization Loans	0	0	0	0	0	0	0	0	0	0	0	0
37	Prepayments	0	0	0	0	0	0	0	0	0	0	0	0
38	Misc. Deferred Debits	0	0	0	0	0	0	0	0	0	0	0	0
39	Misc. Rate Base Additions/(Deductions)	0	0	0	0	0	0	0	0	0	0	0	0
40	**Total Average Rate Base**	**($9)**	**($54)**	**($4,176)**	**($2,568)**	**($80,850)**	**$0**	**$0**	**$0**	**($1,819)**	**($5)**	**($269)**	**($32)**
41	**Revenue Requirement Effect**	**$471**	**($1,752)**	**($11,414)**	**($7,017)**	**($12,438)**	**$0**	**$0**	**$0**	**($10,557)**	**($156)**	**($8,743)**	**($1,040)**

PORTLAND GENERAL ELECTRIC
UE 197/UE 198
SUMMARY OF ADJUSTMENTS
TWELEVE MONTHS ENDED DECEMBER 31, 2009
(000)

	Staff Adjustments	WECC, RCM, Misc Soft & GP (S-13)	Property Taxes (Taxes Other) (S-14)	NVPC Adjustment (S-15)	Revenue Sensitive Costs (S-16)	Schedule 300 (S-17)	True up of Port Westward Biglow Canyon (S-18)	Energy Audit Costs (S-19)	UPDATE NVPC (S-20)	Total Adjustments (Base Rates)
1	**Operating Revenues**									
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Wholesale Sales	0	0	0	0	0	0	0	0	$0
4	Other Revenues	0	0	0	0	455	0	0	0	$0
5	**Total Operating Revenues**	**$0**	**$0**	**$0**	**$0**	**$455**	**$0**	**$0**	**$0**	**$0**
6	**Operating Expenses**									
7	Net Variable Power Costs	$0	$0	($4,860)	$0	$0	$0	$0	$9,710	$4,850
8	Production	(500)	0	0	0	0	0	0	0	($9,900)
9	Other Power Supply (Trojan)	0	0	0	0	0	0	0	0	$0
10	Transmission	0	0	0	0	0	0	0	0	($150)
11	Distribution	0	0	0	0	0	0	0	0	($20,203)
12	Customer Accounting	0	0	0	0	0	0	(276)	0	($276)
13	OPUC Fees	0	0	0	0	0	0	0	0	$0
14	Uncollectibles	0	0	0	(1,734)	0	0	0	0	($1,734)
15	Administrative and General	0	0	0	0	0	0	0	0	($8,190)
16	**Total Operation & Maintenance**	**($500)**	**$0**	**($4,860)**	**($1,734)**	**$0**	**$0**	**($276)**	**$9,710**	**($35,603)**
17	Depreciation	0	0	0	0	0	(24)	0	0	($3,005)
18	Amortization	0	0	0	0	0	0	0	0	$0
19	Taxes Other than Income	0	(4,244)	0	0	0	0	0	0	($4,244)
20	Income Taxes	192	1,629	1,865	665	174	18	106	(3,726)	$17,566
21	Local Taxes and Franchise Fees	0	0	0	0	0	0			$0
22	**Total Operating Expenses**	($308)	($2,615)	($2,995)	($1,069)	$174	($6)	($170)	$5,984	($25,286)
23	**Net Operating Revenues**	**$308**	**$2,615**	**$2,995**	**$1,069**	**$281**	**$6**	**$170**	**($5,984)**	**$25,286**
24	**Average Rate Base**									
25	Electric Plant in Service	0	0	0	0	0	(725)	0	0	($89,244)
26	Accumulated Depreciation & Amortization	0	0	0	0	0	10	0	0	$10
27	Accumulated Deferred Income Taxes	0	0	0	0	0	(20)	0	0	($20)
28	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0	0	$0
29	**Net Utility Plant**	$0	$0	$0	$0	$0	($735)	$0	$0	($89,254)
30	Plant Held for Future Use	0	0	0	0	0	0	0	0	$0
31	Acquisition Adjustments	0	0	0	0	0	0	0	0	$0
32	Working Capital	(16)	(136)	(156)	(56)	9	0	(9)	311	($1,316)
33	Fuel Stock	0	0	0	0	0	0	0	0	$0
34	Materials & Supplies	0	0	0	0	0	0	0	0	$0
35	Customer Advances for Construction	0	0	0	0	0	0	0	0	$0
36	Weatherization Loans	0	0	0	0	0	0	0	0	$0
37	Prepayments	0	0	0	0	0	0	0	0	$0
38	Misc. Deferred Debits	0	0	0	0	0	0	0	0	$0
39	Misc. Rate Base Additions/(Deductions)	0	0		0	0	0	0	0	$0
40	**Total Average Rate Base**	**($16)**	**($136)**	**($156)**	**($56)**	**$9**	**($735)**	**($9)**	**$311**	**($90,570)**
41	**Revenue Requirement Effect**	**($520)**	**($4,416)**	**($5,058)**	**($1,805)**	**($471)**	**($113)**	**($287)**	**$10,106**	**($55,210)**

PORTLAND GENERAL ELECTRIC
UE 197/UE 198
SUMMARY OF TAX ADJUSTMENTS
TWELEVE MONTHS ENDED DECEMBER 31, 2009
(000)

	Income Tax Calculations	Other Revenues (S-1)	Research & Develop Adjust (S-2)	Workforce Adjustment (S-3)	Corp Incentives (S-4)	Cap Ex (S-5)	Lease Adjust (S-6)	M&S Fuel Adjust (S-7)	Membership Adjust (S-8)	A&G and O&M (S-9)	WECC Rel, Reg Trans Plan Flow Mitigation (S-10)	Fixed Plant Costs (S-11)	Kelso-Beaver Pipeline Transmission (S-12)
1	Book Revenues	($455)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	Book Expenses Other than Depreciation	0	(1,683)	(10,396)	(6,392)	0	0	0	0	(9,922)	(150)	(8,400)	(1,000)
3	State Tax Depreciation	0	0	(131)	(80)	(2,719)	0	0	0	(51)	0	0	0
4	Interest	(0)	(2)	(137)	(84)	(2,655)	0	0	0	(60)	(0)	(9)	(1)
5	Schedule M Differences	0	0	0	0	0	0	0	0	0	0	0	0
6	State Taxable Income	($455)	$1,685	$10,664	$6,556	$5,374	$0	$0	$0	$10,033	$150	$8,409	$1,001
7	Add OR Depletion Adjustment-Net	0	0	0	0	0	0	0	0	0	0	0	0
8	Total State Taxable Income	($455)	$1,685	$10,664	$6,556	$5,374	$0	$0	$0	$10,033	$150	$8,409	$1,001
9	State Income Tax	($23)	$86	$546	$336	$275	$0	$0	$0	$514	$8	$431	$51
10	State Tax Credits	0	0	0	0	0	0	0	0	0	0	0	0
11	Net State Income Tax	($23)	$86	$546	$336	$275	$0	$0	$0	$514	$8	$431	$51
12	Additional Tax Depreciation	0	0	0	0	0	0	0	0	0	0	0	0
13	Other Schedule M Differences	0	0	0	0	0	0	0	0	0	0	0	0
14	Federal Taxable Income	($432)	$1,599	$10,118	$6,220	$5,099	$0	$0	$0	$9,519	$142	$7,978	$950
15	Federal Tax @ 35%	(151)	560	3,541	2,177	1,785	0	0	0	3,332	50	2,792	333
16	Federal Tax Credits	0	0	0	0	0	0	0	0	0	0	0	0
17	Current Federal Tax	($151)	$560	$3,541	$2,177	$1,785	$0	$0	$0	$3,332	$50	$2,792	$333
18	**ITC Adjustment**												
19	Deferral	0	0	0	0	0	0	0	0	0	0	0	0
20	Restoration	0	0	0	0	0	0	0	0	0	0	0	0
21	Total ITC Adjustment	0	0	0	0	0	0	0	0	0	0	0	0
22	Provision for Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	0
23	Total Income Tax	($174)	$646	$4,087	$2,513	$2,060	$0	$0	$0	$3,846	$58	$3,223	$384

PORTLAND GENERAL ELECTRIC
UE 197/UE 198
SUMMARY OF TAX ADJUSTMENTS
TWELEVE MONTHS ENDED DECEMBER 31, 2009
(000)

	Income Tax Calculations	WECC, RCM, Misc Soft & GP (S-13)	Property Taxes (Taxes Other) (S-14)	NVPC Adjustment (S-15)	Revenue Sensitive Costs (S-16)	Schedule 300 (S-17)	True up of Port Westward Biglow Canyon (S-18)	Energy Audit Costs (S-19)	UPDATE NVPC (S-20)	Total Adjustments (Base Rates)
1	Book Revenues	$0	$0	$0	$0	$455	$0	$0	$0	$0
2	Book Expenses Other than Depreciation	(500)	(4,244)	(4,860)	(1,734)	0	0	(276)	9,710	($39,847)
3	State Tax Depreciation	0	0	0	0	0	(24)	0	0	($3,005)
4	Interest	(1)	(4)	(5)	(2)	0	(24)	(0)	10	($2,974)
5	Schedule M Differences	0	0	0	0	0	0	0	0	$0
6	State Taxable Income	$501	$4,248	$4,865	$1,736	$455	$48	$276	($9,720)	$45,826
7	Add OR Depletion Adjustment-Net	0	0	0	0	0	0	0	0	$0
8	Total State Taxable Income	$501	$4,248	$4,865	$1,736	$455	$48	$276	($9,720)	$45,826
9	State Income Tax	$26	$218	$249	$89	$23	$2	$14	($498)	$2,347
10	State Tax Credits	0	0	0	0	0	0	0	0	$0
11	Net State Income Tax	$26	$218	$249	$89	$23	$2	$14	($498)	$2,347
12	Additional Tax Depreciation	0	0	0	0	0	0	0	0	$0
13	Other Schedule M Differences	0	0	0	0	0	0	0	0	$0
14	Federal Taxable Income	$475	$4,030	$4,616	$1,647	$432	$46	$262	($9,222)	$43,479
15	Federal Tax @ 35%	166	1,411	1,616	576	151	16	92	(3,228)	$15,219
16	Federal Tax Credits	0	0	0	0	0	0	0	0	$0
17	Current Federal Tax	$166	$1,411	$1,616	$576	$151	$16	$92	($3,228)	$15,219
18	**ITC Adjustment**									$0
19	Deferral	0	0	0	0	0	0	0	0	$0
20	Restoration	0	0	0	0	0	0	0	0	$0
21	Total ITC Adjustment	0	0	0	0	0	0	0	0	$0
										$0
22	Provision for Deferred Taxes	0	0	0	0	0	0	0	0	$0
										$0
23	Total Income Tax	$192	$1,629	$1,865	$665	$174	$18	$106	($3,726)	$17,566

PORTLAND GENERAL ELECTRIC
UE 197/198
REVENUE SENSITIVE COSTS
TWELEVE MONTHS ENDED DECEMBER 31, 2009
(000)

REVENUE SENSITIVE COSTS	COMPANY REQUEST	STAFF ADJUSTED
Revenues	1.00000	1.00000
Operating Revenue Deductions		
Uncollectible Accounts	0.00480	0.00380
Taxes Other - Franchise	0.02514	0.02514
OPUC Fees (separate line item on Model)	0.00313	0.00313
- Resource supplier		
State Taxable Income	0.96694	0.96794
State Income Tax @ 5.375%	0.05197	
State Income Tax @ 5.120%		0.04956
Federal Taxable Income	0.91496	0.91838
Federal Income Tax @ 35%	0.32024	0.32143
Total Taxes	0.37221	0.37099
Total Revenue Sensitive Costs	0.40527	0.40306
Utility Operating Income	0.59473	0.59694
Net-to-Gross Factor	**1.68145**	**1.67520**

Input:		
	5.12000%	STATERATE (Incom
	5.20000%	WORKINGCAP

PORTLAND GENERAL ELECTRIC
UE 197/198
COST OF CAPITAL ASSUMPTIONS
TWELEVE MONTHS ENDED DECEMBER 31, 2009
(000)

INPUT ASSUMPTIONS

COST OF CAPITAL - Company	% of CAPITAL	COST	WEIGHTED COST
Long Term Debt	50.00%	6.567%	3.284%
Preferred Stock	0.00%	0.000%	0.000%
Common Equity	50.00%	10.100%	5.050%
Total	100.00%		8.334%

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 104

Exhibits in Support
Of Direct Testimony

July 9, 2008

Portland General Electric

UE 197/UE 198

Test period ending December 31, 2009

(000)

Staff reviewed the Company's expenditures related to Research & Development (R&D) for the years 2002 through 2007. (See Data Response 269) percentage in the years prior to a rate case. Staff normalized the trend and adjusted the amount to match the 3-year average for 2005, 2006 and 2007.

R&D Expenditures *None due to cost containments. See Data Response 269-A

2002 Actuals	2003 Actuals	2004 Actuals	2005 Actuals	2006 Actuals	2007 Actuals	Average
385,003	*None	219,420	338,983	167,123	307,725	283,651

PGE Proposed		
2008 Budget	2009 Budget	Delta between Average and Budget
256,076	1,995,000	1,711,349

Average of five years * 1.10 (5% per year)	312,016
	(1,682,984)
Staff Proposed Adjustment	**(1,683)**

Staff Initiator:
Carla Owings

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 105

Exhibits in Support
Of Direct Testimony

July 9, 2008

Portland General Electric
UE 197/UE 198
Test period ending December 31, 2009
(000)

Staff proposes to adjust FTE count. Staff reviewed PGE's historical FTE level and compared it to the proposed level for 2009 test period. Staff proposes to normalize the growth of FTE in line with the historic levels as well as allowing an additionaly 26 FTE in acknowledgment of incremental programs.

Staff Proposed Workforce Adjustment

		PGE	Staff	Adjustment
PGE				
2009 FTE Count		2,733	2,612	(121)
				Workforce Adjustment
Wages & Salaries w/PTO		**$223,794**	**$209,557**	**($14,237)**
Percentage O&M			73.02%	**($10,396)**
Percentage Capital - from Corp Incentives Worksheet			26.98%	**($3,841)**
Depreciation Adjustment	Gross Plant		5,173,537	
Annual Depreciation			175,781	
% Depreciation to RB			3.398%	**($131)**

Staff Initiator:
Carla Owings

PORTLAND GENERAL ELECTRIC
UE 197/UE 198
WORKFORCE ADJUSTMENT WORKPAPERS

Class	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2007Budget UE180
Exempt	1,165	1,124	1,134	1,150	1,169	1,153	n/a
Hourly	564	574	574	570	573	584	n/a
Officer	15	14	13	13	14	13	n/a
Union	852	826	810	795	798	810	n/a
Grand Total	2,596	2,538	2,531	2,529	2,554	2,560	2,629

Delta Employees Budget to Actual	**69**	Exhibit 800/wkp 8
Delta Employees Exhibit 800 to Actual	**128**	2688

2008 Budget	2009 Budget
1,213	1,232
615	624
12	12
852	865
2,692	2,733

Change	
2008 Budget	2009 Budget
5.16%	**1.53%**

	From Actuals above					
% Change	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	**Overall Average Change**
Average Annual Change	**-2.29%**	**-0.28%**	**-0.08%**	**0.98%**	**0.23%**	**-0.29%**

3-Yr Average Change
0.38%

taff Proposed Adjustment:

Staff Proposed Adjustment
0.50%

	Base Year of 2007 Actuals	PGE Proposed # of FTE	Impact of Additional FTE per PGE		
2007 Base Year FTE ST	2,560				
Adjust using 3 year Average	0.50%		222,944,010	2009 Total Comp.	See Table 1 Exhibit 800/2
2008 Budgeted FTE	2,573	2,692	425,000	Errata Filing	
Adjust using 3 year Average	0.50%		12,909,269	Overtime	See Table 1 Exhibit 800/2
2009 Budgeted FTE	**2,586**		210,459,741		
Staff Proposed Incremental FTE	**26**		52.18%	PTO	
	2,612	2,733	320,277,634	Fully loaded	See Table 2 Exhibit 800/5
			2,733	2009 Budgeted FTE	
Disallowed Number of FTE	**121**		117,189	per Employee	
Fully Loaded Cost per Employee	**117,189**		77,007	w/out PTO	
Staff Proposed Adjustment	**14,236,827**		40,182	PTO per Employee	

2007 Actuals from Cost allocation Manual	
31.30%	Benefits
9.97%	Payroll Taxes
7.48%	Incentives
3.43%	Employee Support
52.18%	

Staff Proposed FTE	2,612
PGE 2009 W&S adj to include Errata	**210,884,741**
Overtime	12,909,269
ljusted PGE proposed W&S (includes OT)	223,794,010

Staff Proposed W&S	$196,647,914
Overtime	12,909,269
Staff Proposed W&S	**$209,557,183**

(14,236,827) Workforce Adjustment

($14,236,827) check

-6.79% Percentage Adjustment

Incentive Portion of PTO=7.48%	
3,006	CIP per employee
121	adjusted FTE
363,681	See Corp Incentive Adjustment S-4

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 106

Exhibits in Support
Of Direct Testimony

July 9, 2008

Portland General Electric
UE 197/UE 198
Test period ending December 31, 2009
(000)

Staff proposes to adjust PGE incentive program based on a three-year and five-year historical average of actual incentives paid as well as an adjustment to recognize work force adjustment.

Staff Proposed Adjustment for Corp Incentives

PGE

Proposed O&M expense for Corp Incentives		(9,976,762)	-73.02%
Proposed Capital Costs for Corp Incentives		(3,686,365)	-26.98%
	$	**13,663,127**	

Staff Proposal

Proposed Staff Adjustment	$	**(8,754)**
Staff Adjustment to O&M for Corp Incentives		**(6,392)**
Staff Adjustment to Capital for Corp Incentives		**(2,362)**

Depreciation Adjustment		
Gross Plant	5,173,537	
Annual Depreciation	175,781	
% Depreciation to RB	3.398%	**($80)**

PORTLAND GENERAL ELECTRIC
UE 197/UE 198
Corp Incentive Workpaper

FROM OPUC AUDIT (prerate case 2005)
"Company-wide awards are based on several factors including PGE's financial performance, operational performance, and approval by the Board of Directors.
by the Board of Directors. Incentive program goals and awards are directly tied to PGE's earnings and performance. Therefore, in a poor financial year,
it is possible that incentive awards may not be approved."

Corporate Incentive Program (CIP) Adjustment			From UE 180			
Exhibit 900, WP 11	2002 Actual	2003 Actual	2004 Actual	2005 Projected	2006 Budget	2007 Forecast
Boardman	145,905	112,802	-2,274	105,478	88,198	90,844
Pelton	27,990	7,384	11,118	2,124	2,103	2,166
PGE	5,730,056	6,523,309	5,428,578	6,791,500	7,528,498	7,754,353
Boardman, Pelton, PGE	5,903,952	6,643,494	5,437,422	6,899,102	7,618,799	7,847,363
Offset for Capitalized Incentives	-2,623,803	-3,219,169	-2,545,305	-2,754,120	-3,025,710	-3,016,168
Other CIP	635,806	521,568	319,612	290,897	202,808	522,322
Total CIP (O&M)	3,915,954	3,945,893	3,211,729	4,435,879	4,795,897	5,353,517
	9,163,561	10,384,231	8,302,340	9,944,119	10,847,317	11,385,853
# of Straight time FTE	2,596	2,538	2,531	2,528	2,554	2,560

	Exhibit 800/wk10		
	2007 Forecast	2008 Budget	2009 Budget
Boardman	127,052	108,248	108,248
Pelton	2,463	2,266	2,266
PGE	10,768,976	8,587,083	9,823,214
Boardman, Pelton, PGE	10,898,491	8,697,597	9,933,728
Offset for Capitalized Incentives	-4,163,205	-3,437,085	-3,839,913
Other CIP	490,239	445,238	458,595
Total CIP O&M	7,225,525	5,705,750	6,552,410
Capitalized Portion of CIP			-26.98%
	15,551,935	12,579,920	14,232,236
# of Straight time FTE	2,688	2,692	2,733

	PGE/800 wkpaper 10	PGE/800 wkpaper 12
92.49%	$ 13,663,127	$ 14,773,000

Officer ACI			1,736,870
Stock Incentive Plan			2,812,721
Apply percentage reduction			92.49%
Remove Officer CIP and Stock Incentive Plan		$	**4,207,787**
CIP and Teamworks less SIP and Officer ACI		$	**9,455,340**
Staff proposed Adjustment to remove 121 FTE		$	**363,681** See Workforce Adjustment S-3-A
Remaining CIP and Teamworks		$	**9,091,659**
Remove 50% of Remaining		$	**4,545,829**
TOTAL STAFF CORP INCENTIVE ADJUSTMENT		$	**(8,753,617)**
Percentage O&M	73.02%	$	**(6,391,891)**
Percentage Capital	26.98%	$	**(2,361,726)**

Incentive Portion of PTO
2545 per employee
121 adjusted FTE
363,681 See Workforce Adjust
Adjustment S-4

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 107

Exhibits in Support
Of Direct Testimony

July 9, 2008

STAFF EXHIBIT 107

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 08-133. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 197 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 108

Exhibits in Support
Of Direct Testimony

July 9, 2008

Portland General Electric
UE 197/UE 198
Test period ending December 31, 2009
(000)

Staff proposes to remove $66 M associated with costs for Clackamas relicensing. Staff believes that the chance of these costs being finalized is not known and measurable for the 2009 Test period. Additionally, Staff proposes to limit the costs associated with the Selective Water Withdraw for Round Butte closer to the initial cost estimate provided to FERC by PGE.

Staff Proposed Capital Expenditures Adjustment

	PGE	Staff	Adjustment
Remove Sel Water Withdraw	63,974,583	0	(63,974,583)
Remove Boardman Costs	4,948,417		(4,948,417)
Remove Boardman Costs	7,884,250	0	(7,884,250)
Remove Boardman Costs	492,167	0	(492,167)
Remove Clackamas Relicensing	2,716,792	0	(2,716,792)
2009 Cap Ex close to book	80,016,208	0	(80,016,208)
	Total Proposed Adjustment		**(80,016)**

Staff proposed RB Adjustment

Depreciation Adjustment

Gross Plant	5,173,537	
Annual Depreciation	175,781	
% Depreciation to RB	3.398%	**(2,719)**

Relevant Testimony: PGE/400/20-22

Relevant Staff Data Requests: 221, 244, 245, 283, 368, 369, 370, 403, 404, 408

Staff Initiator:

Carla Owings

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 109

Exhibits in Support Of Direct Testimony

July 9, 2008

PGE
Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204
PortlandGeneral.com

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P.U.C.

June 03, 2008

Bill McNamee, Economist
Public Utility Commission of Oregon
550 Capitol Street, NE, Suite 215
Salem, OR 97301-2551

Bill:

Attached is our 17th quarterly hydro relicensing activity update report, which includes material subsequent to our November 2007 report. Since the previous report, PGE plans to file a new 401 Water Quality Application for the Clackamas River Project with the DEQ early in the third quarter of 2008.

At our Pelton and Round Butte facilities additional juvenile salmonids were released into the Metolius and Crooked Rivers and into Whychus Creek. Chinooks were released in March 2008 and the Steelheads were released in May 2008. The recently released juvenile salmonids will migrate down into Lake Billy Chinook in the spring of 2009. The Selective Water Withdrawal Tower is expected to be complete in 2009.

At Williamette Falls, we began the initial phases of guidance and mortality testing in March 2008. We plan to remove the Blue Heron Powerhouse in 2008.

As we have previously discussed, the information in the hydro licensing update reports is intended for you, other members of OPUC Staff, and/or the Commission, as you find appropriate.

If you have questions about any of the specific items in the reports, please call me at (503) 464-7580 or Steve Schue at (503) 464-2624.

Sincerely,

Patrick G. Hager
Manager, Regulatory Affairs

cc: Ed Busch, OPUC
John Esler
Bonnie Tatom, OPUC
Julie Keil

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PGE Hydro Relicensing Summary

Second Quarter 2008

June 03, 2008

Introduction

This is the 17th PGE Hydro Relicensing Summary filing. Below is a summary of events and changes, listed by Project, that have occurred since the first Summary in 2003:

Clackamas River

- PGE filed its Final License Application in August 2004.
- PGE filed the Preliminary Draft Environmental Impact Statement in August 2004.
- PGE convened a multi-party settlement process in the fall of 2004.
- PGE and parties reached an Agreement in Principle, which was filed with FERC in June 2005.
- PGE began work with the DEQ to resolve water quality issues.
- Thirty-three parties signed the Settlement Agreement on March 2, 2006.
- PGE filed the Settlement Agreement with FERC on March 30, 2006.
- FERC issued the Draft Environmental Impact Statement in June, 2006.
- Comments on the Draft Environmental Impact Statement were due at FERC on August 7, 2006.
- Agency terms and conditions were filed at FERC by October 6, 2006.
- FERC issued the Final Environmental Impact Statement in late December 2006.
- PGE refiled its 401 Water Quality Application with the Oregon Department of Environmental Quality (DEQ) on December 28, 2006.
- PGE withdrew its 401 Water Quality Application.
- *Upcoming events are:*
    - PGE will file a new 401 Application early in the third quarter of 2008.

Pelton and Round Butte

- FERC issued its Final Environmental Impact Statement in June 2004.
- Parties signed the Settlement Agreement on July 13, 2004.

- PGE filed the Settlement Agreement with FERC on July 30, 2004.
- FERC issued the new long-term license on June 21, 2005.
- Some parties filed petitions for rehearing soon thereafter.
- FERC ruled on petitions for rehearing in October 2006.
- PGE filed a license amendment in early January 2007 to "true up" the fish passage requirements to the latest design.
- PGE began construction of the Selective Water Withdrawal Tower in the summer of 2007.
- PGE made the first significant releases of juvenile salmonids into the tributaries above the dams in the summer of 2007.
- Additional juvenile salmonids were released into the Metolius and Crooked Rivers and into Whychus Creek. Chinooks were released in early March 2008 and steelhead were released in May 2008.
- *Upcoming events are:*
    - The juvenile salmonids released in 2007 will migrate down into Lake Billy Chinook in the spring of 2009.
    - We expect to complete the Selective Water Withdrawal Tower in 2009.

Willamette Falls

- PGE filed the Settlement Agreement with FERC in January 2004.
- DEQ issued the final 401 Water Quality Certification, and FERC issued its Final Environmental Assessment, in November 2004.
- NOAA issued its Biological Opinion June 27, 2005, finding no jeopardy to listed species.
- FERC issued the new long-term license on December 8, 2005.
- PGE filed a rehearing request soon thereafter.
- FERC issued an order on rehearing early in 2006. Changes resulting from this order had only a very minor impact on license conditions.
- PGE constructed the North Fish Bypass, a license measure, in 2006.
- PGE filed a license amendment application in December 2006 to increase the height of flashboards at the dam.

- The Oregon DEQ certified in April 2007 that the license amendment would not have a negative effect on water quality.
- PGE completed construction of the Flow Control Structure at the apex of Willamette Falls in the fall of 2007.
- FERC issued an order approving a license amendment that allows increased flashboard height.
- PGE has begun to assess the effectiveness of recently installed fish passage facilities (north fish bypass and flow control structure).
- PGE began the initial phases of guidance and mortality testing in March 2008.
- *Upcoming events are:*
  - PGE will remove the Blue Heron Powerhouse in 2008.

Background Information

PGE owns and operates eight hydroelectric plants. They are:

- Two plants located on the Deschutes River near Madras: Pelton (PGE share 73 MW) and Round Butte (PGE share 225 MW).
- Four plants located on the Clackamas River: Oak Grove (44 MW), North Fork (58 MW), Faraday (46 MW), and River Mill (25 MW).
- Sullivan (16 MW), located on the Willamette River at Willamette Falls.
- Bull Run (22 MW), located on the Bull Run River, just upstream from its confluence with the Sandy River.

At the nameplate ratings listed above, these hydro resources account for approximately 26 percent of PGE's current generation capacity. In addition to energy production, these resources provide valuable peaking and load following capabilities. A portion of PGE's hydro capacity is also used to meet spinning reserve requirements, which are necessary for responding to system emergencies.

PGE's hydro plants operate under long-term licenses (30 to 50-years) issued by the Federal Energy Regulatory Commission (FERC). The FERC long-term license for Pelton and Round Butte expired at the end of 2001, and these plants operated under "annual licenses" until June 21, 2005, when FERC issued a new 50-year license. The FERC long-term license for Willamette Falls, which covered our Sullivan plant, expired at the end of 2004. The plant operated under an "annual license" until December 8, 2005, when FERC issued a new 30-year license. PGE is in the license renewal process for four hydro plants located on the Clackamas River, which were covered by long-term licenses for the Oak Grove (Oak Grove plant) and North Fork (North Fork, Faraday, and River Mill plants) Projects. These licenses expired at the end of August 2006, and the Clakamas River facilities are now operating under "annual licenses" until FERC issues a new long-term license, which will cover all four plants under the Clackamas River Project designation. PGE decided not to seek a new long-term license for Bull Run, whose long-term license expired in November 2004.

The FERC relicensing process is complex and time consuming (i.e., minimum of five years). In making its relicensing decisions, FERC is required to consider fish and wildlife, recreational, land use, cultural and aesthetics issues equally with energy production. Certain federal and state resource agencies, known as "mandatory conditioning agencies," have specific authority to impose conditions on FERC-issued licenses. These conditions are often expensive, and can limit operational flexibility. Examples are mandatory measures for fish passage and minimum in-stream flows. Often there is insufficient scientific knowledge to objectively determine the environmental effectiveness of some mandatory conditions. Therefore, the FERC relicensing process can become extremely contentious and political.

A summary of the status of PGE's relicensing actions and results follows.

Clackamas River Relicensing

<u>Upcoming Events:</u>

- *PGE will file a new Application with the Oregon DEQ under Section 401 of the Clean Water Act early in the third quarter of 2008.*

<u>Overview:</u>

We expect to renew two current long-term licenses, one for our Oak Grove facility (Oak Grove Project), the other for our North Fork, Faraday, and River Mill facilities (North Fork Project). Both licenses expired on August 31, 2006, and for renewal purposes, FERC had consolidated the two Projects into one, designated the Clackamas River Project. On August 31, 2006, the Clackamas River Project began operating under an "annual license."

For the Clackamas River Project, we used a variant of FERC's Alternative Licensing Process. Under this process, FERC's National Environmental Policy Act (NEPA) contractor, the firm that would eventually write the Environmental Impact Statement for FERC, participated in the process from the beginning, working with the applicant and relevant agencies. Relicensing participants worked in a collaborative fashion, tackling issues incrementally in small technical work groups.

With the completion of the Final License Application, PGE convened a settlement group whose goal was to resolve remaining issues via a collaborative settlement. This effort was successful and resulted in an Agreement in Principle, which PGE filed in June 2005.

<u>Milestones Completed:</u>

- Relicensing participants completed scoping, the first phase of the collaborative process. PGE issued a revised Scoping Document in April 2003.

- Concurrent with relicensing, PGE asked for a license amendment as part of its Endangered Species Act (ESA) compliance strategy. In June 2003, FERC granted this amendment, which included several fishery conservation measures and authorized new turbine runners at North Fork and Faraday #6.

- PGE issued the initial draft of its Preliminary Draft Environmental Impact Statement at the end of September 2003.

- PGE filed its Final License Application and associated Preliminary Draft Environmental Impact Statement in August 2004.

- PGE filed an Agreement in Principle with FERC on behalf of all settlement parties on June 30, 2005.
- Parties signed a Settlement Agreement on March 2, 2006.
- PGE filed the Settlement Agreement with FERC on March 30, 2006.
- FERC issued the Draft Environmental Impact Statement in June, 2006.
- Comments on the Draft Environmental Impact Statement were due at FERC on August 7, 2006.
- Agency terms and conditions were filed at FERC by October 6, 2006.
- FERC issued the Final Environmental Impact Statement in late December 2006.
- PGE refiled its 401 Water Quality Application with the Oregon DEQ on December 28, 2006.
- PGE withdrew its 401 Application.

Future Milestones:

- PGE will file a new 401 Application with the Oregon DEQ early in the third quarter of 2008. In support of the application, PGE will continue to discuss issues with and provide information to other settlement parties.
- The DEQ will likely issue a 401 Water Quality Certification.
- The Water Quality Certification will lead to issuance of a Biological Opinion under the Federal Endangered Species Act.
- The issuance of a Biological Opinion will allow FERC to issue a new long-term operating license.

As noted above, the licenses for the Oak Grove and North Fork Projects expired on August 31, 2006. However, an "annual license" currently allows the four Clackamas River plants to continue operating under the terms of the existing licenses while FERC considers the long-term license application. If additional "annual licenses" are required prior to a new long-term license, they will issue automatically.

Issues:

- Much of the Oak Grove portion of the Project is on Forest Service lands, which gives the Forest Service broad authority to mandate license conditions. FERC cannot refuse to include the Forest Service conditions in the eventual license.

- Flow below the Harriet Lake diversion dam is a significant issue. PGE currently diverts the entire Oak Grove Fork (up to the capacity of the flow line), and it is certain that some minimum flow below Harriet Lake will be required. Because the Oak Grove Fork water is very valuable for generation, we have sought an appropriate balance between fisheries enhancement and power production.

- Most portions of the Project have some form of up- and down-stream fish passage. The efficiency and appropriateness of the fish passage system, in light of changing and uncertain management priorities on the part of the fish agencies, has been a major concern throughout the relicensing process.

- Proximity to the metropolitan area increases recreational use of the Clackamas Basin. PGE's responsibility for new or upgraded facilities, particularly in the Timothy Lake area, has been a major issue.

- Agencies involved in the Clackamas River Project negotiations include Oregon Department of Environmental Quality (DEQ), Oregon Department of Fish and Wildlife, Oregon Water Resources Department, Oregon Division of State Lands, Oregon Parks, State Marine Board, US Fish and Wildlife Service, National Marine Fisheries Service, Forest Service, and Bureau of Land Management.

- The Project may not be able to comply with the State's water quality standard for temperature below River Mill Dam. If no feasible alternatives exist, the DEQ could begin a rulemaking to change the temperature standard for this location. However, we are working with the DEQ to resolve water quality issues.

Pelton and Round Butte Relicensing

<u>Upcoming Events:</u>

- *Juvenile salmonids released in 2007 will migrate down into Lake Billy Chinook in the spring of 2009.*
- *We expect to complete the Selective Water Withdrawal Tower in 2009.*

<u>Overview:</u>

The long-term license for our Pelton Round Butte Project expired at the end of 2001. The Project then operated under "annual licenses" until June 21, 2005, when FERC issued a new 50-year license. This licensing process was successful in substantial part because in January 2003, PGE and the Confederated Tribes of the Warm Springs (Tribes) (as joint licensees – the Tribes have a one-third ownership interest) began a multi-party, facilitated negotiation process, which resulted in a comprehensive settlement agreement.

<u>Milestones Completed:</u>

- PGE and the Tribes filed their Final Joint Application Amendment in June 2001.

- On August 12, 2002, FERC issued the Ready for Environmental Analysis Notice. This notice is FERC's determination that it has sufficient information to analyze the environmental impacts of relicensing the Project. Agencies involved in license negotiations must respond to this notice by providing to FERC their preliminary terms, conditions and recommendations. Agency comments, recommendations and preliminary terms and conditions were filed in November 2002.

- On August 29, 2003, FERC issued its Draft Environmental Impact Statement.

- In December 2003 PGE and the Tribes filed a description of the Proposed Preferred Alternative with FERC.

- FERC issued its Final Environmental Impact Statement in June 2004.

- Parties signed the Settlement Agreement on July 13, 2004.

- PGE filed the Settlement Agreement with FERC on July 30, 2004.

- FERC issued a new 50-year license on June 21, 2005.

- Some parties filed petitions for rehearing soon after issuance of the new license. The issues which formed the basis for the rehearing request were relatively minor, and not expected to greatly impact license conditions.

- FERC ruled on petitions for rehearing in October 2006. This resulted in no major changes in license conditions.

- PGE filed a license amendment application in early January 2007 to "true up" the fish passage requirements to the latest design.

- PGE began construction of the Selective Water Withdrawal Tower in the summer of 2007.

- PGE made the first significant releases of juvenile salmonids into the tributaries above the dams in the summer of 2007.

- Additional juvenile salmonids were released into the Metolius and Crooked Rivers and into Whychus Creek. Chinooks were released in early March 2008 and steelhead were released in May 2008.

<u>Future Milestones:</u>

- The juvenile salmonids released in 2007 will migrate down into Lake Billy Chinook in spring 2009.

- We expect to complete the Selective Water Withdrawal Tower in 2009.

<u>Issues:</u>

- Negotiations concerning fish passage, minimum flows below the plants, and associated operational issues, were complex and time consuming.

- Discussions of the plants' water rights, related to future municipal and other water use demands, involved many parties. Much time was required to reach consensus.

- Agencies involved in Pelton/Round Butte Project negotiations included Oregon Department of Environmental Quality, Oregon Department of Fish and Wildlife, Oregon Water Resources Department, Oregon Division of State Lands, Oregon Parks, State Marine Board, US Fish and Wildlife Service, National Marine Fisheries Service, Forest Service, Bureau of Land Management, and Bureau of Indian Affairs. Local government participants include Jefferson County, Deschutes County, the Deschutes Valley Water District, and the cities of Bend, Redmond, and Madras. Non-government organizations (NGOs) included American River and Waterwatch.

Willamette Falls Relicensing

<u>Upcoming Events:</u>

- *PGE will remove the Blue Heron Powerhouse in 2008.*

<u>Overview:</u>

The long-term license for PGE's Willamette Falls Project expired on December 31, 2004. The Project then continued to operate under an "annual license" until December 8, 2005, when FERC issued a new 30-year license. For relicensing, we used a variant of FERC's Alternative Licensing Process, under which PGE prepared the environmental assessment on FERC's behalf. Relicensing participants worked in a collaborative fashion, tackling issues incrementally in small technical work groups. This process was successful, and resulted in the filing of a Settlement Agreement with FERC in January 2004. Achievement of this Settlement Agreement was a major element in the successful licensing process.

<u>Milestones Completed:</u>

- PGE filed the Final License Application in a timely manner in December 2002.
- FERC issued its Draft Environmental Assessment in January 2004.
- PGE filed the Settlement Agreement with FERC in January 2004, slightly after FERC issued the Draft Environmental Assessment. All parties signed it.
- FERC issued its Final Environmental Assessment in October 2004.
- NOAA Fisheries issued its Biological Opinion in June 2005.
- FERC issued a new 30-year license on December 8, 2005.
- PGE filed a request for rehearing soon after issuance of the new license. The issues which formed the basis for the rehearing request were relatively minor, and not expected to greatly impact license conditions.
- FERC issued an order on rehearing early in 2006. This order retained the requirement for a trails plan, the only issue of substance raised in rehearing.
- PGE constructed the North Fish Bypass, a license measure, in 2006.

- PGE filed a license amendment application in December 2006 to increase the height of flashboards at the dam.

- The Oregon DEQ certified in April 2007 that the license amendment would not have a negative effect on water quality.

- PGE completed construction of the Flow Control Structure at the apex of Willamette Falls in the fall of 2007.

- FERC issued an order approving a license amendment that allows increased flashboard height.

- PGE has begun to assess the effectiveness of recently installed fish passage facilities (north fish bypass and flow control structure).

- PGE began the initial phases of guidance and mortality testing in March 2008.

Future Milestones:

- PGE will remove the Blue Heron Powerhouse in 2008.

Issues:

- The most prominent issue at Willamette Falls was downstream passage of salmonids. Agencies involved in license negotiations believed that existing mortality, both through the powerhouse and over the falls, was unacceptably high. Mitigating measures were expensive.

- Concerns arose about safe passage of lamprey, a species of cultural significance to the Grand Ronde, Siletz, and Warm Springs Tribes. Petitions were submitted for listing lamprey under the Endangered Species Act.

- There were issues regarding traditional tribal uses in the area of the falls.

- Some parties requested increased public access to the falls through the Project and adjacent paper mills. PGE could not meet these requests because of Project and paper mill safety concerns and FERC's recent increased emphasis on project security.

- The collaborative relicensing process was relatively contentious, in part because agencies were often interested in collecting data, rather than in finding solutions to known problems.

- Agencies involved in Willamette Falls Project negotiations included Oregon Department of Environmental Quality, Oregon Department of Fish and Wildlife, Oregon Water

Resources Department, Oregon Division of State Lands, Oregon Parks, State Marine Board, US Fish and Wildlife Service, National Marine Fisheries Service, and Bureau of Indian Affairs. The Confederated Tribes of the Grande Ronde, Siletz, and Warm Springs Reservations, and the Columbia River Inter-Tribal Fish Commission, were also participants. Finally, American Rivers was the primary NGO participant.

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CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 110

Exhibits in Support
Of Direct Testimony

July 9, 2008

Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204
PortlandGeneral.com

April 3, 2008

Email/US Mail

Vikie Bailey-Goggins
Administrator
550 Capitol Street, N.E., Ste 215
Salem, OR 97301-2551

RE: **UE 197 PGE Errata Filing**

Ms. Bailey-Goggins:

Enclosed please find an original and twenty five copies of PGE's Errata filing in UE 197. PGE submits the following seven corrections to the revenue requirement contained in our original filing:

1) State Tax rate: Updates the composite state tax rate to reflect taxable income allocation percentages to Oregon and Montana as used in PGE's 2006B tax return.
2) Heat Pump expenses: Removes certain program expenses inadvertently included in PGE's initial filing.
3) Additional FERC positions: Updates the forecast of FTEs in support of FERC requirements.
4) Equity Issuance Fees: Updates the forecast of equity issuance costs to reflect certain third party fees.
5) Economic Stimulus Act: Updates the forecast of accumulated deferred taxes to reflect the impact of additional bonus depreciation from the Economic Stimulus Act.
6) Bull Run Decommissioning: Updates the forecast of depreciation expense, income taxes and rate base to reflect the results of an RFP for work at Bull Run.
7) Union Wage Escalation: Corrects an error in the development of union wages for 2009.

Attachment 1 summarizes PGE's revised revenue requirement in UE 197. PGE's original filing contained an increase in revenue requirement of $145.9 million. As a result of the corrections identified in this filing, PGE's revised revenue requirement is slightly higher, at $147.2 million. Attachment 2 provides a summary log of the proposed changes and work papers associated with each proposed adjustment. This filing also includes confidential work papers that are subject to

Protective Order No. 08-133, as Attachment 3 and will be sent under separate cover.

Regarding Bull Run decommissioning, an RFP for certain demolition and removal costs results in the overall estimate of decommissioning costs decreasing from $23.9 million as originally filed, to $21.5 million. However, the timing of expenditures has also changed significantly. The majority of the demolition and removal activities are now expected to occur one year earlier, in 2008. As a result, PGE expects a greater tax deduction for the activity in 2008 and a reduced tax deduction associated with the 2009 test year, which is reflected in this filing. Customers will benefit from the larger tax deductions in 2008 through the application of SB 408 to the 2008 tax year.

Referencing PGE Exhibit 1204, page 14, the Schedule 91 fixed revenue requirement of $7,501,000 is understated. The correct amount is $7,857,000 as reflected on page 157 of the Exhibit 1200 (Pricing) work papers. The proposed Schedule 91 prices reflect the correct $7,857,000 figure. PGE will make the correction to PGE Exhibit 1204 in conjunction with future rate spread/design updates.

PGE Exhibit 1200, pages 30 and 31 reference an analysis contained in PGE Exhibit 1200 (Pricing) work papers. The analysis was inadvertently excluded from PGE's initial filing and is provided here as Attachment 4.

With regard to the builder's risk property insurance related to Biglow Canyon Phase 2, PGE incorrectly noted in PGE Exhibit 500, page 7, that we would reduce A&G costs to reflect these premiums being capitalized rather than expensed. In fact, these premiums were not included the 2009 A&G forecast, so no additional entry is necessary.

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

Sincerely,

Patrick G. Hager

Patrick G. Hager
Manager, Regulatory Affairs

cc: UE 188 Service List
Encl.

g:\ratecase\opuc\dockets\ue-197\errata filing\cvrltr_errata.doc

Portland General Electric Company
2009 Revenue Requirement (Revised per Errata)
Dollars in $000s

	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	-	1,586,821	147,233	1,734,054
2 Sales for Resale	-	-	-		-
3 Other Revenues	19,346	-	19,346		19,346
4 Total Operating Revenues	1,606,167	-	1,606,167	147,233	1,753,400
5 Net Variable Power Costs	806,699	-	806,699		806,699
6 Production O&M (excludes Trojan)	108,111	140	108,251		108,251
7 Trojan O&M	129	-	129		129
8 Transmission O&M	11,639	298	11,937		11,937
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	-	7,617	707	8,323
12 OPUC Fees	4,959	-	4,959	460	5,419
13 A&G, Ins/Bene., & Gen. Plant	115,107	58	115,165		115,165
14 Total Operating & Maintenance	1,187,584	607	1,188,191	1,167	1,189,357
15 Depreciation	176,327	(546)	175,781		175,781
16 Amortization	18,764	17	18,781		18,781
17 Property Tax	36,965	-	36,965		36,965
18 Payroll Tax	12,793	63	12,856		12,856
19 Other Taxes	1,411	-	1,411		1,411
20 Franchise Fees	39,893	-	39,893	3,701	43,594
21 Utility Income Tax	14,632	2,373	17,005	54,527	71,532
22 Total Operating Expenses & Taxes	1,488,367	2,514	1,490,881	59,395	1,550,276
23 **Utility Operating Income**	117,799	(2,514)	115,286	87,838	203,123
					203,123
24 **Average Rate Base**					
25 Avg. Gross Plant	5,173,287	250	5,173,537		5,173,537
26 Avg. Accum. Deprec. / Amort	(2,675,492)	554	(2,674,938)		(2,674,938)
27 Avg. Accum. Def Tax	(265,949)	(20,920)	(286,869)		(286,869)
28 Avg. Accum. Def ITC	(271)	-	(271)		(271)
29 **Avg. Net Utility Plant**	2,231,574	(20,116)	2,211,458	-	2,211,458
30 Misc. Deferred Debits	23,755	162	23,917		23,917
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	131	77,526	3,089	80,614
34 **Average Rate Base**	2,362,677	(19,824)	2,342,853	3,089	2,345,942
35 **Rate of Return**	4.986%		4.921%		8.658%
36 **Implied Return on Equity**	3.405%		3.274%		10.750%

Portland General Electric Company
2009 Revenue Requirement (Revised per Errata)
Dollars in $000s

	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%	5.375%
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%	38.494%
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	1.626
51 ROE Target	10.750%	10.750%	10.750%	10.750%	10.750%
52 Grossed-Up COC	11.999%	11.999%	11.999%	11.999%	12.022%
53 OPUC Fee Rate	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%
Utility Income Taxes					
54 Book Revenues	1,606,167	-	1,606,167	147,233	1,753,400
55 Book Expenses	1,473,735	141	1,473,876	4,868	1,478,745
56 Interest Deduction	77,578	(651)	76,928	101	77,029
57 Production Deduction	-	-	-		-
58 Permanent Ms	(13,234)	(4,751)	(17,985)	-	(17,985)
59 Deferred Ms	42,599	(183)	42,416	-	42,416
60 Taxable Income	25,488	5,444	30,932	142,263	173,195
61 Current State Tax	1,305	719	2,024	7,284	9,309
62 State Tax Credits	(2,084)	-	(2,084)	-	(2,084)
63 Net State Taxes	(779)	719	(60)	7,284	7,225
64 Federal Taxable Income	26,267	4,725	30,991	134,979	165,970
65 Current Federal Tax	9,193	1,654	10,847	47,243	58,090
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	2,373	17,005	54,527	71,532
70 SB 408 Ratio - Net to Gross	8.35%		8.34%		15.84%
71 SB 408 Ratio - Effective Tax Rate	11.05%		12.85%		26.04%
72 Check SB 408 Calc	-		0.00		0.00
73 Regulated Net Income	40,221		38,358		126,094
74 Check Regulated NI					126,094

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)	603
PGE-2 (Remove Heat Pump Costs)	(307)
PGE-3 (Add'l FERC positions)	452
PGE-4 (Economic Stim Act)	(2,605)
PGE-5 (Update Equity Issuance Fees)	49
PGE-6 (Update Bull Run Decommissioning)	2,560
PGE-7 (Correct Union labor escalation)	584
Total Errata Items	1,336
Rounding	6
Revised Requested Increase	147,233
Check	147,233

Adjustments to Filed Case
Dollars in $000s

	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	356	113	(166)	263	(2)	2,016
22 Total Operating Expenses & Taxes	356	(181)	267	263	15	1,470
23 **Utility Operating Income**	(356)	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				(20,897)		(23)
28 Avg. Accum. Def ITC						
29 **Avg. Net Utility Plant**	-	-	-	(20,897)	-	531
30 Misc. Deferred Debits					162	
31 Operating Materials & Fuel						
32 Misc. Deferred Credits						
33 Working Cash	19	(9)	14	14	1	76
34 **Average Rate Base**	19	(9)	14	(20,883)	162	607
35 **Rate of Return**						
36 **Implied Return on Equity**						

Adjustments to Filed Case
Dollars in $000s

	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	10.750%	10.750%	10.750%	10.750%	10.750%	10.750%
52 Grossed-Up COC	11.999%	11.999%	11.999%	11.999%	11.999%	11.999%
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	1	(0)	0	(686)	5	20
57 Production Deduction						
58 Permanent Ms					(17)	(4,734)
59 Deferred Ms	(183)					
60 Taxable Income	182	294	(433)	686	(5)	5,260
61 Current State Tax	450	15	(22)	35	(0)	269
62 State Tax Credits						
63 Net State Taxes	450	15	(22)	35	(0)	269
64 Federal Taxable Income	(267)	279	(411)	651	(5)	4,991
65 Current Federal Tax	(94)	98	(144)	228	(2)	1,747
66 Federal Tax Credits						
67 ITC Amort						
68 Deferred Taxes		-	-	-	-	-
69 Total Income Tax Expense	356	113	(166)	263	(2)	2,016
70 Rev Req Effect	603	(307)	452	(2,605)	49	2,560

Adjustments to Filed Case
Dollars in $000s

	Correct Union Labor Esc PGE-7	Total Adjustments
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)	233	140
7 Trojan O&M		-
8 Transmission O&M	10	298
9 Distribution O&M	288	288
10 Customer & MBC O&M	33	(177)
11 Uncollectibles Expense	-	-
12 OPUC Fees	-	-
13 A&G, Ins/Bene., & Gen. Plant	(96)	58
14 Total Operating & Maintenance	468	607
15 Depreciation		(546)
16 Amortization		17
17 Property Tax		-
18 Payroll Tax	63	63
19 Other Taxes		-
20 Franchise Fees	-	-
21 Utility Income Tax	(207)	2,373
22 Total Operating Expenses & Taxes	324	2,514
23 **Utility Operating Income**	(324)	(2,514)
24 **Average Rate Base**		-
25 Avg. Gross Plant	250	250
26 Avg. Accum. Deprec. / Amort		554
27 Avg. Accum. Def Tax		(20,920)
28 Avg. Accum. Def ITC		-
29 **Avg. Net Utility Plant**	250	(20,116)
30 Misc. Deferred Debits		162
31 Operating Materials & Fuel		-
32 Misc. Deferred Credits		-
33 Working Cash	17	131
34 **Average Rate Base**	267	(19,824)
35 **Rate of Return**		
36 **Implied Return on Equity**		

Adjustments to Filed Case
Dollars in $000s

	Correct Union Labor Esc PGE-7	Total Adjustments
37 Effective Cost of Debt	6.567%	6.567%
38 Effective Cost of Preferred	0.000%	0.000%
39 Debt Share of Cap Structure	50.000%	50.000%
40 Preferred Share of Cap Structure	0.000%	0.000%
41 Weighted Cost of Debt	3.284%	3.284%
42 Weighted Cost of Preferred	0.000%	0.000%
43 Equity Share of Cap Structure	50.000%	50.000%
44 State Tax Rate	5.120%	5.120%
45 Federal Tax Rate	35.000%	35.000%
46 Composite Tax Rate	38.328%	38.328%
47 Bad Debt Rate	0.480%	0.480%
48 Franchise Fee Rate	2.514%	2.514%
49 Working Cash Factor	5.200%	5.200%
50 Gross-Up Factor	1.621	1.621
51 ROE Target	10.750%	10.750%
52 Grossed-Up COC	11.999%	11.999%
53 OPUC Fee Rate	0.3125%	0.3125%
Utility Income Taxes		
54 Book Revenues	-	-
55 Book Expenses	531	141
56 Interest Deduction	9	(651)
57 Production Deduction		-
58 Permanent Ms		(4,751)
59 Deferred Ms		(183)
60 Taxable Income	(540)	5,444
61 Current State Tax	(28)	719
62 State Tax Credits		-
63 Net State Taxes	(28)	719
64 Federal Taxable Income	(512)	4,725
65 Current Federal Tax	(179)	1,654
66 Federal Tax Credits		-
67 ITC Amort		-
68 Deferred Taxes	-	-
69 Total Income Tax Expense	(207)	2,373
70 Rev Req Effect	584	1,336

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%	10.750%	5.375%
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%		**8.659%**

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	0.05197
Federal Taxable Inc.	0.91742	0.91497
Federal Tax @ 35%	0.32110	0.32024
Total Income Taxes	**0.37061**	0.37221
Total Rev. Sensitive Costs	**0.40367**	0.40527
Utility Operating Income	0.59633	0.59473
Net To Gross Factor	**1.67693**	1.68144
RSC Gross-Up Factor	1.0342	1.0342
Working Cash Factor	0.0024	0.0024
NTG w/Working Cash	1.6809	1.6855
RSC Gross-Up w/Working Cash	1.0367	1.0367

State Income Tax:	Appor	Rate	Weighted	Updated: Appor	Rate	Weighted
Montana	4.09%	6.75%	0.276%	4.56%	6.75%	0.308%
Oregon	73.40%	6.60%	4.844%	76.77%	6.60%	5.067%
State			5.120%			5.375%
Composite Tax Rate:			**38.328%**			**38.494%**

Check:			
	Fed Tax	35.00%	35.00%
	State Tax	5.120%	5.37%
	Tax Shield	-1.79%	-1.88%
	Composite	38.328%	38.494%

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 111

Exhibits in Support Of Direct Testimony

July 9, 2008

April 15, 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. 105

Request:

Please reconcile the composite FIT/SIT rate shown on PGE/200, Tooman - Tinker/18, of 38.33% and the rate shown on PGE/205, Tooman – Tinker/1, of 35.06%. Please show the calculation of the 35.06% rate

Response:

The composite statutory tax rate of 38.33% represents the legal binding rates that apply to taxable income consistent with the reporting requirements of government entities to which PGE reports taxable income. The Federal statutory tax rate on taxable income is 35%. The State statutory tax rate represents a combined rate based on the states to which we report. For UE 197, the forecast statutory combined state tax rate was 5.12% in PGE's initial filing[1] and was derived from an approximate 73% allocation of taxable income to Oregon with a 6.6% statutory rate and an approximate 4% allocation of taxable income to Montana with a 6.75% statutory rate. The combined Federal and State statutory tax rate in PGE's initial filing is thus the sum of 5.12% and 35%, less the impact of the deduction of state income taxes on the federal tax return. The calculation is thus:

Composite statutory tax rate = 5.12% + 35% - (5.12% * 35%) = 38.33%

This is shown on PGE/200, Tooman-Tinker/18. The rate of 38.33% is also the marginal tax rate. A $1 change in PGE's taxable income results in a $.3833 change in our forecast income tax liability.

[1] In PGE's Errata filing, we propose to modify the combined state statutory rate to reflect more recent information regarding the allocation of taxable income to Oregon and Montana. The updated combined state statutory rate from that filing is 5.37%.

Absent the existence of tax credits, or book-tax differences that have not been normalized (i.e., deferred taxes not recorded on the differences), PGE's effective tax rate of 35.06% would equal the composite statutory tax rate. For UE 197, we forecast state tax credits of about $2.1 million, federal tax credits of $8.4 million and ITC amortization of $1.5 million. The impact of these tax credits is to reduce the effective tax rate below the combined statutory rate. In addition, due to the reversal of previously flowed through accelerated tax depreciation (i.e., differences for which PGE did not record deferred taxes), the effective tax rate is increased above the statutory tax rate. On a combined basis, the impact of flow-through differences is outweighed by the impact of tax credits and the effective tax rate in UE 197 of 35.06% is lower than the combined statutory tax rate (35.06% versus 38.33%).

The effective tax rate of 35.06% shown in PGE Exhibit 205 is calculated as the projected tax liability in the test year of $68.7 million divided into the projected book taxable income in the test year of $195.8 million.

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 112

Exhibits in Support
Of Direct Testimony

July 9, 2008

June 26, 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 June 17, 2008
Question No. 402

Request:

On May 28th, Staff sent out data request no. 25 in Docket No. UM1277 requesting information about residential energy experts. The response to this data request was due June 11, 2008. Staff has not yet received a response. However, for completeness of record, Staff is repeating its questions, including a few edits and specifications, in behalf of Docket, UE 197:

During the week of May 19, 2008, local news channel, KATU Channel 2, reported a story upon which the news channel had "partnered-up" with PGE's "*Residential*" Energy Expert, Garret Harris to do a residential energy audit of phantom load.

a. **How many Energy Experts are currently employed by PGE?**
b. **How many of PGE's Energy Experts are considered "Residential" Energy Experts?**
c. **Please demonstrate whether the salaries earned by PGE's Energy Experts are included in UE 180 rates or the current proposed 2009 test period for UE 197. If not, please demonstrate how they are not included. *Please provide a breakout of the amounts included in UE 180 and in the 2009 test period. Please indicate where these costs are booked (I.e., O&M or A&G).***
d. **Are PGE's Energy Experts currently employed in other capacities in behalf of PGE? If so, please demonstrate how many hours per week and per month are estimated to be dedicated to the role of Energy Experts (residential or otherwise).**
e. **When doing an Energy Audit in behalf of PGE, does the Energy Expert drive a PGE vehicle? If so, please provide details on the costs associated with fleet expense and insurance related to Energy Audits and any PGE Energy Expert Employees. Please explain.**
f. **What funds are used to pay the costs of the PGE vehicle used by PGE's Energy Expert?**

g. **Please identify the amount of costs attributable to vehicles, fleet insurance and fuel related to providing energy audits (either residential or industrial) that are included in UE 180 rates for 2007. Separately provide the same information for the 2008 budget and the 2009 test period. Please identify where these costs are booked.**
h. **Were costs to train employees to become Energy Experts (either residential or industrial) included in UE 180 rates? Please identify the amount of costs attributable to training employees in order to provide energy audits (either residential or industrial) that are included in UE 180 rates for 2007. Separately provide the same information for the 2008 budget and the 2009 test period. Please identify where these costs are booked.**
i. **How are ratepayers benefitting from providing Energy Experts?**

Response:

KATU's report is not related to PGE's activities funded under the Conservation Rate Credit (CRC).

KATU News approached PGE for assistance in a news segment that focused on so called "phantom load" or appliances that use energy by just being "plugged in" as opposed to being actively used by consumers. Attachment 402-A includes a copy of the segment transcript. It is not unusual for a news organization to approach PGE with questions on how their viewers/readers can use electricity wisely. PGE usually sees an increase in these types of requests prior to high-use seasons (Winter and Summer).

It is PGE's policy to promote wise electricity use through behavioral tips and available energy efficiency resources such as the Energy Trust and Oregon Department of Energy programs.

a. **How many Energy Experts are currently employed by PGE?**

In the context of the KATU news segment, Energy Expert is an informal title used to identify PGE employees that can help customers with answering high bill[1] questions. Almost every Customer Service Representative (CSR) can be considered an "Energy Expert" as they are trained to help customers with troubleshooting high bills on a daily basis. Annually, PGE CSRs answer thousands of high bill related questions and requests. High bill calls that arrive in through our general customer service and billing phone queues are not specifically tracked, but each CSR handles several high bill calls per day.

[1] "High Bill Questions" refer to a general set of questions dealing with the size of customer's bills and/or ways to use less electricity. This can lead to discussions of possible behavioral changes as well as referrals to ETO energy efficiency programs.

In many instances a general billing question may result in a high bill discussion where the CSR would walk the customer through various steps to diagnose the customer's consumption over the phone. In addition, the CSR would provide behavioral tips on ways to reduce customer's usage. For example, in order to diagnose customer's consumption patterns, the CSR would instruct the customer on how to read his/her own electric meter, calculate his/her daily consumption and how to perform a breaker test.[2] The CSR would also discuss electrical appliances that are plugged in the customer's home, from heating, cooling, lighting as well as possibly recreational appliances (hot tubs, pools, garden lighting and fountain pumps). Based on the discussion with the customer, the CSR would provide tips on how to reduce consumption such as lowering thermostat settings on heating appliances (furnaces or water heaters), closing fireplace dampers, usage of timers on garden appliances etc. If the CSR is unable to pinpoint the cause of the high-bill, the CSR would either transfer the customer to a senior representative with more experience in the Energy Expert phone queue or would request a "High Bill Field Check Request" (High Bill FCR). In 2007, CSRs assigned to the Energy Expert phone queue answered over 15,000 high bill calls. In addition to the Energy Expert phone queue, if a high bill concern cannot be resolved over the phone, PGE has three field representatives that could help customers troubleshoot high bills on site. In 2007, PGE's three field representatives responded to 1,108 High Bill FCRs.

b. How many of PGE's Energy Experts are considered "Residential" Energy Experts?

The majority of PGE's CSRs respond to residential inquiries. The three field representatives performing High Bill FCRs respond to both residential and non-residential high bill inquiries.

c. Please demonstrate whether the salaries earned by PGE's Energy Experts are included in UE 180 rates or the current proposed 2009 test period for UE 197. If not, please demonstrate how they are not included. ***Please provide a breakout of the amounts included in UE 180 and in the 2009 test period. Please indicate where these costs are booked (I.e., O&M or A&G).***

Costs associated with responding to residential phone inquiries are tracked under PGE Ledger N41902. Costs associated with responding to non-residential phone inquiries are tracked under PGE Ledger N41903. Both of these ledgers include costs responding to all phone inquiries such as move in and out calls, payment arrangements, billing and high bill inquiry related costs. Residential and Non-Residential High Bill FCRs are tracked under ledgers N41325 and N41326, respectively. Please see Attachment 402-B for a summary of expenses for years 2005 through 2009.

d. Are PGE's Energy Experts currently employed in other capacities in behalf of PGE? If so, please demonstrate how many hours per week and per month are estimated to be dedicated to the role of Energy Experts (residential or otherwise).

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[2] Breaker test refers to isolating various electric circuits in the house using the Customer's breaker box, while monitoring the Customer's meter to pinpoint electrical circuits with "high usage" appliances.

In addition to high bill requests, PGE's CSRs also respond to inquiries regarding billing issues, payment arrangements, move in and out requests as well as other general inquiries. In addition to High Bill FCRs, the three field representatives also perform Switched Meter checks, Billing Schedule checks, Address checks and other miscellaneous field activity that arises in the course of PGE's day-to-day customer service operations.

e. **When doing an Energy Audit in behalf of PGE, does the Energy Expert drive a PGE vehicle? If so, please provide details on the costs associated with fleet expense and insurance related to Energy Audits and any PGE Energy Expert Employees. Please explain.**

The use of the term "Audit" in the KATU segment was the choice of the reporter, not PGE. In the course of a high-bill complaint, PGE does not perform energy audits, nor does PGE have programs that perform energy audits for energy efficiency or conservation purposes. In rare occasions when high-bill complaints cannot be resolved over the phone, PGE will perform High Bill FCRs. Field representatives use their own vehicles to perform field activity. PGE reimburses its field representatives for the use of their own vehicles using standard mileage rate which is currently 50.5 cents per mile.

f. **What funds are used to pay the costs of the PGE vehicle used by PGE's Energy Expert?**

Funds used to reimburse PGE's field representatives for using their own vehicles are part of PGE's Customer Service O&M costs.

g. **Please identify the amount of costs attributable to vehicles, fleet insurance and fuel related to providing energy audits (either residential or industrial) that are included in UE 180 rates for 2007. Separately provide the same information for the 2008 budget and the 2009 test period. Please identify where these costs are booked.**

Please see PGE's response to part (f) above.

h. **Were costs to train employees to become Energy Experts (either residential or industrial) included in UE 180 rates? Please identify the amount of costs attributable to training employees in order to provide energy audits (either residential or industrial) that are included in UE 180 rates for 2007. Separately provide the same information for the 2008 budget and the 2009 test period. Please identify where these costs are booked.**

Responding to high-bill customer questions is an important aspect of PGE's customer service. Every new CSR, as part of his/her training, goes through a high-bill training module. In addition, prior to the high bill season, refresher training is held for CSRs during team meetings. PGE does not distinguish costs incurred for high bill training from its general customer service training costs. General Customer Service Training costs were part of PGE's UE-180 rate case, and are included in the UE-197, 2009 test year budget. No formal training exists for field-representatives performing "High Bill FCRs".

i. **How do ratepayers benefit from providing Energy Experts?**

PGE customers benefit from interacting with our Energy Experts by learning how to use electricity wisely, how to lower their electric consumption and lower their bill, as well as learn about available energy efficiency resources (ETO and Oregon Department of Energy programs). When a PGE customer receives a high bill, they expect PGE to provide answers and reasons for their high bill. Therefore, training PGE's CSRs to be Energy Experts and be able to respond to Customers' high bill concerns is an integral aspect of PGE's customer service. In rare occasions when a customers' high bill questions cannot be resolved over the phone, PGE field representatives perform a "High Bill FCR" to pinpoint possible causes for the customer's high bill. During a "High Bill FCR" the customer is educated on ways to save on their electric bill. During their visit with the customer, PGE field representatives also promote ETO's available energy efficiency programs including ETO audits.

UE 197
Attachment 402-A

KATU News Segment "Phantom Load" Transcript

KATU 2

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Unplugging some appliances could save you cash

YouNewsTV™

Story Published: May 19, 2008 at 6:38 PM PDT
Story Updated: May 20, 2008 at 9:42 AM PDT

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.

Find this article at:
http://www.katu.com/news/problemsolver/19085034.html

☐ Check the box to include the list of links referenced in the article.

UE 197
Attachment 402-B

Summary for Ledgers N41325, N41326, N41902, N41903

LEDGER	Ledger Name	2005 Actuals	2006 Actuals	2007 Actuals	2008 Budget	2009 Budget
N41325	INVESTIGATE RESIDENTIAL BILL C	$237,032	$202,238	$173,459	$259,315	$273,252
N41326	INVESTIGATE NON-RESIDENTIAL BI	$51,583	$86,704	$86,203	$2,967	$3,082
N41902	PHONE RESPONSE TO RESIDENTIAL	$3,297,350	$3,399,798	$3,444,657	$3,395,923	$3,672,378
N41903	PHONE RESPONSE TO NON-RESIDENT	$336,238	$301,545	$343,675	$479,862	$501,576

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 113

Exhibits in Support Of Direct Testimony

July 9, 2008

Portland General Electric
UE 197/198
Test period ending December 31, 2009
000

Staff proposes to remove costs related to Energy Audits performed by PGE based on calls from customers regarding high bills. Staff believes it is appropriate for PGE to spend extra time on the phone and training its CSR's to respond to high bill calls, however, Staff believes it is inappropriate for PGE to make 1,108 field visits related to high bill calls. PGE should refer these calls to the Oregon Energy Trust.

Ledger Description	Ledger No.	2005 Actuals	2006 Actuals	2007 Actuals	2008 Budget	2009 Budget
Investigate Res. Bills	N41325	$ 237,032	$ 202,238	$ 173,459	$ 259,315	$ 273,252
Investigate Non Res Bills	N41326	$ 51,583	$ 86,704	$ 86,203	$ 2,967	$ 3,082

PGE	$ 276,334
Staff Proposal	0
Proposed Staff Adjustment	$ (276)

See DR 402

Staff Initiator:
Carla Owings

CASE: UE 197
WITNESS: Paul Rossow

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 200

Direct Testimony

July 9, 2008

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

A. My name is Paul Rossow. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551. I am a Utility Analyst in the Electric and Natural Gas Division of the Utility Program of the Public Utility Commission of Oregon.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/201, Rossow/1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of this testimony is to explain Staff's recommended uncollectible expense adjustment to PGE's rate case filing in Docket UE 197.

Q. DID YOU PREPARE EXHIBITS FOR THIS DOCKET?

A. Yes. I prepared Staff Exhibits 202, 203 and 204. Exhibit 202 is an Excel spreadsheet showing figures used to determine Staff's adjustment. Exhibit 203 is selected pages from the U.S. Department of Labor and the Oregon Employment Department. Exhibit 204 is selected pages from the Office of Economic Analysis executive summary.

Q. WHAT DOES PGE INCLUDE IN ITS REVENUE REQUIREMENT FOR UNCOLLECTIBLE EXPENSE?

A. PGE includes $8.3 million in revenue requirement for uncollectible expense. PGE explains that this level of expense is based on an uncollectible rate of 0.48 percent.

Q. HOW HAS PGE FORECASTED 2008 AND 2009 WRITE-OFFS OF UNCOLLECTIBLE ACCOUNTS?

A. PGE breaks down the uncollectible expense into two components: 1) light and power revenue, and 2) other revenue. PGE averaged the last three years of actual activity for both components, resulting in 0.43 percent for light and power and 0.05 percent for other revenues, totaling 0.48 percent. (PGE/700, Hawke/5.)

Q. DO YOU AGREE THAT AN UNCOLLECTIBLES RATE OF .48 PERCENT IS APPROPRIATE?

A. No. The last time uncollectibles were around $8.3 million, as PGE has proposed in its filing, was in the year 2004 (See Exhibit Staff/202, Rossow/1), when Oregon was experiencing high unemployment.

Q. WHAT WAS THE AVERAGE UNEMPLOYMENT RATE FOR THE YEAR 2004?

A. According to the U.S. Department of Labor and the Oregon Employment Department the average unemployment rate for the year 2004 was 7.3 percent (See Exhibit Staff/203, Rossow/1).

Q. WHAT REASONABLE EXPECTATIONS MAY BE SEEN FOR OREGON'S AVERAGE UNEMPLOYMENT RATE FOR THE YEARS 2008 AND 2009?

A. For years Oregon's unemployment rate has been higher than the U.S. unemployment rate. As of May 2008, the national unemployment rate was 5.5 percent while Oregon's unemployment rate was 5.6. The variance between both rates is minor (See Exhibit Staff/203, Rossow/3). For 2009, the forecast for the National rate is 5.8 percent (See Exhibit Staff /203, Rossow/4). This rate is significantly lower than 2004.

Q. WHAT DOES THE OFFICE OF ECONOMIC ANALYSIS FORECAST OREGON JOB GROWTH FOR 2008 AND 2009?

A. The Office of Economic Analysis is forecasting little change in 2008 from the fourth quarter of 2007 with a growth rate of 1.3 percent in the second half of 2008. The forecast for annual average job growth is 1.7 percent for 2009 (See Exhibit Staff/204, Rossow/2). This provides further support that Oregon's unemployment rate should be relatively stable.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PGE'S WRITE-OFFS OF UNCOLLECTIBLE ACCOUNTS.

A. I am holding PGE to their current, actual rate for uncollectibles of 0.38 percent to calculate an allowable level of uncollectible expenses for 2009. This rate includes both the light and power revenues and the other revenue components. My adjustment includes the year 2009 retail revenues of $1.7 billion multiplied by PGE's actual 2007 uncollectible rate of 0.38 percent totaling $6.5 million for this level of expense (See Exhibit Staff/202, Rossow/1).

Q. WHY DO YOU PROPOSE THIS ADJUSTMENT?

A. For the last five-years, PGE's uncollectible expenses have decreased from $9.3 million in 2003 to $5.5 million in 2007; while the total of Billed and Unbilled Revenues reported in PGE's FERC FORM 1, page 304 have increased from $1.2 billion in 2003 to $1.4 billion in 2007. For the same five-year period, PGE's actual rates for uncollectibles have decreased each year: 0.73 percent in 2003, 0.65 percent in 2004, 0.61 percent in 2005, 0.44 percent in 2006, and 0.38 percent in 2007 (See Exhibit Staff/202, Rossow/1).

Q. WHAT IS STAFF'S UNCOLLECTIBLE ADJUSTMENT RECOMMENDATION?

A. I recommend that the Commission hold PGE to their 2007 uncollectible rate of 0.38 percent, which provides an uncollectible expense of $6.5 million, and an adjustment of $1.7 million. This adjustment provides a reasonable estimate for the expected level of this expense. This overall adjustment is to decrease uncollectible accounts to better reflect account balances.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 197
WITNESS: Paul Rossow

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

July 9, 2008

WITNESS QUALIFICATION STATEMENT

NAME: Paul Rossow

EMPLOYER: Public Utility Commission of Oregon

TITLE: Utility Analyst, Electric and Natural Gas Division, Rates and Tariffs

ADDRESS: 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.

EDUCATION: Professional Accounting and Computer Application Diplomas
Trend College of Business 1987

EXPERIENCE: I have been employed with the Public Utility Commission of Oregon as a Utility Analyst since October of 2002. Current responsibilities include research issues relating to energy utilities. I have actively participated in regulatory proceedings in Oregon, including UE 147, UE 167, UE 170, UE 179, UE 180, UG 152, UG 153, and UG 181.

I have attended the Utility Rate School sponsored by the Committee on Water of the National Association of Regulatory Utility Commissioners in May of 2005 and the Institute of Public Utilities sponsored by the National Association of Regulatory Utility Commissioners at Michigan State University in August of 2005.

CASE: UE 197
WITNESS: Paul Rossow

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Direct Testimony

July 9, 2008

Analysis of Uncollectibles to Billed and Unbilled Revenues

Description	PGE Ledger	2009 Results at 0.38%	2007	2006	2005	2004	2003
Write-offs of Uncollectible Accts.	N41501		$5,599,691	$6,012,211	$7,792,168	$8,280,346	$9,309,621
Staff allowable amount of Exp.		$6,589,405					
Total Billed and Unbilled Rev. (FERC FORM 1 pg 304)			$1,456,350,074	$1,369,315,258	$1,277,223,133	$1,270,560,476	$1,283,136,445
2009 Retail Rev.		$1,734,054,000					
Rates		0.38%	0.38%	0.44%	0.61%	0.65%	0.73%

CASE: UE 197
WITNESS: Paul Rossow

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits in Support
Of Direct Testimony

July 9, 2008

Staff/203
Rossow/1

Labor Force Data

Unemployment Rate

Area: STATEWIDE Oregon

Seasonally Adjusted Data

Download Spreadsheet

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2008	5.5	5.4	5.6	5.4	5.6	-	-	-	-	-	-	-	-
2007	5.1	5.0	5.0	5.0	5.1	5.2	5.3	5.3	5.3	5.4	5.4	5.4	5.2
2006	5.5	5.4	5.3	5.3	5.3	5.3	5.4	5.4	5.4	5.3	5.3	5.2	5.4
2005	6.5	6.4	6.3	6.4	6.3	6.4	6.3	6.3	6.1	6.0	5.8	5.7	6.2
2004	7.9	7.7	7.6	7.3	7.3	7.4	7.3	7.4	7.2	7.1	6.9	6.7	7.3
2003	7.7	7.9	8.1	8.4	8.4	8.5	8.5	8.3	8.2	8.0	7.9	7.8	8.1

Data sources and limitations

Show all data measures for this Region / Time Period

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WORKSOURCE OREGON EMPLOYMENT DEPARTMENT

News

State of Oregon • Employment Department • 875 Union NE, Salem, OR 97311 • www.QualityInfo.org

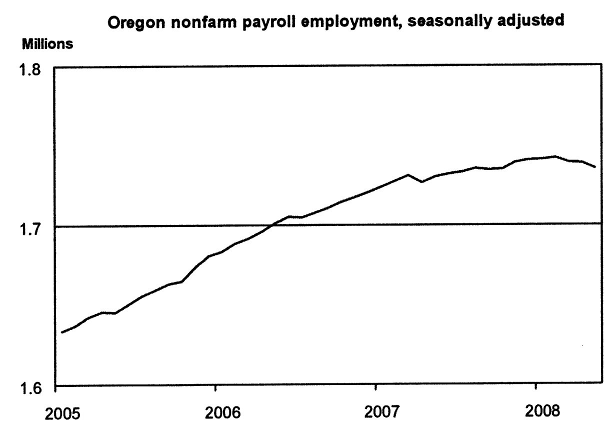
FOR IMMEDIATE RELEASE: June 16, 2008

CONTACT INFORMATION: David Cooke, Economist, (503) 947-1272

Oregon's Employment Situation: May 2008

Oregon's seasonally adjusted unemployment rate was 5.6 percent in May and the revised figure for April was 5.4 percent. The U.S. seasonally adjusted unemployment rate rose to 5.5 percent in May from 5.0 percent in April.

In May, Oregon's seasonally adjusted nonfarm payroll employment declined 3,700, following a revised loss of 300 jobs in April.



Industry Payroll Employment (Establishment Survey Data)

In May, total seasonally adjusted payroll employment dropped by 3,700, the third consecutive monthly decline. Payroll employment stood at 1,735,200, the lowest level since 1,735,100 in October 2007.

In May, four major industries posted sizeable seasonally adjusted job declines: construction (-1,600 jobs); manufacturing (-2,300); trade, transportation, and utilities (-1,600); and professional and business services (-1,000). Only one major industry posted a substantial seasonally adjusted monthly gain: educational and health services (+3,500 jobs).

Construction continued to trend downward, with a seasonally adjusted job loss of 1,600 in May. The industry reached a peak in July 2007, when 105,800 were employed. The May figure of 96,400 indicates that 9,400 jobs were cut during that 10-month period, a decline of 8.9 percent.

Looking at construction jobs prior to seasonal adjustment, residential building construction was down 600 jobs in May and down 2,600 since May 2007. Specialty trade contractors shed 800 jobs

— more —

TABLE N. 1

U.S. Forecast Summary 2006-2015 (April 2008 Forecast)

	Quarterly			Annual									
	2008:1	**2008:2**	**2008:3**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
GDP (Bil of 2000 $) Chain Weight	11,673	11,653	11,724	11,319	11,567	11,704	11,903	12,266	12,672	13,040	13,359	13,681	14,016
% Ch	(0.1)	(0.7)	2.4	2.9	2.2	1.2	1.7	3.0	3.3	2.9	2.4	2.4	2.5
Personal Income (Bil of $)	11,975	12,166	12,177	10,983	11,660	12,147	12,589	13,214	13,971	14,796	15,566	16,323	17,116
% Ch	4.0	6.6	0.4	6.6	6.2	4.2	3.6	5.0	5.7	5.9	5.2	4.9	4.9
Nonagricultural Employment (Millions)	138.0	137.8	137.8	136.1	137.6	137.9	138.4	140.0	142.4	144.4	145.9	147.0	148.0
% Ch	(0.1)	(0.5)	(0.1)	1.8	1.1	0.2	0.4	1.2	1.6	1.5	1.0	0.8	0.7
Unemployment Rate	4.9	5.2	5.4	4.6	4.6	5.3	5.8	5.6	5.2	4.8	4.8	4.8	4.7
% Ch	5.6	26.4	16.9	(9.0)	0.7	13.2	9.5	(2.6)	(7.8)	(6.7)	(1.3)	0.0	(0.9)
Industrial Production Index (2002=100)	112.0	111.4	112.1	109.6	111.4	112.1	114.2	117.8	122.0	124.5	126.5	129.0	131.6
% Ch	(0.5)	(2.0)	2.5	2.2	1.7	0.6	1.9	3.2	3.5	2.1	1.6	1.9	2.1
Corporate Profits (Bil of $)	1,681	1,539	1,599	1,806	1,877	1,601	1,889	1,893	1,924	1,891	1,869	1,884	1,909
% Ch	(36.1)	(29.7)	16.7	14.3	3.9	(14.7)	18.0	0.2	1.7	(1.7)	(1.2)	0.8	1.3
Money Supply (M2) (Bil of $)	7,575	7,655	7,730	6,996	7,412	7,801	8,187	8,599	9,034	9,485	9,955	10,456	10,978
% Ch	9.1	4.3	4.0	4.9	5.9	5.2	5.0	5.0	5.1	5.0	5.0	5.0	5.0
Prime Rate	6.20	4.89	4.50	7.96	8.05	5.02	5.09	7.14	7.75	7.75	7.75	7.75	7.75
% Ch	(54.0)	(61.1)	(28.5)	28.6	1.2	(37.6)	1.3	40.4	8.5	0.0	0.0	0.0	0.0
Consumer Price Index (1982-84=100)	2.128	2.138	2.154	2.016	2.073	2.145	2.179	2.214	2.251	2.294	2.337	2.383	2.430
% Ch	4.3	1.9	3.1	3.2	2.9	3.5	1.6	1.6	1.7	1.9	1.9	2.0	2.0
Federal Budget (unified) (Bil of $, Fed FY)	(185.5)	(11.6)	(110.2)	(209.2)	(187.9)	(434.2)	(397.3)	(367.5)	(305.0)	(282.1)	(271.1)	(332.4)	(357.4)
Current Account Balance (Bil of $)	(675.1)	(708.6)	(648.4)	(811.5)	(738.6)	(666.0)	(605.7)	(652.0)	(671.4)	(693.0)	(680.4)	(676.6)	(676.1)
% Ch	(9.3)	21.4	(29.9)	7.5	(9.0)	(9.8)	(9.1)	7.6	3.0	3.2	(1.8)	(0.6)	(0.1)
Population (Millions)	304.5	305.2	305.9	300.1	302.8	305.5	308.2	310.9	313.5	316.2	318.9	321.6	324.3
% Ch	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8

Staff/203
Rossow/4

U.S. Department of Labor

Bureau of Labor Statistics

Bureau of Labor Statistics Data

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include graphs **NEW!**

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Data extracted on: June 27, 2008 (12:13:17 PM)

Local Area Unemployment Statistics

Series Id: LASST41000003
Seasonally Adjusted
Area: Oregon
Area Type: Statewide
State/Region/Division: Oregon

Year	Period	labor force	employment	unemployment	unemployment rate
2003	Jan	1847650(b)	1704544(b)	143106(b)	7.7(b)
2003	Feb	1847422(b)	1702025(b)	145397(b)	7.9(b)
2003	Mar	1849431(b)	1700102(b)	149329(b)	8.1(b)
2003	Apr	1851696(b)	1696203(b)	155493(b)	8.4(b)
2003	May	1851541(b)	1695682(b)	155859(b)	8.4(b)
2003	Jun	1852846(b)	1695291(b)	157555(b)	8.5(b)
2003	Jul	1853030(b)	1696263(b)	156767(b)	8.5(b)
2003	Aug	1851746(b)	1698833(b)	152913(b)	8.3(b)
2003	Sep	1849945(b)	1699108(b)	150837(b)	8.2(b)
2003	Oct	1850234(b)	1702345(b)	147889(b)	8.0(b)
2003	Nov	1847187(b)	1701591(b)	145596(b)	7.9(b)
2003	Dec	1847556(b)	1704154(b)	143402(b)	7.8(b)
2004	Jan	1847377(b)	1702351(b)	145026(b)	7.9(b)
2004	Feb	1846956(b)	1705563(b)	141393(b)	7.7(b)
2004	Mar	1849765(b)	1709259(b)	140506(b)	7.6(b)
2004	Apr	1850892(b)	1715019(b)	135873(b)	7.3(b)
2004	May	1850984(b)	1715166(b)	135818(b)	7.3(b)
2004	Jun	1853831(b)	1716815(b)	137016(b)	7.4(b)
2004	Jul	1856652(b)	1720818(b)	135834(b)	7.3(b)
2004	Aug	1857396(b)	1720874(b)	136522(b)	7.4(b)
2004	Sep	1855893(b)	1722321(b)	133572(b)	7.2(b)
2004	Oct	1856898(b)	1725108(b)	131790(b)	7.1(b)
2004	Nov	1856369(b)	1727449(b)	128920(b)	6.9(b)

2004	**Dec**	1854343(b)	1730292(b)	124051(b)	6.7(b)
2005	**Jan**	1853980(b)	1733450(b)	120530(b)	6.5(b)
2005	**Feb**	1856029(b)	1736803(b)	119226(b)	6.4(b)
2005	**Mar**	1857132(b)	1740754(b)	116378(b)	6.3(b)
2005	**Apr**	1861850(b)	1743514(b)	118336(b)	6.4(b)
2005	**May**	1862323(b)	1744201(b)	118122(b)	6.3(b)
2005	**Jun**	1866304(b)	1747323(b)	118981(b)	6.4(b)
2005	**Jul**	1868718(b)	1750807(b)	117911(b)	6.3(b)
2005	**Aug**	1870895(b)	1753800(b)	117095(b)	6.3(b)
2005	**Sep**	1871096(b)	1757883(b)	113213(b)	6.1(b)
2005	**Oct**	1873102(b)	1761421(b)	111681(b)	6.0(b)
2005	**Nov**	1875200(b)	1766758(b)	108442(b)	5.8(b)
2005	**Dec**	1879116(b)	1772594(b)	106522(b)	5.7(b)
2006	**Jan**	1881676(b)	1777869(b)	103807(b)	5.5(b)
2006	**Feb**	1885313(b)	1783520(b)	101793(b)	5.4(b)
2006	**Mar**	1887892(b)	1787058(b)	100834(b)	5.3(b)
2006	**Apr**	1893248(b)	1792384(b)	100864(b)	5.3(b)
2006	**May**	1898403(b)	1797788(b)	100615(b)	5.3(b)
2006	**Jun**	1902891(b)	1801207(b)	101684(b)	5.3(b)
2006	**Jul**	1904461(b)	1802554(b)	101907(b)	5.4(b)
2006	**Aug**	1907421(b)	1804820(b)	102601(b)	5.4(b)
2006	**Sep**	1910583(b)	1808155(b)	102428(b)	5.4(b)
2006	**Oct**	1913693(b)	1811822(b)	101871(b)	5.3(b)
2006	**Nov**	1916400(b)	1814349(b)	102051(b)	5.3(b)
2006	**Dec**	1916721(b)	1816157(b)	100564(b)	5.2(b)
2007	**Jan**	1917184(b)	1819862(b)	97322(b)	5.1(b)
2007	**Feb**	1920105(b)	1823159(b)	96946(b)	5.0(b)
2007	**Mar**	1921230(b)	1824974(b)	96256(b)	5.0(b)
2007	**Apr**	1920649(b)	1823915(b)	96734(b)	5.0(b)
2007	**May**	1924403(b)	1825847(b)	98556(b)	5.1(b)
2007	**Jun**	1927115(b)	1827271(b)	99844(b)	5.2(b)
2007	**Jul**	1928842(b)	1827512(b)	101330(b)	5.3(b)
2007	**Aug**	1931102(b)	1829102(b)	102000(b)	5.3(b)
2007	**Sep**	1932926(b)	1829807(b)	103119(b)	5.3(b)
2007	**Oct**	1936063(b)	1830821(b)	105242(b)	5.4(b)
2007	**Nov**	1936463(b)	1832648(b)	103815(b)	5.4(b)
2007	**Dec**	1937537(b)	1832500(b)	105037(b)	5.4(b)
2008	**Jan**	1948098	1841847	106251	5.5
2008	**Feb**	1941418	1836184	105234	5.4
2008	**Mar**	1952691	1843016	109675	5.6

Staff/203
Rossow/6

2008	**Apr**	1948481	1842931	105550	5.4
2008	**May**	1947687(p)	1837963(p)	109724(p)	5.6(p)

b : Reflects revised population controls, seasonal factors, and model reestimation for 2003-07.
p : Preliminary.

CASE: UE 197
WITNESS: Paul Rossow

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 204

Exhibits in Support
Of Direct Testimony

July 9, 2008

Staff/204
Rossow/1

Oregon Economic and Revenue Forecast

March 2008

Volume XXVIII, No. 1

Theodore R. Kulongoski
Governor

State of Oregon
Department of Administrative Services
Kris Kautz, Interim Director

Prepared By:
Office of Economic Analysis

EXECUTIVE SUMMARY

March 2008

Oregon Economic Forecast

The fourth quarter 2007 initial estimate of job growth was a 2.5 percent annual rate over the third quarter. This follows a decrease of 0.3 percent in the third quarter. This relatively strong fourth quarter is in sharp contrast to the slowing growth of jobs over the last two quarters. On an annual average basis, the year 2007 finished with job gains of 1.4 percent. On a Y/Y basis, jobs increased in the fourth quarter by 1.3 percent. The job growth has been positive Y/Y since the first quarter of 2004 but has slowed through the last 4 quarters.

Troubles to the U.S. economy are coming from two sources: housing and energy. The housing market downturn and subprime mortgage problems are working their way through the financial sector. As home prices are starting to retreat, consumers are not tapping their home equity values. Consumer spending may also slow due to tighter credit criteria, and energy prices are pinching budgets. These actions have the potential to impact all sectors of the economy.

The Oregon economy has likewise experienced a slowdown. Housing starts are down almost 17.0 percent in 2007 following an 11.0 percent drop in 2006. Although housing foreclosures are up, Oregon has one of the lowest rates in the country. We also have one of the lowest proportions of subprime mortgages. On the other hand, Oregon is relatively high in the proportion of variable rate mortgages. In terms of employment, Oregon job growth slowed dramatically in 2007 but ended with a relatively strong fourth quarter. Oregon's initial job claims are higher on a 4-week moving average in early January compared to 2007, but the last few weeks has shown some improvement.

Turning points are difficult to forecast. Many indicators are now pointing to a further slowing of the economy, but not all signals are negative. With the sun possibly setting on this expansion phase of the business cycle, the skies on the horizon are code colored reddish-orange—very cautious about further downturns in the economy.

OEA forecasts 0.3 percent growth for the first quarter of 2008. Job growth will be less in 2008 than in 2007, at 1.0 percent. Jobs will do slightly better in the second half of 2008, with a 1.3 percent growth rate and gradual improvement into 2009. OEA forecasts annual average job growth at 1.7 percent in 2009 and 1.8 percent in 2010.

OEA expects the wood products sector job growth to continue declining at a 0.5 percent rate in 2008 and 0.1 percent in 2009.

OEA projects that the computer electronics industry will grow 0.9 percent in 2008 and decline 1.0 percent in 2009. OEA expects this sector's job growth to remain relatively flat through the forecast horizon of 2013.

OEA expects the transportation equipment sector to see job declines of 7.8 percent in 2008 with a return to job gains of 1.9 percent in 2009.

Metals and machinery job growth was 6.4 percent in 2007, with continued growth of 5.7 percent expected in 2008 and 1.5 percent in 2009.

OEA forecasts employment in food processing to increase 0.9 percent in 2008 and 1.6 percent in 2009.

Construction employment will continue to decline in 2008 with job losses of 3.4 percent. 2009 will see essentially no improvement with minimal job growth of 0.1 percent.

Trade, transportation, and utilities sector employment will mildly increase 0.5 percent in 2008 followed by 1.9 percent growth in 2009.

The information sector, which includes traditional publishers such as newspapers and publishers of software, will continue strong growth of 5.0 percent in 2008 and milder growth of 0.8 percent in 2009.

The financial activities sector will continue to soften with job declines of 0.5 percent in 2008 before returning to positive job growth of 1.8 percent in 2009.

OEA projects that professional and business services will grow 0.8 percent in 2008 and 3.9 percent in 2009.

Education and health services will grow 3.1 percent in 2008 and 2.7 percent in 2009.

OEA projects that leisure and hospitality will grow 2.4 percent in 2008 and 1.8 percent in 2009, slower than the 3.9 percent growth of 2006 and 2007.

The government sector will increase by 1.4 percent in 2008 and 0.8 percent in 2009. OEA projects that local government employment will grow 2.1 percent in 2008 and 1.1 percent in 2009. OEA forecasts that state government employment will grow 0.5 percent in 2008 and 0.4 percent in 2009.

Forecast Risks

The forecast projects a slowing Oregon economy in 2008 with mild growth returning in 2009. This outlook faces heightened risks for a much deeper downturn in 2008. "Risks" are similar to the statistician's probabilities. Based on information about likely outcomes, the statistician assigns probabilities to various outcomes. The indicators in the national and Oregon economies raise the probability of a more severe downturn. Unlike risk, uncertainty is a situation lacking in data and information. Uncertainty surrounds the financial system. The extent of the housing crisis and the securitization of bad loans are unknown. Whether the financial system will lead to a wide spread credit crunch is the largest question facing the US economy—and thus the Oregon economy. Broadly we place "uncertainty" under "risks", and note that the Oregon economy is at a precarious juncture of the business cycle.

With the national economy going through a slowdown in 2007, the risks are higher from any disturbances that could throw the economy off track. The same major drag for the slowdown, a slowing housing market, could hurt the economy further when it is most susceptible. The credit crunch and the ensuing instability in the global financial market bring added uncertainty. Businesses are nervous about potential repercussions from the turmoil in the financial markets across the world. Any geopolitical disruptions during this time would be more harmful than when the economy is stronger.

CASE: UE 197
WITNESS: Dustin Ball
Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Direct Testimony

July 9, 2008

Q. PLEASE STATE YOUR NAMES, OCCUPATIONS, AND BUSINESS ADDRESS.

A. My name is Dustin Ball. I am employed by the Public Utility Commission of Oregon as Senior Financial Analyst, Corporate Analysis and Water Regulation, in the Economic Research and Financial Analysis section of the Utility Program. My business address is 550 Capitol Street NE, Salem, Oregon 97308-2148.

My name is Michael Dougherty. I am employed by the Public Utility Commission of Oregon as Program Manager, Corporate Analysis and Water Regulation in the Economic Research and Financial Analysis section of the Utility Program. My business address is 550 Capitol Street NE, Salem, Oregon 97308-2148. Collectively, we are referred to as Staff.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUNDS AND WORK EXPERIENCES.

A. Our Witness Qualification Statement is found in Exhibit Staff/301, Ball-Dougherty/1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of Staff's testimony is to recommend adjustments to Portland General Electric's health and dental benefit expenses, other benefit expenses, insurance expenses, Director's fees, Officer Vehicle Plan, porcelain insulator expenses, locating costs, Arc-flash clothing costs, EMS development costs, tree trimming, other non-labor Administrative and General expenses (A&G), Operations and Maintenance (O&M) expenses, and Property Tax Expenses.

In addition, Staff addresses PGE's proposed changes to its Distribution Services operations.

Q. DID YOU PREPARE EXHIBITS FOR THIS DOCKET?

A. Yes. Staff prepared Exhibit Staff/302 (13 pages of supporting calculations), Exhibit Staff/303 (PGE data request responses cited in this testimony), and Exhibit Staff/304 (documentation in support of footnotes).

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. Staff's testimony is organized as follows:

ISSUE 1, MEDICAL & DENTAL BENEFIT EXPENSE ADJUSTMENTS

Q. PLEASE SUMMARIZE THIS ADJUSTMENT.

A. This adjustment focuses on PGE's Medical and Dental benefit expenses. Staff proposes the following adjustment:

Medical & Dental Benefit Expenses	($1,284,621)

This adjustment is shown in Exhibit Staff/302, Ball-Dougherty/2.

Q. PLEASE EXPLAIN YOUR ADJUSTMENTS TO MEDICAL & DENTAL BENEFIT EXPENSES.

A. In UE 197, PGE submitted a total cost of $31,554,803 in medical and dental expenses. Staff recommends a total cost of $30,271,182. To determine the adjustment, Staff closely examined PGE's health benefit costs for both union and non-union personnel.

For union personnel, Staff started with PGE's actual fiscal year 2007 expenses of $10,056,070 and escalated the costs to 2009 using an 8.5 percent annual increase based on recent studies concerning benefit costs.[1] Although this rate is on the high end of the estimates, it appears similar to the rate PGE has previously used to increase its union benefits. The escalation resulted in a calculated expense of $11,858,257. This is an increase of $1,782,187. Because PGE's current union contract does not expire until March 1, 2009, an additional adjustment was performed based on the expiration of the contract. Under the current contract, the amount PGE contributes for medical coverage is set at $5.25 per straight time compensable hour (PGE response to data request 255). Because this is a set rate that will not increase until a new contract is in place, Staff proposes to adjust an increased benefit amount to apply to the months of March through December 2009. As a result of the ten-month period, the $1,782,197 increase is reduced to $1,485,189 to reflect that PGE's current contract is set at a predetermined amount for the first two

[1] Recent studies (Hewitt Associates Outlook for 2008 and Towers Perrin 2008 Health Care Cost Survey) show increases to PPO premiums (100% of PGE's union benefits are a PPO plan) for 2008 in the range of 6 - 8.5 percent.

months of 2009. Because of this adjustment, Staff's recommended expense for union medical and dental benefits is $11,541,226.

For non-union personnel, Staff used PGE's forecasted amount of $22,403,058 and applied an 84 employer / 16 employee percent sharing to receive a projected cost of $18,818,569. Although PGE used an 85/15 sharing, PGE stated in testimony the industry average is 84/16 rather than 85/15.[2] Additionally, independent health care studies show that the employees' share of benefits has been increasing as a way to defray the premium increases to companies. Studies show that sharing in the range of 80/20 is becoming standard over multiple industries.[3]

PGE's UE 197 expenses also included $434,722 in actuarial study and other contracted health and welfare benefit costs. Because these costs reflect actual and recurring expenses, Staff did not make any adjustments to this expense category.

After totaling the union, non-union, and other costs, an additional adjustment was performed based on PGE's non-utility allocation. PGE's Cost Allocation Manual for the Year 2007 (submitted as an attachment to the 2007 Annual Affiliated Interest Report) shows a non-utility allocation of 1.79 percent. As a result of this non-utility allocation, the medical & dental benefits were adjusted to remove the non-utility portion of the costs. The following table summarizes the adjustments to PGE medical & dental expenses.

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[2] PGE Pretrial Brief, UE 197/PGE 800, Barnett – Bell/14.
[3] Kaiser Family Foundation Employer Health Benefits 2007 Survey, Towers Perrin 2008 Health Care Cost Survey, and Hewitt Associates Outlook for 2008.

Table 1 – Medical & Dental Benefits

PGE's UE 197 Expense	**$31,554,803**
Staff Recommended Union Benefit	$11,541,226
Staff Recommended Non-union Benefit	$18,818,569
Staff Recommended Actuarial Study	$434,722
Sub-total	*$30,794,517*
Total (Remove non-utility expense)	**$30,271,182**
Total Adjustment	**$1,283,621**

<u>ISSUE 2, OTHER BENEFIT EXPENSE ADJUSTMENTS</u>

Q. PLEASE SUMMARIZE THIS ADJUSTMENT.

A. This adjustment focuses on PGE's Other Benefit expenses. Staff proposes the following adjustment:

Other Benefit Expenses ($320,067)

This adjustment is shown in Exhibit Staff/302, Ball-Dougherty/3.

Q. PLEASE EXPLAIN YOUR ADJUSTMENTS TO OTHER BENEFIT EXPENSES.

A. In UE 197, PGE submitted a total cost of $20,950,370 in other benefit expenses. Staff recommends a total cost of $20,629,863. Staff made numerous adjustments to Other Benefit expenses as explained below.

- <u>Occupational Health</u> - The main source for PGE's increase over 2007 actuals was a $70,000 increase in wellness incentive programs. Staff reviewed the testimony references for the wellness incentive programs and it appears that all these items were in place during 2007 and will not be new for 2009. As a result, Staff escalated the actual 2007 expense by the Consumer Price Index for all Urban Consumers (CPI-U)[4] to arrive at a forecasted 2009 amount.

- Ergonomics and Integrated Absence Management (IAM) - The source of the benefit increase ($41,046) over 2007 actuals was identified as relating to IAM costs. According to PGE, the Integrated Absence Management (IAM) program was launched on October 1, 2007, to provide a more efficient, centralized, and collaborative approach to absence management within PGE. In response to Data Request 102, PGE was unable to identify cost benefits (reductions) related to this program. Although PGE expects that long-term costs will decrease, these prospective costs efficiencies are currently unknown and not measurable. As a result, Staff does not recommend the additional cost for IAM. The recommended expense for this category ($34,251) results from escalating the 2007 actual cost for Ergonomics to 2009 using the CPI-U.
- Occupational Fitness - Staff escalated the 2007 actual cost to 2009. There does not appear to be any new programs or new costs for 2009. PGE did identify the 2008 and 2009 costs as being related to drug testing for new hires; however, drug testing for new hires is not new to PGE and these costs were not removed by PGE from 2007 A&G accounts.

[4] The CPI-U includes expenditures by urban wage earners and clerical workers, professional, managerial, and technical workers, the self-employed, short-term workers, the unemployed, retirees and others not in the labor force. CPI is sometimes referred to as "headline inflation."

- Recreation Program – Staff recommends disallowance of these employee led activities because this expense is discretionary and not required to provide safe and adequate service to customers.
- Health Club Partial Reimbursement - Although PGE has expanded this program to include activities such as yoga, Pilates, tai chi, etc. that may increase participation by employees, it is unlikely that participation will almost double as presented by PGE in response to Data Request 299. As a result, Staff allowed for an approximate growth in participation of 20 percent and further increased the expense to 2009 using the CPI-U.
- Commuter Program – Although this expense is discretionary and not required to provide safe and adequate service to customers, Staff recommends a 50 percent sharing between customers and shareholders to support PGE's participation in commuter fairs, which promote alternate forms of employee commuter transportation methods.
- Service Awards – According to the Company, PGE honors employees for their years of service at five-year anniversary intervals.[5] Staff recommends a 50 percent sharing between customers and shareholders as these service awards should be considered similar to merit-based bonuses. Commission policy is to disallow 50 percent of merit-based bonuses because they equally benefit shareholders and ratepayers.

[5] PGE UE 197/PGE 800. Barnet-Bell/17.

- Retiree Association and Retiree Luncheon – Staff recommends disallowance of this expense because this expense is discretionary and not required to provide safe and adequate service to customers.
- Executive Financial Planning – Staff recommends disallowance of this expense because this expense is discretionary and not required to provide safe and adequate service to customers.
- Other – PGE was not able to identify this expense. As a result, Staff recommends disallowance of this unidentifiable expense.

The following table highlights Staff's other benefit adjustments.

Table 2 – Certain Other Benefit Adjustments

Expense	PGE Baseline 2009 Benefit Costs	Staff Adjustments	Staff's 2009 Benefit Costs
Occupational Health	$253,360	($28,926)	$224,434
Ergonomics and IAM	$75,297	($41,046)	$34,251
Occupational Fitness	$58,620	($10,644)	$47,976
Recreation Program	$25,825	($25,825)	$0
Health Club Partial Reimbursement	$100,000	($35,000)	$65,000
Commuter Program	$25,101	($12,551)	$12,550
Service Awards	$225,000	($112,500)	$112,500
Retiree Activities	$13,200	($13,200)	$0
Executive Financial Planning	$31,500	($31,500)	$0
Other	$9,315	($9,315)	$0
Total	**$817,218**	**($320,507)**	**$496,711**

No adjustments were made to numerous other benefit expenses, such as Retirement Savings Plan, Short-term Disability Insurance, Long-term Disability Insurance, Health Reimbursement Accounts, and other miscellaneous benefits. As a result, PGE's 2009 baseline costs were reduced from the UE 197 amount of $20,950,370 to Staff's recommended amount of $20,629,863, a $320,507 reduction.

ISSUE 3, INSURANCE EXPENSE ADJUSTMENTS

Q. PLEASE SUMMARIZE THESE ADJUSTMENTS.

A. These adjustments focus on PGE's insurance premium expenses and uninsured losses. Staff proposes the following adjustments:

Insurance Premiums	($2,078,699)
Uninsured Losses	($1,798,860)

These adjustments are shown in Exhibit Staff/302, Ball-Dougherty/4 and 5.

Q. PLEASE EXPLAIN YOUR ADJUSTMENTS TO INSURANCE PREMIUMS.

A. In UE 197, PGE submitted a total cost of $8,993,050 in insurance premium expenses. Staff recommends a total cost of $6,914,351. Four adjustments concerning insurance premiums were performed. These adjustments are:

1. Staff examined all insurance policies that are in effect. The calculated costs of all insurance policies in effect at $7,854,038, which is $1,139,012 less than PGE's UE 197 expense of $8,993,050. The current policies were not escalated due to the current soft market for insurance.[6]

2. Removed 50 percent of Excess Directors & Officer (D&O) Liability as a Shareholder Cost since shareholder claims account for approximately one-half of D&O claims.

3. Removed $170,000 from total costs due to a contingent "undeclared" policy holder credit (All-Risk). This contingent "undeclared" policyholder credit was identified by PGE in response to Data Request 70. According to the Company, PGE is optimistic that this credit will occur.

[6] MarketScout (a Dallas-based electronic insurance exchange, which underwrites and distributes product lines to a 60,000-member agency network has been tracking the U. S. P-C market since 2001 - http://www.marketscout.com) reports that the current energy property and casualty insurance for the energy industry is down 10 percent.

4. Removed $50,000 from total costs due to a contingent “undeclared” policy holder credit (Nuclear). Per a telephone conversation with PGE on May 23, 2008, PGE is expecting to receive a policy holder credit of $50,000 in 2009 for its Nuclear liability insurance.

Q. PLEASE EXPLAIN THE EXCESS DIRECTORS AND OFFICERS LIABILITY INSURANCE ADJUSTMENT.

A. Staff removed 50 percent of PGE’s Excess Directors & Officers (D&O) Liability Insurance. Excess liability insurance (1) overlays a specific liability insurance policy that an organization already owns by increasing the per person and per accident or per occurrence limits of liability in that particular policy; (2) incorporates all the provisions of the specific underlying policy, such as its insuring agreements, definitions, exclusions, and limitations (or “follows form” with the underlying policy); but (3) does not have any effect on any other liability insurance policies that the insured organization may have.[7]

Staff removed this amount from PGE’s revenue requirement because:

1. According to Foley & Lardner LLP, "Shareholder-claims are the largest source of this risk, accounting for 50% of all D&O claims."[8]

2. According to Towers Perrin's, regarding D&O liability insurance claims, "The claimant distribution continues to be heavily dependent on the ownership structure of survey participants. For example, 49% of the claims against public participants were brought by shareholders."[9]

Because a large number of claims are brought by shareholders, customers should not have to pay the full costs of total D&O insurance. The excess insurance should be considered a joint shareholder/customer cost. It is

[7] Increasing Your Liability Protection, Excess vs. umbrella limits, George L. Head, Ph.D., Special Advisor, Nonprofit Risk Management Center, Nonprofit Risk Management Center Newsletter, http://www.nonprofitrisk.org/library/articles/liability071105.shtml
[8] www.foley.com/files/tbl_s31Publications/FileUpload137/4087/DOLiability.pdf
[9] http://www.insurancejournal.com/news/national/2007/05/03/79327.htm

important to note that Staff did not recommend any adjustments to the primary D&O insurance costs ($539,695). The 50 percent reduction in excess D&O liability insurance cost only represents 32.3 percent of total D&O liability insurance costs. This was a balanced approach for adjusting costs.

Q. PLEASE EXPLAIN YOUR ADJUSTMENTS TO UNINSURED LOSSES.

A. In UE 197, PGE submitted an adjusted total cost of $4,077,767 in uninsured losses. Staff recommends a total cost of $2,278,908. Staff examined PGE's automobile liability, general liability, and workers' compensation uninsured losses for the five year period of 2003 through 2007. For each year of losses, the 2008 losses were escalated using the CPI-U. Staff then took the five year average of the losses, escalated the average to 2009, and subtracted the amounts from PGE's UE 197 amount. As a result, Staff received a $1,187,099 adjustment to PGE's automotive and general liability uninsured losses and a $611,760 adjustment to PGE's workers' compensation uninsured losses for a total adjustment of $1,798,860.

ISSUE 4, DIRECTORS FEES AND OFFICER VEHICLE PLAN ADJUSTMENTS

Q. PLEASE SUMMARIZE THIS ADJUSTMENT.

A. This adjustments focus on PGE's Directors Fees and Officer Vehicle Plan. Staff proposes the following adjustments:

Directors Fees	($325,100)
Officer Vehicle Plan	($103,800)

This adjustment is shown in Exhibit Staff/302, Ball-Dougherty/6 and 7.

Q. PLEASE EXPLAIN YOUR ADJUSTMENTS TO DIRECTORS FEES.

A. In UE 197, PGE submitted a total cost of $1,213,375 in Directors fees. Staff recommends a total cost of $888,275. Three adjustments concerning Directors fees were performed. These adjustments are:

1. Removed the Directors' Retirement Accrual ($15,300) as a Supplemental Executive Retirement Plan (SERP). The Commission has not previously allowed recovery of SERP expenses in utility cases. (Order 01-787 at 44)

2. Removed the Directors' Stock Incentive ($270,000) as it is an incentive. As described in PGE's 10-K, " The Portland General Electric Company 2006 Stock Incentive Plan, as amended and restated (the "Plan") is intended to provide incentives which will attract, retain and motivate highly competent persons as officers, directors and key employees of Portland General Electric Company (the "Company") and its subsidiaries and Affiliates, by providing them with appropriate incentives and rewards in the form of rights to earn shares of the common stock of the Company ("Common Stock") and cash equivalents."[10]

   Additionally, Section 6. Participants states in part: "Participants will consist of (i) such officers and key employees of the Company and its subsidiaries and Affiliates as the Committee in its sole discretion determines to be significantly responsible for the success and future growth and profitability of the Company…"[11]

   The Commission has previously not allowed utilities to charge customers for bonuses paid to company executives that are based on the financial performance of the utility or its parent company. As such, the Commission policy has been to disallow 100 percent of officer bonuses because they are based on increased earnings. (Order 99-033 at 62; Order 97-171 at 74-76)

3. Removed the Director's Deferred Compensation Interest ($39,800) as a form of SERP.

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[10] PGE's SEC Form 10-K, for the Fiscal year ending December 31, 2007, Exhibit 10.23.
[11] *Ibid.*

Q. PLEASE EXPLAIN YOUR ADJUSTMENTS TO THE OFFICER VEHICLE PLAN.

A. In UE 197, PGE submitted a total cost of $103,800 in other benefit expenses. Staff recommends a total cost of $0. The Officer Vehicle Plan expenses ($103,800) were adjusted out because it should be considered a bonus to executives. As mentioned above, Commission policy has been to disallow 100 percent of officer bonuses because they are based on increased earnings.

ISSUE 5, NON-LABOR ADMINISTRATIVE AND GENERAL EXPENSE ADJUSTMENTS

Q. PLEASE SUMMARIZE THESE ADJUSTMENTS.

A. These adjustments focus on PGE's miscellaneous non-labor administrative and general (A&G) expenses. Staff proposes the following adjustments:

Miscellaneous A&G	($596,036)

These adjustments are shown in Exhibit Staff/302, Ball-Dougherty/8.

Q. PLEASE EXPLAIN THE ADJUSTMENT FOR MISCELLANEOUS A & G EXPENSES.

A. Staff made numerous adjustments to PGE's A&G miscellaneous non-labor expenses. These adjustments are standard adjustments typically made by Staff in a rate case. The majority of the $596,036 of miscellaneous expense is associated with the following adjustments: 1) 50 percent of certain meal & entertainment expenses; 2) 50 percent of office refreshments and catering; 3) 50 percent of gifts such as flowers and awards; 4) 100 percent of civic activities recorded in A& G accounts; and 5) 100 percent of legal charges related to the California Refund lawsuits.

Meals and Entertainment Expenses

Staff removed 50 percent of all meals and entertainment expenses. Although these expenses are discretionary and not required to provide safe and adequate service to customers, a 50 percent sharing between customers and shareholders is recommended. This is a fair approach that somewhat mirrors the policy associated with bonuses (50 percent sharing between customers and shareholders) and the handling of these expenses for income tax purposes. For income tax purposes, the amount allowable as a federal income tax deduction for business meal and entertainment is generally limited to 50 percent of the total expense. Entertainment generally includes any activity engaged in for amusement or recreation and must be ordinary and necessarily incurred in the operation of a business.[12] As previously mentioned, these costs are not core to PGE's business and are not directly related to the generation, transmission, and distribution of electricity. As such, customers should not have to assume the full burden of these costs and a 50 percent sharing with shareholders should be accepted by the Commission.

Office Refreshments, Catering, and Gifts

These costs (including flowers and awards) and office refreshments are discretionary and are not directly related to the generation, transmission, and distribution of electricity. As such, customers should not have to assume the

[12] 2006-2007, Car, Travel, Entertainment and Home Office Deductions CPE Course. CCH.

full burden of these costs and a 50 percent sharing with shareholders, as proposed above in meal and entertainment expenses, should be accepted by the Commission.

Civic and Political Activities

Staff removed 100 percent of civic activities because the Commission has not allowed regulated utilities to recover contributions to charities, community affairs, and economic development organizations through rates charged for regulated services. These expenses are discretionary and are not required to provide safe and adequate service to customers. In addition, Commission policy does not require customers to support causes in which they do not believe.[13]

Certain Legal and Other Charges

Staff removed legal charges related to the California Refund lawsuits. These lawsuits were specific to the California electricity market crisis in 2001. These legal expenses ($66,295) are not reflective of ongoing costs and should not be allowed in rates as a customer cost.

Staff also removed $2,700 in costs for training to be a state-certified energy auditor and inspector. Staff recommends this adjustment because customers pay public purpose funds for these activities and any PGE costs for these types of activities should be recorded “below the line”.

[13] OPUC Order 87-406 states at pp. 40-41, “Since community affairs expenditures are discretionary, the funds could be retained by the business’s owners. . . .Owners of unregulated businesses, rather than their customers, make community affairs contributions." Also see Order 91-186 at 16.

Staff also removed $29,500 in customer research. Since PGE's residential customers are captive (service area) customers, any PGE costs for these types of activities should be recorded "below the line".

Additionally, Staff removed $49,532 for an environmental services agreement with the Forestry Service. These services were procured to help pay for operational forest fish traps on the lower Clackamas River (Faraday/North Fork/River Mill), analyzing data, and performing habitat surveys. These types of costs would be more appropriately included in licensing costs.

Staff also removed $24,140 in 2008 annual rent for storage used by PGE's underground crews. The 2008 costs were removed because PGE's transaction summaries also included a 2007 cost. Without further information, this would result in a doubling of costs.

ISSUE 6, NON-LABOR TRANSMISSION AND DISTRIBUTION OPERATIONS AND MAINTENANCE EXPENSE ADJUSTMENTS

Q. PLEASE SUMMARIZE THE OPERATION AND MAINTENANCE EXPENSE ADJUSTMENTS.

A. Staff proposes the following adjustments:

Porcelain Insulator Replacement Project	($287,496)
Locating Expenses	($271,135)
Arc-Flash Mitigation Expenses	($270,750)
EMS Development Expenses	($174,451)
Tree Trimming Expenses	($1,346,103)

FITNESS	($900,000)
Miscellaneous O&M Adjustments	($163,137)

These adjustments are shown in Exhibit Staff/302, Ball-Dougherty/9-12.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE PORCELAIN INSULATOR PROJECT COSTS.

A. In UE 197, PGE submitted a total non-labor cost of $683,763 in porcelain insulator project costs. Staff recommends a total cost of $396,267. According to the Company's response to Staff Data Request 180, the Porcelain Insulator Replacement Program is a targeted maintenance program to replace aging and failing porcelain insulators. In its UE 197 application, PGE submitted a 2009 non-labor expense for the insulators of $683,763, which is a significant increase ($302,132) over 2007 actual costs of $381,631.

According to the Company, failures to porcelain insulators occur randomly and independent test labs have not been able to establish any predictable indicators of imminent failure. Additionally, according to the Company, PGE began a long-term project in 2005 to replace its porcelain post insulators with reliable, lightweight polymer insulators. The program is scheduled to continue until 2011.[14] Because this porcelain insulator replacement program has been in place for over two years, the 2007 costs would be reflective of ongoing costs. As such, Staff proposes to maintain the cost of the porcelain insulator replacement project and escalate the 2007 costs to 2009 using the CPI-U. The recommended cost is $396,267 resulting in a $287,496 adjustment.

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[14] PGE Pretrial Brief, UE 197/ PGE/600, Hawke/15.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO LOCATING COSTS.

A. In UE 197, PGE submitted an 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. As PGE explains in its testimony, PGE outsources most of its locate work and in 2007 used two different contractors to perform the locates. According to PGE, the Company after noting the poor performance of the lower-cost contractor, was required to renegotiate with the higher cost contractor that the Company previously used.[15] In testimony, PGE attributes the increased costs to contractor rising rates and increased number of locates.[16] However, in its response to Data Request 94, PGE reported that 95 percent of the projected increase over the 2007 actual is a result of higher contract costs. As a result, Staff calculated an estimated cost of locates under the higher cost contract as if it had been in place all of 2007. Staff did not include an escalation for the contract cost as the current contract does not expire until May 31, 2009, and it does not appear to contain an escalation clause. The recommended cost increase of $417,413 results in a downward adjustment of $271,135.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO ARC-FLASH COSTS.

A. In UE 197, PGE submitted an UE 197 increase in Arc-flash costs of $361,000. Staff recommends an increase in Arc-flash costs of $90,250. In its testimony, PGE states that it is conducting a study in 2008 to determine the most effective

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[15] PGE Pretrial Brief, UE 197/PGE/600, Hawke/13.
[16] PGE Pretrial Brief, UE 197/PGE/600, Hawke/13 and 14.

method to mitigate Arc-flash. PGE further states that most of the Arc-flash expenditures will go to purchasing protective clothing for its employees.[17] In response to Data Request 99, PGE estimated that the useful life of this clothing was between 3 and 5 years. As a result, Staff set the useful life at 4 years, the middle of this estimate and calculated the annual expense over the clothing's useful life, which equaled an annual expense of $90,250. The calculated annual expense results in a $270,750 adjustment to PGE's UE 197 costs.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO EMS DEVELOPMENT COSTS.

A. In UE 197, PGE submitted a total non-labor O&M cost of $174,451 in EMS Development costs. Staff recommends a total cost of $0. In its testimony, PGE stated that the Company's new Energy Management System (EMS) is scheduled to be operational and replaces the existing legacy system that is over 12 years old.[18] After a review of the system's costs, Staff removed non-capital O&M costs ($174,451 – PGE response to Data Request 288) incurred during the development of EMS. These costs were one time costs that should not reoccur in 2009.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO TREE TRIMMING COSTS.

A. In UE 197, PGE submitted a total non-labor cost of $12,301,905 in tree trimming costs. Staff recommends a total cost of $10,955,802. Staff examined this expense using two different methods. In the first method, Staff reduced the forecasted tree trimming expense as the 2006 and 2007 actual expenses

[17] PGE Pretrial Brief, UE 197/PGE/600, Hawke/17.
[18] PGE Pretrial Brief, UE 197/PGE/600, Hawke/5.

include additional work which is not likely to reoccur in 2009. As a result, Staff set tree trimming expenses at the forecasted 2008 amount identified in UE 188[19] and allowed one year of escalation at 8 percent. An 8 percent escalation was used 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.

However, due to additional information provided by PGE in Data Request 382, Staff adjusted the 2009 forecast upwards to $10,955,802. Because the adjusted 2009 forecasted amount was 11.45 percent greater than the 2009 forecasted amount (based on UE 188), an additional escalation was not performed. As a result, Staff's adjustment to PGE's tree trimming costs is $1,346,103.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO FITNES O&M COSTS.

A. Staff removed PGE's $900,000 increase to the FITNES program, which was explained by PGE as resulting from the early completion of the second 10-year cycle in 2007.[20] The FITNES program consists of both overhead O&M, which is on a 10-year cycle, and underground O&M, which is on a 4-year cycle. After examining various responses to data requests, it appeared that the 2007 overhead FITNES costs were relatively consistent with 2005 and 2006 expenses. The actual lower total program costs for 2007 were a result of the underground FITNES program, which experienced a cost reduction of

[19] PGE UE 188/PGE/200, Tooman-Tinker-Schue/24 addresses the major drivers of the O&M decrease from 2006 to 2008 and states: "A $1.8 million reduction in tree trimming costs. PGE engaged in additional work regarding trees that we do not expect to occur."
[20] PGE Pretrial Brief, UE 197/PGE/600, Hawke/12.

$1,007,438 from 2006 to 2007 (PGE response to Data Request 93). Additionally as a check to the recommended adjustment, Staff examined the budgeted and actual expenses for the past five years (2003 – 2007). During this time period, PGE actual expenses were lower than PGE's budgeted expenses (PGE response to Data Request 306).

Q. PLEASE EXPLAIN THE ADJUSTMENT FOR MISCELLANEOUS O & M EXPENSES.

A. Staff made similar adjustments to meals and entertainment, gifts, catering, and civic activities as explained in the Miscellaneous A&G adjustments. In addition, a $51,356 payment for a contract Forester (Washington Forestry Consultants, Inc.), which is a component of PGE's tree trimming costs was adjusted out. PGE has added a full-time equivalent (FTE) for this function, but has not provided any documentation of removal of this cost from its budget.

ISSUE 7, PGE'S DISTRIBUTION SERVICES

Q. PLEASE EXPLAIN PGE'S PROPOSED CHANGES TO ITS DISTRIBUTION SERVICES.

A. PGE proposes to move this program from a non-utility "below-the-line" activity to a utility "above-the-line service."[21]

Q. DO YOU AGREE WITH PGE'S PROPOSAL?

A. No.

[21] PGE Pretrial Brief UE 197/PGE 600, Hawke/17-19.

Q. PLEASE EXPLAIN.

A. The function that PGE wants to shift “above-the-line” is described in PGE’s Schedule 715, Electrical Equipment Services. Schedule 715 is categorized under PGE’s Non-utility Services. According to the tariff:

> The Company provides engineering, electrical design and construction, equipment maintenance and repair, preventative diagnostic and prevention maintenance, electrical oil containment and compliance with the Environmental Protection Agency’s Spill Prevention Control and Countermeasure Oil Program (SPCC), equipment leasing, Energy recovery and revenue protection and electrical equipment refurbishing and disposal services.

Being categorized as a non-utility service makes perfect sense because this service meets the definition of a competitive operation pursuant to OAR 860-038-0005(8)(b), Definitions for Direct Access, which states:

> (8) "Competitive operations" means any electric company's activities involving the sale or marketing of electricity services or directly related products in an Oregon retail market. Competitive operations include, but are not limited to, the following:
>
> (a) Energy efficiency audits and programs;
>
> (b) Sales, installation, management, and maintenance of electrical equipment that is used to provide generation, transmission, and distribution related services or enhances the reliability of such services; and
>
> (c) Energy management services, including those services related to electricity metering and billing.

In fact, Schedule 715 specifically states:

> Electrical Equipment Services will be provided in accordance with the Code of Conduct as set forth in OAR 860-038-0500 through 806-038-0640.

Because this service was specifically addressed in OAR 860-038-0005(8)(b), PGE customers should not have to subsidize electrical services provided for or to facilities owned by PGE customers. Associated actual costs for this program need to be paid by the customer receiving the Schedule 715 service, and not PGE customers as a whole. According to Schedule 715:

> All fully distributed costs and revenues associated with the provision of Electrical Equipment Services will be charged or credited to non-utility accounts.

As a result, the costs charged by PGE must include both direct and indirect costs including liability insurance, engineering, corporate overhead, etc.

Additionally, PGE customers as a whole need to be held harmless from PGE liabilities in performing construction, operation and maintenance work on customer wiring systems. As a result, this service needs to continue as a non-utility, “below-the-line” service.

ISSUE 8, PROPERTY TAX ADJUSTMENTS

Q. PLEASE SUMMARIZE THE PROPERTY TAX ADJUSTMENT.

A. This adjustment focuses on PGE’s property tax expenses. Staff proposes the following adjustment:

Property Tax Expenses	($4,243,307)

This adjustment is shown in Exhibit Staff/302, Ball-Dougherty/13.

Q. PLEASE DESCRIBE YOUR PROPOSED PROPERTY TAX ADJUSTMENT.

A. IN UE 197, PGE proposes to increase property tax expense from a 2007 forecast of $34.7 million in UE 180 to $37.0 million for the 2009 test period in UE 197. The Company states that the request is based primarily on two factors: a) 2009 property tax expense related to Biglow I of $2.0 million due to the addition of this facility since UE 180, and b) increased rate base (in addition to Biglow I) increases PGE's property tax base in 2009 relative to the 2007 test year in UE 180.[22]

Q. WHAT DID STAFF FIND IN ITS REVIEW OF THIS ISSUE?

A. Staff compared the UE 180 forecast of $34.7 million to the actual 2007 property tax expense. In 2007, PGE's property tax expense increased by approximately $2.4 million due to a delay in Port Westward. This one-time increase will not reoccur due to the property tax exemption granted by the Oregon Department of Economics and Sherman County. In addition, PGE estimates that 2009 test period expenses for property taxes will increase due to the implementation of Biglow Canyon. To determine the a 2007 base year, Staff took the actual 2007 property tax amount, removed the $2.4 million related to Port Westward (non-reoccurring) and added the increased

$2.0 million related to Biglow Canyon. Staff then applied CPI of 1.022 and 1.016 for 2008 and 2009, respectively, to determine the forecast for 2009. Staff compared its forecast of the 2009 test period to the $36.9 million requested by PGE in its UE 197 application to determine an adjustment of $4.2 million.

[22] PGE Pretrial Brief, UE 197/PGE/200, Tooman-Tinker/20.

Q. WHY DOES STAFF BELIEVE ITS PROPOSED ADJUSTMENT IS REASONABLE?

A. Staff believes this adjustment is reasonable because it aligns PGE's actual property tax expense to its budgeted expenses. In response to Staff's Data Request 76, PGE states that it regularly participates in a negotiated process with the Oregon Department of Revenue when the Department of Revenue determines PGE's assessed value. In addition, PGE's most recent addition of generating assets were built in enterprise zones which grant PGE property tax exemptions for a period of approximately five years.[23]

Q. IF PGE'S REAL-MARKET VALUE OF PROPERTY INCREASES DOESN'T ITS PROPERTY TAX INCREASE AS WELL?

A. Not necessarily. According to the Oregon Department of Revenue:

> "The Oregon Constitution limits the rate of growth of property value subject to taxation. The limit is based on a property's maximum assessed value (MAV). The MAV was established for all property in existence in 1997-98 by a formula described in the constitutional amendment, Measure 50. MAV for new property is computed using a different formula also contained in the constitution.
> MAV is allowed to increase each year by no more than 3 percent. There are exceptions to this limit, however. The addition of a new structure, major improvement of an existing structure, and subdivision or partition of the property are examples of exceptions that would increase MAV by more than 3 percent.
>
> Each year the MAV and real market value for each property are figured. The property is then taxed on the lesser value, which is called the taxable assessed value." (*See* http://www.oregon.gov/DOR/PTD/property.shtml)

[23] In UE 188/PGE/200, Tooman-Tinker-Schue/7, PGE refers to this as a property tax "holiday."

Q. IF PGE'S RATE BASE INCREASES DOESN'T ITS PROPERTY TAX INCREASE AS WELL?

A. Not necessarily. The Oregon Department of Revenue assess the value of all real and personal property for an industrial or utility property; however, the value of intangible property is not included in the assessed value. Therefore, large hydro projects properly classified as costs attributed to relicensing would not be considered as tangible real property and would not likely increase the value of real property. Additionally, 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. Staff believes the property tax expense for the 2009 test period should reasonable reflect the final rate base amount determined in the UE 197 rate proceeding and not an estimate of future rate base additions.

Q. WHAT DOES STAFF RECOMMEND?

A. Staff believes the Commission should adjust PGE's 2009 test period property tax expense to reflect Staff's forecast of approximately $32.6 million for the 2009 test period.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF STAFF'S PROPOSED ADJUSTMENT?

A. The revenue requirement impact is a reduction to revenue requirement of approximately $4.4 million

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 197
WITNESS: Dustin Ball
Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualification Statement

July 9, 2008

WITNESS QUALIFICATION STATEMENT

NAME:	DUSTIN BALL
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	SENIOR FINANCIAL ANALYST, ECONOMIC RESEARCH & FINANCIAL ANALYSIS DIVISION
ADDRESS:	550 CAPITOL STREET NE SUITE 215, SALEM, OREGON 97308-2148.
EDUCATION:	Bachelor of Science, Business focusing in Accounting, Western Oregon University (2003)
EXPERIENCE:	Employed with the Oregon Public Utility Commission since August 2007. I am a Senior Financial Analyst for the Economic Research & Financial Analysis Division.
	Employed by the Oregon Real Estate Agency as a Financial Investigator in the Regulations Division from January 2006 to August 2007.
	Employed by the Oregon Department of Revenue as an Income Tax Auditor, in the Personal Tax and Compliance Section from January 2004 to January 2007.
	Licensed Tax Consultant in the State of Oregon.

WITNESS QUALIFICATION STATEMENT

NAME:	MICHAEL DOUGHERTY
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	PROGRAM MANAGER, CORPORATE ANALYSIS AND WATER REGULATION
ADDRESS:	550 CAPITOL STREET, SUITE 215, NE, SALEM, OREGON 97308-2148
EDUCATION:	Master of Science, Transportation Management, Naval Postgraduate School, Monterey CA (1987) Bachelor of Science, Biology and Physical Anthropology, City College of New York (1980)
EXPERIENCE:	Employed with the Oregon Public Utility Commission as the Program Manager, Corporate Analysis and Water Regulation. Also serve as Lead Auditor for the Commission's Audit Program. Performed a five-month job rotation as Deputy Director, Department of Geology and Mineral Industries, March through August 2004. Employed by the Oregon Employment Department as Manager - Budget, Communications, and Public Affairs from September 2000 to June 2002. Employed by Sony Disc Manufacturing, Springfield, Oregon, as Manager – Manufacturing; Manager - Quality Assurance; and Supervisor - Mastering and Manufacturing from April 1995 to September 2000. Retired as a Lieutenant Commander, United States Navy. Qualified naval engineer. Member, National Association of Regulatory Commissioners Staff Sub-Committee on Accounting and Finance.

CASE: UE 197
WITNESS: Dustin Ball
Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support of Testimony

July 9, 2008

PGE
UE 197
Test Year December 31, 2007
000's of Dollars

Adjustment is based on a series of adjustments in Account 901 through 935 and Accounts 560 through 598. The accompanying pages explain these adjustments in detail.

(Rounded to the nearest $1,000)

Description/ Account No.	Company Filing	Staff	Adjustment
A&G Accounts			
Medical & Dental Benefits	$ 31,555	$ 30,271	$ (1,284)
Other Employee Benefits	$ 20,950	$ 20,630	$ (321)
Insurance Premiums	$ 8,993	$ 6,914	$ (2,079)
Uninsurred Losses	$ 4,078	$ 2,279	$ (1,799)
Directors Fees	$ 1,213	$ 888	$ (325)
Officer Vehicle Plan	$ 104	$ -	$ (104)
Various A&G Account Summary Adjustments			$ (596)
Total A&G Adjustments			**$ (6,507)**
Transmission & Distribution O&M Accounts			
Porcelain Insulator Project	$ 684	$ 396	$ (287)
Locating Costs	$ 689	$ 417	$ (271)
Arc-Flash	$ 361	$ 90	$ (271)
EMS Development Costs	$ 174	$ -	$ (174)
Tree Trimming	$ 12,302	$ 10,956	$ (1,346)
FITNES Program Increase	$ 900	$ -	$ (900)
Various O&M Account Summary Adjustments			$ (163)
Total O&M Adjustments			**$ (3,413)**
Total OMAG Adjustments			**$ (9,919)**
Property Tax Adjustment			
Oregon Property Tax	$ 32,651	$ 29,102	$ (3,549)
Montana Property Tax	$ 4,279	$ 3,584	$ (695)
Total Adjustment to Taxes Other Than Income			**$ (4,244)**

UE 197 PGE - Medical & Dental Plan - A&G

				DR's
Union				
	2009 Forecast @ 8.5% Inflation	$	11,838,257	DR 301
	Increase over 2007	$	1,782,187	
	10 Months of Increase over 2007	$	1,485,156	DR 255
	2007 Actual	$	10,056,070	
	2009 Test Year	$	11,541,226	
Non-Union				
	Forecasted 2009 non-union benefits (employer & employee share)	$	22,403,058	DR 300
	Employers sharing percentage		84%	
	Employers share of forecasted 2009 non-union benefits	$	18,818,569	

	2007 Actual	Adjustments	Staff's Forecast
Union	$ 10,056,070	$ 1,485,156	$ 11,541,226
Non-Union			$ 18,818,569
Total			$ 30,359,795

		Check
Total Health and Dental Benefits per UE 197	$ 31,554,803	
Sub-total Health and Dental Benefits as adjusted	$ 30,359,795	
Actuarial and Other contracted costs	$ 434,722	
Remove Non-utility Allocation	$ 523,335	$ 523,335
Remove Non-utility Allocation	$ 30,271,182	$ 30,271,182
Adjustment	**$ (1,283,621)**	

Comments:

1. PGE's current union contract is set to expire on March 1, 2009. Under the current contract the amount PGE will contribute for medical coverage is set at $5.25 per straight time compensable hour. Because this is a set rate that will not increase until a new contract is in place, Staff proposes to allow an increased benefit amount to apply to the months of March through December 2009.

2. Staff has set the escalation rate for the Union medical/dental benefits at 8.5 percent annually over the 2007 cost. This appears to be similar to the rate at which PGE has increased its non-union benefits. Additionally, recent studies (*Hewitt Associates Outlook for 2008 and Towers Perrin 2008 Health Care Cost Survey,*) show increases to PPO premiums (100 percent of PGE's union benefits are a PPO plan) for 2008 in the range of 6 - 8.5 percent.

3. Staff has adjusted the sharing for Non-Union medical/dental from 85/15 to 84/16 sharing. Per PGE's Testimony the industry average is 84/16 rather than 85/15. Additionally, health care studies show that the employee's share of benefits has been increasing as a way to defray the premium increases to companies. Studies show that sharing in the range of 80/20 is becoming standard over multiple industries. *(Kaiser Family Foundation Employer Health Benefits 2007 Survey, Towers Perrin 2008 Health Care Cost Survey, and Hewitt Associates Outlook for 2008.)*

UE 197 PGE - Other Employee Benefits - A&G

	Revised UE 197	Additional Staff Adjustment	Staff Revised 2009	DR
Employee Wellness Program				
Occupational Health	$ 253,360	$ (28,926)	$ 224,434	DR 298
Ergonomics and IAM	$ 75,297	$ (41,046)	$ 34,251	DR 298, 102
Occupational Fitness	$ 58,620	$ (10,644)	$ 47,976	DR 298
Employee Training	$ 9,972	$ -	$ 9,972	
Employee Assistance Program	$ 64,257	$ -	$ 64,257	
Short Term Disability Insurance	$ 633,902	$ -	$ 633,902	
Long Term Disability Benefits	$ 1,358,332	$ -	$ 1,358,332	
Group Life Insurance	$ 828,400	$ -	$ 828,400	
Health Reimbursement Account	$ 1,530,768	$ -	$ 1,530,768	
Retirement Savings Plan	$ 14,656,491	$ -	$ 14,656,491	
Pension Plan	$ -	$ -	$ -	
Education Plan	$ 485,074	$ -	$ 485,074	
Recreation Program	$ 25,825	$ (25,825)	$ -	DR 299
Misc. Employee Benefits				
Colstrip Charge-Back	$ 139,400	$ -	$ 139,400	
Health Club Partial Reimbursement	$ 100,000	$ (35,000)	$ 65,000	DR 299
Commuter Program	$ 25,101	$ (12,551)	$ 12,550	DR 299
Service Awards	$ 225,000	$ (112,500)	$ 112,500	DR 299
Retiree Association and Retiree Luncheon	$ 13,200	$ (13,200)	$ -	DR 299
Executive Financial Planning	$ 31,500	$ (31,500)	$ -	DR 299
Other	$ 9,315	$ (9,315)	$ -	DR 299
Benefits Administration	$ 426,556	$ -	$ 426,556	
Total	$ 20,950,370	$ (320,507)	$ 20,629,863	

Total Other Employee Benefits Per UE 197	$ 20,950,370
Total Other Employee Benefits Per Staff	$ 20,629,863
Total Adjustment	$ (320,507)

Comments

1. Staff Adjusted the Employee Wellness, Employee Assistance, Retirement Savings, and Benefit Administration from the amounts shown in the I&B Expense 2009 FOM to the amount supported in Testimony.

2. Occupational Health: The main source for the increase over 2007 actuals' was for a $70,000 increase for wellness incentive programs, with a reference to items described in testimony. Staff reviewed the testimony references and it appears that all these items were in place during 2007 and were not new for 2009. Staff escalated the actual 2007expense by CPI to arrive at a forecasted 2009 amount.

3. Ergonomics and Integrated Absence Management: The source of the increase over 2007 actuals was identified as relating to IAM costs. In response to DR 102 PGE was unable to identify cost benefits (reductions) related to this program. Staff did not allow the additional cost for IAM and inflated the 2007 actual cost for Ergonomics to 2009.

4. Occupational Fitness: Staff escalated the 2007 actual cost to 2009. There does not appear to be any new programs or new costs for 2009. PGE did identify the 2008 and 2009 costs as being related to drug testing for new hires, however drug testing for new hires is not new to PGE and these costs were not removed from 2007 A&G accounts.

5. Recreation Program: Employee recreation and social activities should not be funded by customers.

6. Health Club Partial Reimbursement: Although the expansion of this program to include activities such as yoga, Pilates, tai chi, etc may increase participation by employees, Staff does feels that it is unlikely that participation will almost double. Staff allowed for approximately 20% participation growth + inflation.

7. Commuter Program: PGE's participation in transportation fairs should not be funded by customers.

8. Service Awards. Remove 50% as bonuses

9. Retiree Association and Retiree Luncheon: Should not be funded by customers.

10. Executive Financial Planning: Should not be funded by customers.

11. Other. Disallowed unidentified expenses.

UE 197 PGE - Insurance Premiums- A&G

						Staff Policy Review	UE 197	DR's
Property	70% FM Global	800M	All Risks of Physical Loss or Damage	7-1-07 to 7-1-08	$ 1,604,746.00			
	20% AEGIS	800M	All Risks of Physical Loss or Damage	7-1-07 to 7-1-08	$ 416,510.22			
	10% Lloyd's Syndicate 1225	500M	All Risks of Physical Loss or Damage	7-1-07 to 7-1-08	$ 174,569.70			
	10% AEGIS	300M x 500M	All Risks of Physical Loss or Damage	7-1-07 to 7-1-08	$ 30,592.91	$ **2,226,419**	$ 2,778,647	DR 66, 285
			Trans & Dist Property		$ 1,000,000.00	$ **1,500,000**	$ 1,584,622	
Workers Comp	National Union Fire Insurance Co	55M	Excess Workers Comp	7-1-07 to 7-1-08	$ 260,557.00	$ **260,557**	$ 282,613	DR 66, 285
Liability	AEGIS	35M	Excess Liability (First Layer)	3-15-08 to 3-15-09	$ 952,111.76			
	EIM	100M x 35M	Excess General Liability (Second Layer)	3-15-08 to 3-15-09	$ 665,000.00			
	AEGIS Lloyd's Syndicate 1225	25M x 135M	Excess Liability (Third Layer)	3-15-08 to 3-15-09	$ 104,657.00			
	Lloyd's of London	40M x 160M	Excess Liability (Fourth Layer)	3-15-08 to 3-15-09	$ 93,985.25	$ **1,815,754**	$ 2,031,255	DR 66, 285
	AEGIS	25M	Fiduciary Liability Insurance	5-1-08 to 5-1-09	$ 85,000.00			
	US Specialty Insurance Co	10M x 25M	Excess Fiduciary Liability (Second Layer)	5-1-08 to 5-1-09	$ 25,000.00			
	EIM	15M x 35M	Excess Fiduciary Indemnity (Third Layer)	5-1-08 to 5-1-09	$ 31,610.00	$ **141,610**	$ 173,769	DR 66, 285
	Central, American, Tokio, Mitsui	20M	Aviation	11-1-07 to 11-1-08	$ 39,829.00	$ **39,829**	$ 53,813	DR 66, 285
	AEGIS	35M	D&O Liability Insurance	5-1-08 to 5-1-09	$ 539,695.00			
	EIM	50M x 35M	Excess D&O (Second Layer)	5-1-08 to 5-1-09	$ 508,775.00			
	US Specialty Insurance Co	25M x 85M	Excess D&O (Third Layer)	5-1-08 to 5-1-09	$ 220,875.00			
	XL Specialty	30M x 110M	Excess D&O (Fourth Layer)	5-1-08 to 5-1-09	$ 251,100.00	$ **1,520,445**	$ 1,769,355	DR 66, 285
	Illinois National Insurance Co	1M	Business Automobile Coverage	3-31-08 to 3-31-09	$ 33,462.00	$ **33,462**	$ 37,143	DR 66, 285
	Zurich American Insurance Co	10M each class	Commercial Crimes	3-1-07 to 3-1-09	$ 55,000.00	$ **55,000**	$ 57,100	DR 66, 285
	ANI	100, 200, 300 M	Nuclear Energy Liability Program	1-1-08 to 1-1-09	$ 260,962.00	$ **260,962**	$ 221,400	DR 66, 285
	Lloyd's of London		Builders Risk Coverage	4-1-07 to 4-1-08	$ 256,528.14			DR 66, 285
			Special Coverage			$ **-**	$ 3,333	DR 285
	Sub-Total					$ **7,854,038**	$ **8,993,050**	
	Adjustments		Remove 50% Excess D&O Insurance			$ (490,375)		
			Contingent "undeclared" Policyholder Credit (All-Risk)			$ (170,000)		DR 70
			Contingent "undeclared" Policyholder Credit (Nuclear)			$ (50,000)		
	Sub-Total					$ 7,143,663	$ 8,993,050	
			Utility Allocation			96.79%		
	Adjustment				**$ (2,078,699)**	**$ 6,914,351**	**$ 8,993,050**	

Comments:

1. Removed 50% of Excess D&O Liability and Fiduciary as a Shareholder Cost (Allowed 100% of primary coverage) since two main reasons for claims are financial statements issues and insider trading.
2. According to Foley & Lardner LLP, *"Shareholder-claims are the largest source of this risk, accounting for 50% of all D&O claims."* http://www.foley.com/files/tbl_s31Publications/FileUpload137/4087/DOLiability.pdf
3. According to Towers Perrin's, regarding D&O liability insurance claims, *"The claimant distribution continues to be heavily dependent on the ownership structure of survey participants. For example, 49% of the claims against public participants were brought by shareholders."* http://www.towersperrin.com/tp/jsp/tillinghast_webcache_html.jsp?webc=Tillinghast/United_States/Press_Releases/2007/20070413/2007_04_13.htm
4. Per a telephone conversation with PGE on 5/22/08, special coverage insurance for 2009 will be set at $0.
5. Contingent "undeclared" policyholder credit identified by PGE in response to DR 70. PGE is optimistic that this credit will occur.
6. Per a telephone conversation with PGE on 5/23/2008, PGE is expecting to receive a policy holder credit of $50,000 in 2009 for its Nuclear liability insurance.
6. Builders Risk Coverage for Phase II of Biglow should be capitalized into the project. See UE 197/PGE/500, Piro - Tooman/7.
7. Due to the soft state of the insurance market, Staff proposes to not allow any escalation and to hold the recent policy premiums steady for 2009.
8. The Utility Allocation applied above is the rate that was used in UE 180, Staff has Data Requested the updated allocation.

UE 197 PGE - Uninsured Losses - A&G

Actual Uninsured Losses	**Automobile Liability**	**Auto/GL**	**General Liability**	**Workers Compensation** W/C	**DR's** CPI
2003		$760,802			1.023
2004		1,037,712		$1,775,970	1.027
2005		1,247,641		1,117,448	1.034
2006		603,123		1,126,975	1.032
2007		1,233,215		1,388,051	1.029
Escalated to 2008 Dollars					
2003 Loss in 2008 $$$		$877,674			
2004 Loss in 2008 $$$		1,170,208		$2,002,727	
2005 Loss in 2008 $$$		1,369,952		1,226,995	
2006 Loss in 2008 $$$		640,473		1,196,766	
2007 Loss in 2008 $$$		1,268,978		1,428,304	
Total		$5,327,285		$5,854,793	
5 year average		1,065,457		1,170,959	
2009 escalation (1.9%)		1,085,701		1,193,207	
UE 197 Amounts	330,200		1,942,600	1,804,967	
Adj		**$1,187,099**		**$611,760**	

Staff Proposed Adjustment **($1,798,860)**

UE 197 PGE - Directors Fees - A&G

2009 Estimated Board of Directors' Costs	UE 197	Adjustment	Staff Adjusted	DR's
Retainers	$ 393,975	$ -	$ 393,975	DR 72
Meeting Fees	$ 331,000	$ -	$ 331,000	DR 72
Other Expenses	$ 163,300	$ -	$ 163,300	DR 72
Directors' Retirement Accrual	$ 15,300	$ (15,300)	$ -	DR 72
Directors' Stock Incentive	$ 270,000	$ (270,000)	$ -	DR 72
Directors' Deferred Comp Interest	$ 39,800	$ (39,800)	$ -	DR 72
Total Board of Director's Budget	$ 1,213,375	$ (325,100)	$ 888,275	

Board of Directors Cost Per Budget	$ 1,213,375.00
Board of Directors Cost Per Staff	$ 888,275.00
Adjustment	**$ (325,100.00)**

Comments:

1. Staff removed the Directors' Retirement Accrual as a SERP.

2. Staff removed the Directors' Stock Incentive as a bonus. As described in PGE's 10-K, *"The purpose of the Plan is to provide incentives which will attract, retain and motivate highly competent persons as officers directors and key employees of the Company and its subsidiaries and affiliates by providing them with appropriate incentives and rewards in the form of rights to earn shares of the common stock of the Company."*
3. Staff removed the Director's Deferred Comp Interest as a form of a SERP.

UE 197 PGE - Officer Vehicle - A&G

	UE 197	Adjustment	Staff Revised 2009
Officer Vehicle Plan (N44202)	$ 103,800.00	$ (103,800.00)	$ -
Total Officer Vehicle Plan Per UE 197			$ 103,800.00
Total Officer Vehicle Plan Per Staff			$ -
	Adjustment		**$ (103,800.00)**

Comments: 1. Removed the Officer Vehicle Plan as a bonus to executives.

UE 197 PGE - Miscellaneous O&M Adjustments - O&M

Summary of Various Adjustments by FERC Account

Staff Category	Staff Adjustment	Comments
FERC 901-905		
Catering	(38,663)	
Gifts	(16,569)	
Promotional	(4,476)	
Civic Activity	(15,823)	
Civic Activity	(2,700)	Training to be a state-certified energy auditor and inspector - Because customers pay public purpose funds for these activities any PGE costs should be below the line.
Total FERC 901-905	**(78,231)**	
FERC 920-935		
Catering	(96,479)	
Gifts	(58,364)	
Promotional	(76,305)	
Civic Activity	(60,469)	
Non-essential Activity	(15,681)	
Former Directors Life Insurance	(8,448)	
Political Activity	(29,500)	Customer Research - Regulated residential customers are captive (service area) customers.
Corporate Image (50%)	(32,592)	Training on key utility issues for lawyers, officers, and media personnel. Not used every year
Civic Activity	(49,532)	Environmental services per agreement with the Forest Service to help pay for operational forest fish traps on the lower Clackamas river (Faraday/North Fork/River Mill), analyzing data, and perform habitat surveys - **Should be included in licensing costs.**
California Refund	(61,540)	Non-recurring
California Refund/Bankruptcy	(4,755)	Non-recurring
2008 Expense	(24,140)	Annual rent for storage for PGE's underground crews. - Transaction Summaries also showed a 2007 expense
Total FERC 920-935	**(517,805)**	
Total FERC 9XX	**(596,036)**	

UE 197 PGE - Porcelain Insulator Replacement Project - O&M

		DR's
Porcelain Insulator Replacement Project		
Actual 2007 Non-Labor Expenses	$ 381,631	DR's 97, 180, 307
Escalated to 2009	$ 396,267	
UE 197 Non-Labor Expenses	$ 683,763	
Adjustment	$ (287,496)	

Comments:

1. Staff proposes to hold the cost of the porcelain insulator replacement project at the 2007 level escalated for inflation.

2. Staff is unable to justify a cost increase in excess of 79 percent for this program when engineering evaluations have found no definitive cause of the failures. The Insulators have served in PGE's system for over 50 years, and there is no indication that the age of the insulators is a cause of the failures.

UE 197 PGE - Locating Costs - O&M

		Amount	DR's
Actual 2007 N36321 costs to Locating Inc and Stake Center Locating	$	1,114,979	DR 183
Actual 2007 N36321 costs other than Locating Inc or Stake Center Locating	$	173,292	DR 183
Total 2007 N36321 costs	$	1,288,271	
UE 197 Forecasted 2009 cost	$	2,013,058	
Total Forecasted Increase	$	724,787	
95% allocated to contract cost increase	$	688,548	DR 94
5% allocated to increase in locates	$	36,239	DR 94
Locate Underground Lines			
Actual 2007 payments to Locating Inc	$	779,723	DR 303
Locates performed by Locating Inc during 2007		60,725	DR 303
2007 Average cost per locate	$	12.84	
Total locates performed during 2007		119,343	DR 96
Estimated 2007 full year Locating Inc cost	$	1,532,392	
Actual 2007 full year locating for Locating Inc and Stake Center Locating	$	1,114,979	DR 183
Annual Increase due to contract cost increase	$	417,413	
UE 197 increase due to higher contract costs	$	688,548	
Staff adjusted increase due to higher contract costs	$	417,413	
Adjustment	$	(271,135)	

Comments:

1. There were two locating contracts in place during 2007 the higher cost contract will continue into 2009.
2. The higher cost locating contract was in place for the second portion of 2007 and will expire on May 31, 2009, PGE the option to extend this contract by one year.
3. According to PGE's response to DR 94, 95 Percent of the projected increase over the 2007 actual is due to higher contract cost.
4. Staff calculated an estimated cost of locates under the higher cost contract as if it had been in place all of 2007. Staff did not include an escalation for the contract cost as it does not appear that the locating contract calls for one.

UE 197 PGE - Additional O&M Adjustments - O&M

				DR
Arc-Flash Mitigation				
	Proposed UE 197 cost (mostly to purchase protective clothing)	$	361,000	
	Useful life		4-Years	DR 99
	Annual expense over useful life	$	90,250	
	Annual expense per UE 197	$	361,000	
	Adjustment	$	(270,750)	
EMS Development Costs				
	Remove EMS development costs not capitalized	$	174,451	DR 83 & 288
Tree Trimming Costs				
	Method 1			
	Actual 2006 expense	$	10,901,677	
	Variance for 2008 identified in UE 188	$	(1,800,000)	
	Forecasted 2008 per UE 188	$	9,101,677	
	Forecasted to 2009 @ 8%	$	9,829,811	
	Method 2			
	Updated 2009 Forecasted Cost	$	10,955,802	DR 382
	UE 197 Tree Trimming Expense	$	12,301,905	
	Adjustment	$	(1,346,103)	
	Difference from forecasted 2009 and updated 2009		11.45%	
FITNES				
	Remove forecasted increase due to early completion in 2007	$	900,000	DR 93, 179, 306

Comments:

1. Staff adjusted Arc-Flash Mitigation to amortize the cost of protective clothing over its useful life. In response to DR 99, PGE estimated that the useful life of this clothing was between 3 - 5 years. Staff set the useful life at 4 years, the middle of this estimate.
2. Staff removed costs incurred in connection with the development of EMS from O&M. These costs were one time costs which should not reoccur in 2009.

3. Due to additional information provided by PGE in Data Request 382, Staff adjusted the 2009 forecast upwards to $10,955,802. Because the adjusted 2009 forecasted amount was 11.45 percent greater than the 2009 forecasted amount (based on UE 188), an additional escalation was not performed. As a result, Staff's adjustment to PGE's tree trimming costs is $1,346,103.

4. Staff removed the $900,000 increase to the FITNES program, which was explained by PGE as resulting from the early completion of the second 10-year cycle in 2007. The FITNES program consists of both overhead O&M, which is on a 10-year cycle, and underground O&M, which is on a 4-year cycle. Staff found that the overhead FITNES costs were relatively consistent with previous years and identified the lower 2007 cost with the underground FITNES program, saw a cost reduction of $1,007,438 from 2006 to 2007.

UE 197 PGE - Miscellaneous O&M Adjustments - O&M

Summary of Various Adjustments by FERC Account

Staff Category	Staff Adjustment	Comments
FERC 56X		
Catering	(244)	
Civic Activity		
Total FERC 56X	**(244)**	
FERC 580		
Catering	(37,193)	
Gifts	(4,719)	
Promotional	(54,230)	
Civic Activity	(12,335)	
Total FERC 580	**(108,477)**	
FERC 593		
Catering	(791)	
Promotional	(2,449)	
Civic Activity	(51,356)	Payment for a contract Forester (Washington Forestry Consultants, Inc.) as part of PGE's tree trimming costs. PGE has added a FTE for this function, but has not provided any documentation of removal of this cost from its budget.
Total FERC 593	**(54,596)**	
Total FERC 5XX	**(163,317)**	

UE 197 PGE - Taxes OTI Adjustment

	2007 Actual	Adjustment	Adjusted 2007	2009 Forecasted	Adjustment	Staff's 2009	UE 197	DR's
Property Tax								
Oregon	$ 28,519,422	$ (2,418,000)	$ 26,101,422	$ 27,102,464	$ 2,000,000	$ 29,102,464	$ 32,650,774	DR 75, 76
Montana	$ 3,451,819	$ -	$ 3,451,819	$ 3,584,203		$ 3,584,203	$ 4,279,200	DR 75, 77
Total OR & MT Property Tax	$ 31,971,241	$ (2,418,000)	$ 29,553,241	$ 30,686,667	$ 2,000,000	$ 32,686,667	$ 36,929,974	

Total OR & MT Prop Tax Per UE 197	$ 36,929,974.00
Total OR & MT Prop Tax Per Staff	$ 32,686,666.90
Adjustment	$ (4,243,307.10)

Notes:

1. Oregon Property Taxes for 2007 were $2.418 Million higher due to an Port Westward being delayed and PGE not receiving its Property Tax exemption from Columbia County. This Credit will start in 2008 and Property Taxes will be $0 for five years. See Commission Order 08-118.
2. Oregon Property Taxes for 2009 will be $2.000 Million higher due to Biglow 1 being in service. PGE received a SIP for which costs of approximately $.700 Million are included as A&G costs.
3. Staff increased the adjusted 2007 property tax cost by CPI to arrive at the 2009 forecasted amount.

CASE: UE 197
WITNESS: Dustin Ball
Michael Dougherty

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 303

Exhibits in Support of Testimony

July 9, 2008

April 30, 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 18, 2008
Question No. 255

Request:

As a follow up to DR No. 58, please provide a detailed explanation regarding bargaining unit employee's medical benefits through the Taft Hartley Trust. Please also identify the employer/employee contributions to medical (health, dental, and vision) plans (i.e. 90/10, 85/15, 80/20, etc.).

Response:

Medical, dental and vision benefits are provided through the Taft Hartley Trust for bargaining unit employees. Union medical benefits include coverage for doctor visits, hospitalization, surgery, diagnostic lab/x-ray, prescriptions, etc. The EBA (Employee Beneficiary Association) serves as the administrator of the plan.

As defined in the collective bargaining agreement, the employer contributions are $5.25 per straight time compensable hour (i.e., 174 hours per month per enrolled full-time employee). The employee contributes $0.52 per straight time compensable hour. Further details are provided in section 15.5 of the 2004-2009 Agreement, provided as Attachment 255-A.

April 15, 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. 102

Request:

Please quantify the following cost reductions, and show how (and to what extent) the implementation of an Integrated Absence Management Program has been included as a reduction to projected 2009 costs.

Response:

The Integrated Absence Management (IAM) program was launched on 10/1/2007 to provide a more efficient, centralized, and collaborative approach to absence management within PGE.

A cost reduction analysis from PGE's IAM program is not available. We are currently developing key metrics for the program to monitor the direct and indirect costs as well as indicators of IAM effectiveness. PGE expects that long-term costs will decrease and we may see some short-term intangible benefits by reducing the days away from work through increased efficiency managing absences, providing return-to work assistance, and improving the use of health care resources during recovery periods. Additionally, we will collect and act on employee feedback in an effort to continuously improve the efficiency and value of the program.

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 May 1, 2008
Question No. 299

Request:

Please provide, in a table format, a breakdown of the forecasted $1,054,000 in miscellaneous benefits costs for 2009. Please also provide a breakdown of the 2005 through 2007 and estimated 2008 miscellaneous benefits costs in this same table. Please explain the reason for any annual increases in a specific cost category (i.e. education assistance, service awards, etc) which exceed 10%.

Response:

Attachment 299-A provides a breakdown of 2005 through 2007 and estimated 2008 and 2009 miscellaneous benefits cost.

Colstrip Charge-Back (36.8%) – PGE co-owns the Colstrip 3 & 4 generation plants and is "charged-back" a lump sum for health care premiums and other benefits for PGE's share. The 2009 forecast reflects an increase in these benefits costs.

Health Club Reimbursement (NA) – This program supports our Energy for Life program. PGE believes that promoting a healthy work force reduces long-term medical costs, and attendance-driven partial reimbursement supports this goal. The health club reimbursement program is not a new cost, and the percentage increase from 2005 does not reflect 2005 costs. Prior to 2007, costs were recorded as a payroll expense. Total costs increase from 2007 because PGE has expanded the eligibility of the programs to include non-traditional health and wellness club activities (e.g., Yoga, Pilates, Tai Chi, etc).

Commuter Program (14.6%) – PGE supports transportation fairs which promote alternate forms of employee commuter transportation methods. Each Transportation Fair features a variety of transportation experts from area agencies and businesses.

Service Awards (21.9%) – As a retention strategy, PGE honors employees for their years of service at five year anniversary intervals. PGE has been below the industry standard for a long time and in 2008 and 2009 we increased the budget to bring our Service Awards program closer to market. Attachment 299-B provides a comparison of the average dollars spent on employee recognition for 7 energy utilities (combined) and PGE's previous average dollars spent on employee recognition.

Retiree Association and Retiree Luncheon (NA) – PGE supports the Retiree Association and sponsors a retiree luncheon to honor PGE's employees who have served the company. These costs were not recorded to a specific benefit job in 2005.

Executive Financial Planning (NEW) – PGE's total compensation for executives provides this benefit.

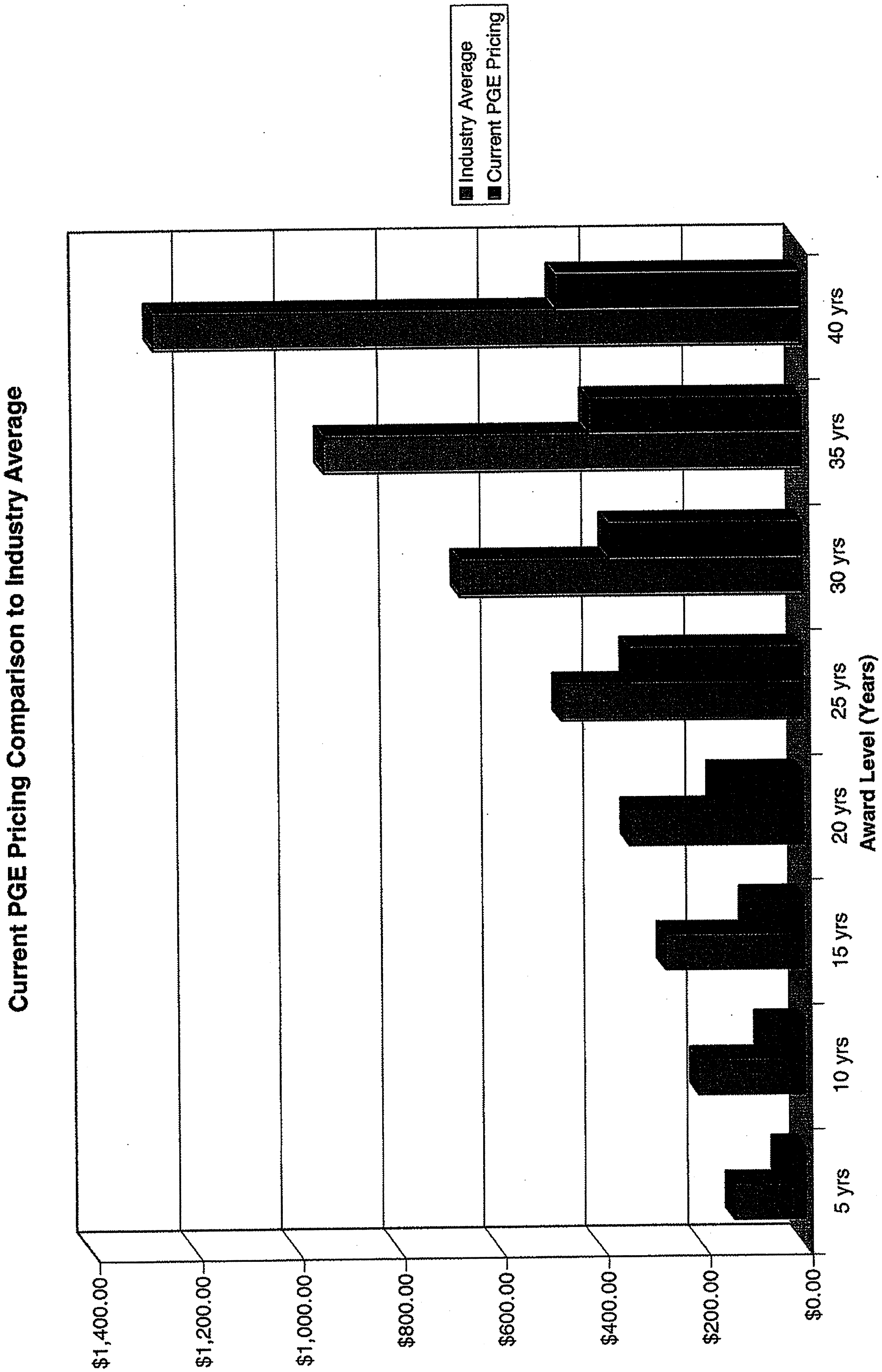
UE 197
Attachment 299-A

Miscellaneous Benefits Costs

Ledgers and Cost Descriptions	2005 ACTUALS	2006 ACTUALS	2007 Actuals	2008 FOM	2009 FOM	Annual % Change 2005 - 2009
N44457-EDUCATION PROGRAM Total	458,870	494,949	532,736	453,340	485,074	1.4%
N44454-RECREATION PROGRAM Total	23,241	19,244	18,749	25,000	25,825	2.7%
N44459						
Colstrip Charge-Back	39,847	30,067	73,043	116,000	139,400	36.8%
Health Club Partial Reimbursement	0	0	49,905	100,000	100,000	N/A
Commuter Program	14,549	17,604	6,475	25,101	25,101	14.6%
Service Awards	102,053	93,443	84,442	100,000	225,000	21.9%
Retiree Association and Retiree Luncheon	0	2,500	11,862	13,200	13,200	N/A
Executive Financial Planning	0	0	0	31,500	31,500	NEW
Other	34,678	19,002	74,726	9,315	9,315	-28.0%
N44459 - MISCELLANEOUS EMPLOYEE BENEFIT Total	191,126	162,615	300,454	395,116	543,516	29.9%
Total Miscellaneous Benefits	673,237	676,808	851,938	873,456	1,054,415	11.9%

UE 197
Attachment 299-B

Comparison of Market and PGE
Service Award Costs per Employee


Current PGE Pricing Comparison to Industry Average
Industry Average
Current PGE Pricing
$1,400.00
$1,200.00
$1,000.00
$800.00
$600.00
$400.00
$200.00
$0.00
5 yrs
10 yrs
15 yrs
20 yrs
25 yrs
30 yrs
35 yrs
40 yrs
Award Level (Years)

April 18, 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. 070

Request:

Please provide work papers showing how the $550,000 projected increase to All-Risk property insurance, identified in UE 197/PGE /500, Piro – Tooman/6, was calculated.

Response:

See Attachment 070-A for a detail of the increase to All-Risk property insurance.

The 4 percent increase, which equals approximately $90,000 for each of two years (total $180,000), reflects the valuation of the overall property asset base to which the premium rate applies. PGE uses Handy-Whitman cost trend factors to value utility property. See further discussion below.

An annual premium rate increase assumption of 5 percent contributes approximately $215,000. Offsetting this, PGE has included a contingent policyholder credit (premium reduction) of $170,000. It is impossible to know whether or not the mutual insurers will actually declare a credit. However, at this time the market is and remains fairly soft so we are somewhat optimistic. We do not control this action, however, and absent such a credit, costs would rise accordingly.

The remaining increase of approximately $320,000 represents the placement of All-Risk property coverage for Phase I of Biglow Canyon.

Handy-Whitman

PGE uses Handy-Whitman cost trend factors to trend PGE utility property to current day values. These trend factors are maintained and updated twice a year by Whitman, Requardt & Associates, an engineering firm located in Maryland. These cost factors have been published continuously since 1924 and are widely used in the electric industry.

PGE uses the cost trend factors listed in the Electric Utility Construction section for the Pacific Region. The factors, separated by Function, which PGE uses to value property are Steam, Hydro, and Other. See Attachment 070-B.

March 28, 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 28, 2008
Question No. 180

Request:

Regarding the porcelain insulator replacement program, please:

a. **Describe the program in detail;**
b. **Describe the depreciable lifetime of an insulator such as the ones being replaced in this program;**
c. **Explain whether the company is replacing the insulators in conjunction with other routine maintenance being performed on the distribution system; and**
d. **Identify any effect the distribution level porcelain insulator failure has on the safety and reliability metrics in the PGE SQM, and explain that effect.**

Response:

a. The Porcelain Insulator Replacement Program is a targeted maintenance program to replace aging and failing porcelain insulators our system. In 1999, PGE began noticing upward trends in the failures of these insulators. Since then, over 32 of these insulators have failed. Engineering evaluations have been conducted to try and determine the root cause of the failures, but no definitive cause has been found. There is no indication that the age of the porcelain insulators is a cause of failure. The only common event is that the failures typically occurred during relatively calm weather conditions when the insulator loading is at its lowest.

PGE's testimony in UE 180, specifically PGE Exhibit 600, page 9 has additional information regarding the Porcelain Insulator Replacement Program. This material is included as Attachment 180-A.

b. Porcelain insulators are recorded in FERC 365, Overhead Conductors / Devices. Pursuant to Order No. 06-581 in Docket UM 1233, PGE depreciates porcelain insulators (FERC 365) over a 43 year life. Since porcelain insulators are not retirement units, only the first installation is capitalized. Thereafter, as insulators are replaced, the cost is expensed.

c. This is a stand-alone program to replace just the porcelain insulators. However, if a line is being relocated or reconductored, the insulators are replaced at that time.

d. The failure of the porcelain insulators sometimes results in outages because as the insulators shear away, the energized lines fall onto distribution circuits that are carried on the same poles. These types of outages increase the SAIDI, SAIFI, and MAIFI numbers for that circuit, may result in customer complaints, and present potential safety hazards.

UE 197
Attachment 180-A

UE 180, PGE Exhibit 600, Page 9

A. Our FITNES program represents a cost-effective approach to maintaining poles for our distribution infrastructure. In 2007, we will begin our fourth cycle to inspect and treat poles and overhead facilities. We now focus on inspection and treatment, which costs only about $25 per pole, rather than replacement, which costs more than $2,000 per pole. This results in an increase in O&M costs, but a greater decrease in capital expenditures and overall costs. The focus on inspection and treatment increased O&M costs by approximately $1.5 million over the 2002-2007 period.

This focus on pole inspection and treatment rather than replacement is the result of practices dating back more than 40 years. In 1963, PGE pioneered a new pole treatment technique, and poles installed since then are far less likely to have decay problems than those installed earlier. Our pole rejection rate is now significantly less than one percent, one of the lowest rates in the country. In addition to the treatment technique, we have an ongoing testing program, which is supported by the research capabilities of Oregon State University.

Q. What are the advantages of PGE's porcelain insulator replacement program?

A. Our porcelain insulator replacement program is a least-cost approach to working with an aging system to provide safe, reliable power to customers. This program will increase distribution O&M costs by approximately $0.5 million by 2007. We have experienced a number of random failures of our porcelain insulators, many of which have been in place for almost 40 years. Replacing all porcelain insulators will maintain our current high reliability standards. Therefore, over a 16-year period beginning in 2006, we will replace all 57 kV and 115 kV porcelain horizontal post insulators with polymer insulators. We currently have approximately 25,000 insulators in our system, of which more than 19,000 are porcelain.

April 22, 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. 094

Request:

Please provide a breakdown of the estimated locating expense for 2009. What portion of the projected $700,000 increase is due to the higher contract cost, and what portion is due to the projected increase in Locating requests?

Response:

2009 Projected:

Locating Requests	Costs
136,500	$1,787,197.00

Approximately 95% of the projected cost increase is due to the higher contract cost. The remaining portion of the cost increase, approximately 5%, is due to the projected increase in locating requests.

April 15, 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. 099

Request:

Please describe the protective clothing that will be purchased in 2009 to mitigate Arc-flash? What is the useful life of the items that will be purchased?

Response:

Clothing will consist primarily of specialized shirts and pants with additional coveralls and outer wear as needed to protect the worker. Garment life is impacted by weight of material and type of manufacturing process used. Industry tests tell us that the material we are considering for wear trials could last as long as 3-5 years.

May 15, 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 25, 2008
Question No. 288

Request:

As a follow up to DR No. 83, please provide a breakdown of the 2007 costs, which were not capitalized and incurred in connection with the development of the new EMS system. Please provide the FERC Account and Ledger number indicating where these expenses were booked?

Response:

FERC	Ledger	2007 Actuals
556	N25113	82,353
561.2	N30505	17,441
569.2	N30401	74,657
	Total	174,451

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. 093

Request:

What were the actual expenses for the FITNES program during 2004, 2005, 2006, and 2007? When was the second full cycle of the FITNES program completed during 2007?

Response:

	2003	2004	2005	2006	2007
Overhead O&M	709,363	803,794	2,042,027	1,827,945	1,923,345
Underground O&M	47,855	448,484	1,474,885	1,536,240	528,802
	757,218	1,252,278	3,516,912	3,364,185	2,452,147

The second full cycle of FITNES was completed by the end of the second quarter of 2007, with the exception of miscellaneous dry weather work and special situations.

The increase from 2004 to 2005 is explained as follows: When the program was first initiated, the majority of FITNES costs were charged to capital. In 2005 we changed the accounting to charge the majority of FITNES costs to expense; PGE determined that the activities associated with the program had changed from asset replacement (replacing the poles) to the inspection and treatment of equipment (upkeep of existing poles and equipment).

May 20, 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. 306

Request:

What are the annual FITNES budgets versus actual costs for the last five years for this program? Break out separately for (1) safety inspections, (2) pole structural testing & maintenance, and (3) corrections and repairs?

Response:

Attachment 306-A provides the annual overhead FITNES budgets and actual costs for the years 2003 through 2007, separated by the above classifications.

UE 197
Attachment 306-A

2003-2007 FITNES Budget and Actual Costs

UE-197
OPUC DR # 306

Question:
What is the annual FITNES Budgets versus actual costs for the last five years for this program? Break out separately for (1) safety inspections, (2) pole structural testing & maintenance, and (3) corrections and repairs?

Operating only

	2003 Budget	2003 Actuals	2004 Budget	2004 Actuals	2005 Budget	2005 Actuals	2006 Budget	2006 Actuals	2007 Budget	2007 Actuals
Safety Inspections	$ 148,174	$ 92,984	$ 130,904	$ 80,721	$ 135,864	$ 62,525	$ 117,629	$ 45,615	$ 117,537	$ 62,658
Pole Structural Testing & Maint [1]	$ -	$ 526,088	$ -	$ 710,884	$ -	$ 697,734	$ -	$ 848,902	$ -	$ 829,488
Correction & Repairs	$ 675,100	$ 14,507	$ 900,000	$ 3,847	$ 2,234,250	$ 875,539	$ 1,994,450	$ 889,532	$ 2,244,459	$ 1,076,772
Other [2]	$ 100,247	$ 75,784	$ (38,168)	$ 8,342	$ 242,120	$ 406,228	$ 152,621	$ 43,896	$ 154,022	$ (45,573)
Total	$ 923,521	$ 709,363	$ 992,736	$ 803,794	$ 2,612,234	$ 2,042,027	$ 2,264,700	$ 1,827,945	$ 2,516,018	$ 1,923,345

Capital Only

	2003 Budget	2003 Actuals	2004 Budget	2004 Actuals	2005 Budget	2005 Actuals	2006 Budget	2006 Actuals	2007 Budget	2007 Actuals
Safety Inspections	$ 3,000	$ 1,388	$ -	$ 67	$ -	$ -	$ -	$ -	$ -	$ -
Pole Structural Testing & Maint [1]	$ 1,771	$ 1,780	$ -	$ 25,245	$ -	$ 6,326	$ -	$ -	$ -	$ -
Correction & Repairs	$ 2,171,968	$ 1,946,285	$ 2,264,927	$ 2,244,310	$ 995,855	$ 508,600	$ 287,737	$ 557,299	$ 983,797	$ 338,982
Other [2]	$ 1,624,541	$ 2,075,663	$ 2,325,151	$ 2,340,131	$ 1,910,825	$ 681,668	$ 2,039,706	$ 921,664	$ 1,927,420	$ 667,615
Total	$ 3,801,280	$ 4,025,116	$ 4,590,078	$ 4,609,753	$ 2,906,680	$ 1,196,594	$ 2,327,443	$ 1,478,963	$ 2,911,217	$ 1,006,597

[1] - A separate budget is not prepared for this line. Instead, it's include within the budget for "Correction & Repairs."
[2] - Includes corporate loadings & allocations as well as other miscellaneous charges.

April 15, 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. 076

Request:

Please provide documentation of property tax statements for Oregon property taxes from July 1, 2005 through June 30, 2006, from July 1, 2006 through June 30, 2007, and from July 1, 2007 through June 30, 2008. Has PGE litigated its assessed property value for any of these tax periods? If so, were any of these reported assessments reduced?

Response:

PGE objects to this request on the basis of undue burden. PGE receives in excess of 850 property tax statements each year. Without waiving objection, PGE responds as follows:

Attachment 076-A provides copies of the Notice of Proposed Assessment from the Oregon Department of Revenue (DOR) for tax year 2005/2006, 2006/2007, and 2007/2008. Attachment 076-A is confidential and subject to the Protective Order in this docket (Order 08-133).

PGE did not formally litigate the DOR's assessed values for those tax years. However, PGE engaged in informal negotiations with the DOR. For the 2005/2006 and 2007/2008 tax years, PGE negotiated reduced assessed values as shown in the DOR's Revised Notice of Proposed Assessment, included as Attachment 076-B. Attachment 076-B is confidential and subject to the Protective Order in this docket (Order 08-133).

CASE: UE 197
WITNESS: Dustin Ball
Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 304

Exhibits in Support of Testimony

July 9, 2008

Staff/304
Ball-Dougherty/ 1

Hewitt Associates Data Reveals Rate of Increases for U.S. Health Care Costs Declines for Fifth Consecutive Year

Contacts:
Catherine Brandt, Hewitt Associates, (847) 442-7665
MacKenzie Lucas, Hewitt Associates, (847) 442-7662

2007-09-24

Companies Focusing on Health Plan Designs and Keeping Employees Healthy to Help Mitigate Impact of Rate Increases

LINCOLNSHIRE, Ill. – U.S. companies enjoyed a nine-year low in health care cost rate increases this year, but employers and employees should not expect to see that trend continue in 2008, according to Hewitt Associates, a global human resources services company. In 2007, average health care rate increases were 5.3 percent, down from 7.9 percent in 2006. However, Hewitt is projecting an 8.7 percent average increase for employers in 2008.

Outlook for 2008

According to Hewitt, the average health cost per person for major companies will increase from $7,982 in 2007 to $8,676 in 2008. The amount employees are being asked to contribute in 2008 will be $1,859, representing approximately 21 percent of the overall health care premium and up from $1,690 in 2007. Average employee out-of-pocket costs, such as copayments, coinsurance and deductibles, are also expected to increase from $1,576 in 2007 to $1,738 in 2008. Overall, employees' total health care costs — including employee contribution and out-of-pocket costs — are projected to be $3,597 in 2008, up 10.1 percent from $3,266 in 2007.

"It's encouraging to see rate increases soften because it means that companies are making a concerted effort to manage health care costs," said Jim Winkler, practice leader of Hewitt's Health Management Consulting business. "However, one of the primary ways employers have been accomplishing this is by passing a significant percentage of costs to employees, and we're seeing evidence that this strategy is prompting an increasing number of employees to forego necessary preventative care and/or not comply with prescribed medications. While some cost shifting is appropriate, it's critical that companies design their health care programs in a way that encourages employees to use them — and use them wisely. Otherwise, they are essentially trading preventative care now for 'rescue care' later, which will lead to unhealthy employee populations, a decrease in employee productivity and ultimately — higher health care costs."

2007 Cost Increases by Major Metropolitan Area

While Hewitt's data shows a decline in overall cost increases in 2007, a few major U.S. markets experienced rate increases two-to-three times higher than the average: Nashville (14.1 percent), San Diego (11.5 percent) and San Francisco (11.5 percent).

"It's hard to pinpoint the exact reasons why health care cost increases vary in each region, but differences in health plan competition, demographics and market dynamics of health care providers are all factors," said Bob Tate, chief actuary of Hewitt's Health Management Consulting business. "We've noticed that several of the cities with the highest rate increases this year have a large number of employees enrolled in HMO plans, and these plans have experienced higher cost increases in recent years."

2007 Cost Increases by Plan Type

On average, Hewitt saw average cost increases in 2007 of 9.1 percent for traditional indemnity plans, 8.7 percent for health maintenance organizations (HMOs), 3.9 percent for point-of-service (POS) plans and 2.4 percent for preferred provider organizations (PPOs).

For 2008, Hewitt forecasts that companies will receive cost increases of 9.0 percent for traditional indemnity plans, 8.5 percent for POS plans, 9.0 percent for HMOs, and 8.5 percent for PPOs. That means from 2007 to 2008, the average cost per person for major companies will increase from $7,957 to $8,673 for HMOs; $7,790 to $8,452 for PPOs; $8,573 to $9,302 for POS plans; and $9,277 to $10,112 for indemnity plans.

"We believe the 2007 rates of increase for POS and PPO plans represent somewhat of a 'market correction' from prior-year, conservative pricing assumptions, especially for self-insured plans," said Tate. "Actual experience has been trending favorably relative to employer forecasts, resulting in less of a need for an increase for 2007."

Employer Response to Rate Increases

While rate increases remain moderate, employers continue to take proactive steps to mitigate costs and enable employees to make smarter and more effective health care decisions, including:

Adopting best practices and creating more stringent requirements around vendor selection. As employers adopt leading-edge strategies to impact the health of their workforce, they are increasingly contracting with an array of vendor partners, each focused on specific elements of the health care program. "Choosing best-in-class vendors can help make programs more cost-effective as long as the employer has built in an appropriate degree of cross-program accountability for the vendors," noted Winkler.

Pinpointing the drivers of costs. More companies are taking a closer look at the health risks and needs of their employee population and offering more focused programs and solutions targeted to employees who incur the majority of health care costs. According to recent Hewitt research, more than three-quarters (77 percent) of responding companies profiled the chronic health conditions prevalent in their workforce in 2007, compared with just 43 percent in prevalent in their workforce in 2007, compared with just 45 percent in 2006. In addition, between 65 percent and 79 percent of companies gave employees — or planned to give them in 2007 — access to targeted condition management or wellness programs through health plans or focused programs.

"By obtaining insight into the health risks and chronic conditions of at-risk populations in their workforce, employers can identify portions of the employee population that are currently — or likely to become — the most costly and make changes to their plan designs that will drive employees to make better, more consistent decisions about their health," said Winkler. "These types of programs not only influence healthy employee behaviors through integrated health management, but they provide companies with significant opportunities for short- and long-term cost savings."

Offering new health plans. Account-based plan designs are gaining traction by employers as a way to control costs. Hewitt's research found that more than 20 percent of companies offer, or plan to offer, a high-deductible health plan with a health savings account (HSA) by the end of this year and almost half are considering offering one at a future date. While just 3 percent of employees elected these plans last year, most companies anticipate that enrollment will grow to 20 percent in five years.

In addition, as fully insured HMO rates increase in excess of overall medical cost increases, an increasing number of companies are eliminating local HMO offerings and are now offering HMOs under a self-insured arrangement. This enables companies to offer more consistent plan designs and health care programs across their entire employee population, reducing administrative costs and simplifying communication messages to employees during annual enrollment.

Encouraging use of health care via "value-based" plan design changes. While still an emerging concept, more companies are beginning to incorporate value-based design changes into their health care programs. These types of plans remove the unnecessary barriers to care that employees face by providing them with incentives to use appropriate care/services to manage their health.

According to recent Hewitt research, almost one in five (19 percent) large companies has implemented a value-based plan design, and another 40 percent are interested in learning more about them. Hewitt recently introduced a Value-Based Design Model that enables companies, in real time, to analyze the compliance effects and financial impact of reducing employee cost sharing for specific health care services and increasing employee cost sharing for others. Using companies' existing prescription drug utilization and cost data, the tool also helps them understand how to make these clinically desirable plan design changes without increasing overall health care costs.

Changing prescription drug coverage. Companies are focusing more on generic and value drug programs, aggressive Pharmacy Benefit Manager (PBM) contracting and coinsurance in their drug plans to continue to influence utilization and costs. They are also taking more interest in measuring employee compliance with prescription drug usage so that they can make changes to their plans

– including adding incentives – in order to encourage employees to take medications for which they were prescribed.

About Hewitt's Data

Hewitt's health care cost data is derived from the Hewitt Health Value Initiative, a cost and performance analysis database of more than 1,800 health plans throughout the U.S., including 400 major employers and more than 18 million health plan participants.

About Hewitt Associates

With more than 65 years of experience, Hewitt Associates (NYSE: HEW) is the world's foremost provider of human resources outsourcing and consulting services. The company consults with more than 2,300 organizations and administers human resources, health care, payroll and retirement programs on behalf of more than 340 companies to millions of employees and retirees worldwide. Located in 35 countries, Hewitt employs approximately 24,000 associates. For more information, please visit www.hewitt.com.

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SURVEY HIGHLIGHTS

Health care costs for U.S. employers will increase by 6% in 2008, according to the Towers Perrin 2008 Health Care Cost Survey. Although this increase is lower than rates we've seen in recent years, it's still greater than overall CPI or wage increases. In dollar terms, gross health care expenditure will rise by an average of $526 per employee, to an average total cost of $9,144. Notably, the survey results suggest that the average cost increase would have been closer to 8%, or about $200 per employee more, if not for employer efforts to aggressively manage benefit program performance.

The most significant findings in the 2008 survey highlight the contrasts between high-performing and low-performing companies.* On average, high-performing companies will see a total cost of $8,532 per active employee — 16% (or $1,668) lower than the $10,200 total cost per active employee reported by low-performing companies.

Overall, high-performing companies are more aggressive in managing their health plans and delivery processes. Broadly speaking, these companies focus on the underlying causes of health care cost increases, have strategies in place to drive improvements in employees' overall health and wellness, and consistently support engagement in health care decisions and health-related behaviors. In addition, high-performing companies identify problems early on and take advantage of opportunities for improvement by keeping close tabs on the current state of their benefit programs and the health care system overall.

CUMULATIVE COST INCREASES MEAN HEAVIER BURDENS

Although this year's actual percentage increase is slightly lower than last year's 7% increase, the cumulative effect of ongoing inflation continues to produce record-high cost numbers for both employers and employees. In fact, employers are paying 39% more than they spent five years ago ($5,100 in 2003 versus $7,080 in 2008), and employees are paying 61% more ($1,284 in 2003 versus $2,064 in 2008). Clearly, high dollar levels can be especially problematic for low-wage workers and individuals who retire before reaching Medicare eligibility.

Annual costs per employee for retirees under age 65, up 6% over 2007, will rise by an average of $719, to an average total cost of $12,696 in 2008. It may therefore be no surprise that, according to our data, organizations are taking a different view of — and exhibiting different commitment levels to — programs for retirees, a trend that will have significant long-term workforce and social implications.

Only 29% of the survey respondents say their organization plays a large/primary role in meeting postretirement health care needs for current retirees. Less than half of the companies surveyed (47%) currently subsidize retiree medical coverage for current and future retirees. Moreover, among those that are continuing a subsidy, the share they ask retirees to provide is rapidly increasing, particularly for retirees under age 65.

INTEREST IN ACCOUNT-BASED HEALTH PLANS CONTINUES

Seeking new ways to approach cost issues and help active employees understand and prepare for future health care expenses (during both active years and retirement), employers continue to explore account-based health plans (ABHPs) as an attractive solution. Our survey results show that approximately half (46%) of survey respondents had ABHPs in place in 2007. A further 7% plan to implement an ABHP in 2008. This rate of new implementations is a bit slower than in prior years, which may be due to the maturing of the approach** (see page 10 for details).

* Towers Perrin divided respondents in its annual health care cost database into three categories — low-performing, average-performing and high-performing companies. Performance designations are based on relative costs and cost increases, as well as whether an organization is meeting its health benefit objectives in certain key areas. See page 5 for details.

** *Account-Based Health Plans: What Works and Why,* Towers Perrin, 2007

A CLOSER LOOK AT THE NUMBERS

Employers face, on average, a 6% increase in health care costs in 2008, according to the Towers Perrin 2008 Health Care Cost Survey. Corresponding employer-sponsored dental plan costs will increase 3% in 2008, a rate similar to those seen in prior years *(Exhibit 1).*

The survey findings are based on projected increases in premium rates or, in the case of self-insured plans, premium equivalents for plans offered by 500 of the nation's largest employers, covering approximately 10 million U.S. employees, retirees and dependents. Health benefits for survey participants cost more than $46 billion annually.

Although 2008 marks the fourth year the growth rate has been under 10% after a double-digit peak in 2003 *(Exhibit 2),* the cumulative effect of rising costs has produced cost levels at record highs for employer-sponsored health plans and, consequently, employee contributions. Compared with costs just five years ago, employers are paying 39% more today while employees are paying 61% more.

EXHIBIT 1
Average growth in health care costs
All plan types and participant groups combined

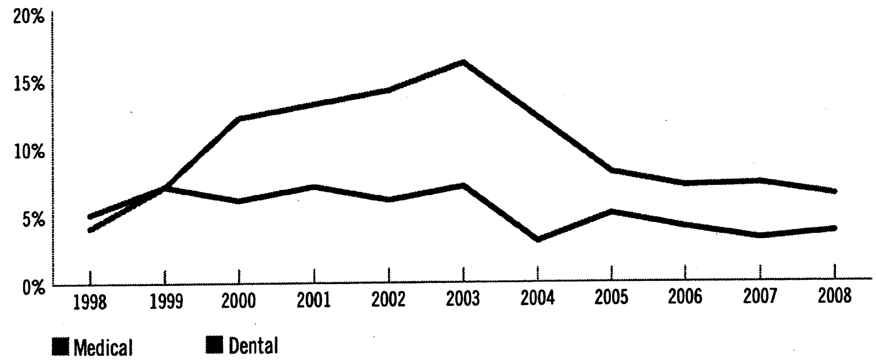


EXHIBIT 2
Total employee/employer health care costs 2003 vs. 2008

2003 Total Cost = $6,384 **2008 Total Cost = $9,144**

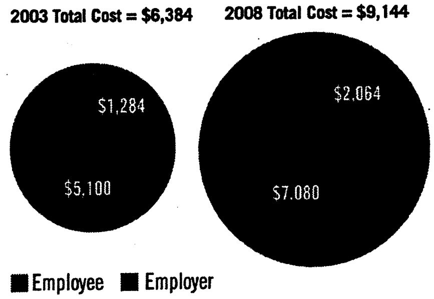


EXHIBIT 3
Average cost increases
1998-2008

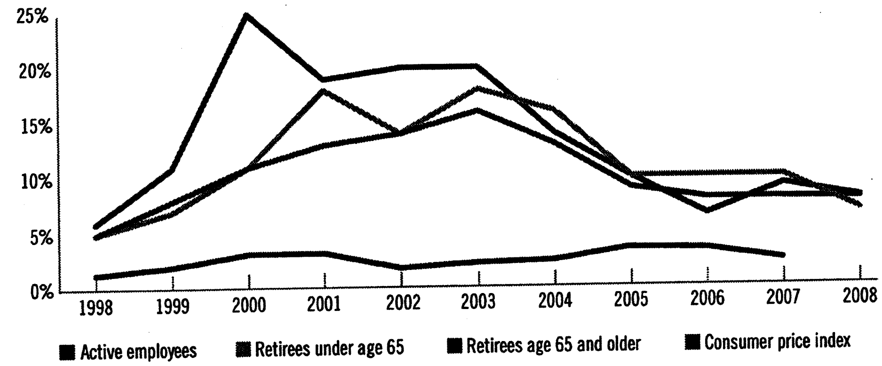


EXHIBIT 4
Average cost increases
1998-2008

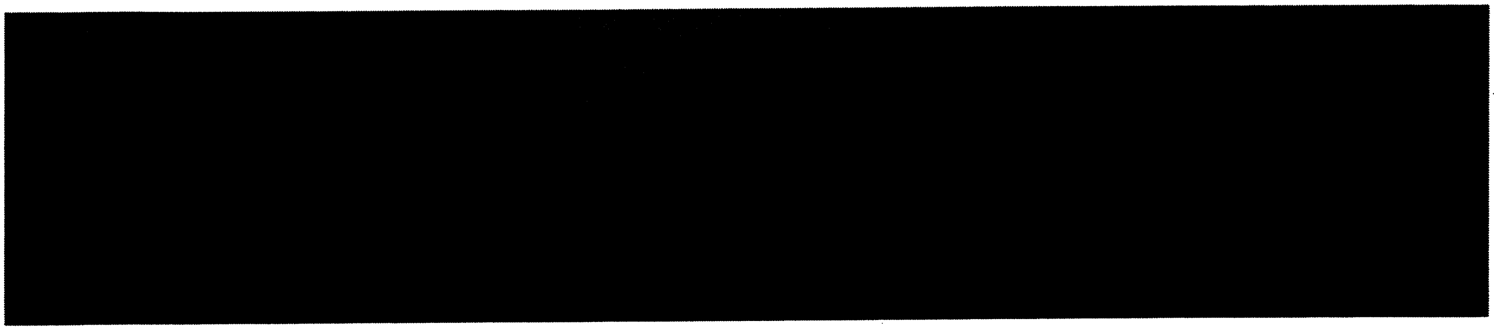
	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Medical Plans											
Active employees	4%	7%	10%	12%	13%	15%	12%	8%	7%	7%	6%
Retirees under age 65	4	6	10	17	13	17	15	9	9	9	6
Retirees age 65 and older	5	10	24	18	19	19	13	9	6	8	7
Combined	4	7	12	13	14	16	12	8	7	7	6
Dental Plans											
Active employees	5%	7%	6%	7%	6%	7%	5%	5%	4%	3%	3%
Retirees under age 65	4	4	6	6	5	6	5	7*	7*	2*	5*
Retirees age 65 and over	3	3	6	4	4	5	6				
Inflation Measures											
Consumer price index (CPI)	2%	2.7%	3.4%	1.6%	2.0%	2.3%	3.2%	4.3%	2.5%	3.5%**	
Medical care component of CPI	3	3.7	4.2	4.7	4.8	4.0	4.5	4.1	3.6	4.2**	

*Average cost increase for retirees under and over age 65
**Unadjusted 12 months as of October 2007

Increasing at 6%, per-employee costs for active employees will rise by an average of $44 per month, to an average total cost of $762. Also rising at 6%, per-employee costs for retirees under age 65 will increase by an average of $60, to an average total monthly cost of $1,058 *(Exhibit 3).*

For the past five-year period, health care costs overall rose by 43%, while the compounded increase in the consumer price index (CPI) was only 17%. If this trend continues as expected *(Exhibit 4),* the issue of affordability — for businesses, employees and retirees — will become considerably more challenging in the years ahead.

The employer share of the average total health care premium is likely to affect company profit margins, employee wage increases, resources available for other rewards and the ability to continue to offer employer-provided health care coverage. These pressures, in turn, have an impact on effective workforce management — the company's ability to attract, retain and engage high-performing employees.



From the individual's perspective, low-wage workers and retirees not yet eligible for Medicare are hardest hit by the ongoing cost increases. Even so, affordability for all employees and retirees is quickly becoming a national agenda item in the presidential election season.

In 2008, employees will contribute 20% of the cost for employee-only coverage, and 24% for family coverage *(Exhibit 5).* Those percentages haven't changed much in the past several years, and employers clearly continue to shoulder most of the burden. In flat dollar terms, however, the employee share in 2008 — an average of $78 per month ($936 annually) for employee-only coverage and $262 per month ($3,144 annually) for family coverage — represents a significant cost for many employees and a potentially prohibitive cost for some workers.

The average employee share of 2008 premium costs will increase 8%, while the average employer share will increase 6%. In flat dollar terms, of the total premium increase of $526, employers pay $370, and employees, on average, will pick up the remaining $156.

Meanwhile, retirees are among the most exposed to health care cost increases. For this group, there are very practical issues around access to affordable health care — even if some form of employer-sponsored medical coverage is still available. For example, as a result of a much larger cost base and employers' efforts to restructure their retiree financial obligations, retirees are being asked to pick up a much greater proportion of their average monthly health care costs than their active employee counterparts. Retirees under age 65 will contribute approximately 50% of the premium for retiree-only coverage and 52% for family coverage.

In flat dollar terms, retirees under age 65 will pay an average of $283 per month ($3,396 annually) for retiree-only coverage and $585 per month ($7,020 annually) for retiree plus dependent coverage. Retirees age 65 and older will pay an average of $136 per month ($1,632 annually) for retiree-only coverage and $276 per month ($3,312 annually) for retiree plus one dependent coverage *(Exhibit 6).*

EXHIBIT 5

Average monthly employee/retiree share of 2008 medical coverage costs

	Employee/ Retiree Only (% of total cost)	Employee/Retiree Plus Dependent (% of total cost)	Family (% of total cost)
Employees	20%	23%	24%
Retirees under age 65	50	51	52
Retirees age 65 and older	45	45	NA

EXHIBIT 6

Average employee/retiree share of monthly medical costs and cost increases — by covered group

	Employee/ Retiree Only	Employee/Retiree Plus Spouse	Family	Average Increase Composite*	From 2007
Active employees	$78	$180	$262	$172	8%
Retirees under age 65	283	585	782	544	7
Retirees age 65 and older	136	276	N/A	218	6

*Composite (i.e., employee/retiree only, employee/retiree plus spouse and family combined)

PRACTICES VARY WIDELY AMONG HIGH- AND LOW-PERFORMING COMPANIES

Similar to findings in previous years, a number of companies have succeeded in keeping a tight rein on program costs for 2008, achieving dramatically lower overall rates of cost increase than the double-digit jumps experienced just four years ago. But some companies are still struggling to strike a balance between health care cost pressures and workforce goals and continue to experience increases more characteristic of the late 1990s.

To better understand the factors that contribute to the wide variation in costs, for the third consecutive year our survey analysis divides respondents into three categories — low-performing, average-performing and high-performing companies. Performance designations are based on relative costs and cost increases, as well as whether an organization is meeting its health benefit objectives in the following areas:

- managing employer costs
- managing employee costs
- enhancing efficient purchasing of health care service
- enhancing employee understanding and engagement
- enhancing employee satisfaction, attraction and retention.

EXHIBIT 7
Cost variation across companies

	High-Performing Companies	Low-Performing Companies
Cost per employee per year	$8,532	$10,200
Increase in employer cost	5%	7%
Increase in employee cost	8	9

Similar to last year's findings, the survey results show wide variation across these groups — and among companies of similar size. While 20% of the survey respondents continue to grapple with double-digit cost increases, high-performing companies are managing to get their increases much closer to the medical CPI (roughly 4%). In fact, among high performers, 46% have cost increases of 5% or less. In dollar terms, companies in the low-performing group face a total cost of $10,200 per employee in 2008, while high-performing companies will pay $8,532 per employee *(Exhibit 7).*

Some of this variation is attributable to differences in geography or employee demographics. Nonetheless, the average cost per employee is based on a uniform distribution of dependent enrollment.

Notably, high-performing companies aren't achieving low costs through cost shifting. Instead, they're employing a broad range of tactics and strategies to actively and consistently manage their programs for maximum efficiency and value. As a result, employees at high-performing companies will pay significantly less on average in 2008 than employees at low-performing companies — approximately $1,980 per year versus $2,256. In addition, employees at high-performing companies typically get more for their money — such as health care information, decision support tools and other valuable resources — than their counterparts at low-performing companies.

THE KAISER FAMILY FOUNDATION -AND- HEALTH RESEARCH AND EDUCATIONAL TRUST

Employer Health Benefits

2007 Summary of Findings

Staff/304
Ball-Dougherty/10

AS THE LEADING SOURCE OF HEALTH INSURANCE, EMPLOYER-SPONSORED INSURANCE COVERS ABOUT 158 MILLION NONELDERLY PEOPLE IN AMERICA.[1] TO PROVIDE CURRENT INFORMATION ABOUT THE NATURE OF EMPLOYER-SPONSORED HEALTH BENEFITS, THE KAISER FAMILY FOUNDATION (KAISER) AND THE HEALTH RESEARCH AND EDUCATIONAL TRUST (HRET) CONDUCT AN ANNUAL NATIONAL SURVEY OF PRIVATE AND PUBLIC EMPLOYERS OF THREE OR MORE WORKERS.

The key findings from the 2007 survey include the fourth consecutive year of a lower rate of growth for health insurance premiums, the lowest since 1999. However, as in prior years, the average premium increase continues to outpace workers' earnings and inflation. The types of plans in which workers enroll are similar to last year. The percentage of employers sponsoring insurance remains stable, with no significant increase in the percentage of employers offering high-deductible health plans with a savings option (HDHP/SO).

The 2007 survey repeated the detailed questions regarding deductibles and out-of-pocket maximum amounts that were introduced in the 2006 survey and expanded the number of questions on office-visit and other types of cost sharing.

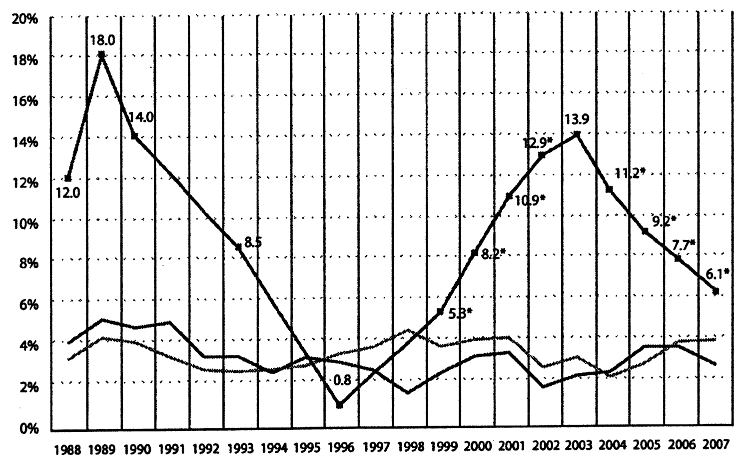
HEALTH INSURANCE PREMIUMS

Between spring of 2006 and spring 2007, premiums increased an average of 6.1% for employer-sponsored health insurance, a slower rate than the 7.7% increase in 2006 (Exhibit A).[2] This is the fourth consecutive year with a lower rate of growth than the previous year, and the lowest rate of growth since 1999, when premiums increased 5.3%. Even as premium growth moderates, the rate of increase continues to be higher than the growth in workers' earnings (3.7%) and inflation (2.6%).

While the average premium increase is 6.1% in 2007, 10% of covered workers are employed by firms that experienced premium increases of greater than 15%, and 46% are in firms with premium increases of 5% or less. The rate of growth was similar for small firms (3–199 workers) and large firms (200 or more workers) and for fully insured and self-funded plans.

EXHIBIT A

Increases in Health Insurance Premiums Compared to Other Indicators, 1988–2007



1988	1989	1990	1993	1996	1999	2000	2001	2002	2003	2004	2005	2006	2007	
12.0	18.0	14.0	8.5	0.8	5.3*	8.2*	10.9*	12.9*	13.9	11.2*	9.2*	7.7*	6.1*	HEALTH INSURANCE PREMIUMS
3.9	5.1	4.7	3.2	2.9	2.3	3.1	3.3	1.6	2.2	2.3	3.5	3.5	2.6	OVERALL INFLATION
3.1	4.2	3.9	2.5	3.3	3.6	4.0	4.0	2.6	3.0	2.1	2.7	3.8	3.7	WORKERS' EARNINGS

*Estimate is statistically different from estimate for the previous year shown (p<.05). No statistical tests are conducted for years prior to 1999.

Note: Data on premium increases reflect the cost of health insurance premiums for a family of four. The average premium increase is weighted by covered workers.

Source: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 1999–2007; KPMG Survey of Employer-Sponsored Health Benefits, 1993, 1996; The Health Insurance Association of America (HIAA), 1988, 1989, 1990; Bureau of Labor Statistics, Consumer Price Index, U.S. City Average of Annual Inflation (April to April), 1988–2007; Bureau of Labor Statistics, Seasonally Adjusted Data from the Current Employment Statistics Survey, 1988–2007 (April to April).

The average annual total premium cost is $4,479 for single coverage and $12,106 for family coverage (Exhibit B). Average premiums for single and family coverage are similar for small firms (3–199 workers) and large firms (200 or more workers). Average premiums for HDHP/SOs are lower than the overall average for all plan types for both single and family coverage (this premium amount does not include any employer contributions to savings account options).

About 80% of workers with single coverage and 94% of workers with family coverage contribute to the total premium for their coverage. The average annual worker contributions for single and family coverage are $694 and $3,281, respectively, and are significantly higher than the amounts reported in 2006. For single coverage, workers in small firms (3–199 workers) contribute less on average than workers in large firms (200 or more workers) ($561 vs. $759).

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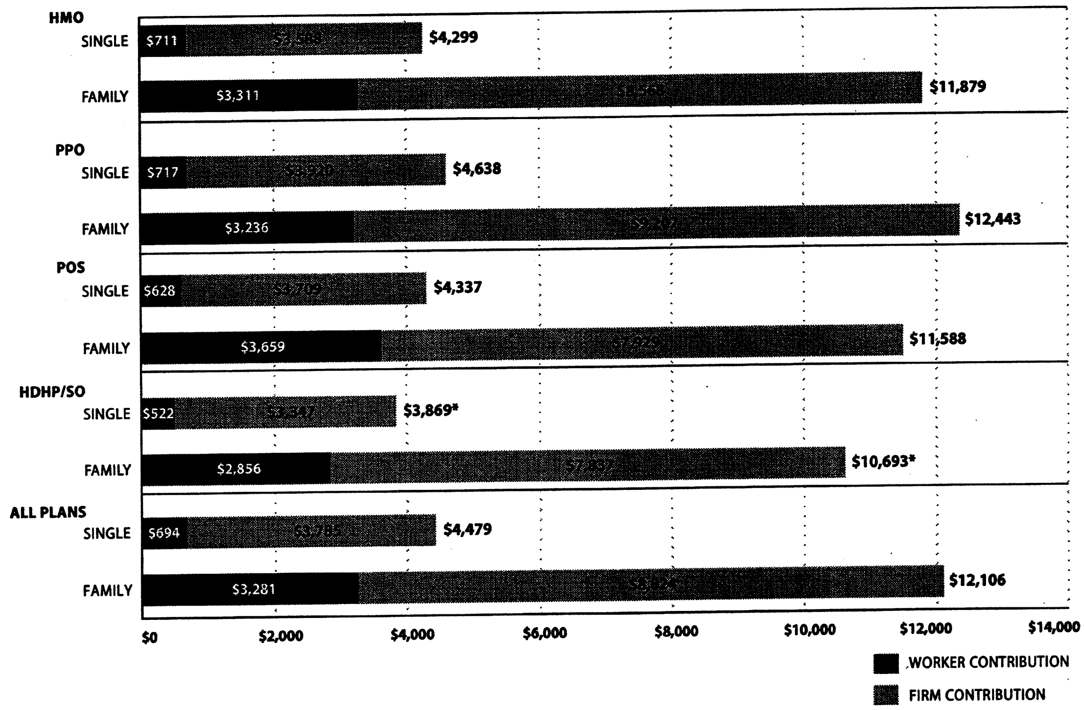
EXHIBIT B

Average Annual Firm and Worker Premium Contributions and Total Premiums for Covered Workers for Single and Family Coverage, by Plan Type, 2007

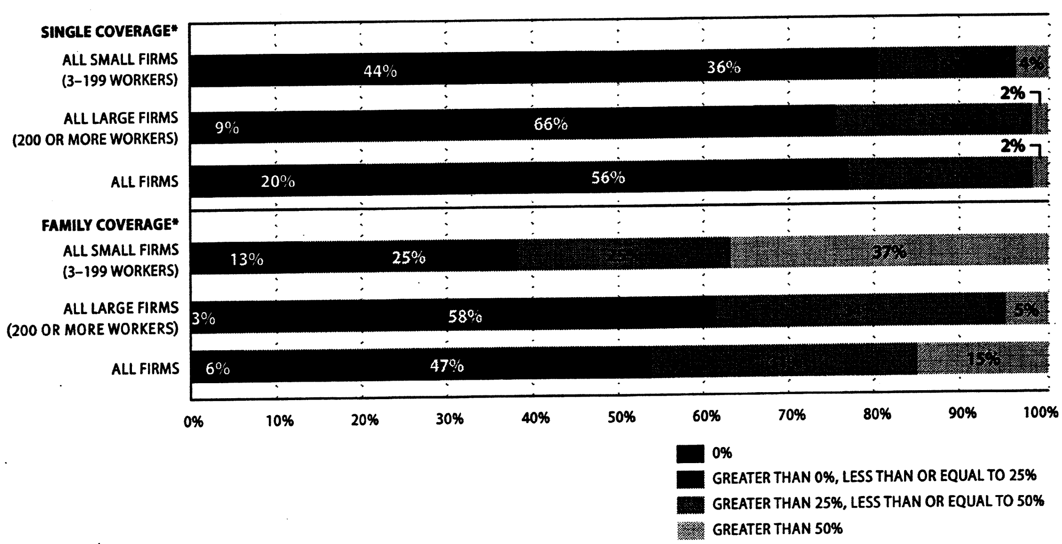


* Estimate of Total Premium is statistically different from All Plans estimate by coverage type (p<.05).

Source: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 2007.

EXHIBIT C

Distribution of Percentage of Premium Paid by Covered Workers for Single and Family Coverage, by Firm Size, 2007



* Distributions for All Small Firms and All Large Firms are statistically different (p<.05).

Source: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 2007.

This trend reverses for family coverage, where workers in small firms contribute significantly more than workers in large firms ($4,236 vs. $2,831). While the dollar amounts are increasing, the share of the premium paid by covered workers remains stable. In 2007, the average percentage of the premium paid by covered workers is 16% for single coverage and 28% for family coverage, similar to the percentages reported for the last several years. However, for single coverage, over one-fifth of workers pay greater than 25% of the total premium while another fifth pay no contribution. For family coverage, 47% pay greater than 25% of the total premium and only 6% have no contribution (Exhibit C).

The majority (57%) of covered workers are enrolled in preferred provider organizations (PPOs). Health maintenance organizations (HMOs) cover 21%, followed by point-of-service (POS) plans (13%), HDHP/SOs (5%), and conventional plans (3%).

EMPLOYEE COST SHARING

In addition to their premium contributions, most covered workers face additional payments when they use health care services. In PPOs, 71% of covered workers with single coverage have a general annual deductible that they pay before coverage for most services begins. Almost half (48%) of workers in POS plans and about 18% of workers in HMOs face a general annual deductible for single coverage. Many workers with no deductible have other forms of cost sharing for office visits or other services.

The average general annual deductibles (for workers with a deductible) for single coverage are $461 for workers in PPOs, $401 for workers in HMOs, $621 for workers in POS plans, and $1,729 for workers in HDHP/SOs (who by definition have high deductibles). Like last year, workers in small firms (3–199 workers) face higher deductibles than workers in large firms (200 or more workers) for PPOs, POS plans, and HDHP/SOs.[3] However, some plans cover certain services before the deductible is met. For example, 66% of covered workers with a general annual deductible enrolled in PPOs, the most common plan type, do not have to meet the deductible before preventive care is covered.

In addition to any general plan deductible, over 95% of covered workers face cost sharing when admitted to the hospital or when they have outpatient surgery. Cost sharing may include a separate hospital deductible, copayment, coinsurance, or a per diem charge. About 12% of workers in PPOs, 15% of workers in HMOs, and 23% of workers in POS plans have a separate hospital deductible. The average hospital deductibles are similar across plan types ($334 for PPOs, $323 for HMOs, and $340 for POS plans). Forty-three percent of covered workers have coinsurance for hospital admissions in addition to any deductible with an average coinsurance rate of 17%. A smaller percentage of workers (20%) have a copayment, which averages $208.

Most workers face some form of cost sharing when visiting the emergency room, for urgent care, or for an advanced diagnostic test. For example, 86% of covered workers have cost sharing for urgent care visits. Similarly, almost all covered workers (93%) have cost sharing for emergency room visits, but 79% of workers with emergency room cost sharing are in plans where the cost sharing is waived if the individual is admitted to the hospital.

The majority of workers have copayments or coinsurance for physician office visits. Among the 79% of workers with copayments for in-network office visits, 75% have a copayment of $15, $20, or $25 per visit with a primary care physician. Workers in HDHP/SOs are more likely to have coinsurance than workers with other plan types and are also more likely to have no cost sharing once the deductible has been met. Workers that see out-of-network physicians are more likely to pay coinsurance (80%) rather than copayments (9%).

As with physician office visits, most covered workers face copayments or coinsurance for prescription drugs. About three in four covered workers are in plans with three or four-tier cost-sharing arrangements, and most face copayments rather than coinsurance for the first three

EXHIBIT D

Percentage of Firms Offering Health Benefits, by Firm Size, 1999–2007*

FIRM SIZE	1999	2000	2001	2002	2003	2004	2005	2006	2007
3–9 Workers	56%	57%	58%	58%	55%	52%	47%	48%	45%
All Small Firms (3–199 Workers)	65%	68%	68%	66%	65%	63%	59%	60%	59%
All Large Firms (200 or More Workers)	99%	99%	99%	98%	98%	99%	98%	98%	99%
ALL FIRMS	66%	69%	68%	66%	66%	63%	60%	61%	60%

*Tests found no statistical difference from estimate for the previous year shown (p<.05).

Note: As noted in the Survey Design and Methods section, estimates presented in this exhibit are based on the sample of both firms that completed the entire survey and those that answered just one question about whether they offer health benefits.

Source: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 1999–2007.

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tiers. For workers in plans with a fourth tier, the percentages of covered workers facing copayments and coinsurance are roughly comparable. Among workers with three or four-tier plans, the average copayments are $11 for generic drugs, $25 for preferred drugs, and $43 for nonpreferred drugs. The average copayment for fourth-tier drugs is $71 and the average coinsurance is 36%.[4] Covered workers in HDHP/SOs are less likely to be in plans with three or four-tier cost sharing. In contrast, they are more likely to be in plans where there is no cost sharing after the deductible is met and in plans where the payment is the same regardless of the type of drug, where they are also more likely to face coinsurance than workers in HMOs or PPOs.[5]

Most covered workers are in a plan that partially or totally limits the cost sharing that a worker must pay under their health plan in a year, generally referred to as an out-of-pocket maximum. Seventy-one percent of workers with single or family coverage have an out-of-pocket maximum, down from 79% (for single coverage and 78% for family coverage in 2006). However, it should be noted that some workers with no out-of-pocket limit may have low cost sharing.[6] Out-of-pocket limits vary considerably; for example, among covered workers in plans that have an out-of-pocket limit for single coverage, 22% are in plans with an annual out-of-pocket maximum of $3,000 or more, while 28% are in plans with out-of-pocket maximum of less than $1,500. For family coverage, 24% of workers are in plans with an out-of-pocket maximum of $6,000 or more and 10% are in plans with a limit of less than $2,000.[7] However, not all spending counts towards the out-of-pocket limit. For example, among workers in PPOs, 73% are in plans that do not count office-visit copayments and 32% are in plans that do not count spending for the general annual deductible when determining if an enrollee has reached his or her out-of-pocket maximum.

AVAILABILITY OF EMPLOYER-SPONSORED COVERAGE

Sixty percent of employers offer health benefits in 2007, similar to the 61% offer rate reported in 2006 but lower than the 69% offer rate in 2000. The drop in the overall offer rate is driven by the declining percentage of small firms (3–199 workers) that offer coverage. Among firms with 3 to 9 workers, the offer rate has dropped from 57% in 2000 to 45% in 2007. Over this same time period, the offer rate has remained stable for firms with 200 or more workers at 98% or 99% (Exhibit D).

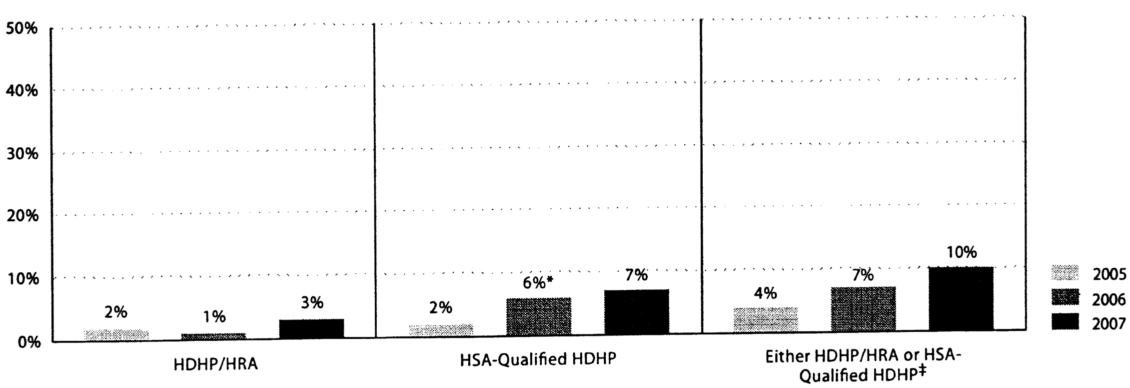
The percentage of firms offering coverage increases as the size of the firm increases. As previously mentioned, the smallest firms (3–9 workers) remain least likely to offer health benefits at 45%. Among firms with 10 to 24 workers, the percentage jumps to 76%, and among firms with 25 to 49 workers it increases to 83%. Over 95% of firms with 50 or more employees offer health insurance.

As we have seen in past years, the offer rate is higher for firms with at least some union workers (99%) compared to firms with no union workers (57%). Firms with a lower proportion of lower-wage workers (less than 35% of workers earn $21,000 or less annually) are also more likely to offer benefits compared to firms with a higher proportion of lower-wage employees (35% or more earn $21,000 or less annually) (67% vs. 36%).

Even in firms that offer coverage, not all workers are covered. Some workers are not eligible to enroll as a result of waiting periods or minimum work-hour rules, and others choose not to enroll, perhaps because they must pay a share of the premium or can get coverage through a spouse. Among firms that offer coverage, an average of 79% of workers are eligible for the health benefits offered by their employer. Of those eligible, 82% take up coverage, resulting in 65% of workers in firms offering health benefits having coverage through their employer. Among both firms that offer and do not offer health benefits, 59% of workers are covered by health plans offered by their employer.

EXHIBIT E

Among Firms Offering Health Benefits, Percentage That Offer an HDHP/HRA and/or an HSA-Qualified HDHP, 2005–2007



* Estimate is statistically different from estimate for the previous year shown (p<.05).

‡ The 2007 estimate includes 0.2% of all firms offering health benefits that offer both an HDHP/HRA and an HSA-qualified HDHP. The comparable percentages for 2005 and 2006 are 0.3% and 0.4%, respectively.

Source: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 2005–2007.

This year, the survey asked employers that offer health insurance if they offer health benefits to domestic partners. Thirty-seven percent offer health benefits to same-sex domestic partners and 47% of firms offer health benefits to opposite-sex domestic partners. These percentages are considerably higher than those we reported in 2004 (14% for same-sex domestic partners and 12% for opposite-sex domestic partners), but a change in the way the question was asked may account for some or all of the difference.[8]

HIGH-DEDUCTIBLE HEALTH PLANS WITH SAVINGS OPTION

Last year was the first year information on high-deductible health plans with a savings option (HDHP/SO) was collected as a separate plan type. HDHP/SOs include (1) health plans with a deductible of at least $1,000 for single coverage and $2,000 for family coverage offered with an Health Reimbursement Arrangement (HRA), referred to as "HDHP/HRAs," and (2) high-deductible health plans that meet the federal legal requirements to permit an enrollee to establish and contribute to a Health Savings Account (HSA), referred to as "HSA-qualified HDHPs."

Ten percent of firms offering health benefits offer an HDHP/SO in 2007, but the difference from the 7% reported in 2006 is not statistically significant. Firms with 1,000 or more workers are more likely to offer HDHP/SOs (18%) than firms with 3 to 999 workers (10%). Among firms offering health benefits, 3% offer an HDHP/HRA and 7% offer an HSA-qualified HDHP; neither estimate is a significant increase from the percentages reported in 2006 (Exhibit E). About 3.8 million (5%) covered workers are enrolled in HDHP/SOs, with about 1.9 million (3%) covered workers enrolled in each type of HDHP/SO (Exhibit F).

Annual deductibles for single coverage for HDHP/HRAs and HSA-qualified HDHPs average $1,556 and $1,923, respectively. However, these deductibles vary considerably; for example, 24% of workers enrolled in an HSA-qualified HDHP for single coverage have a deductible between $1,100 and $1,499, while 54% have a deductible of $2,000 or more. The average aggregate annual deductible for family coverage for HDHP/HRAs is $3,342 and $3,883 for HSA-qualified HDHPs. Some HDHP/SOs cover preventive services before the deductible is met; 88% of workers in HDHP/HRAs and 86% of workers in HSA-qualified HDHPs have preventive benefits covered before having to meet the deductible.

Average total premiums for HDHP/SOs are lower than the average premium for workers in plans that are not HDHP/SOs for both single and family coverage (Exhibit G). The average worker premium contribution for HDHP/SO coverage is lower than the average worker premium contribution for single coverage for workers not in HDHP/SOs.

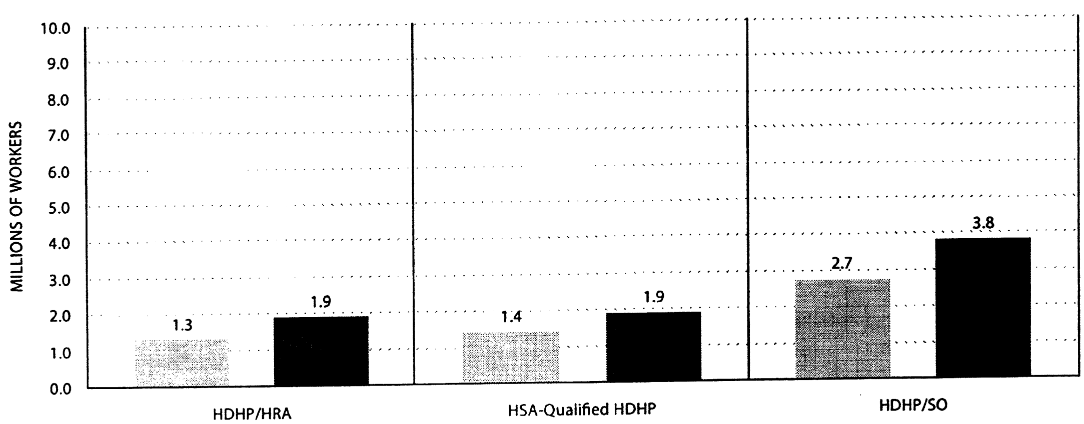
The distinguishing aspect of these high deductible plans is the savings feature available to employees. Workers enrolled in an HDHP/HRA receive an average annual contribution from their employer of $915 for single coverage and $1,800 for family coverage (Exhibit H). The average contributions to HSAs are $428 for single coverage and $714 for family coverage. However, among firms offering an HSA-qualified HDHP, about two-thirds of firms do not make a contribution to the HSA for single coverage (covering 47% of workers in these plans) and 47% of firms do not make a contribution to the HSA for family coverage (covering 45% of workers with these plans). If workers with no employer contribution to their HSA are excluded from the calculation the average annual employer HSA contributions are $806 and $1,294 for single and family coverage, respectively.

RETIREE COVERAGE

The percentage of large firms (200 or more workers) offering retiree health benefits in 2007 is 33%, similar to the 2006 offer rate of 35%. Among large firms (200 or more workers) that offer

EXHIBIT F

Number of Covered Workers Enrolled in HDHP/SOs, 2006–2007*



*Tests found no statistical differences from estimate for the previous year shown (p<.05).

Source: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 2006–2007.

retiree health benefits, 92% offer health benefits to early retirees and 71% offer health benefits to Medicare-age retirees. These percentages are similar to the percentages reported in 2006.

UTILIZATION MANAGEMENT

The survey periodically asks about the utilization management provisions of the firm's plan with the largest enrollment. In 2007, about two-thirds of firms report that their health plan with the largest enrollment requires pre-admission certification for inpatient hospital care. About 55% report that the plan requires pre-admission certification for outpatient surgery, and 48% state that the plan includes case management for large claims.

OTHER BENEFITS

Section 125 of the Internal Revenue Service Code permits employers to establish programs that allow employees to make contributions towards the cost of health insurance and to pay for health care services with pre-tax dollars through a flexible spending account.[9] Sixty-one percent of firms that offer health benefits allow employees to use pre-tax dollars to pay for health insurance premiums. Large firms (200 or more workers) are more likely to offer this benefit than small firms (3–199 workers) (92% vs. 60%). A smaller percentage (22%) of offering firms offer a flexible spending account, but again, large firms (200 or more workers) are more likely to offer this benefit than small firms (3–199 workers) (73% vs. 20%) (Exhibit I).

We asked employers for the first time this year if they offer long-term care insurance to their employees. Nineteen percent of employers offering health benefits reported that they offer long-term care insurance, with no significant difference between the percentage of small firms (3–199 workers) and large firms (200 or more workers) offering the benefits.

OUTLOOK FOR THE FUTURE

Each year we ask employers what changes they plan to make to their health plans in the next year. Among those that offer benefits, large percentages of firms report that in the next year they are very or somewhat likely to increase the amount workers contribute to premiums (45%), increase deductible amounts (37%), increase office visit cost sharing (42%), or increase the amount that employees have to pay for prescription drugs (41%). Although firms report planning to increase the amount employees have to pay when they have insurance, few firms report they are somewhat or very likely to drop coverage (3%) or limit eligibility (5%) in the next year. And even though the HDHP/SO offer rate or enrollment did not increase significantly from 2006, one-fifth of firms report being somewhat likely (18%) or very likely (2%) to offer an HSA-qualified HDHP in the next year, and almost one-quarter report being somewhat likely (21%) or very likely (3%) to offer an HDHP/HRA in the next year.

The employer-sponsored health benefits market did not experience large changes in 2007. Employers and employees benefited from the continued moderation in the rate of premium increases, a welcome relief from the much higher growth rates earlier in the decade. History suggests that premium trends are cyclical,[10] and after four years of downward premium trends, it is unclear how much longer this relative lull in premium growth will continue before pressures on health insurers to improve profitability will push premium trends on an upward path. While widespread adoption of HDHP/SOs could help maintain lower premium growth with firms moving to less expensive packages

EXHIBIT G

Average Annual Premiums, Worker and Firm Contributions for Covered Workers in HDHP/SOs and All Other Non-HDHP/SO Plans, 2007

	All Other Non-HDHP/SO Plans‡		HDHP/SO	
	Single	Family	Single	Family
Worker Contribution to Premium	$704*	$3,304	$522*	$2,856
Firm Contribution to Premium	$3,810*	$8,879*	$3,347*	$7,837*
Total Annual Premium	$4,514*	$12,183*	$3,869*	$10,693*
Annual Firm Contribution to the HRA or HSA	NA	NA	$682	$1,298
Total Annual Spending (Total Premium Plus Firm Contribution to HRA or HSA)	$4,514	$12,183	$4,550	$11,991

* Estimate for All Other Non-HDHP/SO Plans is statistically different from estimate for HDHP/SOs (p<.05).

NA: Not Applicable.

‡ In order to compare spending for HDHP/SOs to all other plans that are not HDHP/SOs, we created composite variables excluding HDHP/SO data.

Source: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 2007.

EXHIBIT H

Average Annual Premiums and Contributions to Spending Accounts for Covered Workers, HDHP/HRA and HSA-Qualified HDHP, 2007

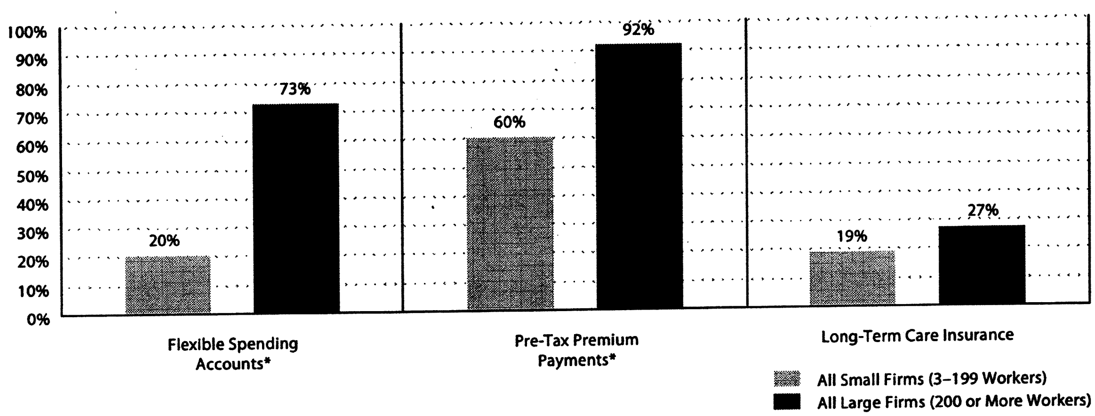
	HDHP/HRA		HSA-Qualified HDHP	
	Single	Family	Single	Family
Total Annual Premium	$3,894	$11,492	$3,826	$9,666
Worker Contribution to Premium	$617	$3,113	$413	$2,564
Firm Contribution to Premium	$3,277	$8,379	$3,412	$7,102
Annual Firm Contribution to the HRA or HSA‡	$915	$1,800	$428	$714
Total Annual Firm Contribution (Firm Share of Premium Plus Firm Contribution to HRA or HSA)	$4,192	$10,179	$3,840	$7,815
Total Annual Spending (Total Premium Plus Firm Contribution to HRA or HSA)	$4,809	$13,292	$4,254	$10,380

‡ When those firms that do not contribute to the HSA (66% for single coverage and 47% for family coverage) are excluded from the calculation, the average firm contribution to the HSA for covered workers is $806 for single coverage and $1,294 for family coverage.

Source: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 2007.

EXHIBIT I

Among Firms Offering Health Benefits, Percentage of Firms Offering Flexible Spending Accounts, Pre-Tax Premium Payments, and Long-Term Care Insurance, By Firm Size, 2007



*Estimates are statistically different between All Small Firms and All Large Firms within category (p<.05).

Note: Section 125 of the Internal Revenue Service Code permits employees to pay for health insurance premiums with pre-tax dollars and also allows the establishment of flexible spending accounts (FSAs).

Source: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 2007.

and higher cost sharing reducing service use, enrollment to date in these plans remains low.

Unfortunately, the recent moderation in premium trends has not reversed the erosion in the percentage of employers offering health benefits that occurred between 2000 and 2005. During that period, the percentage of employers offering coverage fell from 69% to 60%. While the offer rate seems to have stabilized with lower premium increases and a reasonably strong economy—it is essentially unchanged over the last three years—it is unclear what conditions would be necessary for the employer offer rate to move back toward the higher levels that we saw at the beginning of the decade.

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METHODOLOGY

The Kaiser Family Foundation/Health Research and Educational Trust 2007 Annual Employer Health Benefits Survey (Kaiser/HRET) reports findings from a telephone survey of 1,997 randomly selected public and private employers. Firms range in size from small enterprises with a minimum of three workers to corporations with more than 300,000 employees. The Kaiser/HRET Employer Health Benefits Survey is based on previous surveys sponsored by the Health Insurance Association of America (HIAA) from 1987–1990 and Bearing Point (KPMG at the time of the surveys) from 1991–1998. Findings in this report draw on the Kaiser/HRET Survey of Employer-Sponsored Health Benefits; the 1993, 1996, and 1998 KPMG Surveys of Employer-Sponsored Health Benefits; and the 1988, 1989 and 1990 studies conducted by HIAA. Researchers at Health Research and Educational Trust, the National Opinion Research Center at The University of Chicago, and the Kaiser Family Foundation designed and analyzed the survey. National Research LLC conducted the fieldwork between January and May 2007. In 2007 our overall response rate is 49%, which includes firms that offer and do not offer health benefits. Among firms that offer health benefits, the survey's response rate is 50%.

From previous years' experience, we have learned that firms that decline to participate in the study are more likely not to offer health coverage. Therefore, we asked one question of all firms with which we made phone contact where the firm declined to participate. The question was, "Does your company offer or contribute to a health insurance program as a benefit to your employees?" A total of 3,078 firms responded to this question (including 1,997 who responded to the full survey and 1,081 who responded to this one question). Their responses are included in our estimates of the percentage of firms offering health coverage. The response rate for this question was 75%. Since firms are selected randomly, it is possible to extrapolate from the sample to national, regional, industry, and firm size estimates using statistical weights. In calculating weights, we first determined the basic weight, then applied a nonresponse adjustment, and finally applied a post-stratification adjustment. We used the Statistics of the U.S. Census Bureau as the basis for the stratification and the post-stratification adjustment for firms in the private sector, and we used the Census of U.S. Governments as the basis for post-stratification for firms in the public sector. In a few cases, numbers from distribution exhibits referenced in the text may not add due to rounding effects. Unless otherwise noted, differences referred to in the text use the 0.05 confidence level as the threshold for significance.

For more information on the survey methodology, please visit the Survey Design and Methods Section at www.kff.org/insurance/7672.

***The Kaiser Family Foundation**, based in Menlo Park, California, is a private, nonprofit operating foundation dedicated to providing information and analysis on health care issues to policymakers, the media, the health care community and the general public. The Foundation is not associated with Kaiser Permanente or Kaiser Industries.*

***The Health Research and Educational Trust** is a private, not-for-profit organization involved in research, education, and demonstration programs addressing health management and policy issues. Founded in 1944, HRET, an affiliate of the American Hospital Association, collaborates with health care, government, academic, business, and community organizations across the United States to conduct research and disseminate findings that help shape the future of health care.*

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1 Kaiser Family Foundation, Kaiser Commission on Medicaid and the Uninsured, *Health Insurance Coverage in America, 2005 Data Update,* May 2007. Available at www.kff.org/uninsured/upload/2005dataupdate.pdf.

2 Data on premium increases reflect the cost of health insurance for a family of four.

3 For HMO coverage, there is insufficient data to report the result.

4 For the first time this year, we present cost sharing for prescription drugs by tier level. For example, average copayments are presented separately for those that report three or four-tier cost sharing, two-tier cost sharing, or the same cost sharing regardless of type of drug. See the introduction to Section 9 for more information available at http://www.kff.org/insurance/7672/sections/ehbs07-sec9-1.cfm

5 For POS plans, there is insufficient data for the percentage of workers with coinsurance to make the comparison.

6 Among those with no out-of-pocket limit for single coverage, 88% have a deductible of less than $500, 16% face coinsurance for hospital admissions, and 22% face coinsurance for an outpatient surgery episode.

7 Data presented is for workers with a family aggregate out-of-pocket maximum where the limit applies to spending by any covered person in the family.

8 The 2004 survey asked firms whether nontraditional partners were eligible for health benefits and, if so, whether their definition included same-sex couples or opposite-sex couples or both. In 2007, the survey asked whether firms offered coverage to nonmarried same-sex or opposite-sex couples or both.

9 Section 125 of the Internal Revenue Service Code permits employees to pay for health insurance premiums with pre-tax dollars. Section 125 also allows the establishment of flexible spending accounts (FSAs). An FSA allows employees to set aside funds on a pre-tax basis to pay for medical expenses not covered by health insurance. Typically employees decide at the beginning of the year how much to set aside in an FSA, and their employer deducts that amount of the employee's paycheck over the year. Funds set aside in an FSA must be used by the end of the year or are forfeited by the employee. FSAs are different from HRAs and HSAs.

10 Joy M. Grossman and Paul B. Ginsburg, "As the Health Insurance Underwriting Cycle Turns: What Next?" *Health Affairs,* 23, no. 6 (2004): 91. Alice Rosenblatt, "The Underwriting Cycle: The Rule of Six," *Health Affairs,* 23, no. 6 (2004): 103.

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The full report of survey findings (#7672)
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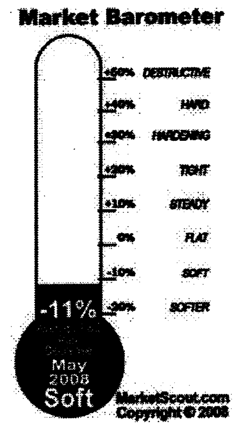

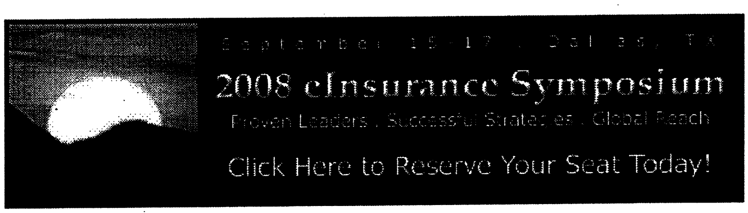

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principal and executive vice president for the Chicago-based Aon Brokerage Group, noting his observations are primarily focused on large-to-midmarket accounts.

"We're seeing 12-to-15 percent rate declines in most lines," he said. "But the underwriting community is showing reasonable underwriting diligence."

"There is a lot of underwriting capacity," agreed Mr. Bowles. "Insurers have robust budgets for 2008 and are aggressively looking for opportunities to deploy that capital."

"This time last year we began to see a deceleration in pricing," noted Mr. Reece, adding that price declines have been broad-based and fallen more quickly than anticipated. There was some thought price cuts would moderate, but that has not been the case for many accounts, as premiums have continued to drop, he observed.

One effect of the market decline has been significant movement of risk from the excess and surplus lines market back to standard carriers as insurers expand their risk appetite, he said.

"It's all the classic signs of a soft market," remarked Mr. Reece, adding that he sees this as "a normal market correction."

Integro's Mr. Garvey observed that the market is as "soft as you read about it," but noted there are isolated pockets where price declines are not as severe as others.

Indeed, there does not appear to be anything on the horizon likely to change the overall commercial insurance market's downward direction—not even recent declines in investment portfolios or the general economic downturn, he said.

"A lot of carriers are coming off a year with a lot of profitability, but...with a lack of growth from a premium standpoint, they are still in need to write new business," said Mike Pesch, area president of Arthur J. Gallagher Risk Management Services.

He warned that some insurers are on the verge of becoming "irrational" and losing their underwriting discipline, predicting that over the next six-to-12 months, carriers will begin to write business at pricing levels that will negatively affect their 2008 results.

However, if you are a commercial insurance buyer, times couldn't be better, Mr. Pesch said. "It's good for the consumer, and we try to stay ahead of that curve by telling our customers to expect favorable pricing upon renewal," he said.

Property market declines are not as steep as they were at the end of 2007, and there are openings for negotiations on terms and conditions, reported Jeffrey Fieldson, managing director of Marsh's Global Property Practice, during a recent webinar to coincide with the brokerage's release of its "U.S. Insurance Market Report 2008," covering the first quarter.

All those interviewed agreed that property-catastrophe exposures—which suffered the greatest premium increases after the 2004-2005 record hurricane seasons—are now experiencing declines with sufficient capacity for the risk.

"Property-catastrophe is seeing some easing," said Aon's Mr. Mula, noting that prices are not declining as fast as for noncat property exposures.

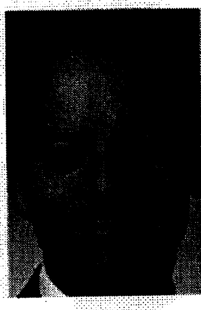
However, Mr. Garvey said it is still difficult to characterize the property-catastrophe market as softening because of the significant increases that policyholders had to swallow in the last couple of years.

For the largest catastrophe risks, rates and terms are improving while capacity is increasing, he noted. Insurance is available, which was not always the case in certain areas, he said—it's just a matter of how much it will cost.

However, another severe catastrophe loss, Mr. Mula warned, could turn the recent price declines around in a hurry.

One market seeing rate hikes is financial

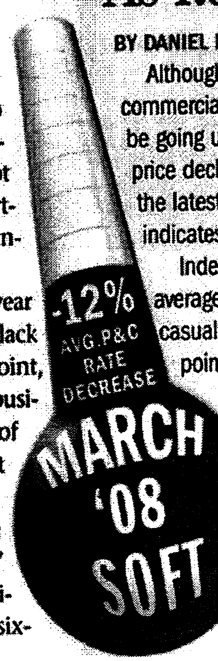
▸ continued on page 15



> **"If you look at the financial services business,** there have been some surprises there that have had an effect on some of the carriers. But there have not been any significant surprises of note in the insurance business yet, so you hope there won't be."
>
> *Peter F. Garvey, President*
> *Integro*

■ MARKET BAROMETER

P-C March Rates Down 12%, As Rate Cut Pace Keeps Slowing



BY DANIEL HAYS

Although players in the market say commercial insurance premiums won't be going up anytime soon, the pace of price declines might be bottoming out, the latest "Market Barometer" survey indicates.

Indeed, last month's 12 percent average rate cut in U.S. property-casualty commercial policies was two points below February's 14 percent average decline, three points less than January and four points lower than December 2007's peak of 16 percent.

Still, while the speed with which premiums fall might be slowing down, that doesn't mean the current buyer's market will be coming to an end, according to Richard Kerr, chairman and chief executive officer of MarketScout, which produces the monthly "Market Barometer" survey.

"We anticipate rate decreases to moderate for the remainder of 2008. However, a lessening rate decrease in 2008 does not mean the soft market is coming to an end," said Mr. Kerr.

"The soft market began in February 2005, so after 36 months, rate reductions will naturally moderate," he noted in a statement accompanying MarketScout's latest survey. "For instance, including the March 2008 reduction of 12 percent, rates are down almost 30 percent from March 2005 to March 2008."

▸ continued on page 30

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■ RISK MANAGER ALERT!

NU Extends WC Award Entry Deadline To June 9

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NATIONAL UNDERWRITER has extended until June 9 the deadline for entries in the second annual "*NU* Award For Excellence In Workers' Compensation Risk Management," sponsored by the National Council on Compensation Insurance.

Risk managers with the most effective and innovative safety and return-to-work programs are encouraged to submit their programs for consideration.

Brokers, insurers and third-party administrators may also nominate no later than May 8 worthy risk managers for consideration, who would then be contacted and invited to enter. However, risk managers need not be nominated by a third party to enter the award program.

Three finalists will receive:

▶ **A free trip to Orlando!**

A representative from the risk management departments of three company finalists will be flown to Orlando to attend the Workers' Compensation Educational Conference from Aug. 17-20, where the 2008 Champion will receive a trophy, while the other two finalists are given plaques for an Honorable Mention.

▶ **Profiles in *NU*!**

The risk management programs of all three finalists will be individually profiled in the Aug. 18 edition of *NU*.

▶ **Additional exposure!**

The finalists will also discuss the risk management challenges facing buyers at a special "*NU* Roundtable" during the WCEC on Aug. 19, with highlights printed in our Oct. 6 edition.

The *NU* award program, sponsored by NCCI, is run in cooperation with the WCEC (at which *NU* presents a National Trends program) and the Florida Workers' Compensation Institute (which manages the annual WCEC event).

For more details and to access the entry form, go to www.propertyandcasualtyinsurancenews.com and click on the accompanying icon at the bottom of the NU home page. The entry form appears with this story as an "associated image." If you have any questions, e-mail sfriedman@nuco.com. NU

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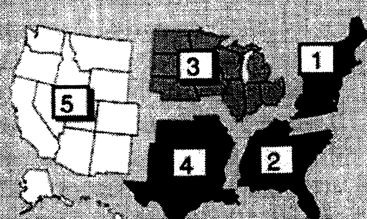

MARCH RATES DOWN

continued from page 13

Mr. Kerr also pointed out that insurers remain hungry for all types of business, including programs with books of business starting as low as $2 million.

"Four years ago, no one would talk to you unless you had a $7.5 million book to kick-start your program," he said. "A good distribution network supported by technical underwriting skills and as little as $2 million in premium will attract attention today."

MarketScout—a Dallas-based electronic insurance exchange, which underwrites and distributes product lines to a 60,000-member agency network—has been tracking the U.S. p-c market since 2001.

The company said its monthly "Market Barometer" is created using data assimilated via its online insurance exchange, further supported by in-person surveys of retail agents, company personnel, wholesale brokers and managing general agents.

MarketScout said its barometer findings are also supported by surveys conducted by The National Alliance for Insurance Education and Research during CIC and CRM institutes across the United States.

More than 40 "A"-rated carriers participate in the MarketScout exchange platform at http://www.marketscout.com.

The rates of decline for March 2008, broken down by coverage class, industry class and account size, were as follows:

▶ **By Coverage Class:**
Commercial Property—14 percent
Business Interruption—12 percent
Inland Marine—11 percent
General Liability—14 percent
Umbrella/Excess Liability—12 percent
EPLI—12 percent
Commercial Auto—8 percent
Professional Liability—9 percent
D&O Liability—9 percent
Workers' Compensation—8 percent
Fiduciary—8 percent
Crime—8 percent
Surety—7 percent

▶ **By Account Size:**
Small Accounts (up to $25,000)—12 percent
Medium Accounts ($25,001 to $250,000)—14 percent
Large Accounts ($250,000 to $1 million)—12 percent
Jumbo Accounts (over $1 million)—13 percent

▶ **By Industry Class:**
Manufacturing—14 percent
Contracting—14 percent
Service—14 percent
Habitational—12 percent
Transportation—12 percent
Public Entity—10 percent
Energy—10 percent

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Increasing Your Liability Protection

EXCESS VS. UMBRELLA LIMITS

By George L. Head, Ph.D.
Special Advisor, Nonprofit Risk Management Center

Many nonprofit organizations seek to increase the amount of their liability insurance protection for a variety of reasons, such as when —

The organization expands, perhaps by internal growth or merger, so that the former liability insurance limits no longer fit the organization's new liability exposures.

A newsworthy jury verdict or appellate court decision alerts the organization's senior management or board to the need for broader or higher limits of liability insurance.

A major change in the organization's leadership (e.g., board chair or CEO) brings in top management that is more conservative, less willing to tolerate uncertainties associated with potentially ruinous liability losses.

When the concerned leaders of these organizations ask for increased liability coverage from their current liability carriers, those carriers that are willing to cooperate often offer these organizations either *excess liability* insurance or *umbrella liability* insurance above their existing primary liability insurance.

Traditionally, there have been clear, significant differences between excess liability and umbrella liability insurance — differences that managers responsible for managing a nonprofit's insurance have had to understand to be sure that their organizations were protected by adequate liability insurance. Recently, however, these once sharp distinctions have become blurred. Insurers have introduced liability policy forms that combine the distinguishing features of excess liability and umbrella liability policies, sometimes renaming these new policies in the process. Consequently, it is no longer safe to judge a liability policy by its title, watching for the key words "excess" and "umbrella." Now, the responsible nonprofit executive often must read several liability policies in their entirety to understand their liability protection.

To make reading these policies more manageable, this fact sheet first describes the traditional distinctions between excess and umbrella liability insurance and then touches upon the differences in some of the newer hybrid forms.

The Traditional Distinctions

For the past several decades and until quite recently, it has been the case that:

<u>Excess</u> liability insurance (1) overlays a <u>specific liability insurance policy</u> that an organization already owns by increasing the per person and per accident or per occurrence limits of liability in that particular policy; (2) incorporates all the provisions of

the specific underlying policy, such as its insuring agreements, definitions, exclusions, and limitations (or "follows form" with the underlying policy); but (3) does not have any effect on any other liability insurance policies that the insured organization may have.

Umbrella liability insurance, in contrast, (1) overlays most of the major policies in an organization's liability insurance program, increasing the limits of liability in each of the liability policies in that organization's program; (2) typically offers broader coverage, with few exclusions or limitations and more liberal definitions than the underlying liability policies in the organization's program, and (3) "drops down" to provide first-dollar liability coverage (above any "self-insured retention" or other deductible) in many (but not all) areas of potential liability for which the organization has no other, more specific, liability coverage.

To illustrate these traditional differences between excess insurance and umbrella insurance arrangements, let us consider first some excess liability insurance and then substitute umbrella insurance. (Only the largest nonprofit organizations carry both excess and umbrella liability policies; most nonprofits rely on one or the other.) Start by supposing that a nonprofit's liability insurance program rests on four underlying primary policies:

Commercial General Liability (CGL) policy with a $2 million per occurrence limit

Automobile liability insurance with a $1 million per occurrence limit

Professional liability insurance with a $3 million per occurrence limit

A Directors' and Officers' (D&O) liability policy with a $1.5 million per claim limit

Suppose, as one alternative, that this nonprofit's program also includes, as a traditional excess liability policy, a CGL policy with a $3 million per occurrence limit. Under this excess-insurance alternative, its liability insurance program consists of:

CGL insurance of $5 ($2 + $3) million per occurrence

Automobile liability insurance of $1 million per occurrence

Professional liability insurance of $3 million per occurrence

Directors' and Officers (D&O) liability insurance of $1.5 million per claim

Now as the second alternative, assume that this organization does not buy excess CGL coverage with a $3 million per occurrence limit but, instead, purchases a traditional umbrella liability policy with the same $3 million per occurrence limits. Each of the original primary insurance limits then increases by $3 million, so that this nonprofit's liability insurance program, under the umbrella insurance alternative, consists of:

CGL insurance of $5 ($2 + $3) million per occurrence

Automobile liability insurance of $4 ($1 + $3) million per occurrence

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Ball-Dougherty/ 23

Professional liability insurance of $6 ($3 + $3) million per occurrence

Directors' and Officers (D&O) liability insurance of $4.5 ($1.5 + $3) million per claim

Nonprofit Risk Management Center ...find the answer here.
15 N. King St., Suite 203, Leesburg, VA 20176 | Phone: (202) 785-3891 | Fax: (703) 443-1990

The traditional umbrella insurance clearly costs — and typically is worth — more than the excess coverage for three reasons. First, the traditional umbrella coverage increases the automobile, professional liability, and D&O coverage limits, but the excess coverage does not. Second, the broadly written umbrella coverage provides insurance for many of the "following-form" exclusions and limitations that the excess coverage imports from the underlying primary policies. Third, traditional umbrella liability insurance provides (subject to any self-insured retentions or other deductibles) first-dollar coverage of exposures the more specific liability policies never address. Umbrella liability policy costs more than excess liability insurance but, for virtually any organization with the range of exposures that characterize its particular rating class, the umbrella provides more protection than the excess insurance policy. At least, that's generally true for the traditional excess and umbrella liability insurance arrangements.

Some Ongoing Changes

But traditions are changing. Some insurance policies with "excess " in their titles now increase policy limits for several underlying policies, not just the traditional single policy. Some policies that are still called "umbrellas" have no "drop down" feature like those that used to fill in many coverage gaps within and between primary policies. Furthermore, some newly named "umbrellas" are almost indistinguishable from traditional excess liability policies.

In short, one can no longer confidently judge many new liability policies by their titles. One has no choice but to read them, or read at least the insurer's very detailed descriptions of these often long and complex documents. The traditional distinctions between excess and umbrella coverages still matter — which primary limits are being increased, what are the exclusions and other coverage limitations, what is happening with coverage gaps within and between the primary policies — but these distinctions are not as clear as they once were, and they may emerge in surprising places and ways. Change is in progress, and change usually brings progress that ultimately benefits consumers of all goods and services. In the meantime, nonprofit buyers of increased limits of liability insurance beware. Stay alert — read carefully!

Dr. Head welcomes feedback on this article.

FOLEY
FOLEY & LARDNER LLP

Director and Officer Liability Trends and D&O Insurance – Advanced Issues

2007 NATIONAL DIRECTORS INSTITUTE

DIRECTOR & OFFICER LIABILITY TRENDS

At Foley's sixth annual National Directors Institute on March 8, 2007 in Chicago, Gordon "Chip" Davenport III, partner Foley & Lardner, moderated a panel discussion on "Director and Officer Liability Trends." Panelists included Michael Rice, managing director, AON Financial Services Group, and Dan Fortin, senior vice president, CNA Financial Corporation. The topic was looked at in more detail during the afternoon session on "D&O Insurance – Advanced Issues" wherein the panelists were joined by Ethan Lenz, partner, Foley & Lardner LLP and Steve Shappell, managing director, Aon.

The panel presentation featured an overview of the latest trends in D&O litigation and the D&O insurance marketplace; how insurance companies scrutinize the companies they write D&O policies for and what a company and its directors and officers can do to get the best possible D&O insurance coverage; and how to avoid gaps in insurance coverage and how to negotiate the best possible policy terms.

Trends in D&O Litigation and the D&O Insurance Market

There are two things that drive the D&O insurance market: the frequency and severity of claims. According to Mike Rice, the year 2006 saw a 50% decrease in the number of federal securities class action lawsuits filed when compared with the average over the preceding ten years. While this decrease in the frequency of lawsuits is good news for those in the market for D&O insurance, it is tempered by a substantial increase in the severity of those lawsuits and resulting claims. The average settlement of a federal securities class action in 2006 was $38.39 million, with 12 settlements in amounts greater than $100 million.

Overall, however, the D&O insurance market is a good one for buyers. First, since frequency of claims tends to drive D&O insurance prices to a greater extent than severity of claims, the downward claim-frequency trend has driven prices down notwithstanding the increase in severity of claims. Second, in recent years, D&O carriers have made significant profits on their policies, which has attracted new insurers into the D&O market. This increase in supply also has put downward pressure on D&O insurance premiums.

The result has been a broad, substantial buyers market for D&O insurance. Over the past three years, the trend has been decreased premiums and increased coverage. In fact, on average, a renewing company's 2006 premiums were 15% lower than its premiums in 2005. While this sort of reduction is not sustainable over the long term, Mr. Rice does believe that the trend will continue in 2007.

Aside from pricing concerns, the strategic selection of a D&O carrier is important, because you are transferring both personal and balance-sheet risk to that carrier. In making that choice, several factors should be considered:

- While D&O insurance pricing acts in a commodity-like fashion, no two carriers write the same policy. Consequently, D&O insurance cannot be viewed as a commodity, and a careful analysis of the insurer's policy form is critical.
- Although there is no S&P AAA rated carrier that writes D&O policies, the financial strength of the carrier is important and needs to be considered.

- Alignment with a carrier that is a market "leader" is important. Mr. Rice explained that from his perspective, D&O carriers are either market "leaders" or "followers." The leaders are those insurers that are willing to write primary policies and that have a sound understanding of risk. The followers are those insurers that are only willing to write excess policies, essentially following those carriers that write primary policies. It is important to be aligned with the leaders – those that understand risk.

D&O Risk Assessment and Implications for Directors

Dan Fortin focused on how D&O underwriters look at risk, how they price risk, and what companies in the market for D&O insurance can do to influence the price they pay. Briefly summarizing some key D&O claim statistics at the outset, he noted that public companies face a 35% chance in any given year of experiencing a D&O claim. Shareholder-claims are the largest source of this risk, accounting for 50% of all D&O claims. Significantly, he noted, 90% of all losses in CNA's public company D&O portfolio consist of costs to defend and resolve securities class action claims brought by shareholders. Private companies face a significantly lower risk of D&O claims, at only 10% per year. The largest number of D&O claims against private companies (50%) are brought by employees.

It's absolutely necessary for buyers to understand Insurer Strategies in order to achieve the best fit with a D&O insurer. Items that buyers ought to consider include:

- *Long-term v. Short-term* – Weigh the pros and cons of buying from insurers who try to time the market or behave erratically.
- *Risk Appetite* – If *your* risk profile changes, is your *insurer's* risk profile broad enough to accommodate that change?
- *Capacity Management* – What's the limit that the insurer will commit to any one risk, and how much of your risk will the carrier bear itself as opposed to passing it to a reinsurer?
- *Primary v. Excess* – Does the insurer have the actuarial and claims structure necessary to be a primary insurer (a "leader"), or are they a "follower"?
- *Claims* – Interview the insurer about its claims process: Is claims administration outsourced? Are claims handled by attorneys? What is the process when there is a dispute about a claim?

In reviewing how D&O carriers price their policies, Mr. Fortin noted that the criteria that underwriters use has become much more objective due to the large amount of information and other data that underwriters have available to them. Typically, the underwriter will plug into a model a set of objective risk factors to come up with base pricing for a D&O policy. Some of the objective risk factors that are usually included in that process are:

- Market Capitalization
- Industry
- Jurisdiction

- Ownership
- Assets
- Revenue
- Beta
- Credit Rating

Once these objective factors are analyzed, subjective factors and intangibles are considered. These are the factors that a company can emphasize to distinguish itself from others with similar objective factors and obtain better pricing and coverage. Subjective risk factors include:

- Financial performance
- Stock price performance, short sales, volume
- Corporate governance
- Investor profile
- Internal controls, compliance, code of conduct
- Secondary offerings
- Corporate transactions
- Restatements
- Change in auditor
- Claim activity, legal proceedings, investigations
- Accounting practices
- Insider trading

Along with these subjective factors, there are other "intangibles" that can help buyers get better pricing and coverage. For example, relationships play a huge role in pricing, terms, and claims. It therefore behooves companies to develop a good relationship with their insurer, and to consider developing relationships with multiple insurers. In addition, underwriters are keen to see that the company is serious about corporate governance and realistic about the risks that it faces. Thus, when meeting with a potential carrier, corporate officers should be ready to confront negative issues and be prepared with a risk self-assessment.

D&O Insurance: Hot Coverage Issues and How to Address them at your next Renewal

There are several key issues to consider and address in making certain that your company obtains the best possible D&O policy. Echoing some of the themes throughout the presentation, Chip Davenport stressed that D&O policy forms and coverage vary widely, with many terms open to negotiation. To get the best policy, it is critical to leave enough time (60 days preferred, but 30 days minimum) to: 1) get the right people involved (a broker plus someone else knowledgeable about D&O insurance), 2) set up a competitive bidding process among carriers, and 3) understand what you need to ask and negotiate for in the policy.

Some examples of important coverage terms that require attention and may be negotiated include:

- *Severability* – This provision determines who loses coverage if the carrier rescinds the policy. If the policy is rescinded for failure to disclose material facts in the application, the presence or absence of a severability provision will determine whether only those responsible for the nondisclosure lose coverage, or everyone – the company, and all officers and directors.
- *Crime/Fraud Exclusion* – There are important differences in the fine print of this exclusion (which appears in every D&O policy) that determine when the exclusion kicks in and what type of conduct it applies to. It comes into play frequently in securities cases, which frequently include allegations of fraud.
- *Nonrescindable A-Side* – This is the part of the policy that covers officers and directors in the event that the company does not indemnify them. It is increasingly possible to obtain policy language that makes this coverage nonrescindable.
- *Punitive Damage Coverage* – Some policies cover punitive damages and some don't. Additionally, some states do not allow this coverage, but there are terms that can be negotiated into a D&O policy to maximize the possibility that punitive damages will be covered.
- *Regulatory Investigation Coverage* – Many D&O policy forms either don't cover or provide only limited coverage for regulatory investigations, which can be quite expensive.
- *General Counsel Coverage* – Many D&O policies do not provide coverage for inside lawyers when acting as a lawyer. A separate policy may be needed for that.
- *Hammer Clause* – This clause gives the insurance company leverage to force a settlement by capping your coverage if you don't agree to settle.

Some of the hot D&O coverage issues include the ongoing options dating investigations and global warming coverage issues. There are currently about 120 options dating investigations being conducted. Coverage for these investigations and any resulting loss can be determined only by a close scrutiny of the D&O policy, and particularly how it defines a "claim" and a "loss." Second, while there currently is not a lot of global warming-related claims activity, it is on the horizon. Cases are split on whether there is D&O coverage for global warming-related claims. Coverage may depend on the language of the pollution exclusion in the D&O policy.

Several other issues should be considered when purchasing or renewing D&O insurance, including:

- *Fiduciary Claims* – These are claims relating to employee-benefits – for example, ERISA and 401(k) claims. They are *not covered* by D&O policies. A separate fiduciary liability policy is necessary. Such policies are no longer simply an afterthought, and companies are buying increased amounts of coverage due to larger exposure for these claims.

- *Non-Rescindable Coverage* – A few carriers are now beginning to offer non-rescindable ABC coverage, though there are some detriments that come with these policies.
- *A-Side Only* – These policies provide an extra layer of protection exclusively for officers and directors. They are quite common.
- *Bankruptcy Issues* – Bankruptcy courts tend to take the view that any insurance coverage belongs to the estate of the bankrupt corporation, which limits the ability of officers and directors to take advantage of the policies. It is important to negotiate provisions into the D&O policy that can help (but not eliminate) this problem.

Private companies also often need D&O insurance, particularly where they are engaged in raising capital (either equity or debt), mergers, or acquisitions.

D&O INSURANCE – ADVANCED ISSUES

Addressing more detailed issues surrounding D&O liability trends, the panel fielded questions from the audience and provided the following feedback:

- *Individual Director Policies*
  These tend to be expensive and there are more gaps in coverage than coverage. They typically are not a great product.
- *Understanding Your Coverage*
  Some directors will have an attorney review a company's D&O policy before joining a new board, however, this isn't necessarily mandatory. It is simply a matter of whatever it takes for the officer or director to be comfortable with the coverage offered by the company. More and more frequently, companies are requesting presentations to their entire board to address coverage questions.
- *Fiduciary Claims Not Covered*
  This is one of the few clear border lines between D&O policies and other insurance policies. Fiduciary claims (ranging from claims pertaining to the administration of employee benefit plans to breach of fiduciary duty in 401(k) administration) are virtually uniformly not covered by D&O policies. Though such claims are neither as frequent nor as feared as D&O claims, they have been increasing over the past few years.
- *Coverage for Non-Officers/Directors*
  A D&O policy can be adjusted to cover individuals who, though not technically officers or directors, engage in the types of activities and decision-making in which officers and directors engage. This can be done by adding the individuals as named insureds to the D&O policy either by position or by name. When doing so, the insurer typically will want a statement from the company that the added

individual would be indemnified by the company as would be any other officer or director.

- *Protection of D&O Insurance in Bankruptcy*
  There are several things that can be done in the D&O policy to protect directors and officers from having to expend personal assets in the event of bankruptcy. First, a priority of payments provision can be added to the policy, which states that if there is not enough insurance money to go around, individuals get it first. Second, a provision can be added to the policy to waive the automatic stay to the extent it would block individuals from getting the proceeds to the policy. Neither of these are perfect, however. One additional thing that can be done, though, is to purchase an A-side only policy.
- *A-Side Only Policies*
  A-side only policies provide coverage to directors and officers to the extent the company cannot or is unable to indemnify them. They protect officer's and director's personal assets. About 70% of companies provide A-side only coverage, but there are many variations.

For More Information

For more information on this session or the sixth annual National Directors Institute, visit Foley.com/ndi2007 or contact the panelists directly.

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INSURANCE JOURNAL

National News

Towers Perrin D&O Report: Spike in Demand for Personal Cover, Higher Limits, Enhancements

May 3, 2007

Public and private companies -- more than 66% of respondents -- have received a record number of inquiries from potential board members who are concerned about their current directors and officers (D&O) liability insurance, an increase of 16% from 2005, according to the D&O Liability 2006 Survey on Insurance Purchasing and Claims Trends conducted by Towers Perrin.

Nonprofit respondents received similar D&O inquiries from approximately 32% of their boards, up slightly (3%) from 2005.

The report also outlines a continued general softening of prices in the D&O market, with some pockets of pricing increases, as well as trends in limits purchased and the claims susceptibility of different industries.

In response to the record D&O inquiries from board members, companies are responding by providing broader personal liability protection for directors and officers, the survey shows. In fact, 14% of those surveyed purchased Side A-only coverage in the past year. Side-A coverage provides D&O coverage for personal liability when they are not indemnified by the organization.

The Towers Perrin survey, which included 2,875 participants, is the 29th in a series of studies on D&O liability insurance purchasing and claims trends and the most in-depth study of its type.

"For the first time, a study is confirming a significant change in how companies are protecting directors and officers from personal liability," said Michael Turk, Senior Consultant. "While Side A-only coverage has been growing in popularity over the last few years, we now have data to show just how prevalent the coverage has become."

The popularity of Side A-only coverage reflects directors and officers desires for improved personal coverage. This is particularly true for public companies, where 38% reported purchasing a Side A-only D&O policy this past year. Notably, the majority of stock option backdating claims seen so far have resulted in shareholder derivative claims, a common source of Side A D&O claims.

Among repeat survey participants, there was a 53% increase in organizations that purchased a Side A-only D&O policy. Twelve percent of repeat participants purchased such a policy, up from 8% in 2005. Although public companies are the most likely to purchase a Side A-only policy, the largest percentage increases occurred with private and nonprofit organizations.

Looking ahead, Towers Perrin expects to see an ongoing demand for Side A-only coverage, but also anticipates even greater changes in the types of coverage required by independent board members, according toTurk.

"In the coming years, we expect that independent board members will demand specialized policies protecting only their interests. The limits of such a policy – usually called an independent director liability policy ¾ would not be available to officers or internal directors, who typically have a larger exposure to D&O claims," Turk said. "The popularity of Side A-only policies reflects a movement in this direction."

Softening of the D&O Market and Increasing Limits

Towers Perrin's D&O liability insurance average premium index dropped 18% in 2006 after dropping 9% in 2005 and 10% in 2004. For repeat participants, the average premium reduction was 6.5%.

But while the downward change in premiums points toward a softening market, nearly the same percentage of companies experienced a premium increase (36%) as those that had a decrease (38%). Furthermore, changes in premiums varied substantially across organizations. Repeat public company participants with assets less than $6 million reported a 21% reduction, compared to a 4% reduction for public companies with assets greater than $10 billion. In contrast, repeat private organizations reported a 5% increase in premiums.

"Securities claim filings were down in 2006. Many reasons have been cited for this, such as improved corporate governance and reduced stock market volatility. We do not believe, however, that the current improved risk profile will support prolonged soft market premium decreases if underwriters want to write this line profitably," noted Turk.

Consistent with the 2005 survey, 15% of participants reported increasing their D&O limit. The average limit purchased across all participants was $11.55 million, a reduction from 2005 that is based largely on increased participation by smaller organizations. If new participant data is excluded, repeat participants reported an 8% average increase in limits across all asset sizes, from $9.31 million to $10.23 million. The largest increases reported by repeat participants were for organizations with assets between $1 billion and $10 billion. The utilities and durable goods classes showed the highest average limits.

For 2006, claim susceptibility across all business classes decreased 2% from 2005, to 14%. Public companies showed significantly higher claim susceptibility (31%) than private companies (9%) and nonprofit organizations (4%). The claimant distribution continues to be heavily dependent on the ownership structure of survey participants. For example, 49% of the claims against public participants were brought by shareholders. In contrast, 92% of the claims brought against nonprofit participants were brought by employees. The health service and utilities industries are most susceptible to D&O claims, based on survey responses, with the health services industry experiencing the highest claim frequency.

Nearly half (46%) of claims against 2006 participants have been closed, which remains consistent with last year's survey. The large majority of the closed claims were closed by settlement (61%), while the percentage of claims closed by litigation increased slightly from 10% in 2005 to 12% this year.

"While many companies focus on the possible negative impacts of D&O liability, managing D&O risks as part of a global enterprise risk management (ERM) program can deliver positive benefits for the enterprise," said Prakash Shimpi, ERM practice leader. "Well-managed D&O liability risk can improve decision making through corporate governance and also contributes to the retention and attraction of strong directors and officers."

Other highlights of the survey include:

Side A-Only Limits Represent Significant Portion of Total D&O Limits: The average Side A-only limit for those participants who also purchased a Side A, B and C policy was $15.0 million. This represented 31% of the organization's total D&O limits purchased. Interestingly, this percentage was fairly consistent across all asset sizes.

Growing Coverage Enhancements: Thirty-one percent of participants reported an increase in coverage enhancements to their D&O policy, and 8% also reported a decrease in policy exclusions.

Average Retentions Down Slightly: Repeat participants reported an average 6% decline in their retentions (from $484,000 to $456,000). Among all survey respondents, only 20% with renewals since the second half of 2005 reported increases in their retentions, down from 29% in 2005. Overall, 70% of U.S. participants reported no change in their retentions, compared with 63% in 2005.

Participant Profile
The 2,875 U.S. companies surveyed include all major industry groups. The three largest participants by business class, representing over 60% of total participants, continue to be technology, governmental and other nonprofits, and biotechnology and pharmaceuticals. The number of participants increased 6.7% over 2005, with the growth primarily in the number of smaller organizations participating. Survey respondents with assets less than $6 million increased 68%, and

PORTLAND GENERAL ELECTRIC COMPANY

Staff/304
Ball-Dougherty/33

2006 STOCK INCENTIVE PLAN

Effective as of March 31, 2006
(As Amended and Restated October 24, 2007)

1. Purpose. The Portland General Electric Company 2006 Stock Incentive Plan, as amended and restated (the " Plan ") is intended to provide incentives which will attract, retain and motivate highly competent persons as officers, directors and key employees of Portland General Electric Company (the " Company ") and its subsidiaries and Affiliates, by providing them with appropriate incentives and rewards in the form of rights to earn shares of the common stock of the Company (" Common Stock ") and cash equivalents.

2. Definitions. A listing of the defined terms utilized in the Plan is set forth in Appendix A.

3. Effective Date of Plan. The Plan is effective on March 31, 2006.

4. Administration.

(a) Committee . The Plan will be administered by a committee (the " Committee ") appointed by the Board of Directors of the Company (the " Board of Directors ") from among its members (which may be the Compensation and Human Resources Committee) and shall be comprised, solely of not less than two (2) members who shall be (i) "non-employee directors" within the meaning of Rule 16b-3(b)(3) (or any successor rule) promulgated under the Securities Exchange Act of 1934, as amended (the " Exchange Act ") and (ii) "outside directors" within the meaning of Treasury Regulation Section 1.162-27(e)(3) under Section 162(m) of the Internal Revenue Code of 1986, as amended (the " Code ").

(b) Authority . The Committee is authorized, subject to the provisions of the Plan, to establish such rules and regulations as it deems necessary for the proper administration of the Plan and, in its sole discretion, to make such determinations, valuations and interpretations and to take such action in connection with the Plan and any Awards (as hereinafter defined) granted hereunder as it deems necessary or advisable. All determinations and interpretations made by the Committee shall be binding and conclusive on all participants and their legal representatives.

(c) Indemnification . No member of the Committee and no employee of the Company shall be liable for any act or failure to act hereunder, or for any act or failure to act hereunder by any other member or employee or by any agent to whom duties in connection with the administration of this Plan have been delegated, except in circumstances involving his or her bad faith or willful misconduct. The Company shall indemnify members of the Committee and any agent of the Committee who is an employee of the Company, or of a subsidiary or an Affiliate against any and all liabilities or expenses to which they may be subjected by reason of any act or failure to act with respect to their duties on behalf of the Plan, except in circumstances involving such person's bad faith or willful misconduct. For purposes of this Plan, " Affiliate(s) " means any entity that controls, is controlled by or is under common control with the Company; *provided, however* , that neither the Disputed Claims Reserve, the Disputed Claims Overseers, the Plan Administrator nor the Disbursing Agent, as those terms are defined in Fifth Amended Joint Plan of Affiliated Debtors In Re Enron Corp. et al., shall be an Affiliate.

(d) Delegation and Advisers . The Committee may delegate to one or more of its members, or to one or more employees or agents, such duties and authorities as it may deem advisable including the authority to make grants as permitted by applicable law, the rules of the Securities and Exchange Commission (the " SEC ") and any requirements of the New York Stock Exchange (the " NYSE "), and the Committee, or any person to whom it has delegated duties or authorities as aforesaid, may employ one or more persons to render advice with respect to any responsibility the Committee or such person may have under the Plan. The Committee may employ such legal or other counsel, consultants and agents as it may deem desirable for the administration of the Plan and may rely upon any opinion or computation received from any such counsel, consultant or agent. Expenses incurred by the Committee in the engagement of such counsel, consultant or agent shall be paid by the Company, or the subsidiary or Affiliate whose employees have benefited from the Plan, as determined by the Committee.

5. Type of Awards. Awards under the Plan may be granted in any one or a combination of (a) Stock Options, (b) Stock Appreciation Rights, (c) Restricted Stock Awards, and (d) Stock Units (each as described below, and collectively, the " Awards "). Awards may, as determined by the Committee in its discretion, constitute Performance-Based Awards, as described in Section 13 hereof.

6. Participants. Participants will consist of (i) such officers and key employees of the Company and its subsidiaries and Affiliates as the Committee in its sole discretion determines to be significantly responsible for the success and future growth and profitability of the Company and whom the Committee may designate from time to time to receive Awards under the Plan and (ii) each director of the Company who is not otherwise an employee of the Company or any of its subsidiaries and whom the Committee may designate from time to time to receive Awards under the Plan. Designation of a participant in any year shall not require the Committee to designate such person to receive an Award in any other year or, once designated, to receive the same type or amount of Award as granted to the participant in any other year. The Committee shall consider such factors as it deems pertinent in selecting participants and in determining the type and amount of their respective Awards.

7. Grant Agreements.

(a) Awards granted under the Plan shall be evidenced by an agreement (" Grant Agreement ") that shall provide such terms and conditions, as determined by the Committee in its sole discretion, *provided, however,* that in the event of any conflict between the provisions of the Plan and any such Grant Agreement, the provisions of the Plan shall prevail.

SCHEDULE 715
ELECTRICAL EQUIPMENT SERVICES

PURPOSE

To provide construction and maintenance to Customer or utility owned electrical equipment (other than equipment owned by the Company).

AVAILABLE

In the State of Oregon.

APPLICABLE

To all Nonresidential Customers and utilities.

CHARACTER OF SERVICE

The Company provides engineering, electrical design and construction, equipment maintenance and repair, preventative diagnostic and prevention maintenance, electrical oil containment and compliance with the Environmental Protection Agency's Spill Prevention Control and Countermeasure Oil Program (SPCC), equipment leasing, Energy recovery and revenue protection and electrical equipment refurbishing and disposal services.

BILLING RATES

Service will be contractually negotiated.

SPECIAL CONDITIONS

1. All fully distributed costs and revenues associated with the provision of Electrical Equipment Services will be charged or credited to non-utility accounts.

2. Electrical Equipment Services will be provided in accordance with the Code of Conduct as set forth in OAR 860-038-0500 through 806-038-0640.

3. If the Company chooses to use bill inserts to market this schedule to Customers, it will allow other electrical equipment services providers access to place inserts in the Company's bills under the same prices, terms and conditions that apply to the Company's Electrical Equipment Services.

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

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

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

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

Q. How do you calculate net dispatch benefits?

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

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

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

CASE: UE 197
WITNESS: Ed Durrenberger

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Direct Testimony

July 9, 2008

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

A. My name is Ed Durrenberger. I am a Senior Analyst in the Electric & Natural Gas Division of the Oregon Public Utility Commission. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have proposed some adjustments to the expenses that PGE has included in its General Rate Case, Docket UE 197, and I will explain those adjustments and why certain PGE-proposed expenses should not be included in the company's revenue requirement.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/402, consisting of 1 page.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony concerns three adjustments. Each of these adjustments is based on issues brought up by PGE in their direct testimony filed in the general rate case. Each has multiple parts pertaining to an expense that PGE included in an operations expense category. They are the following:

Issue 1, Transmission and Distribution maintenance cost adjustment.

Issue 2, Fixed Plant Maintenance cost adjustment.

Issue 3, General Production Operating and Maintenance adjustment.

TRANSMISSION AND DISTRIBUTION
MAINTENANCE COST ADJUSTMENT

Q. PLEASE EXPLAIN THIS ISSUE.

A. The company's Transmission and Distribution Operating and Maintenance (O&M) costs include increases in expenses for two Transmission related projects that I recommend the Commission adjust downward.

Q. PLEASE DISCUSS THE FIRST PROJECT.

A. The first item is described in the testimony is an increase in expenses of $300,000 for Regional Planning and Professional Services (*See* PGE/ 600, Hawke/ 6). Of this total expense, PGE has forecasted that approximately $200,000 would be for participation in a regional transmission planning group and the other $100,000 would be for professional services for coordinating the company's regional planning effort. Initially I had thought to disallow this increase entirely as unnecessary; PGE's approved budget includes funds for participation in a transmission organization. However PGE has subsequently announced its participation in the "Northern Tier Transmission Group," a regional transmission planning organization and successor to the now defunct Grid West RTO. With annual membership fees for 2009 forecast to be $250,000, PGE's proposed incremental cost of $300,000 does not appear to be appropriate. I propose an adjustment of $50,000 to the company filing in this category from an increase of $300,000 to $250,000.

Q. WHAT IS THE OTHER TRANSMISSION O&M PROJECT COST INCREASE YOU PROPOSE TO ADJUST?

A. The company has proposed an increase to O&M costs to develop Unscheduled Flow Mitigation (UFM) Plans (See PGE/ 600, Hawke/ 7). UFM plans are intended to reduce the possibility of transmission overloads due to unscheduled line flow on Qualified Paths and are required by Transmission Path operators in accordance with the "WECC Unscheduled Flow Procedure of Curtailment Actions".

Q. WHY DO YOU PROPOSE AN ADJUSTMENT IF THIS IS REQUIRED?

A. This requirement has existed for some time: a search of the WECC web site indicates UFM plans have been required for over five years, through at least two PGE general rate cases. PGE has not shown that creating UFM plans and keeping them current is an incremental cost increase to Transmission O&M.

Q. WHAT DO YOU PROPOSE?

A. I propose this cost increase of $100,000 be rejected entirely.

Q. DO YOU PROPOSE ANY OTHER TRANSMISSION O&M COST ADJUSTMENTS?

A. No, I do not. In summary, I propose that the Transmission and Distribution O&M cost increase requested by the company for the 2009 test year be reduced by $150,000.

FIXED PLANT MAINTENANCE COST ADJUSTMENT

Q. WHAT ARE YOU PROPOSING FOR FIXED PLANT MAINTENANCE?

A. The company's testimony at PGE/ 400, Quennoz-Lobdell/ 9 and 10 discusses a number of plant–related O&M increases. Among the items discussed are some one time maintenance costs for the Beaver, Colstrip and Boardman thermal plants that represent nonrecurring expenses.

Q. WHAT DO YOU MEAN BY NONRECURRING EXPENSES AND WHY DOES THAT MATTER?

A. Nonrecurring expenses are unusual expense variations due to some extraordinary or nonrecurring event in a test period that materially distorts a utility's financial position. Since the rates set in a general rate case last in perpetuity or at least until the next general rate case, it is important that the revenue requirement analysis establish a financial test period that reflects reasonably normal operation and expenses to insure that the utility actually needs a rate adjustment. Nonrecurring expenses distort the test period revenue requirement and result in incorrect rate setting.

Q. HOW ARE NONRECURRING EXPENSES TREATED IN A RATE CASE?

A. Nonrecurring expenses in a rate case are adjusted in one of two ways: they are either normalized or amortized.

Q. PLEASE EXPLAIN.

A. Normalization adjustments simply remove or disallow the nonrecurring expense thereby establishing a "normal" level of operating (or maintenance) costs for rate making in the test period. An amortization adjustment allows the expense but spreads it over a number of years so that the test period only includes a portion of the expense.

Q. WHY DO YOU CHARACTERIZE THESE COSTS AS ONE-TIME OR NONRECURRING?

Q. In the case of the Beaver maintenance expenses, the testimony states that costs increased by $2.2 million in 2008 because of extended planned maintenance at Beaver and to repair the roof over some auxiliary equipment, and that the costs for the 2009 test year are expected to be similarly higher than normal. In other words, the costs are characterized as above normal and non-routine. Furthermore, in a response to a data request about plant maintenance cost data going back five years (*See* Exhibit Staff/ 502/ Durrenberger/ 1) the overall maintenance costs for Beaver units 1 through 7 are projected to be higher, on an annual basis, by approximately 45% for 2008 and 2009. In the case of the Colstrip excess maintenance costs, the Colstrip 4 unit is planned for a longer than normal outage in the test year. The main job is a one time installation of low NOx burners and the cost increase over the previous year is $3.2 million, which is approximately 40% higher than historic maintenance costs. For Boardman, the planned outage in the test year is also longer than normal because of a stator rewind. This is a non-routine task which has never been performed at this plant before. Testimony states that this one time maintenance cost increase is expected to be $3 million. This is 22% higher than historic maintenance costs. In addition, a portion of the Boardman stator rewind has been identified as a capital project in PGE testimony (*See* PGE/ 400/ Quennoz- Lobdell/ 20 and 21). All one time expenses associated with a capital project should be part of the overall capital project budget including nonrecurring maintenance expenses.

Q. WHAT RATEMAKING TREATMENT DO YOU PROPOSE FOR THESE MAINTENANCE COSTS?

A. I propose that the fixed plant maintenance costs be normalized and that the nonrecurring expenses for Beaver, Colstrip and Boardman be disallowed because they distort the test period revenue requirement and result in incorrect rate setting.

Q. IF THE COMPANY IS NOT ALLOWED TO INCLUDE THE ONE TIME COSTS FOR THESE NONRECURRING EXPENSES IN THE O&M COSTS USED FOR RATEMAKING HOW CAN THE COSTS BE RECOVERED?

A. PGE has a great deal of discretion over how and what it chooses to spend its maintenance budget on. This means they can choose to take on nonrecurring expenses that may be over the budget in one year but that could result in lower than budgeted costs in subsequent years. Alternately, the Commission may choose to allow an amortizing adjustment where by the nonrecurring excess cost is spread over a number of years so that the test period included only a portion of the expense. Perhaps a suitable amortization period could be the depreciable lifetime of the asset to which it applies. For Boardman, since the company is planning to capitalize some of the stator rewind costs, I recommend that all expenses associated with the rewind be included in the capital budget for this project. That way once the project is complete and the costs have been added to rate base, the company could recover the nonrecurring costs through a return on rate base. The important thing is for rates to be based on as normal of conditions as possible and that one time, excess expenses not included in base rates.

Q. PLEASE SUMMARIZE YOUR ADJUSTMENT TO FIXED PLANT O&M.

A. In summary, I am proposing an adjustment to PGE's filed Fixed Plant O&M costs to disallow one time excess maintenance costs increases of $2.2 million for Beaver, $3.2 million for Colstrip and $3.0 million for Boardman.

GENERAL PRODUCTION O&M ADJUSTMENT

Q. WHAT ARE THE ISSUES WITH THE GENERAL PLANT O&M ADJUSTMENT?

A. This adjustment addresses three cost items described in testimony at PGE/ 400 Quennoz-Lobdell/ 5. One is an increase of $300,000 to be used to hire consultants to develop NERC/WECC compliance procedures. The second is an increase in expenses of $100,000 to fund a Reliability Centered Maintenance (RCM) group. The third is $100,000 for "miscellaneous software purchases and upgrades."

Q. WHAT IS YOUR POSITION ON THESE ITEMS?

A. I recommend that the Commission reject these increases. Based on PGE's description of these three additions, these appear to be either one time costs such as the unspecified software purchases, a reassignment of expenses such as the RCM program, which uses existing employees whose costs are already in rates, or speculative as in the case of the WECC/NERC compliance procedure development expense for safety and reliability rules that are anticipated.

Q. WHAT IS THE TOTAL OF YOUR PROPOSED GENERAL PRODUCTION O&M ADJUSTMENTS?

A. I propose to reduce the company’s test year General Production O&M by $500,000.

Q. DO YOU HAVE ANY OTHER ADJUSTMENTS TO DISCUSS?

A. No, that is all.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 197
WITNESS: Ed Durrenberger

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement

July 9, 2008

WITNESS QUALIFICATION STATEMENT

NAME: Ed Durrenberger

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst, Electric and Natural Gas Division

ADDRESS: 550 Capitol St. NE, Ste. 215, Salem, Oregon 97301

EDUCATION: B.S. Mechanical Engineering
Oregon State University, Corvallis, Oregon

EXPERIENCE: I have been employed at the Oregon Public Utility Commission of since February of 2004. My current responsibilities include staff research, analysis and technical support on a wide range of electric and natural gas cost recovery issues with an emphasis on electricity and fuel costs.

OTHER EXPERIENCE: I worked for over twenty years in industrial boiler plant engineering, maintenance and operations. I this capacity I managed plant operations, fuel supplies and utilities, environmental compliance issues and all aspects of boiler machinery design, installation and repair.
I have also worked as a production manager and machine shop manager for an ISO certified high tech equipment manufacturer servicing the silicon wafer fabrication and biomedical business sectors.

CASE: UE 197
WITNESS: Ed Durrenberger

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibit in Support
Of Direct Testimony

July 9, 2008

(by Marco Espinoza - BDS)

			Data						
ENTITY	LEDGER	Ledger Name	Sum of 2003 Actuals	Sum of 2004 Actuals	Sum of 2005 Actuals	Sum of 2006 Actuals	Sum of 2007 Actuals	Sum of 2008 FOM	Sum of 2009 FOM
133 COLSTRIP	N54411	CORRECTIVE MAINTENANCE	2,794,598	3,395,770	2,351,679	4,170,569	3,929,517	3,894,159	5,513,878
	N54412	PREVENTIVE MAINTENANCE	3,585,504	3,421,995	2,353,275	4,170,669	3,929,517	3,894,159	5,513,878
133 COLSTRIP Total			6,380,102	6,817,765	4,704,954	8,341,237	7,859,035	7,788,318	11,027,756
141 BEAVER UNIT 1-7	N54411	CORRECTIVE MAINTENANCE	2,374,394	2,609,058	2,311,279	2,200,358	1,959,981	2,473,839	2,566,474
	N54412	PREVENTIVE MAINTENANCE	734,933	475,177	584,687	477,002	496,543	2,114,147	2,436,331
141 BEAVER UNIT 1-7 Total			3,109,327	3,084,234	2,895,965	2,677,360	2,456,524	4,587,986	5,002,805
148 BEAVER UNIT 8	N54411	CORRECTIVE MAINTENANCE	6,156	6,502	2,549	261,754	110,569	0	0
	N54412	PREVENTIVE MAINTENANCE	629	2,380	26,878	0	964	0	0
148 BEAVER UNIT 8 Total			6,784	8,882	29,427	261,754	111,533	0	0
161 COYOTE	N54411	CORRECTIVE MAINTENANCE	3,865,913	564,321	2,747,131	2,565,192	1,275,014	2,077,629	5,477,251
	N54412	PREVENTIVE MAINTENANCE	434,943	84,109	39,065	34,721	13,836	123,465	126,684
161 COYOTE Total			4,300,856	648,430	2,786,196	2,599,913	1,288,851	2,201,094	5,603,935
164 PORT WESTWARD	N54411	CORRECTIVE MAINTENANCE	0	0	0	0	3,867,707	5,386,784	5,511,280
	N54412	PREVENTIVE MAINTENANCE	0	0	0	0	137,038	949,689	982,491
164 PORT WESTWARD Total			0	0	0	0	4,004,745	6,336,473	6,493,771
921 BOARDMAN	N54411	CORRECTIVE MAINTENANCE	8,690,628	12,218,073	11,408,462	10,884,433	10,929,209	10,787,787	13,577,236
	N54412	PREVENTIVE MAINTENANCE	751,532	2,825,775	908,395	821,187	1,413,745	1,351,525	1,422,412
921 BOARDMAN Total			9,442,159	15,043,848	12,316,857	11,705,620	12,342,954	12,139,311	14,999,648
Grand Total			23,239,229	25,603,159	22,733,399	25,585,884	28,063,640	33,053,183	43,127,914

* Coyote is all actuals (does not include normalization of LTSA)
* All maintenance costs are incurred cost only, plus materials overhead - no other loadings- (which is the same as provided in the testimony)

Staff/402
Durrenberger/1

CASE: UE 197
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

Direct Testimony

July 9, 2008

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

A. My name is George R. Compton. I am a Senior Economist, employed half time by the Economic Research & Financial Analysis Division (ERFA) of the Oregon Public Utility Commission (OPUC). My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/501.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The principal focus of my testimony is to propose rate design reforms for the major customer schedules so that these rates respond to the higher summer period electricity costs that are being experienced by PGE (or Company) by virtue of its interconnection with California and the desert southwest region of the United States. I also address briefly the following topics: 1) Compliance with the smart meter standard of the federal Energy Policy Act of 2005; 2) load forecasts and elasticity effects; 3) the PGE proposal to adjust Schedule 125 (Annual Power Cost Update) magnitudes to reflect changes in fixed generation cost recovery due to departing or returning customers in Schedules 483 and 489 (Direct Access); 4) the PGE proposal to distribute the Schedule 125 impact to customers on the basis of a uniform percentage of the classes' pro-forma projected generation revenues rather than on a uniform cents per kWh basis; 5) Staff's qualified acceptance of PGE's cost-of-service-based spread of the revenue requirement increase among the rate schedules; and 6) some general comments regarding PGE's rate design and tariff proposals.

Q. LET'S FIRST DISCUSS YOUR BRIEFLY-ADDRESSED TOPICS, AND IN THE SEQUENCE THAT THEY WERE MENTIONED. WHAT IS THE THRUST OF THE SMART METERING STANDARD OF THE ENERGY POLICY ACT OF 2005, AND WHAT IS THE STATUS OF PGE'S COMPLIANCE WITH IT?

A. The pertinent section of the Act requires that by August 8, 2008, or in the first rate proceeding following, the Commission determine whether to adopt the following standard: "each utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology…." The statute lists three types of time-based rates for consideration – time of use pricing, critical peak pricing and real-time pricing – as well as credits for peak load reduction.

Reiterating, the objective is to promote greater efficiency by, and equity among, customers of electric utilities through the use of price signals which better capture how electricity costs change as a function of time. Achieving that objective entails a rate design element and, typically, a technology element. Historically, the technology component was satisfied with time-of-day

(TOD) meters. In the past, the cost of those meters has been such that mandatory TOD rates have only as a rule been implemented for a utility's largest customers (e.g., Schedule 89). Regardless, as a result of the electric industry restructuring law, most major rate classes of PGE, including residential customers, have the *option* of subscribing to time-varying pricing. Residential and small business customers can choose conventional TOD rates, which specify fixed on-peak and off-peak prices. PGE's Large Non-Residential Standard Service Schedule 83 allows customers to choose pricing based on the Dow Jones Mid-Columbia *daily* on- and off-peak electricity firm price index. A monthly price option also is available. In addition, PGE offers a real-time pricing option for its largest customers through Schedule 87.

Q. DO YOU RECOMMEND THAT THE COMMISSION ADOPT THE SMART METERING STANDARD OF THE ENERGY POLICY ACT OF 2005 FOR PGE?

A. No. As noted above, PGE is generally effectuating the policies underlying the standard on a voluntary basis. Furthermore, the Commission approved PGE's plan to install advanced metering infrastructure, including "smart meters" for virtually all of its customers and two-way communication with the meters. Under the plan, the Company will file in early 2009 an experimental critical peak pricing tariff for the Commission's consideration. *See* Order No. 08-245. PGE recently began systems-acceptance testing of a limited number of meters and plans to complete installation before year-end 2010. As these meters are installed, the Commission will have the flexibility to decide how fast and to what degree to implement, with the various rate classes, additional time-varying pricing options. Accordingly, staff does not recommend that the Commission implement the federal standard for all PGE customers at this time.

Q. PERHAPS THE MOST REMARKABLE ELEMENT OF PGE'S LOAD FORECAST IS ITS PROJECTION OF ZERO GROWTH IN TOTAL RESIDENTIAL KWH CONSUMPTION IN 2009 DESPITE AN INCREASE OF ABOUT 1% IN THE RESIDENTIAL CUSTOMER COUNT. DOES STAFF ACCEPT THAT PROJECTION?

A. Yes, with some elaboration. The projection employs a price elasticity figure of minus 0.08 (implying a demand reduction of 0.8% in the presence of a 10% price increase) in the context of a PGE-projected price increase of 8.5%. Combining Staff's recommended increase in PGE's general rates with the stipulated-to net-variable-power-cost (NVPC) increase yields a figure very close to 8.5%. Ordinarily, we would adjust the Company's suggested price elasticity effect downward for inflation, making the overall effect smaller. But the current and projected inflation is different from the historical pattern where wages followed (or led) consumer goods' prices. The current inflation is more limited to food and fuel, creating the effect of declining real income. Insofar as the income elasticity effect can be construed as roughly canceling the general inflation effect, applying the Company's price elasticity figure to the nominal (i.e., not inflation-adjusted) electricity price increase is acceptable. Accordingly, Staff accepts the Company's load projections -- under the assumption that the final case outcome does not depart substantially from the Staff revenue requirement recommendation.

Q. SCHEDULE 125 WAS PUT INTO PLACE TO ALLOW THE COMPANY TO KEEP ITS ENERGY CHARGES IN ALIGNMENT WITH PROJECTED NET VARIABLE POWER COSTS. PGE IS NOW ASKING THAT THE SCHEDULE ALSO INCORPORATE AN OFFSET (OR AUGMENTATION) SUCH THAT, OUTSIDE THE BOUNDS OF A GENERAL RATE CASE, THE COMPANY WOULD BE SHIELDED FROM UNDER-COLLECTING FIXED GENERATION REVENUES WHEN DIRECT ACCESS CUSTOMERS DEPART FROM COST-OF-SERVICE STATUS AND PREVENTED FROM OVER-COLLECTING FIXED GENERATION REVENUES WHEN DIRECT ACCESS CUSTOMERS RETURN. WHAT IS STAFF'S RESPONSE TO PGE'S REQUEST?

A. Staff does not support this proposal. A key principle that guided staff in reviewing direct access concepts is that actions by direct access customer, either departing PGE 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.

Q. MOVING ON, USUALLY A UNIFORM CENTS PER KWH ADJUSTMENT IS USED TO REVISE RATES PURSUANT TO SCHEDULE 125. FOR THIS RATE CASE, PGE IS PROPOSING TO ALLOCATE THE SCHEDULE 125 TOTAL AMONG THE CLASSES AS A UNIFORM PERCENTAGE OF THE

CLASSES' PROJECTED GENERATION REVENUES. DO YOU SUPPORT PGE'S PROPOSAL?

A. Yes. PGE's proposal is consistent with having rates based on cost and reflecting cost causation. When net variable power costs go up or down by a given percentage, the overall marginal-cost based effect on customer classes' costs would seem to be more readily captured by making a common percentage adjustment than by a simple uniform cents-per-kWh adjustment. The latter would not reflect the underlying time differentiation of generation costs.

Q. PGE'S APPLICATION CALLS FOR SPREADING THE RATE INCREASES AMONG THE CUSTOMER SCHEDULES ACCORDING TO THE OUTCOME OF ITS COST-OF-SERVICE ALLOCATIONS – SUBJECT TO AN EXCEPTION BEING MADE FOR LIMITING INCREASES TO NO GREATER THAN TWICE THE OVERALL AVERAGE. IS PGE'S APPROACH REASONABLE?

A. Yes. But bear in mind that those allocations will have to be reconstituted in order to reflect the accounting adjustments that will ultimately be made to the overall revenue requirement. Notably, the various stipulated to or ruled upon cost reductions will differentially affect the different customer schedules. A next order of business will be for the Company to be asked to re-do its cost-of-service-based rates spread to reflect the accounting adjustments already agreed to by PGE plus the additional OPUC Staff's recommended adjustments, and the revenue requirement associated therewith.

Q. DO YOU HAVE A GENERAL STATEMENT REGARDING PGE'S PROPOSED NEW PRICE TARIFFS?

A. Yes. As a general matter Staff finds them acceptable in terms of fostering energy conservation and maintaining continuity with the current rate schedules. It is noteworthy that PGE's price changes are almost entirely limited to the volumetric rates (i.e., per kW and kWh charges) rather than to the basic/customer charge. That emphasis is appropriate. PGE's basic charges are in many (but not all) instances already well above Pacific Power's. (Examples: PGE's residential basic charge is $10/month versus $7.50 for Pacific Power; PGE's basic charge for large, subtransmission customers is $1000/month versus $480 for Pacific Power.)

That general statement aside, the balance of this testimony is dedicated to Staff's recommendation to set prices that better reflect PGE's time-based variations in costs. This would be achieved by 1) introducing seasonally varied rates to all the major customer schedules; 2) adding a third block to the residential rate in the summer, and 3) carving out a super-peak period from the on-peak period as applied in the summer to large industrial customers (Schedule 89).

Q. I NOTE THAT YOUR PROPOSALS PERTAIN TO THE SUMMER PERIOD. HOW WOULD YOU DEFINE "SUMMER" FOR RATEMAKING PURPOSES?

A. The Summer season would include the three months, July through September, for which PGE is projecting its highest marginal power costs for the test period. (*See* PGE 1200 Work Papers 49.)

Q. GIVEN THAT PGE'S HIGHEST LOADS ARE IN THE WINTER, WHY WOULD ITS HIGHEST COSTS PER MWH APPEAR IN THE SUMMER?

A. First, we must distinguish between *energy* (kWh) loads, which are normally viewed on a cumulative or average basis, and *demand* (kW), or peak loads. Recently, PGE has experienced its most critical (in the sense of combining high loads *and* high purchase costs) peak demands in the summer. The most current FERC FORM 1 (2006/Q4, page 400) shows PGE having its highest peak demand (both total and firm service to its own customers) in the month of July, not December or January.

But probably more to the point is the fact that a) PGE relies heavily on market purchases to meet its loads; b) PGE's market is interconnected with California and the American southwest, whose needs tend to establish the market price for the entire region; and c) the loads of California and the American southwest are heavily air-conditioning driven, which means the highest prices during the year are experienced during summer afternoon and early evening periods.

Q. HAVE YOU PREPARED AN EXHIBIT THAT DISPLAYS MARGINAL POWER COSTS FOR PGE ON A MONTHLY AVERAGE BASIS?

A. I have. It is Exhibit 502. It shows the averages on both and on-peak and off-peak basis, by month and season.

Q. WHAT DO YOU CONCLUDE FROM THAT EXHIBIT?

A. I conclude that there is a sizable difference in energy costs between the summer and the rest of the year, and that the difference is driven far more by the on-peak cost disparity than by the off-peak cost disparity. The summer's on-peak costs exceed the on-peak costs for the rest of the year by over $17/MWh while the difference in off-peak costs is only $4/MWh.

Q. WHAT ARE THE RATE DESIGN IMPLICATIONS OF THOSE CONCLUSIONS?

A. At a minimum, the largest customer schedules should incorporate seasonal elements in the energy charges. Feasible added measures should be pursued in order to reflect the summer season's on-peak/off-peak cost disparities.

Q. CAN YOU BE A LITTLE MORE SPECIFIC?

A. I recommend the introduction of a simple summer versus non-summer energy rate differential for Schedules 32 and 83. In addition, the dividing of the on-peak summer period into shoulder-peak and super-peak periods is recommended for Schedule 89 – so as to provide for a higher price in the latter period. Finally, another inverted block is recommended for the summer, to go beyond the existing two-block energy e for the residential Schedule 7.

Q. WHAT IS THE RATE DIFFERENTIAL THAT YOU RECOMMEND FOR SCHEDULES 32 AND 83?

A. Staff's recommended rate differential mirrors the difference in the overall average marginal costs between the summer and the rest of the year. This implies a differential of 1.2 cents per kWh between the Summer Season and Non-Summer Season.

Q. I CAN'T HELP OBSERVING THAT THE SPRING SEASON (APRIL THROUGH JUNE) HAS SIGNIFICANTLY LOWER COSTS THAN DOES THE REST OF THE "NON-SUMMER." WHY ARE YOU NOT RECOMMENDING THREE SEASONS FOR YOUR RATE DIFFERENTIALS RATHER THAN TWO?

A. Simplicity and customer acceptance are served by limiting seasonal rate changes to what are most essential. What is most essential in the instant case is to recognize the summer season as the most critically distinct from the other seasons.

Q. HAVE YOU PREPARED RATE SCHEDULES THAT INCORPORATE THE SEASONAL DIFFERENTIALS YOU JUST DESCRIBED?

A. No. As stated earlier, the rate design process can't be completed until cost-of-service studies have been developed/revised to reflect various accounting adjustments and other alterations to PGE's original case application.

Q. EARLIER YOU REFERRED TO "ADDITIONAL MEASURES" FOR SCHEDULES 7 AND 89. THE LATTER ALREADY HAS MEANINGFUL TOD RATES THAT ARE BASED ON THE ESTABLISHED ON-PEAK AND OFF-PEAK PERIODS. WOULDN'T IT BE SUFFICIENT FOR THE PURPOSE OF THIS CASE TO UTILIZE THE EXISTING TOD FORMAT, BUT WITH SEASONALLY VARIED RATES AND RATE DIFFERENTIALS?

A. No. There are two additional objectives that are readily achievable. One is to recognize in rates the fact that the eight-hour period from noon to 8 p.m. in the summer time has significantly higher costs than the rest of the standard sixteen hour “on-peak” period (from 6 a.m. to 10 p.m.). The other objective is to foster industrial load shifting insofar as it can be easier for some large industrial customers to at least partially vacate an eight hour period than to vacate an entire sixteen hour period. Both objectives would be promoted by the introduction of a noon-to-8 p.m. super peak pricing period within the standard sixteen hour, on-peak period.

Q. WOULD IT MAKE SENSE TO ALSO INTRODUCE A SUPER PEAK RATING PERIOD FOR THE REST OF THE YEAR FOR THE LARGEST CUSTOMERS?

A. It is true that outside of summer there are eight or so hours that experience higher loads than the rest of the on-peak period does. But some of those hours appear during the early morning (when furnaces are turned up), and the remainder appear in the late afternoon and early evening. It would be more than cumbersome for large energy users to adapt their labor shifts to avoid the spread-out, higher-price periods. Furthermore, the on-peak, shoulder-peak, and off-peak pricing disparities in the non-summer seasons are not as great as they are in the summer season.

Q. DO YOU POSSESS QUANTITATIVE EVIDENCE TO SUPPORT YOUR ASSERTION REGARDING HIGHER COSTS IN A CONCENTRATED EIGHT HOUR SUPER-PEAK PERIOD IN THE SUMMER?

A. I do – in the form of three sets of confidential responses to OPUC data requests. Without revealing the protected specifics, the conclusions therefrom can be summarized as follows:

D.R. 364: Power purchases ramp up in a major way at or near the beginning of the super-peak period on high-demand summer days and rapidly fall off after that period.

D.R. 365: Net-variable-power-costs (i.e., total purchase costs minus off-system sales revenues divided by net purchases) are shown to be substantially higher during the super-peak period as compared with the rest of the "on-peak" period on typical and high demand summer days.

D.R. 399: Over the past few summers, super-peak period spot prices – particularly the recorded lows for a given hour – have been significantly above those during the rest of the "on-peak" period.

These observations are not surprising when it is recognized that the times that electric supply and demand becomes the most critical in the West is on hot summer afternoons and early evenings, when air conditioners are going full bore. And in the Central Valley of California, in Southern Nevada, and in Arizona, hot summer afternoons are the norm.

The standard longer-term purchase contract involves acquiring a fixed amount of power over the entire sixteen-hour "on-peak period." In order to accommodate its super-peak-period needs, a utility is often forced to buy in excess of what will be its requirements during the "shoulder" portion of the on-peak period and will subsequently sell off that excess in the daily/hourly spot market. That selling pressure can bring the effective cost of shoulder period power down to a level comparable to that of the off-peak period. That would be a justification for a TOD regimen that prices the shoulder-period power in the summer at a level not much above, or comparable with, the off-peak power.

Q. ARE YOU FAMILIAR WITH ANOTHER UTILITY IN OUR REGION THAT HAS A SUMMER SUPER-PEAK RATE SCHEDULE FOR LARGE INDUSTRIAL CUSTOMERS THAT IS COMPARABLE TO WHAT YOU ARE PROPOSING FOR PGE-OREGON?

A. Yes. Exhibit 503 consists of the relevant tariff sheets for the Rocky Mountain Power Division of PacifiCorp in Utah.

Q. HAVE YOU PREPARED AN EXHIBIT CONTAINING A DERIVATION OF YOUR PROPOSED NEW SCHEDULE 89 TOD RATES?

A. Yes, Exhibit 504. Many of the proposed prices in the exhibit match PGE's recommendations. The energy price increases are designed to yield prices that are more or less uniformly *lower* than the average marginal costs developed for their corresponding time periods as displayed in Staff's Exhibit 502. While accurate in conveying the principles at stake, the numerical figures are estimates and approximations. Pending the receipt of additional load data from PGE, some of the billing determinants are estimates (based upon assumptions about how to break down the published annual MWh totals into the summer's on-, super-, and off-peak periods). True-ups will be circulated as a late-filed exhibit as soon as the information is received. For comparison purposes, the exhibit also shows the rates now in effect.

Q. HAVE YOU PREPARED AN EXHIBIT THAT REVEALS ESTIMATES OF THE IMPACT OF THE PROPOSED RATE INCREASES ON THE LARGE

INDUSTRIAL CUSTOMERS AS A FUNCTION OF THEIR MONTHLY USAGE LEVELS AND LOAD FACTORS?

A. Yes, Exhibit 505.

Q. WITH REGARD TO THE RESIDENTIAL RATE SCHEDULE, I INFER FROM YOUR EARLIER COMMENT ABOUT "ADDITIONAL MEASURES" THAT YOU WOULDN'T BE CONTENT TO MERELY ELEVATE THE EXISTING TWO-BLOCK ENERGY RATE IN THE SUMMER?

A. That is true. Staff recommends a third residential rate block, commencing at 1000 kWh's, applicable in the summer months, reflecting central air conditioning use. The current monthly average consumption by residential customers is 1010 kWh's in the winter (October through March) and 795 kWh's in the spring (April through June). The monthly average in the summer is 773 kWh's, making it the season with the lowest current average. The theory is that while it is relatively easy for most customers who do not have air conditioning to get by with less that 1000 kWh's monthly during the summer, it is much more difficult for customer's who have central air to do so. The heavier level of usage attributable to central air conditioning should be confronted with a price that comes closer to costs than would a price based on conventional, year-round usage.

Q. IT HAS BEEN CLAIMED THAT VERY FEW CUSTOMERS ADJUST THEIR UTILITY CONSUMPTION ON THE BASIS OF PRICE. WITH THAT UNDERSTANDING, IS IT WORTH THE TROUBLE OF INTRODUCING RATE REFORM TO THE RESIDENTIAL CLASS?

A. Yes. Rates should reflect costs and recognize that not all customers have the same usage pattern. Equity in ratemaking entails minimizing cross-subsidies where feasible (politically and practically). And on both equity and economic efficiency grounds it's important that the price signal associated with air conditioning use get out to the public for the benefit of those who *do* respond to price signals – particularly among the new dwelling builders and those who are contemplating retrofitting their domiciles to central air.

Q. ISN'T IT TRUE THAT A CONSIDERABLE PORTION OF RESIDENTIAL CONSUMPTION IN THE OVER-1000 KWH BLOCK WOULD BE COMPRISED OF USES BESIDE AIR CONDITIONING? AND IF SO, WOULDN'T IT BE INAPPROPRIATE TO PRICE THAT ENERGY AT THE HIGHER, PEAK-BASED PRICE?

A. The objective of always matching prices with costs requires the combination of smart meters and real-time pricing. Short of that, the best we can hope for are price signals that *approximate* costs at least much of the time when efficiency concerns are the greatest. Consider the occasional inefficiency of TOD rates. Not every peak period hour experiences peak-period-based costs. For example, many summer days aren't particularly hot. Nevertheless, power consumed during those lower-load "peak" hours are priced at the higher, TOD peak price. The process accepts such a pricing "imperfection" in order to achieve the goal of having a valid price signal during critical periods.

Targeting residential air conditioning loads with an inverted rate actually achieves an important advantage over simple TOD rates. Air conditioning use correlates directly with the high-priced summer periods, rendering the price signal efficacious in this instance for customers who have entered or expect to enter the over-1000 kWh block.

Q. HAVE YOU PREPARED AN EXHIBIT CONTAINING A DERIVATION OF WHAT YOUR PROPOSED NEW RESIDENTIAL RATES WOULD LOOK LIKE – SUBJECT, OF COURSE, TO TRUE-UP ONCE THE FINAL REVENUE REQUIREMENT AND ASSOCIATED ACCOUNTING ADJUSTMENTS ARE ESTABLISHED?

A. Yes. It is Exhibit 506. Besides the inverted block rate at 1000 kWh's that appears for the summer season, it also shows an inversion at 250 kWh's throughout the year per the existing Schedule 7. For ease of comparison, the PGE rates proposal for the Schedule is also contained in the exhibit. Both sets of proposal assume the same, PGE revenue requirement.

For the reader's convenience, the results from the exhibit are displayed in the following table:

RESIDENTIAL RATES – CURRENT AND PROPOSED

Rate Category	Current	Staff -Proposed	PGE-Proposed
Basic Charge $/month)			
Single Phase	10.00	10.00	10.00
Three Phase	13.00	13.00	13.00
Transmission (¢/kWh)	0.201	0.225	0.225
Distribution (¢/kWh)	2.841	3.140	3.140
Energy (¢/kWh)			
First 250 kWh	4.429	4.853 all year	5.066 all year
250<kWh<1000	6.204	6.806 all year	6.841 all year
kWh>1000	6.204	6.806 non-summer 9.116 summer	6.841 all year

Q. STAFF HAS MADE A POINT OF ADVOCATING COST-BASED RATES. WOULD YOU REVIEW BRIEFLY HOW WELL THE RATES IN THE ABOVE TABLE ACHIEVE THAT OBJECTIVE?

A. Basic Charge: What should appear in the Basic Charge has been the subject of much controversy in the past. As discussed previously, Staff is comfortable with preserving the existing residential customer charges. Transmission and Distribution: Shown are estimates of what the revised revenue requirement and cost of service allocations will produce. Energy: Most residential consumption occurs during the "on-peak" period of 6 a.m. to 10 p.m., Mon. – Sat. The first energy block rate is somewhat below the off-peak costs shown in my Staff Exhibit 502. The year-round middle block and the non-summer tail block are also somewhat below the on-peak costs shown in that same Exhibit. The proposed estimated summer tail block is slightly above the indicated summer season on-peak average cost. But bear in mind that the likely principal cause for customers consuming in the tail block is air conditioning, which tends to occur during the eight-hour super-peak. Accordingly, and on the margin, the summer tail block can also be viewed as being slightly below real costs.

Q. HAVE YOU PREPARED AN EXHIBIT THAT REVEALS WHAT THE PERCENTAGE IMPACT OF THE PROPOSED RATE INCREASES WOULD BE TO RESIDENTIAL CUSTOMERS AS A FUNCTION OF THEIR MONTHLY USAGE LEVELS?

A. Yes. It is Exhibit 507. I would note that the proposed prices as shown would have been higher had a separate spring season been adopted, with its *lower* costs and attendant prices.

Q. IN REVIEWING THE SUMMER PERIOD'S BILLINGS IN THIS EXHIBIT, AREN'T YOU CONCERNED ABOUT WHAT MAY BE AN INORDINATELY LARGE INCREASE FOR CUSTOMERS WHOSE MONTHLY USE GREATLY EXCEEDS THE SCHEDULE 7 AVERAGE?

A. I would naturally be concerned if an optional TOD "safety valve" did not exist as part of Schedule 7. The summer on-peak period under the existing time-of-day rate is limited to the hours 3 p.m. to 8 p.m., which are the heaviest air conditioning hours. If the cause of a customer's high usage is something besides air conditioning – e.g., if it is for heating a swimming pool – then much of the customer's usage can readily be shifted to, or limited to, the mid-peak or even the off-peak period, where the rates are much lower. Even if the heavy use is attributable to air conditioning, the burden can be mitigated by minimizing use in the 3-to-8 p.m. period.

Speaking of optional residential TOD rates, I would remind the reader of my previous assertion that the installation of smart meters for all customers, including residential customers, does not carry with it the necessity that TOD rates be made mandatory for everyone.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does. Thank you.

CASE: UE 197
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 501

Witness Qualifications Statement

July 9, 2008

WITNESS QUALIFICATION STATEMENT

NAME:	George R. Compton
EMPLOYER:	Oregon Public Utility Commission
TITLE:	Senior Economist (1/2), Economic & Policy Analysis Section
ADDRESS:	550 Capital Street NE, Suite 215 Salem, OR 97301-2551
EDUCATION:	Doctor of Philosophy, Economics (1976) UCLA – Los Angeles, CA Master of Science, Statistics (1968) Brigham Young University – Provo, UT Bachelor of Science, Mathematics and Psychology (1963) Brigham Young University – Provo, UT
EXPERIENCE:	I have been employed in utility regulation since receiving my Ph.D. in 1976. My primary employer was the Division of Public Utility, within Utah's Department of Commerce (formerly Regulation). I also consulted for a couple of years, early in that period. I testified frequently during my career on rate design, cost-of-service, cost-of-equity, and various policy matters affecting electric, gas, and telephone utilities. While in Utah I also taught economics part-time for about ten years at BYU. I have been employed half-time by the OPUC since "retiring" to Oregon in early 2007. Prior to my utility regulatory career I worked in aerospace for eleven years at McDonnell Douglas in Southern California.

CASE: UE 197
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 502

Exhibits in Support Of Direct Testimony

July 9, 2008

PGE's 2009 Average Power Costs

Marginal Power Supply Cost Estimates -- By Month and Season

Month	On-Peak		Off-Peak		Total	
	MWh	$/MWh	MWh	$/MWh	MWh	$/MWh
Summer Season						
July	937,158	88.17	596,279	56.41	1,533,437	75.82
August	958,749	95.18	578,815	70.37	1,537,564	85.84
September	888,399	89.74	509,238	66.84	1,397,637	81.40
Wt'd Avg.		**91.08**		**64.36**		**81.01**
Spring, Autumn, and Winter Seasons						
April	892,669	61.02	555,087	44.59	1,447,756	54.72
May	909,678	56.17	523,999	35.96	1,433,677	48.78
June	879,228	52.39	522,505	34.89	1,401,733	45.87
October	922,208	78.49	554,495	62.04	1,476,703	72.31
November	1,005,386	84.74	584,915	72.83	1,590,301	80.36
December	1,095,884	87.72	680,662	78.53	1,776,546	84.20
January	1,112,689	82.89	674,574	73.16	1,787,263	79.22
February	959,590	78.57	575,377	69.90	1,534,967	75.32
March	1,022,235	73.69	591,763	61.54	1,613,998	69.24
Wt'd Avg.		**73.67**		**60.47**		**68.73**

The current, year-round "on-peak" is defined as 6a.m.-10p.m., Mon.-Sat.

Data Source: PGE 1200 Work Papers 49

CASE: UE 197
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 503

Exhibits in Support Of Direct Testimony

July 9, 2008

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 9

STATE OF UTAH

General Service - High Voltage

AVAILABILITY: At any point on the Company's interconnected system where there are facilities of adequate capacity.

APPLICATION: This Schedule is for alternating current, three-phase electric service supplied at approximately 46,000 volts or 69,000 volts or greater, through a single point of delivery. Seasonal service will be available only under other appropriate schedules.

MONTHLY BILL:

Customer Service Charge:
$170.00 per Customer

Facilities Charge:
$1.54 per kW

Power Charge:
Billing Months - May through September inclusive
On-Peak: $9.68 per kW
Off-Peak: None

Billing Months - October through April inclusive
On-Peak: $6.56 per kW
Off-Peak: None

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ELECTRIC SERVICE SCHEDULE NO. 9 - Continued

MONTHLY BILL: (continued)

Energy Charge:

Billing Months - May through September inclusive
3.2247¢ per kWh for all On-Peak kWh
2.0247¢ per kWh for all Off-Peak kWh

Billing Months - October through April inclusive
2.4247¢ per kWh for all On-Peak kWh
2.0247¢ per kWh for all Off-Peak kWh

Minimum: The monthly Customer Charge plus appropriate Power and Energy Charges.

SURCHARGE ADJUSTMENT: All monthly bills shall be adjusted in accordance with Schedule 193.

POWER FACTOR: This rate is based on the Customer maintaining at all times a Power Factor of 90% lagging, or higher, as determined by measurement. If the average Power Factor is found to be less than 90% lagging the Power as recorded by the Company's meter will be increased by 3/4 of 1% for every 1% that the Power Factor is less than 90%.

CONTRACT PERIOD: One year or longer.

FACILITIES KW: All kW as shown by or computed from the reading of Company's Power meter for the 15-minute period of Customer's greatest use at any time during the month, adjusted for Power Factor to the nearest kW.

POWER: The kW as shown by or computed from the readings of Company's Power meter for the 15-minute On-Peak period of Customer's greatest use during the month, adjusted for Power Factor to the nearest kW.

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

P.S.C.U. No. 47

First Revision of Sheet No. 9.3
Canceling Original Sheet No. 9.3

ELECTRIC SERVICE SCHEDULE NO. 9 – Continued

TIME PERIODS:

On-Peak:	October through April inclusive 7:00 a.m. to 11:00 p.m., Monday thru Friday, except holidays. May through September inclusive 1:00 p.m. to 9:00 p.m., Monday thru Friday, except holidays.
Off-Peak:	All other times.

Holidays include only New Year's Day, President's Day, Memorial Day, Independence Day, Pioneer Day, Labor Day, Thanksgiving Day, and Christmas Day. When a holiday falls on a Saturday or Sunday, the Friday before the holiday (if the holiday falls on a Saturday) or the Monday following the holiday (if the holiday falls on a Sunday) will be considered a holiday and consequently Off-Peak.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005 the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

FORCE MAJEURE: Neither Company or Customer shall be subject to any liability or damages for inability to provide or receive service to the extent that such failure shall be due to causes beyond the control of either Company or Customer, including, but not limited to the following: (a) the operation and effect of any rules, regulations and orders promulgated by any commission, municipality, or governmental agency of the United States, or subdivision thereof; (b) restraining order, injunction or similar decree of any court; (c) war; (d) flood; (e) earthquake; (f) act of God; (g) sabotage; or (h) strikes or boycotts. Should any of the foregoing occur, the minimum billing demands that would otherwise be applicable under this Schedule shall be waived and Customer will have no liability for service until such time as Customer is able to resume service.

The party claiming Force Majeure under this provision shall make every reasonable attempt to remedy the cause thereof as diligently and expeditiously as possible.

ELECTRIC SERVICE REGULATIONS: Service under this Schedule will be in accordance with the terms of the Electric Service Agreement between the Customer and the Company. The Electric Service Regulations of the Company on file with and approved by the Public Service Commission of the State of Utah, including future applicable amendments, will be considered as forming a part of and incorporated in said Agreement.

Issued by authority of Report and Order of the Public Service Commission of Utah in Advice No. 06-12

FILED: October 9, 2006 **EFFECTIVE**: March 1, 2007

CASE: UE 197
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 504

Exhibits in Support Of Direct Testimony

July 9, 2008

Estimated Billing Determinants and Staff-Proposed Rates – Schedule 89, 2009

Data Sources: PGE Exhibit 1203 (Pages 7 & 8), PGE Response to OPUC DR #400

Billing Category		Customer Category				
Label	**Units**	Quantity	Current Price	Proposed Price	Percent Increase	Proposed Revenue
		Secondary + Primary + Subtransmission				
Transmission	kW On-peak	6,432,182	$ 0.66	$ 0.70	6.06%	$ 4,502,527
Reactive Demand	kVar	1,449,142	$ 0.50	$ 0.50	0.00%	$ 724,571
		Secondary + Primary				
Distribution Demand	kW On-peak	6,911,925	$ 2.27	$ 2.18	-3.96%	$ 15,067,997
		Secondary				
Basic Charge	Customers	106	$ 130	$ 160	23.08%	$ 16,960
Dist. Facilities						
First 1000 kW	kW faccap	1,275,434	$ 1.86	$ 1.90	2.15%	$ 2,423,325
> 1000 kW	kW faccap	749,563	$ 0.37	$ 0.61	64.86%	$ 457,233
Franchise Fees	MWh	717,444	$ 4.20	$ 3.95	-5.95%	$ 2,833,904
Energy						
Non-summer Off-peak	MWh	185,033	$ 50.21	$ 55.00	9.54%	$ 10,176,832
Non-summer On-peak	MWh	335,671	$ 60.71	$ 68.00	12.01%	$ 22,825,609
Summer Off-peak	MWh	55,270	$ 50.21	$ 55.00	9.54%	$ 3,039,833
Summer Shoulder Peak	MWh	50,792	$ 60.71	$ 62.00	2.12%	$ 3,149,121
Summer Super Peak	MWh	55,209	$ 60.71	$ 80.00	31.77%	$ 4,416,720
Total Energy	MWh	681,975			Total Revenues =	$ 49,339,537
		Primary				
Basic Charge	Customers	115	$ 230	$ 230	0.00%	$ 26,450
Dist. Facilities						
First 1000 kW	kW faccap	1,382,000	$ 1.73	$ 1.83	5.78%	$ 2,529,060
> 1000 kW	kW faccap	4,457,968	$ 0.24	$ 0.39	62.50%	$ 1,738,608
Franchise Fees	MWh	2,983,612	$ 3.52	$ 3.75	6.53%	$ 11,188,545
Energy						
Non-summer Off-peak	MWh	552,502	$ 48.33	$ 53.00	9.66%	$ 29,282,593
Non-summer On-peak	MWh	844,821	$ 58.32	$ 66.00	13.17%	$ 55,758,207
Summer Off-peak	MWh	174,474	$ 48.33	$ 53.00	9.66%	$ 9,247,135
Summer Shoulder Peak	MWh	130,058	$ 58.32	$ 60.00	2.88%	$ 7,803,481
Summer Super Peak	MWh	136,728	$ 58.32	$ 78.00	33.74%	$ 10,664,758
Total Energy	MWh	1,838,583			Total Revenues =	$ 128,238,836
		Subtransmission				
Basic Charge	Customers	10	$ 1,000	$ 1,000	0.00%	$ 10,000
Dist. Facilities						
First 1000 kW	kW faccap	120,000	$ 1.73	$ 1.83	5.78%	$ 219,600
> 1000 kW	kW faccap	2,643,937	$ 0.24	$ 0.39	62.50%	$ 1,031,135
Dist. Demand	kW	2,145,328	$ 1.18	$ 1.10	-6.78%	$ 2,359,861
Franchise Fees	MWh	1,299,267	$ 3.25	$ 3.60	10.77%	$ 4,677,361
Energy						
Non-summer Off-peak	MWh	247,529	$ 47.54	$ 52.00	9.38%	$ 12,871,482
Non-summer On-peak	MWh	331,354	$ 57.32	$ 65.00	13.40%	$ 21,537,994
Summer Off-peak	MWh	82,510	$ 47.54	$ 52.00	9.38%	$ 4,290,494
Summer Shoulder Peak	MWh	55,226	$ 57.32	$ 60.00	4.68%	$ 3,313,538
Summer Super Peak	MWh	55,226	$ 57.32	$ 76.00	32.59%	$ 4,197,148
Total Energy	MWh	771,843			Total Revenues =	$ 54,508,612

TOTAL SCHEDULE HYPOTHETICAL PROPOSED REVENUES = $ 251,657,510

NOTE 1: Except for the proposed Summer Super Peak price, instances of exceptionally large or exceptionally small (including negative) price increases reflect PGE's rate case application recommendations. All prices are subject to true-up based upon refinements in billing determinant estimates and revenue requirement adjustments.

CASE: UE 197
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 505

Exhibits in Support Of Direct Testimony

July 9, 2008

EFFECT OF PROPOSED RATES CHANGE ON ANNUAL BILLS:

OPUC Staff Proposal: Tariff Schedule 89 - Secondary Service

Schedule Annual Bill

NOTE: None of the bills incorporate estimates of Schedule 109, 110, 111, 140, 105, or 128 prices.

Load Factor	Monthly Peak Demand (kW)	Annual Energy (MWh)	Current Prices	Proposed Prices	Percent Difference
30%	1,000	2,628	$ 212,408	$ 232,324	9.38%
30%	2,000	5,256	$ 405,376	$ 447,248	10.33%
30%	4,000	10,512	$ 791,312	$ 877,096	10.84%
30%	7,500	19,710	$ 1,466,700	$ 1,629,331	11.09%
30%	10,000	26,280	$ 1,949,120	$ 2,166,641	11.16%
30%	15,000	39,420	$ 2,913,960	$ 3,241,261	11.23%
30%	20,000	52,560	$ 3,878,800	$ 4,315,882	11.27%
50%	1,000	4,380	$ 312,333	$ 344,407	10.27%
50%	2,000	8,760	$ 605,227	$ 671,414	10.94%
50%	4,000	17,520	$ 1,191,013	$ 1,325,427	11.29%
50%	7,500	32,850	$ 2,216,140	$ 2,469,951	11.45%
50%	10,000	43,800	$ 2,948,373	$ 3,287,468	11.50%
50%	15,000	65,700	$ 4,412,840	$ 4,922,502	11.55%
50%	20,000	87,600	$ 5,877,306	$ 6,557,536	11.57%
70%	1,000	6,132	$ 412,259	$ 456,490	10.73%
70%	2,000	12,264	$ 805,077	$ 895,579	11.24%
70%	4,000	24,528	$ 1,590,714	$ 1,773,758	11.51%
70%	7,500	45,990	$ 2,965,580	$ 3,310,572	11.63%
70%	10,000	61,320	$ 3,947,626	$ 4,408,295	11.67%
70%	15,000	91,980	$ 5,911,719	$ 6,603,743	11.71%
70%	20,000	122,640	$ 7,875,812	$ 8,799,191	11.72%
90%	1,000	7,884	$ 512,184	$ 568,572	11.01%
90%	2,000	15,768	$ 1,004,928	$ 1,119,745	11.43%
90%	4,000	31,536	$ 1,990,416	$ 2,222,089	11.64%
90%	7,500	59,130	$ 3,715,020	$ 4,151,192	11.74%
90%	10,000	78,840	$ 4,946,879	$ 5,529,123	11.77%
90%	15,000	118,260	$ 7,410,599	$ 8,284,984	11.80%
90%	20,000	157,680	$ 9,874,319	$ 11,040,846	11.81%

Load Shape Assumptions:

Off-peak Share of Energy consumption = 35%
Summer's Share of On-peak portion of Energy consumption = 24%
Super-peak Share of Summer's On-peak portion of Energy consumption = 52%
Transmission Demand = Distribution Demand = Demand
Lower-priced Facilities Capacity Charge Applied to Total Facilities Capacity Minus 1000 Kwh
Facilities Capacity as Share of Nominal Demand = 150%
Reactive Demand as Equivalent Share of Demand = 21%

EFFECT OF PROPOSED RATES CHANGE ON ANNUAL BILLS:

OPUC Staff Proposal: Tariff Schedule 89 - Primary Service

Schedule Annual Bill

NOTE: None of the bills incorporate estimates of Schedule 109, 110, 111, 140, 105, or 128 prices.

Load Factor	Monthly Peak Demand (kW)	Annual Energy (MWh)	Current Prices	Proposed Prices	Percent Difference
30%	1,000	2,628	$ 204,143	$ 223,934	9.69%
30%	2,000	5,256	$ 387,647	$ 427,828	10.37%
30%	4,000	10,512	$ 754,654	$ 835,616	10.73%
30%	7,500	19,710	$ 1,396,916	$ 1,549,244	10.90%
30%	10,000	26,280	$ 1,855,675	$ 2,058,979	10.96%
30%	15,000	39,420	$ 2,773,192	$ 3,078,449	11.01%
30%	20,000	52,560	$ 3,690,709	$ 4,097,919	11.03%
50%	1,000	4,380	$ 299,319	$ 331,303	10.69%
50%	2,000	8,760	$ 577,998	$ 642,566	11.17%
50%	4,000	17,520	$ 1,135,356	$ 1,265,093	11.43%
50%	7,500	32,850	$ 2,110,733	$ 2,354,514	11.55%
50%	10,000	43,800	$ 2,807,431	$ 3,132,672	11.59%
50%	15,000	65,700	$ 4,200,827	$ 4,688,988	11.62%
50%	20,000	87,600	$ 5,594,222	$ 6,245,304	11.64%
70%	1,000	6,132	$ 394,495	$ 438,673	11.20%
70%	2,000	12,264	$ 768,350	$ 857,305	11.58%
70%	4,000	24,528	$ 1,516,059	$ 1,694,570	11.77%
70%	7,500	45,990	$ 2,824,551	$ 3,159,784	11.87%
70%	10,000	61,320	$ 3,759,188	$ 4,206,365	11.90%
70%	15,000	91,980	$ 5,628,462	$ 6,299,528	11.92%
70%	20,000	122,640	$ 7,497,735	$ 8,392,690	11.94%
90%	1,000	7,884	$ 489,670	$ 546,042	11.51%
90%	2,000	15,768	$ 958,701	$ 1,072,044	11.82%
90%	4,000	31,536	$ 1,896,762	$ 2,124,047	11.98%
90%	7,500	59,130	$ 3,538,368	$ 3,965,053	12.06%
90%	10,000	78,840	$ 4,710,944	$ 5,280,058	12.08%
90%	15,000	118,260	$ 7,056,096	$ 7,910,067	12.10%
90%	20,000	157,680	$ 9,401,248	$ 10,540,076	12.11%

Load Shape Assumptions:

Off-peak Share of Energy consumption =	40%
Summer's Share of On-peak portion of Energy consumption =	24%
Super-peak Share of Summer's On-peak portion of Energy consumption =	52%
Transmission Demand = Distribution Demand = Demand	
Lower-priced Facilities Capacity Charge Applied to Total Facilities Capacity Minus 1000 Kwh	
Facilities Capacity as Share of Nominal Demand =	150%
Reactive Demand as Equivalent Share of Demand =	21%

EFFECT OF PROPOSED RATES CHANGE ON ANNUAL BILLS:

OPUC Staff Proposal: Tariff Schedule 89 - Subtransmission Service

Schedule Annual Bill

NOTE: None of the bills incorporate estimates of Schedule 109, 110, 111, 140, 105, or 128 prices.

Load Factor	Monthly Peak Demand (kW)	Annual Energy (MWh)	Current Prices	Proposed Prices	Percent Difference
30%	1,000	2,628	$ 197,125	$ 216,473	9.81%
30%	2,000	5,256	$ 364,370	$ 403,666	10.78%
30%	4,000	10,512	$ 698,861	$ 778,051	11.33%
30%	7,500	19,710	$ 1,284,219	$ 1,433,227	11.60%
30%	10,000	26,280	$ 1,702,332	$ 1,901,209	11.68%
30%	15,000	39,420	$ 2,538,558	$ 2,837,173	11.76%
30%	20,000	52,560	$ 3,374,783	$ 3,773,137	11.80%
50%	1,000	4,380	$ 290,182	$ 321,348	10.74%
50%	2,000	8,760	$ 550,484	$ 613,416	11.43%
50%	4,000	17,520	$ 1,071,088	$ 1,197,552	11.81%
50%	7,500	32,850	$ 1,982,145	$ 2,219,791	11.99%
50%	10,000	43,800	$ 2,632,899	$ 2,949,961	12.04%
50%	15,000	65,700	$ 3,934,409	$ 4,410,302	12.10%
50%	20,000	87,600	$ 5,235,919	$ 5,870,642	12.12%
70%	1,000	6,132	$ 383,239	$ 426,223	11.22%
70%	2,000	12,264	$ 736,597	$ 823,167	11.75%
70%	4,000	24,528	$ 1,443,315	$ 1,617,053	12.04%
70%	7,500	45,990	$ 2,680,070	$ 3,006,355	12.17%
70%	10,000	61,320	$ 3,563,467	$ 3,998,714	12.21%
70%	15,000	91,980	$ 5,330,261	$ 5,983,430	12.25%
70%	20,000	122,640	$ 7,097,055	$ 7,968,147	12.27%
90%	1,000	7,884	$ 476,296	$ 531,099	11.51%
90%	2,000	15,768	$ 922,711	$ 1,032,917	11.94%
90%	4,000	31,536	$ 1,815,542	$ 2,036,554	12.17%
90%	7,500	59,130	$ 3,377,996	$ 3,792,920	12.28%
90%	10,000	78,840	$ 4,494,035	$ 5,047,466	12.31%
90%	15,000	118,260	$ 6,726,113	$ 7,556,559	12.35%
90%	20,000	157,680	$ 8,958,190	$ 10,065,652	12.36%

Load Shape Assumptions:

Off-peak Share of Energy consumption =	43%
Summer's Share of On-peak portion of Energy consumption =	25%
Super-peak Share of Summer's On-peak portion of Energy consumption =	51%
Transmission Demand = Distribution Demand = Demand	
Lower-priced Facilities Capacity Charge Applied to Total Facilities Capacity Minus 1000 Kwh	
Facilities Capacity as Share of Nominal Demand =	150%
Reactive Demand as Equivalent Share of Demand =	21%

CASE: UE 197
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 506

Exhibits in Support Of Direct Testimony

July 9, 2008

Residential Billing Determinants -- Sched.7, 2009

Data Sources: Attachment 366-A, PGE Response to OPUC DR #366

Cycle Month	Customers Single Phase	Customers 3 Phase	Total Customers	Energy (MWh) kWh<250	Energy (MWh) 250<kWh<1000	Energy (MWh) kWh>1000	Total Energy (MWh)
Jan	712,792	470	713,262	174,735	423,174	287,993	885,902
Feb	713,262	470	713,732	174,536	403,634	231,642	809,812
Mar	713,822	470	714,292	174,637	367,120	180,858	722,615
Apr	714,464	471	714,935	173,257	327,136	129,298	629,691
May	715,050	471	715,521	171,646	308,801	78,833	559,280
Jun	715,649	471	716,120	171,389	275,420	70,856	517,665
Jul	716,209	472	716,681	171,272	287,560	89,759	548,591
Aug	716,888	472	717,360	171,600	290,067	101,367	563,034
Sep	717,431	473	717,904	172,318	292,175	86,738	551,231
Oct	718,164	473	718,637	172,092	274,874	70,878	517,844
Nov	718,799	474	719,273	174,244	323,284	121,167	618,695
Dec	719,428	475	719,903	176,211	380,796	231,333	788,340
Total	8,591,958	5,662	8,597,620	2,077,937	3,954,041	1,680,722	7,712,700
Avg.	715,997	472	716,468	173,161	329,503	140,060	

Seasonal Average Monthly Energy Consumption (kWh's per Customer)

Autumn & Winter	1010	October through March
Summer	773	July through September
Spring	795	April through June

Residential Rate Design Development -- Schedule 7 Estimation

	Autumn, Winter and Spring			Summer			All Year	
		Price ($/kWh)			Price ($/kWh)			Price ($/kWh)
	kWh*1000	Current	Proposed by Staff	kWh*1000	Current	Proposed by Staff	kWh*1000	Proposed by PGE
kWh's < 250	1,562,747	0.07471	0.08218	515,190	0.07471	0.08218	2,077,937	0.08431
250<kWh's<1000	3,084,239	0.09246	0.10171	869,802	0.09246	0.10171	3,954,041	0.10206
kWh's > 1000	1,402,858	0.09246	0.10171	277,864	0.09246	0.12481	1,680,722	0.10206

Note: Shown are the summations of the Transmission, Distribution, and Energy Charges. They do not include CIO (Customer Impact Offset) or Schedules 109, 110, 111, and 140 amounts.

Revenues Given Current Rates = $ 762,226,046	**Schedule Revenue Requirement =** $ 836,268,000
Current and Proposed Monthly Customer Charge	Schedule Revenue Requirement % Increae = 9.7%
Single Phase $ 10.00	**Staff: Primary Volumetric Rates' % Increase = 10.0%**
3 Phase $ 13.00	Staff: Revenues from all but summer tail block = $ 801,588,896
	Staff: Summer tail block necessary to achieve rev. req. = $ 0.12481

CASE: UE 197
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 507

Exhibits in Support
Of Direct Testimony

July 9, 2008

Effect of Proposed Rate Change on Monthly Bills -- OPUC Staff Proposal

Tariff Schedule 7, Residential Service

MONTH'S BILL: Autumn, Winter, and Spring Season (October through June)

Season Average	kWh's	Current Tariff	Staff-Proposed Tariff	Percent Difference	PGE-Proposed Tariff	Percent Difference
	50	$ 13.74	$ 14.11	2.7%	$ 14.22	3.5%
	100	$ 17.47	$ 18.22	4.3%	$ 18.43	5.5%
	200	$ 24.94	$ 26.44	6.0%	$ 26.86	7.7%
	250	$ 28.68	$ 30.55	6.5%	$ 31.08	8.4%
	300	$ 33.30	$ 35.63	7.0%	$ 36.18	8.6%
	400	$ 42.55	$ 45.80	7.6%	$ 46.39	9.0%
	500	$ 51.79	$ 55.97	8.1%	$ 56.59	9.3%
	600	$ 61.04	$ 66.14	8.4%	$ 66.80	9.4%
	700	$ 70.28	$ 76.31	8.6%	$ 77.00	9.6%
	800	$ 79.53	$ 86.48	8.7%	$ 87.21	9.7%
	900	$ 88.78	$ 96.65	8.9%	$ 97.42	9.7%
	1000	$ 98.02	$ 106.82	9.0%	$ 107.62	9.8%
Fall-Winter Average	1010	$ 98.95	$ 107.84	9.0%	$ 108.64	9.8%
	1100	$ 107.27	$ 117.00	9.1%	$ 117.83	9.8%
	1200	$ 116.51	$ 127.17	9.1%	$ 128.03	9.9%
	1300	$ 125.76	$ 137.34	9.2%	$ 138.24	9.9%
	1400	$ 135.01	$ 147.51	9.3%	$ 148.45	10.0%
	1500	$ 144.25	$ 157.68	9.3%	$ 158.65	10.0%
	1750	$ 167.37	$ 183.10	9.4%	$ 184.17	10.0%
	2000	$ 190.48	$ 208.53	9.5%	$ 209.68	10.1%
	2500	$ 236.71	$ 259.38	9.6%	$ 260.71	10.1%
	3000	$ 282.94	$ 310.24	9.6%	$ 311.74	10.2%
	4000	$ 375.40	$ 411.94	9.7%	$ 413.80	10.2%
	5000	$ 467.86	$ 513.65	9.8%	$ 515.86	10.3%
	7500	$ 699.01	$ 767.91	9.9%	$ 771.01	10.3%
	10000	$ 930.16	$ 1,022.18	9.9%	$ 1,026.16	10.3%

	Current	Staff-Proposed	PGE-Proposed
Customer Charge	$ 10	$ 10	$ 10
kWh Unit Charge			
kWh's < 250	$ 0.07471	$ 0.08218	$0.08431
kWh's > 250	$ 0.09246	$ 0.10171	$0.10206

Effect of Proposed Rate Change on Monthly Bills -- OPUC Staff Proposal
Tariff Schedule 7, Residential Service

MONTH'S BILL: Summer Season (July through September)

Season Average	kWh's	Current Tariff	Staff-Proposed Tariff	Percent Difference	PGE-Proposed Tariff	Percent Difference
	50	$ 13.74	$ 14.11	2.7%	$ 14.22	3.5%
	100	$ 17.47	$ 18.22	4.3%	$ 18.43	5.5%
	200	$ 24.94	$ 26.44	6.0%	$ 26.86	7.7%
	250	$ 28.68	$ 30.55	6.5%	$ 31.08	8.4%
	300	$ 33.30	$ 35.63	7.0%	$ 36.18	8.6%
	400	$ 42.55	$ 45.80	7.6%	$ 46.39	9.0%
	500	$ 51.79	$ 55.97	8.1%	$ 56.59	9.3%
	600	$ 61.04	$ 66.14	8.4%	$ 66.80	9.4%
	700	$ 70.28	$ 76.31	8.6%	$ 77.00	9.6%
Average	773	$ 77.03	$ 83.74	8.7%	$ 84.45	9.6%
	800	$ 79.53	$ 86.48	8.7%	$ 87.21	9.7%
	900	$ 88.78	$ 96.65	8.9%	$ 97.42	9.7%
	1000	$ 98.02	$ 106.82	9.0%	$ 107.62	9.8%
	1100	$ 107.27	$ 119.31	11.2%	$ 117.83	9.8%
	1200	$ 116.51	$ 131.79	13.1%	$ 128.03	9.9%
	1300	$ 125.76	$ 144.27	14.7%	$ 138.24	9.9%
	1400	$ 135.01	$ 156.75	16.1%	$ 148.45	10.0%
	1500	$ 144.25	$ 169.23	17.3%	$ 158.65	10.0%
	1750	$ 167.37	$ 200.43	19.8%	$ 184.17	10.0%
	2000	$ 190.48	$ 231.63	21.6%	$ 209.68	10.1%
	2500	$ 236.71	$ 294.03	24.2%	$ 260.71	10.1%
	3000	$ 282.94	$ 356.44	26.0%	$ 311.74	10.2%
	4000	$ 375.40	$ 481.24	28.2%	$ 413.80	10.2%
	5000	$ 467.86	$ 606.05	29.5%	$ 515.86	10.3%
	7500	$ 699.01	$ 918.06	31.3%	$ 771.01	10.3%
	10000	$ 930.16	$ 1,230.08	32.2%	$ 1,026.16	10.3%

	Current	Staff-Proposed	PGE-Proposed
Customer Charge	$ 10	$ 10	$ 10
kWh Unit Charge			
kWh's < 250	$ 0.07471	$ 0.08218	$0.08431
kWh's > 250	$ 0.09246		$0.10206
250<kWh's<1000		$ 0.10171	
kWh's > 1000		$ 0.12481	

CASE: UE 197
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 600

Direct Testimony

July 9, 2008

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

A. My name is Steve Storm. I am employed by the Public Utility Commission of Oregon as a Senior Economist in the Economic & Policy Analysis Section. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Staff Exhibit 601.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses two main issues. First I evaluate PGE's cost studies used to develop PGE's proposed rate spread and rate design. I include in this discussion recommendations for future cost studies in order to better reflect cost causation and to better align with PGE resource decisions.

Second, I summarize Staff's analysis of PGE's Sales Normalization Adjustment (SNA) decoupling proposal and PGE's proposed Lost Revenue Recovery (LRR) mechanism. More specifically, I explain how each of the two proposed mechanisms operate; discuss PGE's stated objectives for their SNA decoupling proposal; and detail concerns I have identified to date with each of the two PGE-proposed mechanisms. I then propose an alternative mechanism that would replace both of PGE's proposed mechanisms.

Finally, I recommend the Commission reject both PGE's proposed SNA mechanism and PGE's proposed LRR mechanism.

Q. WHAT ARE YOUR SUMMARY RECOMMENDATIONS?

A. With respect to PGE's cost studies, I find the cost studies acceptable. However, I have identified a few areas for improvement that I recommend the Commission order PGE to implement.

With respect to PGE's two proposed mechanisms (the SNA decoupling mechanism and the LRR revenue recovery mechanism), I recommend the Commission reject each proposal. Should the Commission find that some form of decoupling or revenue recovery mechanism is necessary, I provide an alternative Staff-supported revenue recovery mechanism proposal.

Q. DID YOU PREPARE EXHIBITS FOR THIS DOCKET?

A. Yes. I prepared Staff Exhibit 602, consisting of 3 pages; Staff Exhibit 603, consisting of 2 pages; Staff Exhibit 604, consisting of 1 page; Staff Exhibit 605, consisting of 2 pages; Staff Exhibit 606, consisting of 1 page; Staff Exhibit 607, consisting of 1 page; Staff Exhibit 608, consisting of 1 page; Staff Exhibit 609; consisting of 2 pages; Staff Exhibit 610, consisting of 3 pages; Staff Exhibit 611, consisting of 1 page; Staff Exhibit 612, consisting of 1 page; Staff Exhibit 613, consisting of 1 page; Staff Exhibit 614, consisting of 6 pages; and Staff Exhibit 615, consisting of 6 pages.

PGE Cost Studies

Q. WHAT COST STUDIES DID PGE PROVIDE AS SUPPORT FOR PGE'S PROPOSED RATE SPREAD AND RATE DESIGN?

A. PGE provided cost studies supporting the allocation of the Company's proposed revenue requirement by marginal costs for each rate class for the functions of Production (fixed generation and Net Variable Power Costs); Transmission; Ancillary Services; Distribution; Metering (predominantly meter reading); Billing; Other Consumer costs (e.g., legally-mandated advertising; general support for serve and respond; and build/enhance customer service technology systems); Trojan Decommissioning costs; Franchise Fees; and the Schedule 129 Transition Adjustment.

Q. YOU RECOMMEND THE COMMISSION ADOPT THE RESULTS OF THE COMPANY'S GENERAL COST ALLOCATION STUDIES. DO YOU HAVE ANY RECOMMENDATIONS FOR IMPROVING THE STUIDES?

A. Yes. I recommend the Commission order the Company to improve its cost studies in order to better allocate meter-reading and "Other Consumer" costs, and to rely less on wholesale market prices in its production cost estimates. Regarding meter-reading costs, PGE uses a meter-reading marginal cost allocation of $9.95 to all customers regardless of size.[1] In contemplating the process of reading a meter at a large industrial site, where the meter reader might have to pass through security before travelling some distance to the meter(s), it is readily understood why, in contrast to PGE's practice, Pacific

[1] See PGE Exhibit 1204/Kuns–Cody/Page 16.

Power assigns a weighting factor for reading large industrial customers' meters that is over ten times the value of the corresponding residential factor.[2] Lacking its own empirical study of this matter, the PGE allocation of meter reading and related costs could not be rectified in this case. Given the technical advantages afforded with near-term AMI deployment, this issue may be moot with regards to PGE's next general rate case.

A material and conceptual concern extending beyond the current rate case pertains to "Other Consumer" costs, which do not necessarily lend themselves to the marginal-cost-based allocations PGE uses for allocating production, distribution, and transmission costs, as well as for allocating the more narrowly defined customer cost categories. According to PGE, with overhead allocations included, "Other Consumer" costs amount to over $52 million. This amount exceeds the combined $50 million for the narrowly defined customer cost categories of meter reading and billing.[3] On a "marginal cost" basis, almost one-half of the "Other Customer" costs are accounted for by "Maintain Customer Service Technology Systems" (Account N41381),[4] which is allocated to the various customer classes in proportion to the number of customers in each class; i.e., without regard for how those classes might differentially be affected by or receive benefits from the services rendered under that account. Services under this account are "…Complex Billing for Direct Access Customers, …GIS to map the location of equipment, WMS to

[2] See PacifiCorp's "Oregon Marginal Cost Study," Tab: 13.1, Line 11; attached as Staff Exhibit 602.
[3] These figures are based on PGE's proposed revenue requirement for the 2009 test year.
[4] See PGE Exhibit 1200/Kuns–Cody/Work Papers 152.

direct crews to work locations, OMS to identify outages and breaks in service…"[5] A similar criticism would apply to other accounts identified within the "Other Customer" cost category.

Staff recognizes instances where PGE attempted to distinguish cost causation/benefit attribution among classes by allocating a designated percentage of Other Consumer costs to the residential and/or other classes. But in general I would draw attention to and commend the much more granular approach of Pacific Power, whereby the numbers 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 in the other schedules impose a burden or receive a benefit that is greater than that imposed upon/received by the average residential customer.

Q. DID YOU IDENTIFY ANY OTHER ISSUES WITH PGE'S COST STUDIES?

A. Yes. The Commission has a long history of using long-run marginal cost estimates to guide the development of rate spread and rate design. To develop allocations of production cost estimates, PGE relied on wholesale market prices. Years ago, long-run marginal cost studies reflected costs of new generating plants that could be added to meet peak and energy demand requirements. For demand, the dollars per kW capacity costs of a single cycle combustion turbine plant was typically used. For energy, more capital intensive plants were modeled to reflect energy costs, recognizing that part of the dollars per KW capacity costs of the plant provided both capacity and energy.

[5] See PGE's response to Staff Data Request 329, attached as Staff Exhibit 603.

Q. WHAT IS YOUR UNDERSTANDING AS TO WHY PGE MAY HAVE RELIED ONLY ON FUTURE WHOLESALE MARKET PRICES?

A. My understanding is that, for a time, PGE was not building major resources and instead relied on the wholesale market for future supply needs. Therefore analysts interested in deriving marginal energy cost estimates may have considered it reasonable to rely on wholesale market prices for long-run marginal cost estimates.

Q. IS PGE AGAIN BUILDING MAJOR RESOURCES AS A MEANS TO MEET FUTURE LOAD GROWTH?

A. Yes. For example, PGE constructed Port Westward and is currently building significant wind resources.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING PGE'S COST STUDIES?

A. Staff strongly recommends the Commission direct PGE to emulate the Pacific Power approach to customer cost allocations in the former's next general rate case application.[6] Further, I recommend the Commission direct PGE to hold workshops for the purpose of considering whether to revise the Company's basis for developing marginal cost estimates. Regarding production marginal costs, it seems reasonable to use potential new electrical generating plants as

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6 This would consist, at a minimum, of analyzing and documenting the extent to which customers in the nonresidential schedules impose a burden or receive a benefit greater than (or less than) that imposed upon/received by the average residential customer. This information is used to weight each class's customer totals in an allocation of expenses, with the *numeraire* established as 1.0 for residential customers.

the basis for capacity and energy costs instead of relying exclusively on wholesale market energy prices.

Q. ARE YOU RECOMMENDING THE COMMISSION ACCEPT PGE'S COST STUDIES IN THIS CASE?

A. Yes. I find the overall results of the cost studies to be reasonable.

PGE's Decoupling Proposal

Q. WHAT IS DECOUPLING?

A. Decoupling is a regulatory tool designed to break the link between a utility's earnings and its retail sales levels.[7] A generic decoupling mechanism is one in which a revenue target is established in some form or fashion that is independent of energy sales. Subsequent under- (or over-) collection of revenue relative to that target are accumulated in a deferred account for recovery (or refund). Under decoupling mechanisms, a utility can not increase earnings by increasing kWh sales because margins from higher than targeted sales are refunded to customers. Therefore, to the extent the utility is indifferent to the level of prices it charges to its customers,[8] a decoupling mechanism diminishes a utility's incentive to increase sales volumes.

Similarly, decoupling may change a utility's support of customers' efforts to increase energy efficiency, all else being equal, from being a disincented

7 See Public Utility Commission Order No. 02-633; page 2.

8 For example, a utility may be concerned with the level of prices due to the impact on stakeholder "goodwill," perceived corporate image, *et cetera*. Additionally, there exists a competitive aspect in that sufficiently high prices may induce a geographic subset of the utility's customers to form a public utility district.

activity to an activity for which the utility is neutral or perhaps positively incented.

PGE proposes two different mechanisms in this docket, each applicable to different and non-overlapping groupings of PGE customers. The Company's proposed Sales Normalization Adjustment (SNA) is a decoupling mechanism applicable to PGE customers in Schedule 7 and Schedules 32/532. These are, respectively, PGE's tariff schedules for Residential and Small Nonresidential standard service customers.[9] PGE's proposed Lost Revenue Recovery (LRR) mechanism is applicable to nonresidential customers other than Schedules 32/532 where the customer's load did not exceed one average megawatt (load ≤ 1.0 MWa) at a Point of Delivery (POD) during the prior calendar year. The LRR mechanism does not apply to nonresidential customers who qualify as Self-Directing Customers.[10] Table 1 (following) summarizes applicability of each proposed mechanism to PGE customers by rate schedule.[11]

9 Schedule 532 is for "Small Nonresidential Customers who have chosen to receive Electricity from an Electricity Service Supplier (ESS)." See PGE Exhibit 1201/Kuns–Cody/Page 62.

10 See Oregon Administrative Rules 860-038-0480(6) for the definition of a Self-Directing Customer.

11 Based on PGE Exhibit 1201/Kuns–Cody/Pages 36 and 41-42. Presumably some customers in Schedules 89/489/589 would be excluded by the maximum load criterion (load ≤ 1.0 MWa).

Table 1

PGE Schedules	Schedule Description	SNA Applies?	LRR Applies?[12]
7	Residential	Yes	No
9	Residential/Small Nonresidential Renewable Portfolio Option with Price Stability	No	No
15/515	Residential/Nonresidential Outdoor Lighting	No	Yes
32/532	Small Nonresidential	Yes	No
38/538	Large Nonresidential with Optional Time-Of-Day Pricing	No	Yes
47	Small Irrigation and Drainage	No	Yes
49/549	Large Irrigation and Drainage	No	Yes
75/575	Large Nonresidential with Self-Generation	No	Yes
76R/576R	Partial Requirements Economic Replacement Power Rider (for Schedule 75 customers)	No	Yes
83/483/583	Large Nonresidential	No	Yes
87	Large Nonresidential (Experimental Real-Time Pricing)	No	Yes
89/489/589	Large Nonresidential (> 1,000 kW)	No	Yes
91/591	Street and Highway Lighting	No	Yes
92/592	Traffic Signals	No	Yes
93	Recreational Field Lighting	No	Yes
94/594	Communication Devices (associated with Streetlights and/or Traffic Signals)	No	Yes

Where:

Schedules in the 400 series refers to the Cost of Service Opt-out, and

Schedules in the 500 series refers to the Direct Access Service

[12] Assuming a customer does not qualify as a Self-Directing Customer.

Q. HOW DOES PGE'S PROPOSED SNA MECHANISM WORK?

A. PGE's proposed SNA decoupling mechanism would work as follows:

First, PGE compares:

> On a monthly basis for a calendar year, actual *weather-normalized*[13] monthly revenues collected on a volumetric basis from Schedule 7 (at 5.082¢ per kWh) and from Schedules 32/532 customers (at 4.625¢ per kWh)[14] for fixed generation; transmission, including ancillary services; and distribution, including Trojan decommissioning and PGE's Customer Impact Offset (CIO);

with

> Revenues that hypothetically would have been collected with a fixed per customer monthly charge of $45.59 for active residential customers (Schedule 7) and $69.10 for active small nonresidential customers (Schedules 32/532).[15]

The dollar values cited above would presumably change as a result of Commission revenue requirement determinations in this rate case.

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[13] Per PGE, "(w)eather-normalized energy usage by applicable rate schedule will be determined in a manner equivalent to that determination of forecasted loads used to set rates." See PGE Exhibit 1201/Kuns–Cody/Page 43/Special Condition No. 2.

[14] See PGE Exhibit 1208/Kuns–Cody/Page 1 for the derivation of these amounts. PGE refers to these rates as the Fixed Charge Energy Rates (see PGE Exhibit 1201/ Kuns–Cody/Page 39).

[15] See PGE Exhibit 1208/Kuns–Cody/Page 1 for the composition and derivation of the fixed $45.59 (Schedule 7) and $69.10 (Schedules 32/532) monthly comparative rates. PGE refers to these rates as the Monthly Fixed Charge per Customer Rates (see PGE Exhibit 1201/ Kuns–Cody/Page 43).

Second, the difference (hypothetical less actual)[16] is collected monthly in a balancing account throughout the calendar year. Balances in the balancing account are proposed to accrue interest at PGE's authorized rate of return.

Next, PGE submits to the Commission, by April 1 of the year following the comparison year, proposed Schedule 123/SNA rates to be effective on June 1st of the submittal year based on the amounts in the SNA balancing account as of the end of the prior calendar year; i.e., the comparative year. PGE proposes to include work papers supporting the Schedule 123/SNA rates and indicate the status of the balancing account with the submittal. The Schedule 123/SNA rates are intended to recover (if actuals are less than the hypothetical revenues; or under-collection) or refund (if actuals are greater than the hypothetical revenues; or over-collection) the prior calendar year's ending balance in the balancing account over the period June 1 of the submittal year through May 31 of the following year. The Schedule 123/SNA rates are volumetric (per kWh) rates; i.e., are billed (charged or credited) based on customers' usage.

In the case of under-collection in the comparison year, Schedule 123/SNA rates will be constrained to be no greater than would reflect an estimated average annual rate increase of 2% for the customer class[17] based on net

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[16] Therefore a positive balance in the balancing account is indicative of cumulative net under-collection and a negative balance is indicative of cumulative net over-collection.

[17] In other words, the 2% positive Schedule 123/SNA rate increase limitation would be separately calculated for Schedule 7 and for Schedules 32/532. See PGE's response to Staff Data Request 388, attached as Staff Exhibit 604.

rates[18] in effect at the time of the Schedule 123/SNA revision.[19] If under-collection in the comparison year was such that Schedule 123/SNA rates would result in an estimated average annual rate increase exceeding 2%, the balance over 2% will be deferred and included in subsequent revisions to that class's SNA rate.[20]

The 2% limitation on Schedule 123/SNA rates does not apply in the case of over-collection in the comparative year; i.e., rate revisions resulting in a Schedule 123/SNA negative rate (a rate decrease) are not subject to the 2% limitation.

Finally, Schedule 123/SNA rates are reset (to 0.000¢ per kWh) for the test year in a general rate case. Any imbalance between the intended and actual monies to be collected (refunded) through the rate charge (credit) would continue to accrue interest in the balancing account until later collected from (refunded to) customers.

Q. WHAT ARE PGE'S STATED OBJECTIVES FOR REQUESTING A DECOUPLING MECHANISM?

A. PGE's stated objectives for its proposed decoupling mechanism include diminishing the Company's disincentive to promote energy efficiency and

[18] Net rates, as used in PGE Exhibit 1200/Kuns–Cody/Page 29/Line 7, does not include the impacts of the Public Purpose Charge, Low Income Assistance Charge, Schedule 109 and other tax-related charges on either side of the actual/hypothetical calculation. See also PGE's response to Staff Data Request No. 386, included as Staff Exhibit 605.

[19] See PGE Exhibit 1200/Kuns–Cody/Page 29/Lines 7-13 and PGE's responses to Staff Data Request Nos. 386 and 389. These responses are included as Staff Exhibits 605 and 606, respectively.

[20] In other words, any amount carried forward in the balancing account as a result of the 2% limitation will be netted against future Schedule 123 rate adjustments for the applicable class; whether positive or negative.

customer-sited renewable energy installations.[21] PGE's position is that under current rate of return regulation, the company has no direct financial incentive to promote customer's energy efficiency efforts, as reduced customer usage is detrimental to the Company's financial results.

A second stated PGE objective for the Company's decoupling proposal is to reduce the inequity resulting from existing regulatory structures which have "utility shareholders absorbing costs while society and customers gain the long-term benefits of expanding energy efficiency efforts."[22]

A third stated objective is to "maintain existing pricing structures for customers, which give price signals that support energy efficiency efforts."[23]

Q. HOW IS REDUCED CUSTOMER USAGE DETRIMENTAL TO PGE'S FINANCIAL RESULTS?

A. An electric utility such as PGE with significant capital investments may be viewed as having essentially three categories of costs: 1) fixed costs that do not vary with either customer usage or the number of customers served; 2) costs that are fixed with respect to usage but vary with the number of customers served; and 3) costs that are fixed with respect to the number of customers served but vary with usage.[24,25] An example of each of these three types of cost

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21 PGE Exhibit 100/Piro/Page 17/Lines 19-21.

22 *Ibid*. Page 18/Line 20-Page 19/Line 2.

23 *Ibid.* Page 17/Lines 21-23.

24 Costs in this third category, which vary with usage (but not with the number of customers served), are typically part of Net Variable Power Costs (NVPC), and are outside the scope of PGE's SNA decoupling proposal.

25 Consideration of the appropriate time horizon is relevant in any discussion of "fixed" versus "variable" costs. By "fixed" in the current context, I mean those expenses typically not considered to vary in response to various levels of usage (e.g., delivered kilowatt hours)

might be, respectively, executive compensation, a meter at a customer's premise, and purchased power. Note that a material proportion of costs which are fixed with respect to usage but vary with the number of customers served are, for Schedules 7 and 32/532, covered with PGE's Basic Charges for these schedules.[26]

Past rate-making processes have resulted in a situation in which revenues generated by PGE's non-volumetric rates[27] do not fully cover the first two types of costs described above—both for many PGE customer classes[28] and for PGE's cost of service provisioning as a whole. Alternatively stated, revenues produced by PGE's volumetric rates more than cover costs that vary with short-term usage and contribute to coverage of costs that are fixed (in the near-term) with respect to either usage or to both usage and the number of customers. Due to this legacy rate structure, as long as rates cover short-term variable costs, PGE is financially incented to increase usage per customer, not undertake actions that decrease usage per customer. Note that, as volumetrically-billed charges are added over time (all else being equal), the negative financial impact of a given decrease in usage per customer is made more negative. In other words, as the proportion of revenue billed on volumetric

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and/or to various levels of customers over a medium-term timeframe; i.e., a timeframe that might be considered by both Oregon-regulated electric utilities and Oregon regulators as a "typical" number of years between general rate cases for an Oregon-regulated electric utility.

[26] See PGE Exhibit 1200/Kuns–Cody/Page 7/Lines 8-10 and Page 9/Lines 8-10.

[27] PGE has monthly Basic Charges for many customer schedules, where the monthly Basic Charge for each customer in the schedule does not change regardless of the customer's monthly usage levels.

[28] Certain PGE customer schedules do not have a Basic Charge. These include Schedule 15 (Outdoor Lighting); Schedule 91 (Street & Highway Lighting); Schedules 92 & 94 (Traffic Signals & Communication Devices); and Schedule 93 (Recreational Field Lighting).

bases increases relative to revenue not billed on volumetric bases (i.e., revenue that is not usage sensitive), the financial impact of a given decrease in usage per customer is made more negative. This is due to an increasing reliance on coverage of fixed costs with revenues generated via volumetric rates.[29] The converse of this observation was likely true during the 2001 energy crisis when short-run variable costs were very high—exceeding prices charged to customers.

Q. WHICH COSTS DOES PGE PROPOSE BE COVERED BY THE SNA DECOUPING MECHANISM?

A. PGE's proposed SNA mechanism would cover revenues associated with coverage of costs for fixed generation, transmission (including ancillary services), and distribution (including costs for Trojan Decommissioning and the Customer Impact Offset).[30,31] PGE intends for the SNA mechanism to cover

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[29] Symmetrical reasoning also applies to a situation having a given <u>increase</u> in usage per customer; i.e., revenues increase more than do costs. This has implications for the degree to which a utility is incented to understate usage in a general rate case.

[30] Most of these costs are shown, as allocated to individual rate schedules, in PGE Exhibit 1203/ Kuns–Cody/Pages 1-2; i.e., Transmission, Ancillary Services, and the several costs for Distribution Demand & Facilities Charges plus the CIO. Note that the Fixed Generation costs are a portion of the costs labeled as Power Supply on Page 1 of the Exhibit.

[31] Note that PGE's proposed SNA mechanism is a <u>revenue</u> decoupling mechanism and therefore the costs to be covered are indirect from the mechanism. What this means is that PGE develops proposed revenue requirements by functional category (e.g., Distribution), allocates to individual rate schedules (rate spread), and then develops rates to cover these revenue requirements (an aspect of rate design). This point can be illustrated for the Schedule 7 portion of the proposed mechanism by viewing PGE Exhibit 1203/Kuns–Cody. The Schedule 7 $212,459 thousand "Distribution Demand & Facilities" subtotal (a portion of PGE's proposed revenue requirement) on page 1 equals the $212,459 thousand for the Schedule 7 theoretic "Distribution Charge" amount on page 3. This in turn leads to a proposed rate of 28.64 mills/kWh for Schedule 7 on page 3. This proposed rate, multiplied by the billing determinant of 7,712,700 MWh's, results in the proposed annual revenue of $220,892 thousand. This amount is the "Distribution" portion of revenue that PGE is proposing for coverage by the SNA. Compare these figures with the Distribution Revenue

$391,959,000 in Schedule 7 revenue and $69,372,000 in Schedules 32/532 revenue in test year 2009 based on PGE-forecasted usage and customer levels for these two customer classes. (See PGE Exhibit 1208/Kuns–Cody/Page 1).[32] The SNA mechanism covers approximately 27% of PGE's proposed 2009 test year revenue requirement of $1,733 million[33] and 97% of PGE's retail customers.

Q. WHAT TYPES OF RISKS ASSOCIATED WITH LOSS OF REVENUE DOES PGE PROPOSE BE COVERED BY THE SNA MECHANISM?

A. PGE's proposed SNA mechanism would cover, for the applicable rate classes, shortfalls against the hypothetical (comparative) revenues for essentially all causes except decline in the number of customers in a covered class and weather.[34] For example, PGE's proposed SNA mechanism would insulate the Company's revenues from the effects of inflation, recession, terrorism, actions or inactions of the Federal Government, *et cetera*.

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amount of $220,891,735 and the 28.64 mills/kWh rate for Schedule 7 of PGE Exhibit 1208/Kuns–Cody/Page 1.

32 These figures are not actually stated by PGE (but are illustrated in PGE Exhibit 1208/Kuns–Cody/Page 1); they are derived by multiplying PGE's proposed 2009 annual average number of Schedule 7 and of Schedules 32/532 customers by PGE's proposed comparative monthly rates of, respectively, $45.59 (Schedule 7) and $69.10 (Schedules 32/532). These comparative monthly rates would presumably change as a result of Commission revenue requirement determinations in this rate case.

33 In comparison Net Variable Power Cost expenses, which are subject to the "automatic adjustment clauses" of Schedule 125 (AUT) and Schedule 126 (PCAM), are proposed by PGE to be 47% of the 2009 test year's revenue requirement. PGE's SNA decoupling proposal would result in approximately 74% of PGE's revenues being "on automatic."

34 Weather as used here refers only to impacts on the demand side; i.e., in terms of weather-induced variation in usage per customer from "normal." Weather impacts on the supply side (e.g., hydro conditions) are presumably covered by the Net Variable Power Cost mechanisms.

Q. WHAT ISSUES HAS STAFF IDENTIFIED WITH PGE'S PROPOSED SNA DECOUPLING MECHANISM?

A. Staff has identified five issues of concern. These issues can be summarized as: 1) comparative values favorable to shareholders at the expense of ratepayers in a demographic environment expected to consistently experience customer growth; 2) shift of burden of regulatory lag from shareholders to ratepayers; 3) insufficiency of provided evidence related to potential impacts resulting from PGE's "disincentive" and the removal thereof; 4) questionable objective for maintaining *status quo* rate structure in the face of near-term AMI deployment and approaching imposition of carbon tax (or cap and trade); and 5) shifting of risk from shareholder to ratepayer.

Q. PLEASE DISCUSS THE FIRST ISSUE YOU IDENTIFIED.

A. The first issue with PGE's proposed SNA decoupling mechanism is that the company is likely to over-collect its fixed costs due to the manner in which the mechanism deals with customer growth.[35] PGE proposes comparative values on a revenue per customer basis. The per customer costs reflect fixed generation, transmission, and distribution costs.[36] To the extent that the costs

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[35] While an imperfect comparative geography with PGE's service area, the Portland-Beaverton-Vancouver OR – WA Primary Metropolitan Statistical Area is expected to average 1.4% annual population growth over the period 2000 through 2035. See 2005 – 2060 Regional Population and Employment Forecast, Public Review Draft May 19, 2008; Metro; page 3. PGE's service area includes portions of all five of the Oregon counties in the PMSA (Multnomah, Clackamas, Washington, Columbia, and Yamhill) plus portions of Marion and Polk counties. Clark and Skamania counties are in the State of Washington portion of the PMSA.

[36] See the preceding section titled "Which Costs Does PGE Propose be Covered by the SNA Decoupling Mechanism?"

being covered by the comparative rates[37] are fixed in the short term,[38] fixed relative to the number of customers, or are higher than the <u>incremental</u>[39] costs per customer for the same categories of costs included in the SNA, PGE benefits under the proposed SNA mechanism when the number of Schedule 7 and/or 32/532 customers exceeds the average number of customers forecast for the test year in a general rate case. This is true for both the test year and for subsequent years (but prior to the test year of a subsequent general rate case).

The Company clearly illustrates this in PGE Exhibit 1208/Kuns–Cody/Page 2, where a) the number of Schedule 7 (residential) customers is increasing in each year subsequent to 2009 (column A); b) the fixed monthly rate of $45.59 per customer applies as the comparative value (column B); c) the annual customer-based revenue comparative value (column C) increases at the same rate as customer growth; d) annual energy-based (volumetrically-billed) revenue (column G) increases; and e) the SNA mechanism results in customer charges, as the customer-based revenues for each year in the example exceeds that year's energy-based revenues; i.e., the SNA amount (column H) is positive for each year. This general result of a positive SNA amount holds for any year relative to the test year in which there is a reduction in average usage per customer. The general result of PGE benefiting from the

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[37] Proposed by PGE to be $45.59 and $69.10 monthly for Schedule 7 and Schedules 32/532, respectively. PGE refers to these rates as the Monthly Fixed Charge per Customer Rates. Similarly, PGE refers to the hypothetical revenues resulting from these rates as the Fixed Charge Revenues. See PGE Exhibit 1201/Kuns–Cody/Page 39.

[38] PGE consistently refers to the costs to be covered by the SNA mechanism as "fixed" without qualification. See PGE Exhibit 100/Piro/Page 20/Line 15-Page 21/Line 6; Page 22 Lines 10-14; and PGE Exhibit 1200/Kuns–Cody/Page 28/Lines 11-14.

[39] PGE's comparative monthly rates per customer are of the average embedded cost nature, not incremental.

number of average customers exceeding that forecast for the test year of the last rate case holds for any year in which, relative to the test year, a positive customer growth rate exceeds (the absolute value of) a negative growth rate in usage per customer.[40]

In a nutshell, PGE's example of the SNA adjustment for Schedule 7 customers[41] illustrates a situation in which revenues for coverage of $392 million in fixed costs increase by over $19 million[42] to $411.1 million four years after the 2009 test year. However, there will be no analysis, review, or procedural step taken to ensure that an increase in costs and in allowed revenue requirements totaling $19 million has in fact occurred. The Company has not demonstrated any cost causative link between growth in customers and the $45.59 target. Note that in PGE's example the following takes place over the period 2010 through 2013 as compared with 2009: 1) the number of customers increases by 4.9%; 2) usage (MWh's) increases 2.2%; and 3) energy-based annual revenue increases 2.2%. Assuming revenues from Basic Charges increase at the same rate as customer growth,[43] the increase in the total of energy-based revenue plus Basic Charge revenue is bounded by 2.2% as a lower limit and 4.9% as an upper limit.

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[40] This reasoning abstracts from potential special cases resulting from the 2% maximum increase limitation on the SNA adjustment in "follow-on" years.

[41] See PGE Exhibit 1208/Kuns–Cody/Page 2.

[42] Note that, in the absence of the proposed SNA mechanism, revenues in PGE's example would increase by $8.5 million; i.e., by the difference between the energy-based revenue (column G in PGE's Exhibit 1208/page 2) of $400,430,556 for 2013 and the $391,959,426 for 2009.

[43] The only way this would not be true, absent changes to one or both Schedule 7 Basic Charges), is if the proportion of three-phase customers to single-phase customers declines over this period.

A variant of PGE Exhibit 1208 page 2 was created using a different rate of annual growth in the number of Schedule 7 customers over the 2010 – 2013 period. (See Staff Exhibit 607: “Schedule 123 Sales Normalization Adjustment, Staff Example A.”) The (positive) 1.2% per year customer growth rate used by PGE was replaced with a negative 1.2% per year customer growth rate to model the impacts this would have on the SNA mechanism. A 6 MWa annual energy efficiency savings from the prior year was assumed for consistency with PGE’s assumption.[44]

Aside from the declines in both customer-based and energy-based annual revenues over the 2009 though 2013 period, there was little change as a result of assuming a different rate of customer growth. Note especially that the Sales Normalization amount (column H) exhibited little change from the values in PGE’s example. In short, PGE’s proposed SNA mechanism is not especially sensitive in terms of *the amount of the SNA adjustment* to growth or decline in the number of customers. PGE’s 2013 revenues inclusive of the SNA in this scenario are, however, $10.8 million[45] higher than would be the case without the SNA mechanism.

Next, a second variant of PGE’s “Schedule 123, Sales Normalization Adjustment Example”[46] was created. (See Staff Exhibit 608: “Schedule 123 Sales Normalization Adjustment, Staff Example B.”) This variant has the same

44 See PGE Exhibit 1208/Kuns–Cody/Page 2/Footnote 1.

45 This is the difference between the $373,487,139 of hypothetical customer-based revenue (column G in PGE’s Exhibit 1208/page 2) for 2013 and the $362,671,036 in energy-based revenue for 2013 in Staff Exhibit 607.

46 See PGE Exhibit 1208/Kuns–Cody/Page 2.

1.2% annual customer growth as PGE's Exhibit 1208/Page 2 example. This variant also assumes the same 6 MWa annual energy efficiency savings from the prior year, consistent with PGE's example. Staff Example B differs from PGE's example by not assuming constant energy usage per residential customer prior to the 6 MWa incremental annual savings over the prior year. Instead, a business cycle or recessionary impact was modeled by assuming the same constant energy usage per customer used in PGE's example except in 2010, where a 3% decline in average use per customer is modeled.[47]

The primary result of this variation on PGE's example is to show that while the Company's energy-based revenues decline in 2010 versus 2009, customer-based revenues <u>increase</u> over 2009, resulting in a positive Sales Normalization adjustment (column G) for 2010. In other words, a recessionary impact on usage per customer in an environment where customer growth continues could result in PGE's revenues increasing under the SNA proposal whereas, absent the proposal, revenues would decline. It appears that, with the assumption of 1.2% annual customer growth, a decline in usage per customer of less than 4% would result in attaining the proposed 2% maximum annual rate increase due to the SNA mechanism; i.e., the SNA mechanism would result in a 2% increase with the excess over 2% deferred to a future year.

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[47] The reduction to 10,368 kWh per customer for 2010 in Staff Exhibit 608 has two components. First is the 3% 2010 reduction from the baseline annual usage per customer of 10,838.25 kWh as used in PGE's Exhibit 1208, page 2. This is a reduction of 325 kWh per customer. The second reduction, due to two years of 6 MWa annual incremental energy savings, is (24 hours x 365 days x 6 MWa x 1,000 kWh's per MWh x 2 years is 105,120,000 kWh; divided by the 2010 average annual number of customers of 725,066 equals approximately) 145 kWh annually per customer. Therefore, the baseline 10,838.25 kWh per customer, less 3%, less 2 years at 6 MWa energy efficiency savings per year, yields the 10,368 kWh per customer for 2010.

Q. PLEASE DISCUSS THE SECOND ISSUE YOU IDENTIFIED.

A. My second issue with PGE's proposed SNA mechanism involves the concept of equity: the mechanism shifts the burden of regulatory lag towards ratepayers and away from shareholders.

PGE's second objective for the Company's decoupling proposal—to reduce the inequity resulting from existing regulatory structures which have "utility shareholders absorbing costs while society and customers gain the long-term benefits of expanding energy efficiency efforts"[48]—can only be viewed as an issue of equity for those years between new effective rates resulting from general rate cases. One intended outcome of a general rate case is a "truing-up" of rates, revenues, and costs based on forecasts of customers and usage levels in a future test year. While the benefits of expanding energy efficiency efforts is likely a long-term gain for society[49] and for PGE customers collectively,[50] it seems clear any inequity suffered by PGE shareholders is not long-term in that it persists only until the next general rate case; i.e., to the extent any inequity exists, it could only exist in the "out" years between (the test years of) general rate cases.

PGE does not include in the Company's decoupling proposal any commitment for periodic general rate case filings. At least two consultants in the energy regulatory field identify as elements for a "fair and effective"

[48] See PGE Exhibit 100/Piro/Page 18/Line 20-Page 19/Line 2.

[49] In the sense that energy efficiency is perhaps the most cost-effective "resource." The benefit to customers would seem to depend on "who pays" versus "who benefits." Presumably "society" benefits as not all members of society are ratepayers; i.e., a "free rider" effect may exist.

[50] While PGE customers may benefit collectively, it seems unlikely that each of PGE's customers necessarily benefit.

decoupling mechanism a requirement for scheduled periodic filing of general rate cases, specifying a frequency of every three to five years.[51] As PGE shareholders are bearing less of the burden of regulatory lag (and customers bearing more), it seems a reasonable expectation, absent any affirmative requirement, that general rate cases would be initiated under decoupling no more frequently than would be the case in the absence of a decoupling mechanism. As PGE's proposed SNA mechanism is a new and unproven mechanism,[52] periodic filing of general rate cases would serve to protect both shareholder and ratepayer. Therefore, I recommend any Commission Order authorizing an SNA-like decoupling mechanism be accompanied by a requirement that general rate cases will be filed on a basis that is no less frequent that every five years.

PGE's SNA decoupling proposal would serve to shift the burden of regulatory lag towards ratepayers and away from shareholders.[53]

Q. PLEASE DISCUSS THE THIRD ISSUE YOU IDENTIFIED.

A. My third issue with PGE's proposed SNA mechanism involves the limited change in actions likely to result from decreasing PGE's "disincentive."[54] Oregon's establishment of the Energy Trust of Oregon in 2002 as the designated provider of energy efficiency promotion and funding for customers

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[51] See "Regulatory Barriers to Energy Efficiency;" a presentation to the Minnesota Public Utilities Commission by Cheryl Harrington and Jim Lazar; May 24, 2006; page 40.

[52] The SNA mechanism is new and unproven for this utility, in this jurisdiction, with these customers.

[53] This would seem to be especially the case in a situation where the customer growth rate more than offsets any decline in usage per customer.

[54] See PGE Exhibit 100/Piro/Page 17/Lines 19-21.

of PGE and other utilities shifts the responsibility of managing conservation acquisition from the utility to the Energy Trust. Oregon has been cited as a model for implementation of a "conservco" entity structurally separated from the utilities. [55]

A quality "hand-off" or referral from PGE personnel to ETO of customers seeking energy efficiency is clearly of high value in acquisition of energy efficiency. PGE claims a change resulting from implementation of the Company's proposed SNA mechanism is "…more opportunities for us to support expanding energy efficiency efforts."[56] The Company, in response to Staff Data Request No. 352(b),[57] which requested the Company "list efforts to encourage customers to pursue energy efficiency PGE has identified but not supported since December 31, 2005 through the present due to financial disincentivization," identified certain activities proposed in Advice No. 07-25 that were subsequently removed.[58]

Q. PLEASE DISCUSS THE FOURTH ISSUE YOU IDENTIFIED.

A. My fourth issue has to do with the questionable efficacy of PGE's objective to "maintain existing pricing structures for customers, which give price signals that support energy efficiency efforts."[59] Given PGE's estimate of short-term price

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[55] Harrington and Lazar, *op. cit.*, page 18. Harrington and Lazar position a legislatively-created, structurally separate "conservco" as an <u>alternative</u> to revenue decoupling mechanisms (emphasis added).

[56] See PGE Exhibit 100/Piro/Page 19/Lines 8-9.

[57] Attached as Staff Exhibit 609.

[58] PGE's list also included $69 thousand in costs related to low-income weatherization programs removed by stipulation in UE 180. See PGE's response to Staff Data Request 352(b) attached as Staff Exhibit 609.

[59] See PGE Exhibit 100/Piro/Page 17/Lines 21-23.

elasticity for residential customers (-0.08) and nonresidential customers (-0.03),[60] the degree to which the existing price structure provides price signals supportive of energy efficiency efforts is unclear. Use of estimated univariate[61] elasticity measures implies constant short-term price elasticity. In other words, by use of these measures, PGE appears to be implicitly saying the price elasticity of high usage customers is equal to that of low usage customers. It is possible high usage customers actually have a lower (in absolute value) price elasticity of demand, which implies increasing the volumetric rate relative to the fixed rate in support of energy efficiency efforts may be targeting the wrong end of the demand function *vis-à-vis* energy efficiency.

What is clear is that high usage Schedule 7 and Schedules 32/532 customers are, based on PGE's cost studies, paying more than cost, while lower usage customers are paying less than cost;[62,63] i.e., a situation exhibiting vertical inequity. This outcome is conceivably the reason for the current status of PGE's pricing structure; i.e., to minimize the impact of rising energy costs on low usage customers.

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[60] See PGE Exhibit 1100/Nguyen/Page 3/Lines 6-10. A price elasticity of -0.08 means, all else being equal, if the price of electricity increases 10%, the quantity demanded would decline by 0.8%.

[61] A univariate elasticity measure, as used here, means elasticity does not change whether the customer is paying a "high price" or a "low price;" i.e., price elasticity is constant for all (relevant) prices.

[62] See the discussion in the "How is reduced customer usage detrimental to PGE's financial results?" section (preceding).

[63] This analysis follows from PGE's embedded cost studies and may have different outcomes using forward-looking marginal costs.

Q. PLEASE DISCUSS THE FIFTH ISSUE YOU IDENTIFIED.

A. An additional issue I have with PGE's proposed SNA mechanism concerns which parties should bear what kind of risks, such as potential under-recovery of costs between general rate cases as a result of declining usage on a per customer basis. It is not clear from the PGE-provided data whether usage per customer is in fact declining for the residential and small nonresidential customer classes.[64] In response to Staff Data Request 347(a),[65] PGE provided usage levels and the number of annual average customers for each of Schedules 7, 32, 532, and 83 for the period 2004 through 2009, with actual values for 2004 through 2007 and 2008 on a budget basis.[66] The usage data was not weather-adjusted. From this data and information in PGE Exhibit 1203, Staff developed a graph of usage per customer for Schedules 7 and the total of Schedules 32 plus 532 (see Staff Exhibit 611). On this unadjusted-for-weather basis,[67] Schedule 7 actual usage per customer ranged from a low of 10,735 kWh/customer (2005) to a high of 10,965 kWh/customer (2006). PGE's 2009 test year forecast for Schedule 7 is 10,765 kWh/customer. On the same basis, usage for the combination of Schedules 32 and 532 ranged from a low of 17,974 kWh/customer (2005) to a high of 18,218 kWh/customer (2007). PGE's 2009 test year forecast for Schedules 32/532 is 17,931 kWh/customer.

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[64] PGE does not include an existing trend of declining usage per customer as a reason for proposing the SNA mechanism.

[65] Attached as Staff Exhibit 610.

[66] Note that both 2008 usage data and the number of customers were unavailable for Schedule 532. The 2007 actual annual average number of customers for Schedule 532 was 9, while the same value for Schedule 32 was 82 thousand.

[67] Note that values for 2008 and 2009 are on a forecast basis and are therefore weather-normalized. See PGE's response to Staff Data Request 350, attached as Staff Exhibit 612.

Next, Staff developed a graph for Schedule 7 incorporating data supplied by PGE requesting the same information on a weather-adjusted basis (see Staff Exhibit 613).[68] On a weather-adjusted basis, Schedule 7 usage per customer ranged from a low of 10,745 kWh/customer (2005) to a high of 11,124 kWh/customer (2004). PGE's forecast for Schedule 7 in 2009 is 10,765 kWh/customer, or lower than all years but 2005 in the 2004 through 2007 period.

It is not clear after viewing these two graphs that there is any downward trend in usage per customer over the 2004 through 2007 period.

As PGE's proposed SNA mechanism is of a "make whole" nature for any declines in usage per customer from a PGE-forecasted comparative value except weather, revenue variability due to the impact of changing economic conditions on usage per customer is clearly causation PGE is proposing be covered. This risk has historically been borne by PGE shareholders, with recourse in the form of a general rate case, rather than by ratepayers. PGE shareholders are compensated for this risk through the Company's authorized return on equity. Implementation of PGE's proposed SNA mechanism would appear to be an obvious shift of risk from shareholders to ratepayers.

[68] Per PGE's response to Staff Data Request 397, attached as Staff Exhibit 614, weather-adjusted usage for nonresidential schedules was only available at an aggregation level for Secondary Voltage schedules including 15, 32, 38, 47, 49, 83, and 89. The Company's response included "PGE weather-normalizes actual customer consumption based on revenue class, not based on its retail schedule as it appears in PGE Exhibit 1203/pages 3 through 9." This would seem to beg the question of how, under the proposed SNA mechanism, PGE will weather-normalize actual usage for Schedules 32 and 532 on individual bases. See PGE Exhibit 1201/Page 43/Special Condition No. 3: "Weather-normalized energy usage by applicable rate schedule will be determined *in a manner equivalent to* that determination of forecasted loads used to set rates" (emphasis added).

Q. WHAT DO YOU RECOMMEND REGARDING PGE'S SALES NORMALIZATION ADJUSTMENT DECOUPLING PROPOSAL?

A. I recommend the Commission reject PGE's SNA proposal.

PGE's Lost Revenue Recovery Proposal

Q. HOW DOES PGE'S PROPOSED LRR MECHANISM WORK?

A. PGE's proposed Lost Revenue Recovery mechanism (or LRR) would work as follows:

First, the Energy Trust of Oregon (ETO) reports to PGE the reduction in kWh sales resulting from Energy Efficiency Measures (EEMs) "implemented during the prior calendar years attributable to EEM funding incremental to Schedule 108."[69,70]

Next, the reduced kWh sales are "adjusted for EEM program kWh savings incorporated into the test year load forecast used to determine base rates."[71] Then PGE multiplies the ETO-supplied and PGE-adjusted kWh sales reductions by "the weighted average of applicable retail base rates[72] (the Lost

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[69] See PGE Exhibit 1201/Kuns–Cody/Page 40.

[70] Schedule 108 is PGE's Public Purpose Charge. Incremental energy efficiency funding incremental to Schedule 108 is defined as energy efficiency funding through PGE's Schedule 109, which was recently approved by the Commission. See PGE Exhibit 1200/Kuns–Cody/Page 30/Lines 4-7.

[71] See PGE Exhibit 1201/Kuns–Cody/Page 40. Note that "lost revenues" could be negative for test year 2009, as PGE has incorporated into usage volumes an estimate of the reduction in usage as a result of Schedule 109 funding. This would be the outcome should actual energy savings be less than the estimated savings incorporated within the forecast. See PGE Exhibit 1200/Kuns–Cody/Page 30/Lines 15-18.

[72] Where "(a)pplicable base rates for nonresidential customers are defined as the schedule weighted average of transmission, distribution, and fixed generation charges including those contained in Schedules 120 and 122" with Schedules 32 and 532 excluded from the calculation. System usage charges are adjusted to include only the recovery of Trojan Decommissioning expenses and the Customer Impact Offset (CIO). See PGE Exhibit

Revenue Rate).” PGE proposes this rate to be 3.520¢ per kWh for 2009 based on the Company’s proposed 2009 test year revenue requirement.

Next, the resulting “lost revenue” is accumulated in a balancing account separate from the proposed SNA balancing account and accrues interest at PGE’s authorized rate of return.

Finally, PGE submits to the Commission by April 1 of the following year proposed Schedule 123/LRR rates to be effective on June 1st of the submittal year based on the amounts in the LRR balancing account as of the end of the prior calendar year. PGE proposes to include work papers supporting the Schedule 123/LRR rate and indicate the status of the balancing account with the submittal.

Q. WHICH COSTS ARE COVERED BY THE LRR MECHANISM?

A. PGE’s proposed LRR mechanism would cover revenues associated with coverage of costs for fixed generation (including Schedule 120, the Biglow Canyon I adjustment, and Schedule 122, the Renewable Resources Automatic Adjustment Clause); transmission (including ancillary services); and distribution (including costs for Trojan Decommissioning and the Customer Impact Offset).

Q. WHAT ISSUES HAS STAFF IDENTIFIED WITH PGE’S PROPOSED LRR MECHANISM?

A. PGE’s LRR mechanism, as proposed, does not link a reduction in revenue due to energy savings resulting from Schedule 109 funding directly back to the

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1201/Kuns–Cody/Page 40. Schedule 120 is the Biglow Canyon I Adjustment and Schedule 122 is the Renewable Resources Automatic Adjustment Clause.

specific customer schedule having reduced usage. Instead, PGE uses the "weighted average" approach; calculating an average transmission and distribution rate weighted by each schedule's cycle megawatt hours of usage (result: 15.91 mills/MWh), then calculating an average fixed generation rate weighted by each schedule's cycle megawatt hours of usage (result: 19.29 mills/MWh), then adding the two: 15.91 + 19.29 = 35.20 mills/MWh, or 3.520¢ per kWh.

Adding transmission and distribution plus fixed generation revenues by schedule, then dividing each schedule's result by the schedule's usage reveals a wide range of LRR rates. Schedule 89-P (primary) has the lowest rate, at 2.873¢ per kWh, and Schedule 15 (Outdoor Lighting) has the highest, at 13.904¢ per kWh.[73] It would seem "a kilowatt hour is not necessarily a kilowatt hour" when viewed on a revenue recovery basis across a variety of schedules. For this reason, the LRR rate development of PGE's proposed LRR does not follow cost causation.

An additional issue I have with PGE's proposed LRR is the lack of "breadth." Whereas an issue I had with PGE's proposed SNA mechanism was one of excessive "depth" in that it covered revenue shortfalls for essentially everything but weather, the LRR mechanism would be more comprehensive with the inclusion of Schedule 7 (residential) and Schedules 32/532 (small nonresidential) customers.

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[73] The foregoing results, as well as PGE's proposed LRR rate of 3.520¢ per kWh, are derived from data in PGE's response to Staff Data Request 198 (file "Ratespread09GRC" tab "commercial LRR").

A final issue I have with PGE's proposed LRR mechanism concerns the proposed tariff language pertaining to the LRR. I feel the proposed tariff language could be modified to more clearly indicate the "ratcheting" outcome of a general rate case as applied to PGE's proposed LRR mechanism. In other words, the outcome of a general rate case, in which revenues, costs, and rates are "trued-up," should result in reestablishing the LRR rates to 0.000¢ per kWh. This would seem to be PGE's intent with the following proposed Schedule 123 tariff language:

> "When base rates are adjusted in the future as a result of a general rate review, the test year load forecast used to determine new base rates will reflect all energy efficiency kWh savings that have been previously achieved. The cumulative kWh savings are eligible for Lost Revenue Recovery until new base rates are established as a result of a general rate review; the kWh base is then reset to equal the amount of kWh savings that accrue from EEMs following an adjustment in base rates."[74]

Q. WHAT IS THE ALTERNATIVE TO PGE'S PROPOSED SNA AND LRR MECHANISMS THAT YOU PROPOSE?

A. I propose an EERR (Energy Efficiency Revenue Recovery) mechanism as an alternative to both PGE's proposed SNA and LRR mechanisms. The EERR mechanism would be broader in scope than PGE's proposed

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74 See PGE Exhibit 1201/Kuns–Cody/Page 40.

LRR mechanism by inclusion of Schedule 7 and Schedules 32/532[75] customers omitted from PGE's proposed LRR, but not be as "deep" or all-inclusive of usage reduction causality as PGE's proposed SNA mechanism. Like the LRR, it would only apply to the energy efficiency kWh savings realized due to ETO funding through PGE's Schedule 109. It would also not apply to nonresidential customers whose load exceeded 1.0 MWa at a Point of Delivery during the prior calendar year or to those nonresidential customers who qualify as a Self-Directing Customer.

A feature I propose for incorporation into an EERR mechanism would be the development of schedule-specific EERR rates, such that each rate class would pay for energy efficiency "lost revenues" generated by the rate class through Schedule 109 ETO funding. This formalizes an "equity partition"[76] and presumably side-steps any question as to whether and how ETO will optimize Schedule 109 funding.[77]

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75 The May 12, 2008 Staff Report of Lori Koho, attached as Staff Exhibit 615, stated 60% of Schedule 109 funding is targeted at the commercial sector based on an analysis by PGE and ETO. This sector is understood to be composed of Schedules 32/532 customers as well as Schedules 83/483/583 customers. See page 3 of the Staff Report.

76 If the rate spread outcome of a general rate case is equitable between rate classes, then a charge-back mechanism based on the rate spread outcome would also appear to be equitable. While this is a second-best solution, in a medium-term timeframe (i.e., between general rate cases), induced distortions should not become overly large.

77 Similar to a capital budgeting exercise, ETO should optimize funding by some measure of cost-benefit such as Net Present Value analysis. While this may in fact be intended with Schedule 109 funding, to my knowledge there does not exist direct oversight of ETO deployments by the Commission.

Additionally, I propose balances in the various balancing accounts accrue interest at PGE's Commission-authorized rate for deferred accounts.

Q. WHAT DO YOU RECOMMEND REGARDING PGE'S LOST REVENUE RECOVERY MECHANISM PROPOSAL?

A. I recommend the Commission reject PGE's LRR proposal.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 197
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 601

Witness Qualifications Statement

July 9, 2008

WITNESS QUALIFICATION STATEMENT

NAME:	Steve Storm
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist, Economic Research and Financial Analysis Division
ADDRESS:	550 Capitol Street NE Suite 215 Salem, Oregon 97301-2148
EDUCATION:	Master of Business Administration University of Oregon Eugene, Oregon A.B. (Economics) Harvard University Cambridge, Massachusetts
EXPERIENCE:	I have been employed at the Public Utility Commission of Oregon since October 2007 as a Senior Economist. My current responsibilities include research on a wide range of cost, revenue, and policy issues for electric, gas, and telephone utilities. Prior regulatory experience includes four years of developing responses to data requests regarding new products and services at US WEST Communications.
OTHER EXPERIENCE:	I was a self-employed financial planner for eight years following an eighteen year career in management positions in pricing and cost analysis; financial analysis, planning and management; and strategic planning in the publishing and telecommunications industries. This included five years of managing the pricing (rate spread and rate design) and cost accounting functions in the Directory department of Pacific Northwest Bell and its successor company, US WEST Direct. I was responsible for departmental budgeting and management reporting functions for three years at US West Direct and responsible for corporate financial planning, analysis, and management reporting for one year at Electric Lightwave. I have seven years experience in capital budgeting, financial analysis, and strategic planning functions at US West Communications.

CASE: UE 197
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 602

Exhibits in Support Of Direct Testimony

July 9, 2008

PacifiCorp
Oregon Marginal Cost Study
Summary of Customer Accounting Expense
By Schedule
December 2007 Dollars

Line	FERC Account	Description	(A) Sch. 4 Res	(B) Sch. 23 Com	(C) Sch. 28 Com	(D) Sch. 30 Com	(E) Sch. 48T Ind	(F) Sch. 41 Irrigation	(H) Streetlighting	(I) Total
1		Average Number of Customers	467,946	70,185	9,623	797	222	2,767	987	552,527
2										
3		Write-offs By Schedule	3,460,429	134,611	166,919	96,594	151,741	3,718	-	4,014,011
4										
5	901									
6	Supervision	Account 902 + 903 + 904	$22,974,227	$2,984,143	$754,988	$195,582	$298,481	$180,519	$25,941	$27,413,882
7		% of Total 902 + 903 +904	83.81%	10.89%	2.75%	0.71%	1.09%	0.66%	0.09%	100.00%
8		Total 901 $	$3,858,403	$501,171	$126,796	$32,847	$50,128	$30,317	$4,357	$4,604,020
9		Dollars Per Customer	$8.25	$7.14	$13.18	$41.21	$225.80	$10.96	$4.41	$8.33
10	902									
11	Meter Reading Expense	902 Weighting Factor	1.00	1.36	2.13	2.48	10.48	2.98	0.04	
12		Weighted Customers	467,946	95,554	20,493	1,977	2,326	8,233	39	596,568
13		% of Total $	78.44%	16.02%	3.44%	0.33%	0.39%	1.38%	0.01%	100.00%
14		Total 902 $	$5,456,207	$1,114,148	$238,947	$23,049	$27,121	$95,992	$460	$6,955,923
15		Dollars Per Customer	$11.66	$15.87	$24.83	$28.92	$122.17	$34.69	$0.47	$12.59
16	903									
17	Cust. Receipts & Collect.	903 Weighting Factor	1.00	0.91	1.02	1.02	5.82	1.10	1.00	
18		Weighted Customers	467,946	64,200	9,841	815	1,293	3,046	986	548,127
19		% of Total $	85.37%	11.71%	1.80%	0.15%	0.24%	0.56%	0.18%	100.00%
20		Total 903 $	$12,091,591	$1,658,908	$254,290	$21,061	$33,409	$78,696	$25,481	$14,163,436
21		Dollars Per Customer	$25.84	$23.64	$26.43	$26.43	$150.49	$28.44	$25.82	$25.63
22	904									
23	Uncollectibles	Total 904 $	$5,426,429	$211,088	$261,751	$151,472	$237,951	$5,831	$0	$6,294,523
24		% of Write-offs	86.21%	3.35%	4.16%	2.41%	3.78%	0.09%	0.00%	
25		Dollars Per Customer	$11.60	$3.01	$27.20	$190.05	$1,071.85	$2.11	$0.00	$11.39
26	905									
27	Misc Cust Acct Expense	Account 902 + 903 + 904	$22,974,227	$2,984,143	$754,988	$195,582	$298,481	$180,519	$25,941	$27,413,882
28		% of Total 902 + 903 +904	83.81%	10.89%	2.75%	0.71%	1.09%	0.66%	0.09%	100.00%
29		Total 905 $	$416,873	$54,148	$13,699	$3,549	$5,416	$3,276	$471	$497,432
30		Dollars Per Customer	$0.89	$0.77	$1.42	$4.45	$24.40	$1.18	$0.48	$0.90
31	907-910									
32	Supervision, Cust. Assist.	Average Number of customers	467,946	70,185	9,623	797	222	2,767	987	552,527
33	Info & Instructional Exp.,	% of Total	84.69%	12.70%	1.74%	0.14%	0.04%	0.50%	0.18%	100.00%
34	Misc Cust Svc & Info Exp.		$1,984,403	$297,631	$40,808	$3,380	$941	$11,734	$4,186	$2,343,083
35		Dollars Per Customer	$4.24	$4.24	$4.24	$4.24	$4.24	$4.24	$4.24	$4.24
36										
37	Total 901 - 910	Total 901 - 910 $	$29,233,907	$3,837,094	$936,292	$235,358	$354,967	$225,845	$34,954	$34,858,417
38										
39		Dollars Per Customer	$62.47	$54.67	$97.30	$295.30	$1,598.95	$81.62	$35.41	$63.09

Cust Exp Year

PacifiCorp
Oregon Marginal Cost Study
Summary of Customer and Metering Expenses
December 2007 Dollars

Line	Description	(A) Actual 2000 Dollars	(B) Actual 2001 Dollars	(C) Actual 2002 Dollars	(D) Actual 2003 Dollars	(E) Actual 2004 Dollars	(F) Adjusted 2007 Dollars
							[(A) x 1.2230+ (B) x 1.1884+ (C) x 1.1547+ (D) x 1.1219+ (E) x 1.0901] / 5
	Customer Accounting						
1	901 Supervision	7,101,431	3,354,894	3,025,373	3,025,374	3,174,507	$4,604,020
2	902 Meter Reading Expense	5,693,901	5,618,486	5,144,957	6,581,669	7,168,249	$6,955,923
3	903 Cust Records & Collection	8,234,758	12,301,979	11,116,621	14,670,810	15,439,733	$14,163,436
4	904 Uncollectible Accounts	2,730,654	5,995,980	6,586,619	8,406,244	3,642,666	$6,294,523
5	905 Misc Cust Acct Expense	334,027	539,153	510,949	389,396	377,084	$497,432
6	Total	24,094,771	27,810,492	26,384,519	33,073,493	29,802,239	$32,515,334
7							
8	Customer Service & Info Expense						
9	907 Supervision	-	-	-	967,318	1,293,118	$498,972
10	908 Cust Assistance Expense	1,952,441	947,797	841,270	871,273	1,388,517	$1,395,343
11	909 Info & Instructional Expense	14,632	146,663	204,561	302,597	329,063	$225,318
12	910 Misc Cust Svc & Info Expense	450,865	148,073	110,054	141,635	95,307	$223,450
13	Total	2,417,938	1,242,533	1,155,885	2,282,823	3,106,005	$2,343,083
14							$34,858,417
15	Distribution Expenses						
16	586 Meter Expenses	$0	$1,479,307	$1,800,451	$2,010,097	$1,892,897	$1,631,113
17	597 Meter Maintenance	$674,571	$664,777	$825,166	$1,190,462	$1,237,234	$1,050,426
18		$674,571	$2,144,084	$2,625,617	$3,200,559	$3,130,131	$2,681,539
19							
20							
21	(1) Inflation Adjustment -	1.2230	1.1884	1.1547	1.1219	1.0901	

Source:
FERC Form 1, State of Oregon
Line 10 - O&M Expense reports summary

Exp Acct 903

Pacificorp
Oregon Marginal Cost Study
Account 903 Cust. Bill & Acctng
Weighting Factors

			(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Description	Residential	Small GS	Large GS	Industrial	Irrigation	Streetlighting	Total
	System customers -	arch 2004 Total PacifiCorp Custome	1,339,827	266,421	17,243	615	23,105	33,703	1,680,914
1	FERC Accounts								
2	903.0	Weighting	1.00	1.00	1.00	1.00	1.00	1.00	(Weighted on C
3	Neighted on Customer	Weighted customers	1,339,827	266,421	17,243	615	23,105	33,703	1,680,914
4		% of Total	79.71%	15.85%	1.03%	0.04%	1.37%	2.01%	100.00%
5		Total $	$7,146,058	$1,420,975	$91,967	$3,280	$123,232	$179,759	$8,965,271
6									
7	903.1	Weighting	1.00	1.00	1.00	1.00	1.00	1.00	(Weighted on C
8	Customer Records& C	Weighted customers	1,339,827	266,421	17,243	615	23,105	33,703	1,680,914
9	Neighted on Customer	% of Total	79.71%	15.85%	1.03%	0.04%	1.37%	2.01%	100.00%
10		Total $	$857,615	$170,535	$11,037	$394	$14,789	$21,573	$ 1,075,943
11									
12	903.2	Weighting	1.00	1.01	1.31	24.90	1.00	1.00	(Weighted on m
13	Customer Accounting-	Weighted customers	1,339,827	270,208	22,622	15,312	22,996	33,545	1,704,510
14	eighted on manual billi	% of Total	78.60%	15.85%	1.33%	0.90%	1.35%	1.97%	100.00%
15		Total $	$7,326,456	$1,477,556	$123,700	$83,729	$125,749	$183,431	$ 9,320,620
16									
17	903.3	Weighting	1.00	0.69	0.87	1.99	1.36	1.00	(Weighted on W
18	Customer Accounting-	Weighted customers	1,339,827	184,344	15,032	1,224	31,321	33,703	1,605,452
19	Weighted on Writeoffs	% of Total	83.45%	11.48%	0.94%	0.08%	1.95%	2.10%	100.00%
20		Total $	$8,772,235	$1,206,954	$98,420	$8,016	$205,067	$220,666	$ 10,511,359
21									
22	903.4	Weighting	1.00	0.69	0.87	1.99	1.36	1.00	(Weighted on W
23	Customer Accounting-	Weighted customers	1,339,827	184,344	15,032	1,224	31,321	33,703	1,605,452
24	(Weighted on Writeoff	% of Total	83.45%	11.48%	0.94%	0.08%	1.95%	2.10%	100.00%
25		Total $	$2,238,082	$307,933	$25,110	$2,045	$52,319	$56,299	$2,681,789
26									
27	903.5	Weighting	1.00	1.00	1.00	1.00	1.00	1.00	(Weighted on C
28	Customer Acct - Requ	Weighted customers	1,339,827	266,421	17,243	615	23,105	33,703	1,680,914
29	Neighted on Customer	% of Total	79.71%	15.85%	1.03%	0.04%	1.37%	2.01%	100.00%
30		Total $	$934,769	$185,876	$12,030	$429	$16,120	$23,514	$1,172,739
31									
32	903.6	Weighting	1.00	1.00	1.00	1.00	1.00	1.00	(Weighted on C
33	Customer Acct - Comr	Weighted customers	1,339,827	266,421	17,243	615	23,105	33,703	1,680,914
34		% of Total	79.71%	15.85%	1.03%	0.04%	1.37%	2.01%	100.00%
35		Total $	$11,280,048	$2,243,008	$145,169	$5,178	$194,521	$283,750	$14,151,675
36									
131									
132	Total Acct. 903	Total 903 $	$38,555,264	$7,012,838	$507,434	$103,071	$731,797	$968,993	$47,879,396
133		Dollars Per Customer	$28.78	$26.32	$29.43	$167.60	$31.67	$28.75	
134									
135		Weighting Factor for 903	1.00	0.91	1.02	5.82	1.10	1.00	

CASE: UE 197
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 603

Exhibits in Support
Of Direct Testimony

July 9, 2008

May 30, 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 14, 2008
Question No. 329

Request:

Regarding PGE 1200 Work Paper 152 (Other Consumer Services Marginal Costs)/2009 Budget Amount for PGE Account N41381 ($16,260,871):

- **a. Please describe the "Customer Service Technology Systems" to which the 2009 budgeted amount in this account applies.**
- **b. Please describe the nature of services provided by such systems and justify their costs.**
- **c. Do large industrial customers individually impose the same costs and receive the same benefits from the Customer Service Technology Systems as do individual residential customers? Please explain.**

Response:

a. Please describe the "Customer Service Technology Systems" to which the 2009 budgeted amount in this account applies.

Customer Service Technology Systems include applications related to Itron Meter Reading, Field Collections, Banner CIS, PowerTrack Meter Inventory, Complex Billing, Geospatial Information System (GIS), Work Management System (WMS), and PGE's Outage Management System (OMS).

b. Please describe the nature of services provided by such systems and justify their costs.

Budget for N41381 includes time and expenses to provide services for Customer Service related applications that measure customer usage, produce and issue bills, collect billed revenues, manage accounts receivable and respond to PGE customer inquiries. These applications include Itron Meter Reading and Field Collections, Banner CIS, PowerTrack Meter Inventory and Complex Billing for Direct Access Customers. In addition, the budget also includes costs associated with providing business services and software applications that connect, restore and maintain service to customers. These applications include GIS to map the locations of equipment, WMS to direct crews to work locations, OMS to identify outages and breaks in service, and a suite of applications that provide inspection and repair services for poles, lights, switches, and transformers N41381 ledger also includes general IT allocations pertaining to voice, data, network, communications and office systems that are not the direct responsibility of one specific functional area.

c. Do large industrial customers individually impose the same costs and receive the same benefits from the Customer Service Technology Systems as do individual residential customers? Please explain.

PGE does not specifically track costs in ledger N41381 by customer class.

CASE: UE 197
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 604

Exhibits in Support
Of Direct Testimony

July 9, 2008

June 9, 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 23, 2008
Question No. 388

Request:

Regarding PGE Exhibit 1200/page 29/lines 6 – 13, is PGE proposing the calculation of the 2% limit separately for each of Schedules 7 and 32/532. If not, please explain.

Response:

Yes, PGE is proposing the calculation of the 2% limit separately for each of the applicable schedules.

CASE: UE 197
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 605

Exhibits in Support
Of Direct Testimony

July 9, 2008

June 9, 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 23, 2008
Question No. 386

Request:

Regarding PGE Exhibit 1200/page 29/lines 6 – 13; PGE Exhibit 1208/page 2; and PGE Exhibit 1201/page 43/#3:

a.Please provide a detailed discussion of how both "net rate increase" and "net rates," as used in line 7, are defined and explain the $839,815,814 for 2009 on PGE Exhibit 1208/page 2 (described in Footnote 3 as "Estimated Base Rate Equivalent Revenue"), including a description of how this amount was calculated.

b. Is it true that PGE is proposing asymmetrical rate revisions as pertaining to proposed Schedule 123; i.e., a charge (weather-adjusted actual < hypothetical) in a future period is subject to a limitation at 2% (of net rates) while a credit/refund (weather-adjusted actual > hypothetical) is without limitation? If not, please explain.

Response:

a. **Please provide a detailed discussion of how both "net rate increase" and "net rates," as used in line 7, are defined and explain the $839,815,814 for 2009 on PGE Exhibit 1208/page 2 (described in Footnote 3 as "Estimated Base Rate Equivalent Revenue"), including a description of how this amount was calculated.**

"Net rate increase" is calculated by dividing each schedule's proposed revenue from Schedule 123 rates by revenues that are generated by current rates without Schedule 123. Revenues on either side would not include the impacts of the Public Purpose Charge, Low Income Assistance Charge, Schedule 109 and other tax related charges.

"Net rates" as used in PGE Exhibit 1200/page 29/line 7 refers to the revenues for each applicable schedule prior to Schedule 123 rate taking effect. Revenues for each rate schedule are calculated by multiplying all applicable rates for each schedule (with the exception of the Public Purpose Charge, Low Income Assistance Charge, Other Tax related charges and Schedule 109) by load forecasted for each schedule and used in the Schedule 123 rate setting proceeding.

PGE Exhibit 1208/page 2 is an example of how Schedule 123, Sales Normalization Adjustment (SNA) would be calculated for residential customer class assuming 6 aMW of energy efficiency saving and weather adjusted annual load growth of 1.2%. The $839,815,814 residential revenue was a preliminary estimate of overall 2009 Schedule 7 revenues.

b. Is it true that PGE is proposing asymmetrical rate revisions as pertaining to proposed Schedule 123; i.e., a charge (weather-adjusted actual < hypothetical) in a future period is subject to a limitation at 2% (of net rates) while a credit/refund (weather-adjusted actual > hypothetical) is without limitation? If not, please explain.

Yes, PGE is proposing asymmetrical rate revisions as pertaining to proposed Schedule 123, where rate increases as a result of SNA would be limited to 2%, but there would not be a limitation on rate decreases as a result of Schedule 123.

CASE: UE 197
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 606

Exhibits in Support
Of Direct Testimony

July 9, 2008

June 9, 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 23, 2008
Question No. 389

Request:

Regarding PGE Exhibit 1201/page 43/ #3: please provide a detailed discussion of PGE's proposed accounting treatment for Oregon regulatory purposes of amounts "carried forward" in one or more balancing accounts should a 2% threshold be exceeded.

Response:

PGE will set up balancing accounts for the SNA, applicable to Schedules 7, 32, and 532 and for the Nonresidential Lost Revenue Recovery for the remaining applicable nonresidential schedules. The balancing accounts will record over– and under-collections resulting from differences as determined by the SNA and Lost Revenue Mechanisms. Remaining amounts in the Balancing Accounts, including un-amortized amounts resulting from reaching the 2% threshold, will be deferred and included in subsequent revisions to the SNA and Lost Revenue Recovery rates. The deferred amounts will be tracked in an associated Regulatory Asset, FERC Account 182.3.

CASE: UE 197
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 607

Exhibits in Support Of Direct Testimony

July 9, 2008

UE 197 PGE
Schedule 123 Sales Normalization Adjustment
Staff Example A

Customer-Based Fixed Costs Revenue

Year	Annual Customer Growth Rate	Customers	Monthly Fixed Costs per Customer	Monthly Revenue	Annual Customer-Based Revenue
		A	*B*	*A x B*	*C = A x B x 12*
2009		716,468	$45.59	$32,663,791	$391,965,496
2010	-1.20%	707,871	$45.59	$32,271,839	$387,262,067
2011	-1.20%	699,377	$45.59	$31,884,597	$382,615,169
2012	-1.20%	690,984	$45.59	$31,501,961	$378,023,527
2013	-1.20%	682,692	$45.59	$31,123,928	$373,487,139

Energy-Based Fixed Cost Revenue

Year	Annual Customer kWh (1)	Customers	Total MWH (2)	Volumetric Fixed Costs per kWh	Annual Energy-Based Revenue
	D	*E*	*D x E / 1000*	*F*	*G = D x E x F*
2009	10,765	716,468	7,712,700	$0.05082	$391,959,426
2010	10,690	707,871	7,566,960	$0.05082	$384,552,918
2011	10,613	699,377	7,422,340	$0.05082	$377,203,327
2012	10,534	690,984	7,278,815	$0.05082	$369,909,366
2013	10,453	682,692	7,136,384	$0.05082	$362,671,036

Sales Normalization Adjustment

Year	Customer Based Revenue	Energy Based Revenue	Sales Normalization	Overall Revenue (3)	Percent Change
	C	*G*	*H = C - G*	*I*	*J = H / I*
2009	$391,965,496	$391,959,426	$6,070	$839,815,814	0.00%
2010	$387,262,067	$384,552,918	$2,709,149	$823,946,563	0.33%
2011	$382,615,169	$377,203,327	$5,411,843	$808,199,262	0.67%
2012	$378,023,527	$369,909,366	$8,114,161	$792,571,155	1.02%
2013	$373,487,139	$362,671,036	$10,816,104	$777,062,244	1.39%

(1) *Assumes 6 aMW Annual Energy Efficiency Savings from prior Year*
(2) *Assumes Temperature Adjusted Energy Usage*
(3) *Overall Revenue = Estimated Base Rate Equivalent Revenue*

CASE: UE 197
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 608

Exhibits in Support
Of Direct Testimony

July 9, 2008

UE 197 PGE
Schedule 123 Sales Normalization Adjustment
Staff Example B

Customer-based Fixed Costs Revenue

Year	Annual Customer Growth Rate	Customers	Monthly Fixed Costs per Customer	Monthly Revenue	Annual Customer-Based Revenue
		A	*B*	*A x B*	*C = A x B x 12*
2009		716,468	$45.59	$32,663,791	$391,965,496
2010	1.20%	725,066	$45.59	$33,055,759	$396,669,107
2011	1.20%	733,767	$45.59	$33,452,438	$401,429,250
2012	1.20%	742,572	$45.59	$33,853,857	$406,246,290
2013	1.20%	751,483	$45.59	$34,260,110	$411,121,320

Energy-based Fixed Cost Revenue

Year	Annual Customer kWh (1)	Customers	Total MWH (2)	Volumetric Fixed Costs per kWh	Annual Energy-Based Revenue
	D	*E*	*D x E / 1000*	*F*	*G = D x E x F*
2009	10,765	716,468	7,712,703	$0.05082	$391,959,562
2010	10,368	725,066	7,517,573	$0.05082	$382,043,069
2011	10,623	733,767	7,795,070	$0.05082	$396,145,467
2012	10,555	742,572	7,837,941	$0.05082	$398,324,161
2013	10,489	751,483	7,881,961	$0.05082	$400,561,239

Sales Normalization Adjustment

Year	Customer-based Revenue	Energy-based Revenue	Sales Normalization	Overall Revenue (3)	Percent Change
	C	*G*	*H = C - G*	*I*	*J = H / I*
2009	$391,965,496	$391,959,562	$5,934	$839,815,814	0.00%
2010	$396,669,107	$382,043,069	$14,626,038	$818,568,653	1.79%
2011	$401,429,250	$396,145,467	$5,283,783	$848,784,863	0.62%
2012	$406,246,290	$398,324,161	$7,922,129	$853,452,952	0.93%
2013	$411,121,320	$400,561,239	$10,560,081	$858,246,136	1.23%

(1) *Assumes 6 aMW Annual Energy Efficiency Savings from prior Year*
(2) *Assumes Temperature Adjusted Energy Usage; 2010 is 3% Decline in Usage per Customer*
(3) *Overall Revenue = Estimated Base Rate Equivalent Revenue*

CASE: UE 197
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 609

Exhibits in Support
Of Direct Testimony

July 9, 2008

June 4, 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 14, 2008
Question No. 352

Request:

Regarding PGE Exhibit 100/page 17/lines 19 – 21 and page 18/lines 3-5:

a. Please list "efforts to encourage customers to pursue energy efficiency" PGE has supported since December 31, 2005 through the present other than through Schedule 108 flows; including documentation of incremental costs incurred by PGE and incremental annual FTE's of PGE employees used in support of such efforts. If such support has had no incremental cost impact, please state this.

b. Please list "efforts to encourage customers to pursue energy efficiency" PGE has identified but not supported since December 31, 2005 through the present due to financial disincentivization; including documentation estimating incremental costs not incurred and incremental annual FTE's of PGE employees not used in support of such efforts. Please describe why, in your opinion, these "efforts" were not supported by PGE.

Response:

a. Please list "efforts to encourage customers to pursue energy efficiency" PGE has supported since December 31, 2005 through the present other than through Schedule 108 flows; including documentation of incremental costs incurred by PGE and incremental annual FTE's of PGE employees used in support of such efforts. If such support has had no incremental cost impact, please state this.

As part of PGE's customer communication and customer service, PGE encourages energy efficiency (EE) through collateral material and customer service representatives, guiding our customers to resources that would help them manage their electric consumption more efficiently. This includes the promotion of Energy Trust (ETO) programs. Please see PGE's external website for examples of customer communication that encourages customers to pursue energy efficiency at http://www.portlandgeneral.com/energyefficiency .

PGE's costs associated with encouraging customers to pursue energy efficiency are part of PGE's overall Customer Service O&M budget. These costs are not incremental. PGE is the first line of contact for energy saving solutions and high bill complaints. When our customers incur high bills or have questions on how to reduce their consumption, they expect PGE to offer and/or guide them to solutions, which includes the promotion of the ETO's EE programs. Printing costs of collateral material have not been separately identified.

PGE recently received approval and implemented Schedule 110 which recovers incremental costs specific to providing ETO programs associated with incremental funding for the ETO under Schedule 109. This is a new program and no history on costs currently exists.

From October 1, 2006 through the suspension of the Conservation Rate Credit (CRC) on June 1, 2007, PGE received from BPA and passed through to the ETO, CRC funds for energy efficiency measures. PGE filed semi-annual reports with OPUC on the status of funds under Docket No. UM-1271 on April 1, 2007, September 30, 2007 and March 21, 2008.

b. Please list "efforts to encourage customers to pursue energy efficiency" PGE has identified but not supported since December 31, 2005 through the present due to financial disincentivization; including documentation estimating incremental costs not incurred and incremental annual FTE's of PGE employees not used in support of such efforts. Please describe why, in your opinion, these "efforts" were not supported by PGE.

PGE generally, does not track "efforts to encourage customers to pursue energy efficiency" that it identified in the past but has not pursued. In UE-180 revenue requirement stipulation, parties agreed to remove $69,000 in costs related to low-income weatherization programs. In PGE's Advice filing No. 07-25, the original proposal included funding to promote energy efficiency programs for schools and low income customers through Schedule 110. Based on discussion with intervening parties, the incremental funding to promote energy efficiency programs was reduced from $2.8 million to about $460,000 eliminating the proposed EE funding for schools and low income programs. Please see PGE Advice Filing No. 07-25 for additional detail.

CASE: UE 197
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 610

Exhibits in Support Of Direct Testimony

July 9, 2008

May 21, 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 14, 2008
Question No. 347

Request:

Regarding PGE Exhibit 100/page 19/lines 3 - 6:

a) **Please provide the annual average number of customers and the annual usage (kWh) for 2004 through 2007 (all actuals) and 2008 (budget) for each of the following tariff schedules and aggregations of tariff schedules: 7, 32, 532, and "large nonresidential customers with loads less than 1 MWa." Please indicate whether these values (both customers and usage) are on a calendar or on a cycle basis.**
b) **Please provide an electronic spreadsheet, with parameters and formulae intact, showing the calculation of "lost margins of approximately $2 million in the first year" from "PGE's residential customers reducing loads by just 0.5% per year;" clearly labeling each parameter and specifying the assumptions used in the analysis.**
c) **Please define "lost margins" as used in line 4.**

Response:

a) Please see Attachment 347-A. 2008 forecast values for schedule 532 are not available.

b) Please see Attachment 347-B sent electronically via email as well as the attached hard copy.

c) When energy efficiency causes PGE customers to use less energy, then
   1) PGE revenues decline because fewer kWh of energy are sold;
   2) PGE variable costs decline for the same reason, and;
   3) The difference between (1) and (2) is referred to as "lost margin".

UE 197
Attachment 347-A

Annual Customer Energy Consumption

Average Customer Counts (Cycle Basis)

	2004	2005	2006	2007	2008
Schedule 7	668,830	680,093	691,931	699,778	709,329
Schedule 32	77,723	79,452	80,781	82,001	83,122
Schedule 532	3	5	3	9	N/A
Schedule 83	12,440	12,381	12,718	12,742	12,317

Annual kWh (Cycle Basis)

	2004	2005	2006	2007	2008
Schedule 7	7,256,128,748	7,300,917,796	7,586,998,598	7,671,522,102	7,628,370,000
Schedule 32	1,398,052,364	1,427,892,019	1,469,088,417	1,494,037,963	1,499,148,000
Schedule 532	89,509	284,260	192,485	38,033	N/A
Schedule 83	5,586,529,639	5,421,412,902	5,575,118,205	4,985,645,289	5,422,609,000

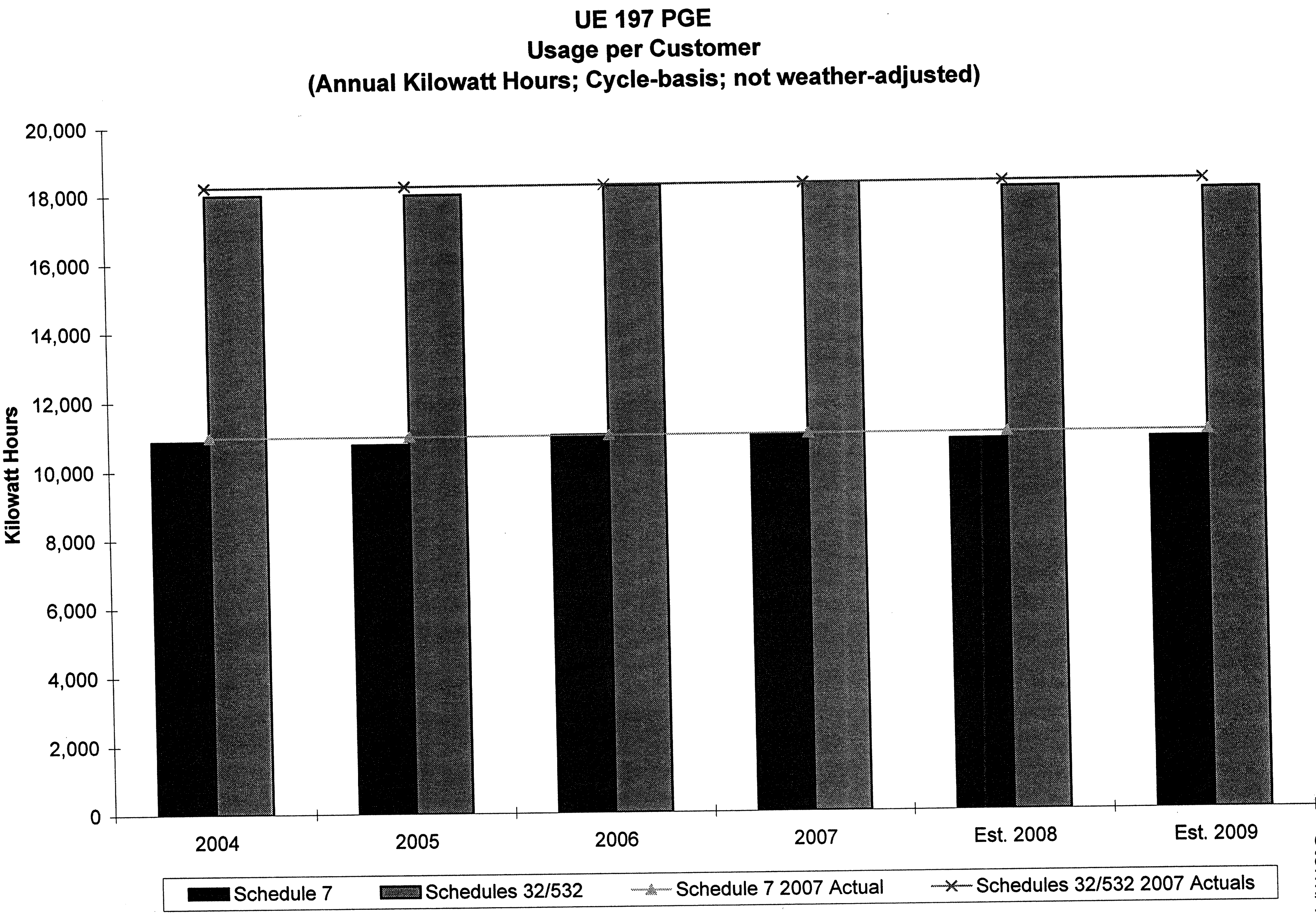
CASE: UE 197
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 611

Exhibits in Support
Of Direct Testimony

July 9, 2008



Storm
6/24/2008
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Source: Response to Staff Data Request 347 Attachment A

CASE: UE 197
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 612

Exhibits in Support Of Direct Testimony

July 9, 2008

May 28, 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 14, 2008
Question No. 350

Request:

Please provide estimates, including an electronic worksheet with all parameters and formulae intact, of the following:

- **a. PGE's quarterly net income over the five year period beginning with 2009; both with and without implementation of the proposed Schedule 123/SNA.**
- **b. PGE's quarterly cash flow over the five year period beginning with 2009; both with and without implementation of the proposed Schedule 123/SNA.**
- **c. PGE's quarterly funds from operation (FFO) over the five year period beginning with 2009; both with and without implementation of the proposed Schedule 123/SNA.**
- **d. Should estimates not have been made for this five year period, please provide any estimates made by PGE of PGE's quarterly net income, cash flow, and/or funds from operations; both with and without implementation of the proposed Schedule 123/SNA.**
- **e. Should PGE not have made any such estimates, please provide any estimates of which PGE is aware made by third parties of PGE's quarterly net income, cash flow, and/or funds from operations covering any part of the period 2009 through 2014 (inclusive); both with and without implementation of the proposed Schedule 123/SNA.**

Response:

a. through d.
As noted in PGE's responses to CUB Data Request Nos. 030 and 035, PGE's forecasts assume annual regulation. This means that we prepare the forecasts on a normalized basis and we do not assume conditions that would produce sales normalization adjustments that would flow through Schedule 123. For detail on PGE's forecast, please see PGE's response to OPUC Data Request No. 113.

e. PGE is not aware of any third party estimates.

CASE: UE 197
WITNESS: Steve Storm

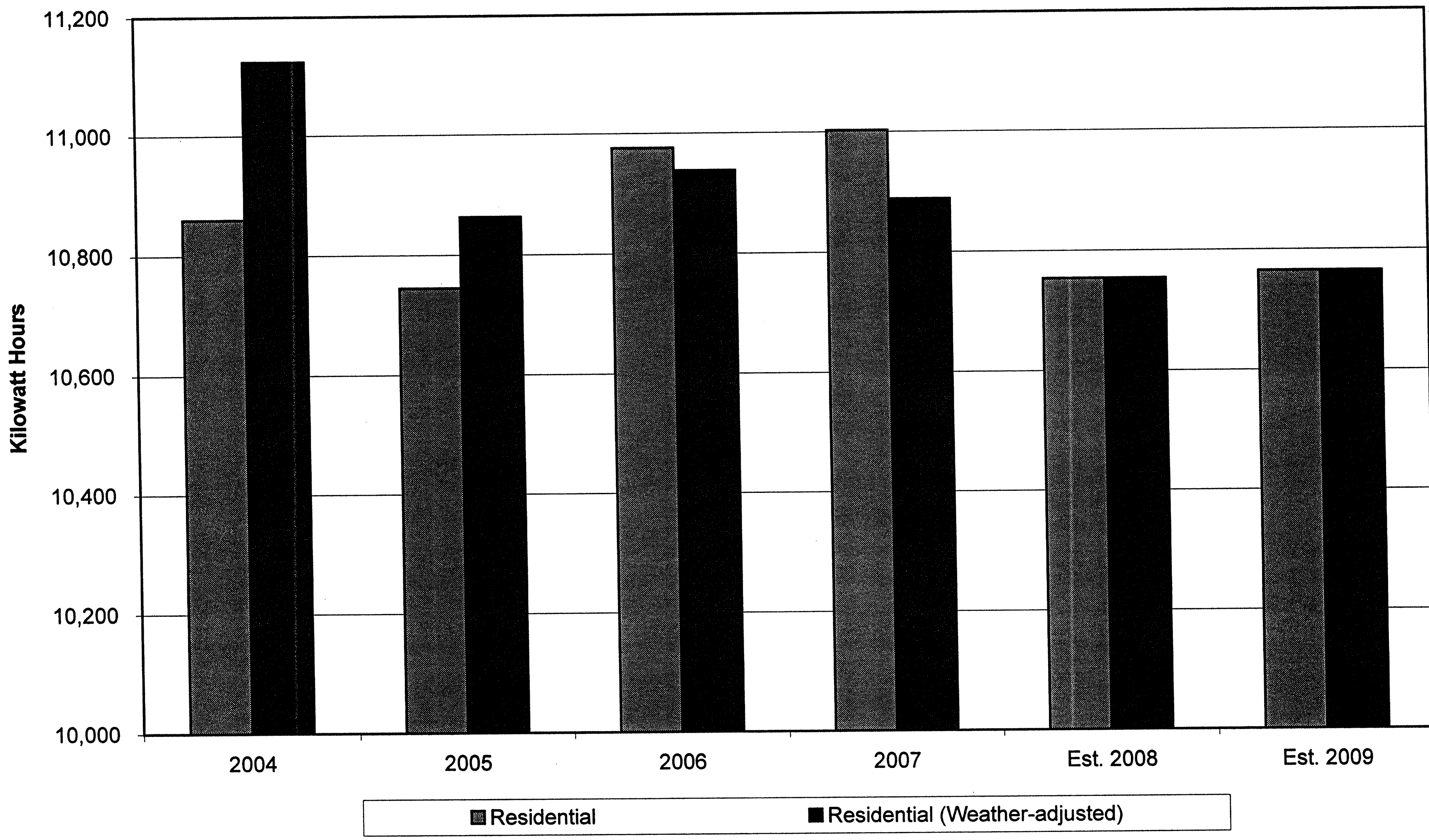
PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 613

Exhibits in Support
Of Direct Testimony

July 9, 2008

UE 197 PGE
Usage per Customer
(Annual Kilowatt Hours; Cycle-basis)



Storm
6/25/2008
DR_347_Attach_A STS 080602

Source: Response to Staff Data Request 397 Attachment A

CASE: UE 197
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 614

Exhibits in Support Of Direct Testimony

July 9, 2008

June 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 June 5, 2008
Question No. 397

Request:

As a follow-up to Staff Data Request No. 347 "a;" please provide the annual average number of customers and the annual usage (kWh) for 2004 through 2007 (all actuals) and 2008 (budget), on a weather-normalized basis, for each of the following tariff schedules and aggregations of tariff schedules: 7, 32, 532, and "large non-residential customers with loads less than 1 MWa" on a cycle basis. Please provide a discussion of any reasons these numbers are not strictly comparable to the data used in PGE Exhibit 1203 (within pages 3 through 9) other than being applicable to years other than 2009 and, for 2004 through 2007, representing weather-normalized actuals (as opposed to forecasts; i.e., 2008 and 2009 data).

Response:

Please see Attachment 397-A for annual usage from 2004 through 2007 on weather normalized basis by revenue class. Revenue Class 1 (ERC1) represents Residential energy class. Revenue Class 3 (ERC3) includes energy for Schedules 32, 83 and 89 as well as its corresponding Direct Access (500 series) equivalents. Revenue Class 1, i.e., Residential class data in Attachment 397-A is comparable to the data used in PGE Exhibit 1203/page 3, Schedule 7 data. Revenue Class 3, weather normalized data in Attachment 397-A is an aggregate of all Secondary Voltage schedules (15, 32, 38, 47, 49, 83 and 89). PGE weather normalizes actual customer consumption based on revenue class, not based on its retail schedule as it appears in PGE Exhibit 1203/pages 3 through 9. For annual average number of customers please see PGE Response to OPUC Data Request No. 347, Attachment 347-A.

Staff/614
Storm/2

UE 197
Attachment 397-A

Annual Usage

PORTLAND GENERAL ELECTRIC COMPANY
ACTUAL AND WEATHER-ADJUSTED CYCLE MONTH SALES BY ERC SCHEDULE
HISTORY/ERC_ENERGY.SAS

YEAR=2004

MONTH	TOTAL ENERGY	TOTAL WEA-ADJ ENERGY	RESIDENTIAL ENERGY ERC1	RESIDENTIAL WEA-ADJ ENERGY	SECONDARY ENERGY ERC3	SECONDARY WEA-ADJ ENERGY
1	1,773,034	1,746,951	849,350	828,262	609,736	605,301
2	1,758,934	1,768,986	802,564	813,976	620,645	619,433
3	1,573,000	1,619,723	655,050	696,582	590,742	595,373
4	1,427,052	1,494,165	542,777	601,587	551,376	558,774
5	1,380,115	1,417,886	491,238	528,978	560,756	560,905
6	1,472,570	1,484,485	513,722	525,373	617,676	617,934
7	1,487,803	1,479,641	513,437	513,773	636,813	629,519
8	1,587,814	1,556,827	562,510	549,117	677,798	662,718
9	1,543,018	1,538,910	532,392	530,784	664,355	662,218
10	1,400,320	1,420,080	481,748	496,980	586,462	590,361
11	1,438,143	1,442,121	578,783	583,645	574,742	573,961
12	1,680,551	1,715,774	739,455	771,188	610,867	613,974
YEAR	18,522,354	18,685,549	7,263,026	7,440,246	7,301,968	7,290,472

MONTH	TRANSMISSION ENERGY ERC4	PRIMARY ENERGY ERC5	PRIMARY WEA-ADJ ENERGY	LIGHTING ENERGY ERC6	AVERAGE MW ACTUAL	SYSTEM PEAK ACTUAL
1	90,453	215,061	214,500	8,434	2,582.5	3,942
2	96,389	230,927	230,778	8,409	2,353.4	3,105
3	96,461	222,286	222,847	8,461	2,138.3	2,917
4	110,706	213,761	214,666	8,432	2,053.4	2,653
5	102,311	217,194	217,075	8,616	2,017.7	2,521
6	98,935	233,849	233,855	8,388	2,124.0	3,094
7	94,296	234,814	233,610	8,443	2,277.4	3,401
8	99,341	239,845	237,330	8,320	2,287.8	3,448
9	97,985	239,721	239,358	8,565	2,064.1	2,634
10	96,509	227,097	227,726	8,504	2,126.2	2,811
11	100,909	175,111	175,009	8,598	2,360.2	3,329
12	93,314	228,374	228,757	8,541	2,512.6	3,234
YEAR	1,177,609	2,678,040	2,675,511	101,711		

PORTLAND GENERAL ELECTRIC COMPANY
ACTUAL AND WEATHER-ADJUSTED CYCLE MONTH SALES BY ERC SCHEDULE
HISTORY/ERC_ENERGY.SAS

YEAR=2005

MONTH	TOTAL ENERGY	TOTAL WEA-ADJ ENERGY	RESIDENTIAL ENERGY ERC1	RESIDENTIAL WEA-ADJ ENERGY	SECONDARY ENERGY ERC3	SECONDARY WEA-ADJ ENERGY
1	1,815,985	1,845,266	837,952	863,876	634,908	637,923
2	1,701,243	1,744,328	732,733	773,990	611,193	612,822
3	1,589,590	1,648,076	647,196	699,447	605,494	611,055
4	1,491,500	1,484,123	593,303	587,056	568,414	567,409
5	1,400,734	1,417,839	511,765	527,542	564,647	565,846
6	1,444,895	1,447,643	507,603	510,381	596,520	596,503
7	1,457,940	1,465,842	498,533	503,862	620,504	622,724
8	1,579,036	1,561,784	553,670	546,766	677,511	668,572
9	1,576,648	1,572,768	537,024	535,232	688,501	686,706
10	1,450,607	1,446,639	491,851	483,384	597,421	601,253
11	1,492,266	1,514,767	577,786	597,920	587,025	589,129
12	1,784,319	1,712,775	818,471	758,264	637,501	627,386
YEAR	18,784,763	18,861,849	7,307,887	7,387,717	7,389,639	7,387,328

MONTH	TRANSMISSION ENERGY ERC4	PRIMARY ENERGY ERC5	PRIMARY WEA-ADJ ENERGY	LIGHTING ENERGY ERC6	AVERAGE MW ACTUAL	SYSTEM PEAK ACTUAL
1	104,814	229,867	230,209	8,444	2,539.5	3,452
2	124,619	224,300	224,500	8,398	2,439.8	3,248
3	107,608	220,750	221,425	8,542	2,228.3	2,863
4	109,319	211,856	211,731	8,608	2,152.5	2,786
5	101,357	214,518	214,647	8,447	2,085.3	3,049
6	105,825	225,629	225,616	9,318	2,087.8	2,790
7	106,990	222,937	223,289	8,976	2,247.1	3,366
8	103,438	235,568	234,159	8,849	2,312.6	3,367
9	98,536	243,867	243,574	8,720	2,109.3	2,839
10	96,589	256,040	256,707	8,706	2,137.2	2,723
11	99,980	218,587	218,850	8,888	2,422.6	3,350
12	93,432	226,502	225,280	8,413	2,664.6	3,606
YEAR	1,252,507	2,730,421	2,729,988	104,309		

PORTLAND GENERAL ELECTRIC COMPANY
ACTUAL AND WEATHER-ADJUSTED CYCLE MONTH SALES BY ERC SCHEDULE
HISTORY/ERC_ENERGY.SAS

YEAR=2006

MONTH	TOTAL ENERGY	TOTAL WEA-ADJ ENERGY	RESIDENTIAL ENERGY ERC1	RESIDENTIAL WEA-ADJ ENERGY	SECONDARY ENERGY ERC3	SECONDARY WEA-ADJ ENERGY
1	1,830,562	1,862,956	845,420	870,667	648,856	655,218
2	1,748,487	1,787,311	767,195	799,004	638,209	644,458
3	1,727,043	1,654,954	762,469	699,519	629,015	620,879
4	1,535,742	1,524,924	616,525	606,767	583,295	582,353
5	1,460,122	1,464,622	525,548	531,478	587,783	586,580
6	1,482,910	1,495,051	510,951	523,720	615,566	615,077
7	1,578,134	1,560,450	546,705	541,994	654,528	643,351
8	1,608,227	1,606,024	557,523	557,188	690,471	688,859
9	1,616,168	1,612,625	554,325	552,079	697,487	696,369
10	1,477,275	1,472,789	508,931	504,406	627,884	627,903
11	1,566,228	1,569,488	609,325	611,568	610,544	611,442
12	1,778,311	1,755,325	789,096	769,440	639,531	636,558
YEAR	19,409,209	19,366,521	7,594,013	7,567,830	7,623,169	7,609,045

MONTH	TRANSMISSION ENERGY ERC4	PRIMARY ENERGY ERC5	PRIMARY WEA-ADJ ENERGY	LIGHTING ENERGY ERC6	AVERAGE MW ACTUAL	SYSTEM PEAK ACTUAL
1	95,157	232,539	233,324	8,590	2,504.9	3,244
2	109,031	225,559	226,325	8,493	2,559.0	3,537
3	97,225	229,673	228,670	8,661	2,428.7	3,235
4	109,850	217,395	217,277	8,677	2,206.1	2,922
5	110,891	227,141	226,914	8,759	2,183.1	3,062
6	117,479	230,121	229,982	8,793	2,242.5	3,586
7	127,146	241,011	239,216	8,744	2,345.1	3,706
8	110,358	241,138	240,883	8,737	2,279.1	3,317
9	101,815	253,587	253,408	8,954	2,202.1	3,032
10	98,093	233,510	233,531	8,857	2,235.9	3,081
11	115,161	222,214	222,332	8,984	2,467.0	3,480
12	106,769	234,098	233,742	8,817	2,660.9	3,607
YEAR	1,298,975	2,787,986	2,785,605	105,066		

PORTLAND GENERAL ELECTRIC COMPANY
ACTUAL AND WEATHER-ADJUSTED CYCLE MONTH SALES BY ERC SCHEDULE
HISTORY/ERC_ENERGY.SAS

------------------------------- YEAR=2007 -------------------------------

MONTH	TOTAL ENERGY	TOTAL WEA-ADJ ENERGY	RESIDENTIAL ENERGY ERC1	RESIDENTIAL WEA-ADJ ENERGY	SECONDARY ENERGY ERC3	SECONDARY WEA-ADJ ENERGY
1	1,900,301	1,855,710	914,501	877,748	670,797	663,743
2	1,856,135	1,817,369	842,893	812,049	658,866	651,764
3	1,654,196	1,686,816	698,179	726,425	628,869	632,797
4	1,536,218	1,553,231	596,990	612,888	586,867	587,865
5	1,498,366	1,487,314	546,073	534,540	592,972	593,335
6	1,515,824	1,511,530	520,956	518,960	635,718	633,750
7	1,580,525	1,574,950	539,290	536,828	657,987	655,332
8	1,636,849	1,658,683	549,832	561,473	699,503	708,234
9	1,575,477	1,583,763	531,881	536,271	678,811	682,148
10	1,491,202	1,465,567	527,863	499,418	617,272	619,538
11	1,585,017	1,576,186	628,716	622,235	610,809	608,686
12	1,802,189	1,774,670	801,825	780,177	650,654	645,393
YEAR	19,632,299	19,545,789	7,698,999	7,619,012	7,689,125	7,682,584

MONTH	TRANSMISSION ENERGY ERC4	PRIMARY ENERGY ERC5	PRIMARY WEA-ADJ ENERGY	LIGHTING ENERGY ERC6	AVERAGE MW ACTUAL	SYSTEM PEAK ACTUAL
1	108,281	197,948	197,164	8,774	2,753.1	3,664
2	110,872	234,652	233,833	8,852	2,523.5	3,383
3	93,618	224,571	225,016	8,959	2,349.0	3,167
4	117,882	225,509	225,627	8,970	2,280.2	3,059
5	128,929	221,409	221,527	8,983	2,192.2	3,059
6	115,662	234,500	234,170	8,988	2,236.2	2,970
7	137,295	236,959	236,501	8,994	2,375.1	3,639
8	128,869	249,677	251,139	8,968	2,257.0	3,257
9	112,536	243,191	243,750	9,058	2,180.3	3,132
10	106,800	230,259	230,804	9,008	2,265.6	2,967
11	109,971	226,475	226,248	9,046	2,486.4	3,518
12	109,933	230,762	230,152	9,015	2,673.6	3,538
YEAR	1,380,648	2,755,912	2,755,930	107,615		

CASE: UE 197
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 615

Exhibits in Support Of Direct Testimony

July 9, 2008

ITEM NO. 2

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: May 20, 2008

REGULAR <u>X</u> **CONSENT** ____ **EFFECTIVE DATE** <u>June 1, 2008</u>

DATE: May 12, 2008

TO: Public Utility Commission

FROM: Lori Koho

THROUGH: Lee Sparling, Ed Busch, and Bonnie Tatom

SUBJECT: <u>PORTLAND GENERAL ELECTRIC</u>: (Advice No. 07-25) Requests approval for incremental energy efficiency funds.

STAFF RECOMMENDATION:

Staff recommends that the Commission approve Portland General Electric's (PGE or Company) request to establish Schedule 109, Energy Efficiency Adjustment and Schedule 110, Energy Efficiency Customer Service Adjustment.

DISCUSSION:

On October 26, 2007, PGE filed Advice No. 07-25. This tariff establishes a funding mechanism for additional cost-effective measures beyond what is attainable through the public purpose funding. Senate Bill (SB) 838, signed into law on June 6, 2007, includes a provision that allows the Commission to approve, in rates, funding for incremental cost-effective conservation.

This tariff was originally intended to be effective January 1, 2008, and consisted of three schedules. Schedule 109, Energy Efficiency Adjustment; Schedule 110, Energy Efficiency Customer Service Adjustment and Schedule 123, Lost Revenue Adjustment. Staff and Citizens' Utility Board (CUB) asked the Company to extend the effective date to allow time for additional data requests and review. On December 10, 2007, PGE filed to extend the effective date to March 1, 2008.

Both CUB and Staff had the following concerns:

- The Company's proposal for lost revenue recovery.
- Specific activities PGE was proposing to fund that could not be shown to be cost effective.

- The number of positions and the job duties of the proposed customer service specialists.
- Marketing activities.

The Company readily agreed to remove Schedule 123, Lost Revenue Recovery Adjustment, from the filing but conveyed to parties that decoupling would be proposed in the next rate case. The Company also agreed that the funding they had proposed for energy efficiency activities in schools and low income housing could not be shown to be cost-effective. The statute requires that the money can only fund incremental, *cost-effective,* energy efficiency acquisition.

On February 1, 2008, the Company made a supplemental filing. With this filing, the Company extended the effective date to June 1, 2008. The Company also removed funding for the non cost-effective energy efficiency activities described above and withdrew Schedule 123, Lost Revenue Recovery Adjustment.

After the February filing, CUB and Staff asked PGE to prepare more explicit information on its marketing outreach plan, job description for the Energy Efficiency Specialist positions and details on how the Company would assure coordination with the Energy Trust of Oregon (ETO).

On April 7, 2008, parties met and PGE presented a draft plan for targeted market outreach. CUB reinforced the fact that any advertising had to be *incremental,* and truly focused at building interest in energy efficiency.

Parties also continued to review the draft job description. The Company initially proposed hiring two specialists and then hiring two additional specialists as the programs ramped, for a total of four. At the April 7 meeting, the Company proposed reducing the total number of specialists to two. Staff continued to express concern that many of the responsibilities the Company identified in the position description were ones better served by ETO's program management contractors (PMC), the ETO itself, or at minimum, under the direct supervision of the ETO.

The supplemental filing the Company made on April 30, 2008, addressed parties' concerns about the Company's proposed specialist positions. The filing now describes a position that should not result in overlap with the PMCs or ETO and should strengthen the Company's ability to direct customers to the appropriate programs. Instead of hiring four Energy Efficiency Specialists, the Company proposes hiring one Customer Program Coordination Manager to educate and coordinate activities with both internal and external stakeholders.

The Company made another supplemental filing on May 9, 2008, to update the wording on Schedule 110 to say that the balancing account will accrue interest at the Commission-authorized rate for deferred accounts. Earlier filings stated that the balancing account would accrue interest at the Company's allowed rate of return. The new wording is not subject to change based on potential Commission decisions in UM 1147.

Assessment of Incremental Savings and Funding

Using a 2006 study, the Trust determined the achievable energy efficiency acquisition potential was 210 aMW, for the years 2008 – 2012. By the end of 2007, the Trust had revised that number to 203 aMW. The provisions of SB 838 exclude customers with loads greater than 1 MW from these proposed tariffs. These larger customers are also barred from benefiting from the incremental funding. PGE determined that approximately 133 aMW can be attributed to customers with loads less than 1 MW. The Trust estimates that they can acquire 65 aMW through programs funded by the Public Purpose Charge, resulting in a gap of 68 aMW that could be targeted by incremental funding.

Conservation Assessment – PGE Territory

Achievable Potential	Remove Customers > 1 MW	Current Funding	Gap
203	133	65	68 aMW

The proposed acquisition target is less than the identified gap for a number of reasons. One is to allow time for the Trust to ramp programs. The expected acquisition rate with the incremental funding is nearly double what is planned for with the public purpose funding. Another is that PGE considered rate impact on customers. In response to a data request from CUB, the Company stated "Funding all cost-effective lost opportunity measures was considered imperative. Acquisition of retrofits was extended beyond 2012 to better match normal replacement cycles, reducing costs and lessening rate impact."[1] Consequently, this tariff is structured to acquire 42 aMW over the next five years. The estimated cost is $69.6 million.

To determine the funding needed, PGE and the Trust identified programs in each sector that could be expanded or strengthened as well as areas that were currently underserved. Based on that analysis, over 60 percent of the funding is targeted at the

[1] PGE response to CUB Data Request 004

commercial sector. This is a sector that historically has been difficult to reach and will benefit from the additional investment.

The estimated costs and targets by sector are shown in the following table:

Sector	aMW Savings	Cost ($ Millions)	$M/aMW
Residential	11.3	25.2	2.25
Commercial	29.1	42.6	1.46
Industrial	1.3	1.8	1.38
	41.7	69.6	
*measures were screened at a 6.5 cent levelized cost			

Program Delivery from the Energy Trust of Oregon
PGE will execute an agreement with the Trust to deliver programs with the funds collected under this schedule.

Energy Trust Reporting and Controls
- Both Staff and PGE agree that the most efficient and cost-effective way for the Trust to administer these funds is to help expand, and improve the penetration of, existing programs. Limiting use of these funds to new and separate programs would actually prevent the Trust from acquiring much of the incremental savings that is achievable. However, this construct will make it more challenging for the Trust to attribute specific energy savings to specific funding sources. Staff, the Trust and both PGE and PacifiCorp have agreed that having the Trust track and report an estimate of the incremental savings acquired, considering the projection of savings that would have been acquired using only public purpose funds, is adequate granularity for review. Overall, the Trust, Staff, utilities and interested parties should agree on appropriate conservative and stretch goals based on total funding levels and track the Trust's performance to those goals.
- There also needs to be assurance that customers larger than 1 MW, who are exempt from the incremental energy efficiency tariff, do not receive benefits from it. The Trust will review its spending and determine the average percent of public purpose funds spent on this customer class historically so it will not materially change in the future.

Energy Efficiency Customer Service
Through Schedule 110, Energy Efficiency Customer Service, the Company plans to fund activities that enable customers to achieve energy efficiency. These qualifying expenses (which are not to exceed $500,000 in any year) and the revenues collected will be recorded in a balancing account that will accrue interest at the Commission-authorized rate for deferred account.

The tariff states that the activities the Company would support include, but are not limited to, project facilitation, technical assistance, education and assistance to support programs administered by the Energy Trust of Oregon.

The Company submitted work papers with this filing that provide more specificity about these activities.

- *Marketing and Communication Activities with Additional SB 838 Funds*
  The Company states it began ramping up activities in early 2008 in anticipation of approval of this tariff. The marketing and outreach activities have been coordinated with the Energy Trust and include:
    - Residential promotions for water heaters, high efficiency washers, windows, insulation and consumer electronics.
    - Expanded advertising targeted at the commercial sector.
    - An annual fall energy efficiency awareness campaign for business customers.
    - Training for small business customers.

  Approximately 75 percent of the Schedule 110 collections will be targeted towards the commercial and small industrial sectors. These are sectors that have been historically difficult to reach and have been identified as needing more outreach.

- *Customer Program Coordinator Manager*
  The Company provided a position description for a Customer Program Coordinator Manager. The responsibilities described in this last filing are quite different from the positions the Company had proposed in the initial filing. CUB, ETO and Staff were very concerned that the roles in the initial filing overlapped or duplicated roles at ETO and at ETO's PMCs.

  CUB and Staff agreed that there is an important role within the utility for directing customers to appropriate programs and a need for the utility to keep its internal staff current on program opportunities. The position described in this filing is more in line with those expectations and very similar to the position PacifiCorp proposed.

<u>Provision for Ramping Up Programs</u>
In preparation for this filing, the Company worked with the Trust on a plan to collect funds at a rate in balance with how quickly the Trust could ramp up programs. Of the estimated $69.6M to be collected over 5 years, PGE is proposing rates that collect $6.7M for the balance of 2008, $14.6M in 2009, $15.4M in 2010, $16.3M in 2011, and $16.4M in 2012.

The term for both of these schedules is June 1, 2008 through December 31, 2012. However, the Company has a provision for a review, to be completed by September 2009, of the efficacy of continued funding beyond 2009. CUB raised concerns that the proposed review period was inadequate for determining the effectiveness of the new funding. CUB was not opposed to the review but cautioned the Company that if faults were found during a review, that the plan of action CUB would support would be to fix the faults as opposed to discontinuing the program.

<u>Large Consumer Exemption</u>
SB 838 excludes large customers from the costs or benefits of achieving incremental energy efficiency beyond what is attained through the public purpose charge. Consumer meters with usage greater than 8,760 megawatt hours (1 aMW) and consumers receiving site certification from the Oregon Department of Energy for the self-direction program will not pay the Energy Conservation Charge in Schedule 109 and 110. This will be based on a twelve month review period and the review will be performed in January of each year.

<u>Ratepayer Impact</u>
The average residential customer, with a usage of 900 kWh per month, will see an increase of approximately 1.1 percent or $0.93.

PROPOSED COMMISSION MOTION:

PGE's request to establish Schedule 109, Energy Efficiency Adjustment and Schedule 110, Energy Efficiency Customer Service Adjustment, effective June 1, 2008, be approved.

CERTIFICATE OF SERVICE

UE 197

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

Dated at Salem, Oregon, this 9th day of July, 2008.

Kay Barnes

Kay Barnes
Public Utility Commission
Regulatory Operations
550 Capitol St NE Ste 215
Salem, Oregon 97301-2551
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UE 197
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