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Douglas C. Tingey
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March 28, 2005

Via Electronic Filing and U.S. Mail

Oregon Public Utility Commission
Attention: Filing Center
PO Box 2148
Salem OR 97308-2148

Re: In the Matter of PORTLAND GENERAL ELECTRIC
Annual Adjustments to Schedule 125 (2007 RVM Filing)
OPUC Docket No. UE 181

Attention Filing Center:

Enclosed for filing in the above-captioned docket are the following documents for PGE's 2007 Resource Valuation Mechanism:

Original and five (5) copies of Direct Testimony of L. Alex Tooman, Michael A. Niman, and Stephen Schue: PGE Exhibits 100 – 103;

Original and five (5) copies of Direct Testimony of Marc Cody: PGE Exhibits 200-203;

Original on CD and three (3) paper copies of Workpapers of Marc Cody.

Please note that Exhibits 101C and 102C are Confidential and subject to OPUC General Protective Order No. 06-142.

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

Thank you in advance for your assistance.

Sincerely,

/s/ DOUGLAS C. TINGEY

DCT:am

cc: UE 172 and UE 180 Service Lists

Enclosure

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing DIRECT TESTIMONY AND WORKPAPERS OF PORTLAND GENERAL ELECTRIC COMPANY to be served by First Class US Mail, postage prepaid and properly addressed, and by electronic mail, upon each party on the attached combined service lists from OPUC Dockets UE 172 and UE 180.

Dated at Portland, Oregon, this 28th day of March, 2006.

/s/ DOUGLAS C. TINGEY____________________
Douglas C. Tingey

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I. Introduction

Q. Please state your names and positions at PGE.

A. My name is L. Alex Tooman. I am a Project Manager in the Rates and Regulatory Affairs Department.

My name is Michael A. Niman. I am Manager of the Financial Analysis Department.

My name is Stephen Schue. I am a Senior Analyst in the Rates and Regulatory Affairs Department.

Our qualifications are provided in Section IV of this testimony.

Q. What is the purpose of your testimony?

A. The primary purpose of our testimony is to present PGE's 2007 forecast of power costs using PGE's existing Resource Valuation Mechanism (RVM). As we discuss in the next section, our current forecast of 2007 power costs is approximately $811.6 million, a $183 million (29.1%) increase from the 2006 RVM forecast in UE 172. However, approximately $42 million of this increase is the result of a higher cost of service load forecast for 2007. On a unit cost basis, PGE's power costs have increased from $32.15/MWh for 2005 to $40.09/MWh for 2007, an increase of 24.7%. Section III, Part B describes the primary drivers of our higher power costs.

As we discuss below, we expect to provide several updates to our 2007 forecast, the number and dates to be determined by the Administrative Law Judge (ALJ). We will file our final 2007 power cost forecast in November 2006.

Q. What is the rate impact of the $183 million increase in power costs?

A. As described in PGE Exhibit 200, we currently expect an overall increase in rates for cost of service loads of 4.3 % (including supplemental tariffs) as a result of the increase in power costs.

Q. How is your testimony organized?

A. There are four sections to our testimony. First, we briefly review the prior Public Utility Commission of Oregon (Commission) orders and stipulations that establish the scope of the 2007 RVM. Second, we summarize our load forecast for 2007, explaining the primary differences between the 2007 forecast and the 2006 load forecast that we provided in UE 172. PGE's expected 2007 loads determine the amount of power that we must generate and/or purchase. Third, we briefly discuss MONET (Monet), PGE's power cost forecasting model that we have used since the mid-1990s. We broadly describe Monet, including the forward price curves and other inputs, and note that no new enhancements have been made to Monet for the 2007 RVM. We also discuss the updates that we have made to the input data since the final Monet run for the 2006 RVM in November 2005, and the updates to the input data that we intend to make before our final 2007 RVM power cost forecast in November 2006. The final section contains our qualifications.

Q. Does PGE have a schedule for updates to Monet for 2007 power costs?

A. No. We anticipate that the ALJ assigned to the 2007 RVM proceeding will establish the schedule of Monet updates based on discussion among and input by the parties. We want these updates to be consistent with the Monet updates in our general rate case (Docket UE 180).

Q. Has PGE made any scope changes or enhancements to the Monet model that are included in the 2007 RVM?

A. No. We have not made any scope changes or enhancements to the Monet model for the 2007 RVM.

Q. What are the differences between the Monet-based net variable power cost forecast you provided in your recent general rate case filing (Docket UE 180) and the forecast you provide in this filing?

A. There are two primary differences. First, we proposed six modeling changes in our general rate case (GRC) filing. PGE Exhibit 400 in UE 180, attached as PGE Exhibit 103, explains these changes on pages 52-56. Second, this filing is based on busbar loads of 2,311 MWa, whereas our GRC power cost estimate uses busbar loads of 2,405 MWa. The difference, 94 MWa, is Schedule 125-B opt-out load. We propose to eliminate this option in our GRC testimony (PGE Exhibit 400), but include it in this RVM filing. Therefore, in this filing we do not have to supply as much load with short-term contracts and/or market purchases. We also do not have to purchase as much transmission. The decomposition of the $45 million difference between net variable power costs in this filing ($812 million) and those in our GRC filing ($857 million) is then:

Factor	$ Million
Higher Loads in GRC	51
More Transmission in GRC	2
Effect of Model Changes in GRC	(8)
Total Change	45

Q. Are other witnesses providing testimony in the 2007 RVM?

A. Yes. PGE is submitting one additional set of testimony and exhibits. PGE Exhibit 200, sponsored by Marc Cody, provides the details of how RVM rates are calculated pursuant to the power cost forecast.

II. 2006 Retail Load Forecast

Q. Please summarize PGE's forecast for its 2007 retail load.

A. PGE Exhibit 202 provides PGE's forecast for retail loads in 2007 by customer class. We summarize the forecast and historical loads below in Table 1.

Table 1
Retail Load Forecast Comparison
(in million kWh)

	Actual 2002	Actual 2003	Actual 2004	Actual 2005	2006 RVM Forecast	Current Forecast (2006)	Current Forecast (2007)
Residential	7,063	7,201	7,440	7,388	7,559	7,467	7,531
Commercial	6,442	6,580	6,761	6,897	7,095	7,067	7,262
Industrial	5,014	4,553	4,286	4,382	4,385	4,474	4,653
Miscellaneous	207	202	199	195	209	209	212
Total Retail	18,726	18,537	18,686	18,862	19,248	19,218	19,658

Note: Actual data are weather-adjusted; forecasts are at normal weather.

Q. Does the forecast include all loads?

A. Yes. The forecast includes both PGE cost of service loads and deliveries of energy to customers who have provided PGE notice "not to plan" for them or "non cost of service" loads. We also sometimes refer to "non cost of service" load as "opt-out" load. PGE Exhibit 201 decomposes the 2007 total retail load into cost of service load by rate schedule, and then adds opt-out load in one figure.

Q. How does this forecast compare to the 2006 RVM (UE 172) forecast?

A. Table 1 shows PGE's actual weather-adjusted retail loads since 2002 and compares the UE 172 (September 2005) forecast with our current forecast of 2006 retail load and our forecast of retail loads by customer group for 2007. Our current 2006 retail load forecast is 19,218 million kWh, approximately 0.2% lower than the UE 172 (RVM) forecast for 2006. We forecast retail load to increase 2.3% to 19,658 million kWh for 2007 from our current

2006 load estimate. Our expected 2007 load remains below our UE 115 2002 test year estimate of 20,227 million kWh. We calibrated Table 1 sector data, primarily commercial and industrial, to the North American Industry Classification System (NAICS).

For our general rate case (UE 180) filing and this proceeding, PGE re-estimated the load model, using recent information on the national economy, state economic and employment forecasts, and the California economy. PGE Exhibit 1200 in Docket UE 180 (particularly pages 7 and 9) explains the estimation procedures in detail.

Q. What load do you use in the power cost forecast?

A. The load listed in Table 1 represents total system load and is used in the rate-making process. The load used to generate power costs with Monet (described in Section III, below) is based on cost of service load (i.e., total system load less Schedule 125, Part B opt-out load). This difference is listed below in Table 2.

Table 2
Comparison of Cost of Service Load with Total System Load
(Cycle Month Energy in million kWh)

	2005 RVM	2006 RVM	2007 RVM
Total System Load	19,181	19,248	19,658
Part B Opt-Out	1,958	1,067	787
Cost of Service Load	17,223	18,181	18,870

Whereas PGE's 2007 total system load forecast is projected to increase by only 2.1% the 2006 RVM forecast, PGE's cost of service load is projected to increase by 3.8%, reflecting less Part B opt-out load. Thus, PGE must plan for additional cost of service load in 2007.

III. PGE's Power Cost Forecast For 2007

A. Scope of the 2007 RVM

Q. What is the scope of the 2007 RVM?

A. The scope of the 2007 RVM is a review of PGE's expected net variable power costs (NVPC) for calendar year 2007 (OPUC Order No. 02-772, at 6). The net variable costs are combined with other resource costs from UE 115 to determine the rates for Schedule 125. PGE Exhibit 200 provides a detailed discussion of the development of Schedule 125 rates.

Q. Did you define "net variable power costs" in your UE 180 testimony?

A. Yes. Pages 13-14 of PGE Exhibit 400 provide this information.

Q. What changes to Monet did you make for this filing?

A. As we discussed in Section I, we proposed six modeling changes in our general rate case filing. However, we do not include them in this RVM filing. Consistent with past RVM proceedings, the changes we plan to make in the RVM model inputs after this initial filing are limited. They include updates for load forecasts, power purchase or sales contracts, fuel and fuel transportation contracts, and forward price curves for electricity and natural gas. The only other changes we plan to make are updates to the Canadian/U.S. dollar exchange rate, hedge contracts, and the price for oil that we use at our thermal plants and distributed standby generation facilities.

B. The Monet Model

Q. Please describe PGE's power cost forecasting model.

A. PGE uses a model called Monet that we built in the mid-1990s and have since refined. Monet is capable of modeling the hourly dispatch of our generating units. Each thermal unit has an individual profile that includes its capacity, heat rate, fuel costs, variable maintenance costs, and other characteristics. Monet models hydroelectric units with peak capabilities and annual, monthly, and hourly usage factors. Since the emergence of forward markets, PGE has input the forward market curves for purchased power and gas, and then run plants under a "dispatch to forward market curve" mode.

Q. Have you provided additional information on Monet in other testimony?

A. Yes. PGE Exhibit 100 in our 2006 RVM filing (Docket UE 172) and PGE Exhibit 400 in our recent general rate case filing (Docket UE 180) describe Monet in detail. Pages 14-15 of PGE Exhibit 400 specifically describe how Monet calculates net variable power costs**.**

Q. What is PGE's current forecast for power costs in 2007?

A. PGE's most recent forecast for 2007 power costs is approximately $812 million.

Q. Could the November open enrollment process affect PGE's power costs in 2007?

A. Yes. All large non-residential customers, regardless whether they have "opted out" or not, are eligible to receive service from PGE or from an ESS. If PGE's non-cost of service load is less than 94 MWa, PGE will have to purchase more energy in order to serve these customers. Conversely, if PGE's non-annual load exceeds 94 MWa, PGE will have to sell energy in order to maintain its relative position.

Q. Can PGE's 2006 and 2007 forecasts for power costs be made consistent with the 2002 test year forecast in UE 115?

A. Yes. If we assume that all of the 2006 and 2007 opt-out loads are supplied at the market prices in PGE's forward curves for 2006 and 2007, then we can compare the three forecasts. We refer to this power cost forecast as the "all loads" forecast.

Q. How do PGE's all loads power cost forecasts for 2006 and 2007 compare with PGE's forecasts for 2002 power costs?

A. The "all loads" forecast for 2007 power costs is $865 million. This is an increase of approximately $146 million above the 2006 "all loads" power cost estimate in UE 172 and greater than power costs in UE 115. Table 3 below provides a summary of our power cost forecasts. As we noted above in Section I, we will further update our forecast for 2007 and our final forecast will be submitted in November 2006. In addition, PGE may be required to adjust Schedule 125 according to the large nonresidential load shift true-up provision identified in Schedule 125-6.

Table 3
Power Cost Forecast Summary

	2002 UE 115[1]	2005 All Loads	2006 All Loads	2007 All Loads	2005 RVM	2006 RVM	2007 RVM
Costs ($'000)	$766,882	$591,007	$718,428	$864,640	$486,266	$628,512	$811,622
Loads[2] ('000 MWh)	21,664	20,591	20,849	21,072	18,551	19,556	20,243
Unit Cost ($/MWh)	$35.40	$28.70	$34.46	$41.03	$26.21	$32.14	$40.09

1. Represents the annualized power costs established in UE 115 based on a 15-month test period for power costs. Includes the impact of the Hydro Rider, Schedule 125, Part C.
2. Calendar busbar loads in 000's of MWh. The 2005, 2006, and 2007 RVM exclude non cost of service loads of approximately 232 MWa, 148 MWa, and 94 MWa respectively.

PGE Exhibits 101-C and 102-C contain the Monet output for our 2007 RVM forecast. The Monet forecast includes transmission costs for opt-out loads and must be adjusted to yield the appropriate 2007 RVM costs[1].

Q. Why are the RVM costs in 2007 higher than in 2006?

A. Our forecasted 2007 RVM costs are higher than our forecasted 2006 RVM costs for four primary reasons, as shown in Table 4.

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[1] For the 2003, 2004, 2005, 2006, and 2007 RVM, transmission costs that are assigned to "Opt-Out" load total $5.3 million, $5.4 million, $4.9 million, $3.0 million, and $2.2 million respectively.

Table 4

Estimate of Change from 2006 Final RVM:	Amount ($Million)
Additional 79 MWa COS Load	42
Lost BPA Subscription Power Benefit	59
Impact of Higher Contract Prices on Term Purchases	32
Impact of Higher Per Unit Gas Cost	46
Other Factors	3
Total	183

Q. Please explain in more detail the four primary reasons for higher 2007 net variable power costs.

A. First, we project 79 MWa in additional cost of service load – 25 MWa due to load growth and 54 MWa due to decreased Schedule 125-B opt-out load. The cost to supply the additional 79 MWa at market purchase or short-term contract prices of approximately $61/MWh is approximately $42 million. Second, we lose 193 MWa of BPA subscription power benefits in 2007. We must then supply this power with market or short-term contract purchases at approximately $61/MWh, rather than at the 2006 BPA subscription power rate of approximately $26/MWh. Third, approximately 800 MWa of 2006 market and short-term contract purchases were at an average price of approximately $56/MWh. However, the comparable 2007 average price is approximately $61/MWh. Fourth, although projected market gas prices are high for both this and the final 2006 RVM filings, the value of gas financials is $46 million higher in the final 2006 RVM filing.

Q. Are there any factors that mitigate power costs in the 2007 RVM?

A. Yes. Expected output from our hydro plants and contracts is approximately 20 MWa higher in 2007. However, other factors off-set the savings related to increased hydro output. These include somewhat lower projected coal-fired output, slightly higher coal and contract hydro prices, and higher transmission costs.

C. Monet Updates

Q. Please describe the overall process of updating Monet with new data.

A. When we fully update Monet, we incorporate available information regarding the inputs affecting our power costs, including retail loads, transmission (or wheeling) costs, generation performance parameters, purchase and sales contracts, coal costs, fuel transportation costs, and the expected wholesale market prices for gas and electricity over the relevant time period. We then run Monet to determine PGE's forecasted net variable power costs.

Q. What is the purpose of the updates to Monet?

A. We update Monet with the latest information available to provide us with the best forecast for our power costs.

Q. Please describe the Monet resource updates that PGE considers significant.

A. All of the resource updates to Monet are provided in the step log, included in our work papers. Table 5 below summarizes significant resource updates made to Monet for this filing.

Table 5
Major Resource Updates

	Data Update	Description
1	Update PGE and Mid-C Hydro Energy	Incorporate results from the new PNCA Headwater Benefit Study.
2	Colstrip Unit 3 HP/IP Turbine Upgrade	Represents the improved capacity and heat rate of the Colstrip facility as a result of the upgrade. Reduces Colstrip's cost per unit of output at the plant and increases its output.
3	PGE Planned Maintenance	Use best current information on planned maintenance outages at our hydro and thermal plants in 2007.
4	Update Heat Rates and Capacities	Use best current plant data to update plant performance statistics.

Q. Please discuss the first resource update, which incorporates the PNCA study of hydro operating constraints and conditions.

A. This update came out in mid-2005 and allowed us to compile a 69-year hydro data set. We discuss this in more detail in our recent general rate case testimony. See pages 56-57 of PGE Exhibit 400.

Q. Do you also discuss the Colstrip Unit 3 HP/IP Turbine upgrade and the updates to planned maintenance outages in PGE Exhibit 400 (Docket UE 180)?

A. Yes. See pages 57-59 of PGE Exhibit 400.

Q. Please summarize the expected thermal plant performance parameters for PGE's thermal resources.

A. Table 6 below summarizes our expectations of thermal plant performance for 2007 and provides a comparison to the 2006 RVM parameters.

Table 6
Thermal Performance Parameters

	Heat Rate		Capacity		Forced Outage		Planned	
	2006 Btu/kWh	2007 Btu/kWh	2006 (MW)	2007 (MW)	2006 Rate	2007 Rate	2006 Days	2007 Days
Beaver	9,299	9,299	521	521	8.7%	20.8%	28.5	See Text
Boardman	9,725	9,725	380	380	6.5%	12.1%	29	30
Colstrip 3	10,913	10,842/10,490	148	143/148	13.0%	12.4%	9	44
Colstrip 4	10,913/10,556	10,490	148/153	148	13.0%	12.4%	52	0
Coyote	7,146	7,128	240	243	6.8%	7.3%	16	16

Q. What is the basis of the forced outage rates (FOR) for the thermal units?

A. For all thermal resources, the FORs are calculated on the basis of rolling 4-year averages. For 2007, this average is calculated based on the actual forced outages experienced from

2002 through 2005. We provided forced outage data in PGE Exhibit 300 in Docket UE 180 (see pages 19-20).

IV. Qualifications

Q. Mr. Tooman, please describe your qualifications.

A. I received a Bachelor of Science degree in Accounting and Finance from the Ohio State University in 1976. I received a Master of Arts degree in Economics from the University of Tennessee in 1993 and a Ph.D. in Economics from the University of Tennessee in 1995. I have taught economics at the undergraduate level for the University of Tennessee, Tennessee Wesleyan College, Western Oregon University, and Linfield College. I have worked for PGE in the Rates and Regulatory Affairs Department since 1996.

Q. Mr. Niman, please describe your qualifications.

A. I received a Bachelor of Science degree in Mechanical Engineering from Carnegie-Mellon University and a Master of Science degree in Mechanical Engineering from the California Institute of Technology. I am a registered Professional Mechanical Engineer in the state of Oregon.

I have been employed at PGE since 1979 in a variety of positions including: Power Operations Engineer, Mechanical Engineer, Power Analyst, Senior Resource Planner, and Project Manager before entering into my current position as Manager, Financial Analysis in 1999. I am responsible for the economic evaluation and analysis of power supply including power cost forecasting, new resource development, least cost planning, and avoided cost estimates. The Financial Analysis group supports the Power Operations, Business Decision Support, and Rates & Regulatory Affairs groups within PGE.

Q. Mr. Schue, please describe your qualifications.

A. I received a Bachelor of Science degree in Economics from the University of Oregon, a Master of Arts degree in Economics from the University of Minnesota, and a Master of

Business Administration degree from the University of Louvain (Belgium). I have taught beginning and intermediate level economics courses at the University of Minnesota, particularly in the area of public finance.

I have been employed at PGE in a variety of positions beginning in 1984, primarily in the Rates and Regulatory Affairs Department. I have worked on Bonneville Power Administration rate cases, particularly in transmission rate design. I was the Project Manager for PGE's 2000 Integrated Resource Plan (IRP), and worked on PGE's 2002 IRP and related Request for Proposals. I also co-sponsored testimony and provided analytical support in the Trojan-related UE 88 Remand docket. In addition, I worked at the Oregon Public Utility Commission during 1986 and 1987, where my primary assignment was economic evaluation of conservation programs.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
101-C	**(Confidential – Sent under Separate Cover)** Output/Assumption Summary Sheet Model Step Change Log and Change Categories Monet Output (Cost and MWa)
102-C	**(Confidential on CD – Sent under Separate Cover)** Monet Model (M606PUC05-045-2007.xls) Cost of Serving Opt-Out Loads (CostofOp031506.xls Step Log (2007RateCase-ModelsSteps-March15Filing.xls) Output Summary (SumM606PUC05-045-2007.xls) **Stacking Model (Stk031506-2007RL.xls)** Hourly Diagnostic Output (M606PUC05-045-2007output-Hrly …xls)
103	Copy of PGE Exhibit 400 in Docket UE 180

Power Cost Framework

Table of Contents

I. Introduction

Q. Please state your names and positions at PGE.

A. My name is Pamela G. Lesh and my position is Vice-President, Regulatory Affairs and Strategic Planning. I am responsible for all aspects of regulatory affairs and for overall strategic planning at PGE. My qualifications are in PGE Exhibit 100.

My name is Michael A. Niman and my position is Manager, Financial Analysis. I am responsible for power cost, project, and other financial analyses at PGE. My qualifications are in Section VI of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to support PGE's forecast of net variable power costs (NVPC) for the purpose of setting cost of service rates for 2007 and to propose a fair methodology for reflecting power costs in PGE's cost of service rates. We propose a framework for power costs that uses three major regulatory tools – a general rate case (GRC), a forward-looking automatic adjustment clause (AAC), and a retrospective automatic adjustment clause – to achieve rates reasonably reflective of actual cost, and to allocate (between PGE and our customers) the risk of variances between the forecast used to set rates and the actual costs experienced. Our proposal includes not only methodologies and allocations, but also process and timing.

In brief, we propose to use a GRC much as we do now. Filed as needed by PGE, or initiated by the Commission or a complainant, the GRC would establish – for a test period and the indefinite future until the next GRC – the following:

- Capital recovery costs for generation investments (return of and return on)
- O&M for plants and power operations

- Operating parameters for PGE resources (or contracts that resemble resources) such as heat rate, maximum capacity, and environmental constraints
- MONET (the PGE power cost model) logic or other changes not specifically included in the annual update

We further propose to replace the Resource Valuation Mechanism (RVM) with Annual Power Cost Update (Annual Update – see Schedule 125). The RVM served two purposes: updating NVPC and providing the methodology for calculating transition adjustments for customers choosing direct access or market-based rate offers. PGE Exhibit 1300 explains the mechanism by which we propose to calculate transition charges in the future. For the Annual Update, each year, PGE will produce a new NVPC forecast by inputting to MONET:

- New power, fuel and transmission contracts (physical and financial) entered into by PGE;
- A load forecast for the following calendar year;
- Forward curves for power and fuel to value any short or long positions;
- Updated forced outage rates, using the traditional four-year rolling average methodology; and
- Planned maintenance outages for the following calendar year.

Unlike the RVM, the Annual Update will not re-spread fixed power costs (developed through unbundling) for the new load forecast. This feature of the RVM related primarily to its use as a transition cost mechanism.

Last, we propose an automatic adjustment clause – the Annual Power Cost Variance (Annual Variance – see Schedule 126) that compares the difference between the forecast

NVPC for a given year with the actual NVPC that PGE incurred, and allocates that difference between PGE and customers according to the following parameters:

- Variances shared 90% to customers and 10% to PGE
- Portion of variance related to changes in load from the forecast neutralized by comparing forecast average NVPC to actual average NVPC
- Prudence review

Both the Annual Update and Annual Variance would be subject to an earnings test, which we modeled on the Commission's 1999 policy ruling relating to Purchased Gas Adjustment (PGA) clauses, Order No. 99-272. Once a year, a proceeding would occur to enable a Commission finding whether the effects of the Annual Update and Annual Variance mechanisms in the prior calendar year, combined with the results of risk allocations from the last general rate case and any other regulatory actions for that year, resulted in reasonable rates. PGE would share equally (50-50) with customers any earnings for that prior calendar year above a threshold, which we propose as 100 basis points above our authorized return on common equity (ROE), adjusted for years between GRCs.

Q. Will PGE make an RVM filing for 2007?

A. Yes. PGE's current Schedule 125 remains effective until the Commission approves its modification. Accordingly, we have included with this filing an RVM estimate, similar to those we have provided over the last several years, and we will file the 2007 RVM by April 1, 2006, per the usual schedule. The RVM estimate differs from the GRC NVPC forecast in two respects:

- It reflects no changes to the MONET model

- The load excludes those customers who have given us notice "not to plan" for them under Part B of Schedule 125. As explained in PGE Exhibit 1300 we propose to eliminate this option beginning in 2007.

The 2007 RVM preliminary estimate is $813.8 million, a 29% increase from 2006. Continued high projected electric and natural gas prices and large unfilled positions are the primary causes of the increase. The forward curves in the final 2006 RVM filing were $67.44 per MWh and $9.35 per DT, respectively. However, at that time we had already filled most of our needs, either on physical or financial bases. The average cost to pay for short-term electric contracts and cover a small open electric position at forward curve prices was $49.76/MWh, and the value of our gas financials was more than $57 million. On the other hand, as of 2/23/06, forward curves for 2007 were $61.49 per MWh and $8.48 per DT, only somewhat lower than those in the final 2006 RVM filing, and we had large unfilled electric and gas needs. The average cost to pay for short-term electric contracts and cover a large open electric position was $60.63/MWh, and the value of our gas financials was less than $10 million. Our confidential workpapers provide detailed MONET model output for our 2007 RVM and GRC NVPC forecasts.

Q. What is your GRC NVPC forecast?

A. Our GRC NVPC forecast is $857 million. Both this forecast and the RVM estimate include:

- Forced outages rates based on the years 2002 through 2005
- Planned maintenance outages for 2007
- Power and fuel contracts entered into through 2/23/06
- Forward electricity and natural gas curves on 2/23/06
- Updated cost and performance parameters for thermal plants

- Updated hydro generation forecast based on the average of 69 years of hydro conditions
- Updated transmission and wheeling assumptions

Q. How do you propose to update your RVM estimate and GRC NVPC forecast?

A. We propose to do this according to the schedule adopted in the 2007 RVM, using that schedule for updating the GRC NVPC forecast as well. We intend to propose a schedule for this GRC docket that enables resolution of PGE's proposed changes to direct access by the end of August, in time for the September Schedule 483 and 489 elections. Assuming this resolution includes the disposition of Schedule 125 Part B opt-out as well, there will be no difference between the GRC NVPC and RVM NVPC forecasts except for any contested MONET changes. The RVM estimated rate change would, however, continue to reflect re-spreading the UE 115 supply function fixed costs over 2007 RVM loads.

Q. How does the Boardman outage that begin briefly in October 2005, and PGE's pending deferral for part of the outage period, affect your RVM and GRC estimates and your proposed framework?

A. In this filing, both the 2007 RVM and GRC NVPC forecasts include the days starting October 23 through December 31, 2005, in the rolling four-year average calculation of Boardman's forced outage rate. We stated in our application for deferred accounting that, to the extent that PGE receives recovery of the cost of replacing Boardman, the forced outage rate calculation should not reflect days included in that recovery. If the deferral proceeding results in a Commission order by October or November, we can reflect the outcome in the RVM and GRC NVPC forecasts.

The effect of the outage and the potential deferral on the Annual Variance component of our proposed NVPC framework is more complex. As we summarized above, the Annual Variance tariff puts in place a sharing of variances, positive and negative. All else being equal, including Boardman's unexpected forced outage days in the rolling average used for forecasting increases the likelihood of a negative variance; i.e., actual NVPC would be lower because Boardman would produce more electricity at its variable cost of approximately $13/MWh, compared to a market price that may be approximately $60/MWh. Under our proposal, customers would receive 90% of such negative variances. This result would deprive PGE of the opportunity to recoup our loss from the outage period, to the extent that the Commission did not allow us direct recovery of the costs through deferral. The reverse could happen as well if, for example, Colstrip or Coyote Springs had performed particularly well in 2004 or 2005. Transition to the Annual Variance tariff could deprive customers of some of the expected compensation for the extraordinary performance that did not benefit them because no variance mechanism was in place.

To address this transition issue, which occurs both at the start and at the eventual end of the Annual Variance tariff, we have included language in the tariff to preserve the "benefit of the bargain" for customers and for PGE of variances related to how we forecast forced outage rates.

Q. How have you organized your testimony?

A. In the remainder of this introduction, we review the regulatory tools available for including power costs in cost of service rates and summarize a study PGE has prepared regarding how regulatory agencies in other states have applied these tools for electric utilities under their jurisdictions. We drew upon our review and this study, as well as the Commission's Order

No. 05-1261, Oregon's regulatory treatment of natural gas utilities' purchased gas, and our interactions with expected parties to this case, in developing our proposed framework. We also briefly review the definition of net variable power costs (NVPC) and how we use our MONET model to produce a forecast of NVPC.

Section II discusses the GRC portion of our framework. We explain why we believe it appropriate to address the selected components of power costs in that forum, rather than in an annual update or a retrospective automatic adjustment clause, and the risk allocation reflected by the proposed treatment of those components.

Section III explains why we included the Annual Update mechanism in our framework. We also support our short list of items eligible for the Annual Update and describe the process and timing we propose to apply to the proceeding. As with Section II, we identify the risk allocation contained within this part of the framework.

Section IV explains why we included a retrospective mechanism in our proposed power cost framework, describes the parameters and process we propose for the Annual Variance tariff and why we chose or designed them and rejected others. We address the guidelines the Commission suggested in Docket UE 165 for the SD-PCAM as well as parameters currently in place for similar mechanisms or used in the past.

In Section V, we discuss the MONET changes that we propose the Commission adopt either for use in a continued RVM or for use in the proposed Annual Update. We present a preliminary estimate of the amount by which each change will affect NVPC.

Q. What regulatory tools are available for handling power costs in cost of service rates in Oregon?

A. Oregon has at least four regulatory tools that it can employ to reflect power costs properly in cost-of-service prices. These are:

- GRCs, which are a comprehensive review of all of a utility's costs, including the cost of capital;
- Forward-looking automatic adjustment clauses, for which the Commission may by statute suspend some of the procedural requirements for processing rates and which generally focus on components of cost of service that change more frequently than most;
- Retrospective-looking automatic adjustment clauses, which by using deferred accounting authority can adjust rates for components of cost of service that change frequently but are difficult or impossible to forecast accurately; and
- Deferred accounting, presently governed by the guidelines the Commission adopted in Docket UM 1147 and which is best suited for unexpected and short-term changes in a utility's costs.

All of the regulatory tools other than the GRC require features that ensure that the prices resulting from their application still meet U.S. Constitutional and statutory requirements. Commonly, this occurs through a prospective or retrospective review of earnings that will or have resulted from the approved cost changes.

Q. What are the characteristics of a GRC that you considered in deciding how to use this tool in the framework?

A. A GRC is the most thorough of all the tools, with a process that provides ample access to information and time to ensure understanding. The inclusion of all costs and revenues allows exploration of all linkages, direct and indirect. Determining whether the resulting prices meet Constitutional and statutory requirements is intrinsic to the proceeding, because the Commission determines the authorized rate of return based upon its application of the requirements to the record developed in the GRC. This is the proceeding in which the Commission can best address the alignment of risk allocation and cost of capital and this is why PGE is proposing a comprehensive regulatory framework for power costs in this filing.

A GRC, with its "test year" core, is not well suited, however, to highly dynamic information, such as near-term power and fuel purchase contracts, and forward curves. Depending on the process, it can become questionable whether the forecasts of such dynamic costs or revenues will be an acceptable representation of what will happen in the test year, let alone subsequent years. In addition, initiation of GRCs in Oregon has been one-sided in practice although not in right: the Commission or a customer can initiate a GRC. The slowness and initiation characteristics make a GRC ill-suited to cost components that can change significantly, up or down, from year to year (e.g., NVPC). This tool is best for cost components that slowly rise or slowly fall over time, such as most fixed costs.

Q. Which characteristics of an automatic adjustment clause (AAC) did you consider important in deciding how to use this tool in the framework?

A. Based on Oregon's experience with PGA clauses and PGE's power cost adjustment clause in the 1980s (1980s PCA) and RVM since 2001, we conclude that AACs are a good regulatory tool for cost of service rates if the cost (or revenue) to which the AAC applies:

- Changes frequently and in ways that could both increase or decrease prices, such that removing the utility's information advantage helps ensure fairness over time;

- Implements an already-decided risk allocation, rather than changing that allocation or revising it to reflect a new risk (such as a major new investment); and
- Generally is actually incurred, third-party generated, per a previously-agreed methodology, or verifiable.

Two items on this list are similar to those mentioned by the Commission in its 1989 order modifying PGA clauses in Oregon, Order No. 89-1046, which noted the standards of: (1) a cost that changes frequently so that tracking is useful to avoid numerous rate proceedings; (2) the significance of the cost in relation to the utility's total expenses; and (3) the degree of control the utility has over the cost. In 1989, gas costs were over 56% of Northwest Natural's total expenses; in 2007, we expect NVPC to be over 50% of our total revenue requirement.

AACs based on the above criteria can proceed rapidly and consume relatively few regulatory resources. The tool works less well if the underlying information is complex or involves choices about which disagreement might exist or if the AAC's timing does not permit review of all information used in adjusting prices.

The primary difference between forward-looking and retrospective AACs is the nature of the cost or revenue change involved. AACs for costs already incurred to serve a future period (e.g. gas purchase contracts) or capable of accurate forecasting can easily be forward-looking. AACs for costs not yet incurred and subject to uncertainty (e.g., energy efficiency program incentives that will depend on how many customers choose the program) require a retrospective AAC.

Q. Why do you believe that AACs, forward-looking or retrospective, and deferred accounting require features to ensure that the prices resulting from their application still meet U.S. Constitutional and statutory requirements?

A. Any time the Commission rules on utility prices, its decision must meet these tests. As we noted above, this happens in a GRC as an intrinsic function of the scope of the proceeding. By their very nature, however, AACs or deferred accounting matters do not involve all costs and revenues and unreasonable prices could result if, for example:

- The cost or revenue adjusted through the AAC or deferred accounting relates integrally to another cost or revenue that is not adjusted; or
- Unrelated costs or revenues have changed significantly.

The Commission typically does this through an earnings test of some sort. In the PGAs, for example, the earnings test generally does not directly relate to the ways in which the AACs update the forecast of future natural gas costs or the variance between forecast and incurred gas costs for a prior period (this is slightly different for Avista). Rather, once a year, the Commission checks whether the complete regulatory framework for the gas utilities (GRCs and PGAs) has resulted in reasonable rates. Earnings above a certain threshold are subject to sharing. See Order No. 99-272 and OAR 860-022-0070. With respect to deferred accounting, the Commission has explained that "the sole issue is whether a utility's earnings for the test period enable it to absorb a cost that has been approved for deferral." Order No. 93-257 at 7.

Q. Did PGE conduct a study of how other states handled power costs for purposes of setting cost of service rates?

A. Yes, PGE engaged NERA Economic Consulting, formerly National Economic Research Associates, to conduct this study on our behalf. NERA completed the study in August 2005. PGE includes the full study entitled The Continuing Role of Power Cost Adjustments in the Electric Utility Industry as PGE Exhibit 401. In addition, PGE routinely tracks how other Northwest states address power cost recovery.

Q. What states and utilities did NERA include in the study?

A. NERA began with the fifty states as well as the District of Columbia and divided them into traditionally regulated states and states that had restructured their electric industry. (Nebraska and Alaska do not have any investor owned utilities.) PGE Exhibit 402 shows the types of states as defined by NERA and the states that have long standing Power Cost Adjustments (PCAs). The study excludes the restructured states and focuses on the traditionally regulated states outside the Northwest (30). Although NERA excluded Arizona as a restructured state, it should probably be included because restructuring is largely halted and the Arizona Corporate Commission has reinstituted a PCA for Arizona Public Service. Tucson Electric Power has not yet filed a rate case because of a prolonged rate freeze associated with the now halted restructuring.

Q. At a high level, what were the results of this study?

A. Of the states and utilities reviewed, the overwhelming majority track through to retail prices 100% of a utility's prudently-incurred NVPC, both power and fuel. This occurs through periodic filings for forward-looking rate adjustments and true-up mechanisms to reconcile past variances. Rate adjustments are usually accompanied by requirements for a regulatory hearing or report to the Commission. The frequency of adjustments varies from state to state, ranging from monthly to annually. Of the 28 states that authorize their utilities to have a power cost adjustment clause, 25 include some form of true-up. The time-lag for full cost recovery of forward-looking adjustments and true-up reconciliation varies from 1 month to 12 months.

Some states include purchased capacity costs in their PCAs. These states include Hawaii, Montana, Oklahoma, South Carolina and South Dakota. Others address capacity in separate clauses (AR, FL, WI) or the utilities' base rate (GA, IA). Some states allow utilities to recover the cost of financial hedges (AL, GA, MS, NV, ND, SD). Utilities may include some or all of the gains/losses from financial hedging aimed at reducing energy costs in the PCA. Distinct geographic characteristics exist. PGE Exhibit 403 provides details of the state process.

Q. What did the survey show regarding the use of dead-bands and sharing?

A. Only Washington has had a dead-band of the nature applied in Oregon to two recent deferred accounting requests and proposed by various parties for ongoing AACs. Sharing mechanisms are infrequent and, where they exist, generally relate to the true-up or retrospective portion of the mechanism. These mechanisms take on a variety of forms. We discuss dead-bands and sharing further in Section IV.

Q. What did NERA do to ensure full understanding of the power cost framework in place in the various states?

A. NERA contacted both the Commissions and the utilities listed in the study. NERA solicited information about the framework of each PCA so that we could understand the mechanics and rationale. Appendix 1 of PGE Exhibit 401 presents the detailed information.

Q. What are your conclusions from the NERA study?

A. We conclude that, among states that continue to regulate utilities on a cost of service basis:

- The use of regulatory tools that allow frequent resetting of rates for power cost components, outside of a general rate case, is common;
- The use of regulatory tools that adjust rates for differences between the forecasted power cost components and actual power costs incurred, is common; and
- Commissions in the Western states tend to allocate more risk of variance to utilities than those in the Southern or Midwestern states.

PGE's current lack of a retrospective tool for variances between forecasted and actual power costs places us in an "outlier" status among cost of service electric (or combination) utilities. This is why our framework includes the Annual Variance tariff.

Q. How does PGE define "net variable power costs" (NVPC)?

A. NVPC include wholesale (physical and financial) power purchases and sales ("purchased power" and "sales for resale"), fuel costs, and other costs of power that generally change as power output changes, such as transmission payments to third parties. PGE records its variable power costs to FERC accounts 501, 547, 555, 565, and 447. Based on historical decisions, we include some fixed power costs, such as Boardman taxes. These items, such as transportation charges and excise taxes, relate to fuel used to produce electricity. We "amortize" these fuel-related costs even though, for purposes of FERC accounting, they appear in a balance sheet account (151). We also exclude some variable power costs, such as variable operation and maintenance costs, because they are already included elsewhere in PGE's accounting. The "net" refers to net of assumed wholesale sales.

Q. How does PGE produce a forecast of NVPC?

A. PGE uses a model to forecast NVPC. The primary purpose of the model is to reflect in estimating NVPC the principles of economic dispatch; i.e., a utility should use lowest variable cost resources to serve customers first, moving up the price/supply curve as load requires. PGE uses a combination of known future costs, forecast cost inputs, and a model to produce a forecast of net variable power costs, built around the principle of economic dispatch. In other words, for PGE and the region, resources such as hydro plants, coal plants, and combustion turbines run to meet load in order of lowest (variable) cost first, and highest cost last. We use a model called MONET that we first built in the mid-1990s and have since refined.

Q. How does PGE use MONET to forecast net variable power costs?

A. PGE uses MONET to "dispatch" PGE’s resources against forward curves for purchased power and gas. To do this, the model employs the following data inputs:

- Forecasted retail loads, on an hourly basis;
- Physical and financial contract and market fuel (coal, natural gas, and oil) commodity and transportation costs;
- Thermal plants, with forced outage rates and scheduled maintenance outage days, maximum operating capabilities, heat rates, and any variable operating and maintenance costs (although not part of net variable power costs for ratemaking purposes);
- Hydroelectric plants, with output reflecting current non-power operating constraints (such as fish issues) and peak, annual, seasonal, and hourly maximum usage capabilities;
- Transmission (wheeling) contract costs;
- Physical and financial electric contract purchases and sales; and
- Forward market curves for gas and electric power purchases and sales.

Using these data inputs, MONET dispatches PGE resources to meet customer loads based on the principle of economic dispatch. Thus, any plant is dispatched when it is available and its dispatch cost is below the market electric price. Any plant can also be operating in one of various stages – maximum availability, ramping up to its maximum availability, starting up, shutting down, or off-line. Given thermal output, expected hydro generation, and contract purchases and sales, MONET fills any resulting gap between total resource output and PGE's retail load with market purchases (or sales) based on the forward market price curve.

II. Power Cost Framework – General Rate Case Role

Q. What components of PGE's power costs do you propose that the Commission reflect in rates only through a GRC?

A. As has historically occurred, we propose that the Commission reflect the following in rates through a GRC:

- Capital recovery costs for generation investments (return of and return on), whether new or capital additions;
- O&M for plants and power operations;
- Operating parameters for PGE resources (or contracts that resemble resources) such as heat rate, maximum capacity, and environmental constraints; and
- MONET logic or other changes not specifically included in the annual update.

Q. Why are capital recovery costs on this list?

A. Oregon's practice for many years has been to change cost of capital only in a GRC, at which time the Commission can ensure that the rate of return (reflecting cost of debt, equity, preferred and cap structure) produces an end result that meets Constitutional and statutory requirements. Similarly, Oregon has, for many years, required that utilities update their depreciation studies every five years, a time frame more suitable to addressing these "return of" issues in a GRC. For major new investment or capital additions, PGE generally knows in advance and a GRC schedule is workable. In addition, a proposed addition to rate base is not a highly variable number that requires frequent updating throughout the process.

Q. Are there circumstances under which PGE and participants in your rate cases might not want to do a full GRC to update power supply capital recovery costs?

A. Yes. We have one instance in this case. PGE plans to complete Port Westward shortly after concluding a GRC for the 2007 test year. PGE could almost simultaneously run a GRC for a test period that ends on Port Westward's on-line date but it makes more sense simply to "track" the plant into the already approved test year when it becomes available. The Commission previously used this procedure for PGE's Coyote Springs plant, and there are other examples as well. In essence, these "tracker" cases operate on the implicit assumption that nothing else requires review to ensure that the end result of the rates is reasonable. As we think ahead to the next five to ten years, it is probable that PGE will have more frequent generation-related major investments or capital additions than in the past 10 years. PGE is open to adapting this framework to accommodate a "tracker" concept for certain resource investments or capital additions.

Q. Why do you propose to address plant-related and power operations O&M in a GRC?

A. We propose this for two reasons. First, costs incurred in other areas, such as information technology, affect plant or power supply O&M costs making it difficult to address only O&M. For example, in this case, IT costs allocable to generation are $3.7 million. Second, these costs are not highly variable, either during a GRC process or after the case's conclusion.

Q. What do you mean by the term "plant operating parameters" that you use to describe the next category of power cost components you propose to address in a GRC?

A. The two main parameters we have in mind here are heat rate (for thermal plants) and maximum output capability (for hydro and thermal plants). Specifically for hydro, we include environmental operating constraints as a parameter matter, but updating "average water" for additional years of data would not be. These are characteristics that change from time to time because of reasons such as capital investments or environmental issues (permits etc.).

Q. Why do you propose to update these plant operating parameters in a GRC?

A. We propose this primarily for two reasons. First, the reasons for changes in these parameters can be complex, such as a new biological opinion affecting Columbia River hydro operations or air quality issues that constrain a given plant's operation during certain hours of the year. Handling such issues in a GRC allows all parties more time to understand the change. Second, particularly for improvements in heat rate or maximum capability, capital additions and higher O&M may be integrally related with the change. It seems unbalanced to reflect the parameter changes without recognizing the capital additions or higher O&M. On the other hand, a planned maintenance outage – which we do intend to reflect in the annual update – may be particularly long in a given year because of the work that is required to improve heat rate or increase maximum capability. This actually occurred with Boardman in 2004 and is underway for Colstrip 4 and 3 in 2006 and 2007, respectively.

In the RVM, we did change operating parameters for these matters. At times, however, our proposed changes generated controversy for a variety of reasons. We are open to discussing this part of the proposal during the process of this case. Solutions to the complexity and linkage issues may appear that we are not aware of right now.

Q. Why do you propose to handle MONET logic and other types of changes not specifically allowed by the Annual Update process in a GRC?

A. We make this proposal primarily because of our experience with the RVM and feedback from parties about the RVM process. The range of logic, data, and other modeling changes that can occur, as we attempt to produce as accurate a forecast as possible, is large. The effect of most such changes, however, is generally small. We may gain some process efficiency by gathering these together for handling in a GRC and parties will gain time to evaluate these changes.

Q. How would your proposed framework operate in a year in which you had a GRC?

A. Much as we are doing in this filing, we would provide an estimate of the upcoming Annual Update with the GRC so that customers understood the combined possible rate change and we would include in the GRC any MONET or operating parameter changes not allowed by the Annual Update process. On the date contained in the Annual Update tariff, we would file the Annual Update for the following year, without the effects of the proposed model changes in the GRC. Once the Commission acted on the GRC, we would include those decisions in the final Annual Update model run for the upcoming year.

Q. What risk allocations does this part of your proposed framework embody?

A. This part of the framework allocates to PGE the following risks:

- Regulatory lag and prudence on the recovery of generation capital investments;
- Changes in load that affect the recovery of these fixed capital recovery and O&M costs;
- Changes in and prudence of fixed O&M costs;
- Regulatory lag on changes in costs related to changes in plant/contract operations; parameters, to the extent of PGE's share per the Annual Variance mechanism; and
- Modeling choices, to the extent of PGE's share per the Annual Variance.

Q. What modeling choices allocate risk to PGE?

A. Two of our inputs to MONET embody significant risk allocations:

- The four-year rolling average methodology used to create a forecast forced outage rate for generating plants; and
- The methodology used to forecast the amount of hydro-electric power PGE's plants and Mid-C contracts will produce.

For both of these, we use a methodology because we have no way of knowing for certain what a given plant's forced outage rate for a year will be or what hydro-electric power we will receive from our projects or contracts. Only by fluke will the methodology result in a forecast that is the same as what actually occurs.

Q. How does the four-year rolling average for forced outages work?

A. We use a four-year rolling average, incorporating data from the four most recent calendar years for which data are available. For the 2007 net variable power cost estimate in this filing, we use data from 2002-2005. For example, if a plant had experienced forced outage rates of 5%, 12%, 3%, and 8% for the years 2002, 2003, 2004, and 2005 respectively, we would assume a 7% forced outage rate in our 2007 power cost estimate. This simple example assumes equal weighting of the forced outage rates. The actual calculation is effectively a weighted average, however, using the total unit forced outage hours, equivalent derated hours, service hours, etc. as applicable over the four calendar year period.

This produces a point forecast for a given year. If the actual forced outage rate for the year is less than this, PGE may experience the benefit of the additional plant availability, subject to the Annual Variance tariff. Customers will receive this benefit, however, over the following four years, as the increased availability lowers the forecast forced outage rate below what would otherwise have been forecast. The reverse occurs also.

Over the last seven years, the actual forced outage rates for PGE's coal generating plants have varied between 2.9% and 24.1%. The range is slightly larger for the gas-fired generating plants: between 0.6% and 30.4%. The financial effects can be significant, however, particularly for the coal-fired resources because of the differences between a given plant's variable cost and the market value of a MWh. The financial effect of forced outage rate changes at Coyote Springs and Beaver (and Port Westward, when it begins operation) are smaller because the natural gas-driven variable costs are often close to market on a given day.

Q. Is this an acceptable risk allocation?

A. Yes, when matched with the Annual Variance tariff we propose. The Annual Variance tariff will ensure that customers see most of the benefit of good plant performance and that PGE recovers most of its costs to provide power despite prudently-incurred plant outages. PGE will, of course, remain subject to bearing the cost of outages caused by imprudence. As we noted in Section I and explain in Section IV, the Annual Variance tariff must include a transition mechanism, however, because the four-year rolling average methodology includes in the mechanism the effects of years before it was in place.

Q. How do you forecast the amount of hydro-electric power production PGE will have available to it?

A. We use the Pacific Northwest Coordination Agreement (PNCA) hydro regulation model to develop an average monthly generation for each hydro resource, based on the historical stream-flows over the period 1929 through 1997, with in-board and out-board adjustments to the model. This produces a point forecast for a given year. If the actual production for the year is less or more than this, PGE will experience the cost of replacing the expected production (subject to the APCV mechanism). Generally speaking, over the last 10 years, actual hydro production has varied between a low of 428 MWa to a high of 708 MWa. This is a large range. Moreover, a swing of 20% or more from one year to the next is not uncommon. The financial effects are also large, because of the difference between the variable cost of hydro power, which is close to zero, and the market value of the power produced. For example, if the market electric price is $60/MWh, and hydro production is 100 MWa different than expected, the financial effect is more than $50 million (60 x 100 x 8,760 > 50,000,000).

Q. Is this similar to the rolling four-year average you use for forced outage rates?

A. No. It is different in a critical respect. Except for periods of highly volatile power markets, the rolling four-year average will roughly ensure an even risk allocation between PGE and customers over a five-year period. The shape of effect to each differs, but the totals should be close. This is NOT the case for how we forecast hydro production. Every year's forecast is a new look, unaffected by the year (or four) that just occurred. Moreover, the vast range of years covers an even larger range of wholesale electricity power prices (or no wholesale power prices, as there likely was little in the nature of a wholesale power market in many of the early decades included in the 69 years). It is doubtful (although we do not have records) that hydro production variations up to and as late as the 1950s had as much financial effect on utilities as they do today.

Thus, only at the end of 69 years could customers and PGE know whether this risk allocation resulted in revenue and cost neutrality and, of that, we have no certainty because we have no way of knowing whether the same distribution of water years will occur over a given sixty-nine years. And, of course, from 2007 forward, it is uncertain whether PGE will have access to production from the Mid-C hydro plants for 69 years and somewhat doubtful even for production from PGE's own hydro facilities, the longest license for which now expires in 2055.

Q. Is this an acceptable risk allocation?

A. No, not without a retrospective AAC of some sort. The Commission has recognized this, encouraging the development of an ongoing mechanism in Dockets UM 1077 and UE 165.

Q. Is there any other methodology PGE could use to create a point forecast of hydro production for purposes of creating a NVPC forecast?

A. Some have suggested that developing "expected value power costs" could produce a point NVPC forecast that reflects an even chance of positive or negative variances and an even size of such variances.

Q. What is expected value power cost?

A. Assuming all relevant variables are defined accurately, it represents a "fair roll of the dice" with respect to expected power cost recovery for the next year. If you roll the dice many times (i.e., many simulations of next year), the deviations between the simulations and Expected Value Power Costs for next year will tend to even out. The method simulates individual or aggregated draws of possible hydro conditions from the period 1929-1997, simulated to occur in the next year. It simulates next year only and not years into the future. In other words, whether one uses Average Hydro Power Cost or Expected Value Power Cost, there can be no reason to expect an inter-temporal matching of the costs and benefits.

Q. What are your concerns with developing Expected Value Power Cost?

A. One of the difficulties in developing Expected Value Power Cost is developing reasonable parameters for the relationship between hydro generation and market electric prices.

Moreover, Expected Value Power Cost does <u>not</u> represent a ratemaking response for treating the volatility of power costs around the baseline forecast. It does not simulate hydro conditions outside of the 1929-1997 period or other more extreme hydro conditions. It does not handle unanticipated events (e.g., the 2000-2001 California Power Crisis), and generally is very poor at reflecting non-fundamental factors such as market psychology. It also does not simulate the next 69 years into the future. This is because:

- Hydro system non-power constraints change over time into the future.
- Hydro resource shares change over time into the future.
- The distribution of potential hydro production outcomes may not be represented by the 69 years because of climate change or changes in environmental requirements.
- The relevant parameters (e.g., hydro/market price relationship, gas/electric price relationship) are not static. As a result, even if the parameters are defined correctly for one year, they will tend to change over time. Thus, a deviation in power cost that is consistent with a distribution of potential outcomes in year 1 could not be expected to be offset with a deviation in power cost in year 2 (or some other future year) that is consistent with a different distribution of potential outcomes.

III. Power Cost Framework – Annual Update Role

Q. What components of PGE's power costs do you propose to address through the Annual Update?

A. We propose to establish a forecast of NVPC – which we defined in Section I – for ratemaking purposes each year through the Annual Update tariff. To create this forecast, we propose to use MONET, updating only for:

- Hourly loads for the forecast year;
- New physical and financial contracts and changes to existing contracts for power, fuel, fuel transportation, or transmission/wheeling;
- Forced outage rates, using the traditional four-year weighted, rolling-average methodology;
- Planned maintenance outage days for the forecast year; and
- Forward curves for long or short open power, natural gas, oil, or U.S./Canadian foreign exchange rate positions.

As we stated in Section II, any model change or data input not on this list would not occur in the Annual Update process.

Q. Why have you included an annual NVPC update in your proposed framework?

A. The primary driver of changes in our NVPC is power and fuel contracts that we purchase in advance for a given future year or years.

With the advent of markets for both power and fuel, and the shift away from long-term (15-year plus) agreements, neither PGE nor customers can have confidence that forecasts created for one year will be even approximately representative for a subsequent year. For example, just from 2002 to 2003, the average price of our power contracts fell by almost

49%; our 2003 RVM passed this cost decrease through to customers with no lag. An even larger drop in natural gas prices occurred after prices based on the UE 88 test year took effect in early 1995. PGE adjusted prices for this decrease at the end of 1996 in UE 100. Without an AAC, reflecting these market-driven changes in PGE's prices may not occur on a timely basis. PGE would have to evaluate whether to file a GRC based on the overall change in our revenue requirements and our belief about how long the changed power and fuel prices would persist.

Q. Doesn't an annual NVPC update eliminate regulatory lag as a risk the utility bears?

A. First, it is important to note that regulatory lag is a two-way risk: a utility has the risk of not receiving timely (via either load growth or rate increases) revenue increases to cover rising costs and customers have the risk of not receiving timely rate decreases as load growth and/or falling costs increase a utility's earnings. The Annual Update eliminates this risk for both PGE and our customers. Moreover, it does so only for this limited set of costs. The framework we are proposing allocates to PGE the regulatory lag risk for several power cost-related components.

Second, one of the traditional purposes of regulatory lag – to create an incentive for prudent decision making – may be less needed for the costs we propose to include in the Annual Update. One of the benefits of regulatory lag in the past was to encourage prudence by aligning interests between the utility and customers; i.e., the lag assured that the utility experienced either the benefits or detriments of the particular decision. For power and fuel contracts entered into in a competitive market, this assurance of prudence is less necessary because the Commission can judge the prudence of decisions according to other available decisions. Even for structured contracts, which may not have directly comparable alternatives, the market will provide enough information to construct a cost-benefit analysis. And, as with the purchased gas costs for which gas utilities also do not experience regulatory lag, PGE earns nothing on its power and fuel contracts. These are not rate base investments.

Q. Does an annual update discourage PGE from entering into multiple-year contracts?

A. No. PGE entered into several multiple-year (five years and longer) power contracts as part of the 2002 IRP Action Plan and RFP process. As market liquidity improves for contracts in the three-to-five year range, we will evaluate entering into these as well.

Q. Why does your proposal update hourly loads?

A. NVPC relates directly to loads. It would make no sense to update the costs without updating the loads.

Q. What model will you use for load forecasting in the Annual Update?

A. We propose to use the same model as we use in a GRC but, as explained in PGE Exhibit 1200, we will need to re-estimate the parameters with current external data. Load forecasts for the annual update process will incorporate the most recent data available for key inputs such as employment, GDP, building permits, and interest rates.

Q. Why will you include updates to power, fuel and transmission contracts in the Annual Update mechanism?

A. Again, these are the drivers of year-to-year changes in forecast NVPC. Chart 1 below shows, in $/MWh the average variable cost of gas resources and of power contracts during the last five years and in millions the total dollars spent. The total results from both the average cost and the volume, which can vary from year-to-year both because of load and because of trade-offs between gas and electricity.

Chart 1

		2001/2	2003	2004	2005	2006
Gas Resources	$/MWh	38.5	38.3	40.9	37.6	50.6
	Total $'s	201M*	98M	91M	51M	103M
Contract Resources	$/MWh	74.8	38.4	42.8	46.1	52.6
	Total $'s	508M*	204M	221M	299M	381M

* indicates 15-month number, from October 1, 2001 through December 31, 2002

Q. Why will you update forced outage rates in the Annual Update?

A. As we explained in Section II, the methodology we use for forecasting a forced outage rate allocates the risk that this forecast is wrong very specifically: the in-year effect goes to PGE and customers experience the variance in the following four years. To make this risk allocation methodology work fairly requires an annual update.

Q. What is the reason you update planned maintenance outages in the Annual Update?

A. These specific plans to perform, or not perform, maintenance vary significantly every year. PGE will purchase power to cover these periods and customers should pay that expected cost, which will change from year to year as maintenance needs change. If we set this only in a GRC, both sides would run a significant risk that the test year estimate was not representative in later years.

In contrast to the current RVM process, we propose to update the planned maintenance outage forecast in October of each year. By October, plant managers have largely completed their budgets, committing dollars to the planned maintenance and firming the timing. This should decrease the chance for variance over the current RVM process, in which we set the planned maintenance outage forecast in March.

Q. Even if you lock your forecasts of planned maintenance outages in October, is there a chance that the outages do not occur as planned?

A. Yes. We experienced this with our Sullivan plant. As of March 2004, we expected to take Sullivan out of service from July through October, 2005. In February 2005, we learned that we could not obtain all the necessary permits in time and would need to reschedule the outage for the following year – 2006. There is also a chance the outages go longer than expected. For example, in 2000, the Boardman outage lasted almost 54 days, rather than the 15 planned.

Q. How will you address this in the Annual Update mechanism?

A. We are open to discussing with the parties means of adjusting for changes between actual and planned maintenance outages. One approach might be to spread the missing or extra days over the following 2-3 years. Other approaches may exist as well.

Q. You noted above that some planned maintenance outages include work to increase the output or decrease the heat rate of a generating plant. Since customers "pay" for the variable cost effects, shouldn't they receive the benefits of the increase in capacity or decrease in heat rate?

A. It is reasonable that customers should get some benefit but, unless we also include the investment and additional O&M costs, it is not fair that customers receive the entire benefit. We are willing to explore allocating the benefits according the proportions represented by capital carrying costs (return of and on), one-time O&M, and foregone power production. As with the potential mismatch between forecasted and actual planned maintenance outages, we have not included a solution in the Annual Update tariff but are open to discussing the issue with the parties.

Q. Why do you need forward gas and electric curves for the Annual Update mechanism?

A. MONET meets load and dispatches PGE's resources on an hourly basis. As we begin a given calendar year, there are always some hours for which we have not purchased power or natural gas as MONET would indicate or have, in fact, purchased more power or gas than MONET calculates that we need to meet load. We input forward curves in MONET to value both what we need to buy and what we need to sell.

Q. What forward curves do you propose to use for the Annual Update?

A. We propose to use the average of five daily forward curves that we generate internally in early November.

Q. Is this a change from the RVM?

A. Yes. In the RVM, we have used PGE's internally-generated curve from just one day.

Q. Why do you propose to average the curves over a five-day period?

A. We have two reasons. First, an average over five days will smooth daily fluctuations from the forward look. Although uncommon, we have seen some extreme one-day moves in the forward curve that would cause us to have significant reservations about using that single day in ratemaking. Second, the use of five days' curves should ease concerns that PGE is proposing an unrealistic curve for purposes of the Annual Update. These are the same curves that we use to adjust our positions on a daily basis. Using an inaccurate curve for five days could have a significant adverse financial effect.

Q. Are externally-generated curves available?

A. We are aware of several external sources for forward curves, including ICE, brokers, and Energy Market Report. The difficulty with any of these is that we do not have direct access to their sources. We cannot validate their projections. We base our curve on actual conversations with trusted sources and document those. We do validate our curve against the externally-generated curves.

Q. Is it feasible for parties to the Annual Update process to audit PGE's internally generated gas and power curves?

A. Yes. We could make available to parties our documentation and the externally-generated curves from the same period. Review of these materials would not take much time.

Q. What process and timing do you propose for the Annual Update process?

A. We would initiate the process each July 1, providing an estimate of NVPC for the following calendar year, along with projected rate changes. This filing would include final forced outage rate calculations and all structured (including capacity) or multi-year power or fuel contracts that PGE intended to include. For the latter, the filing would include the basis on which we determined that the price of the structured contracts was reasonable. The estimate would also reflect preliminary planned maintenance outages, market contracts, pricing changes under old contracts, such as long-term transmission/wheeling agreements, and forward curves as of a certain date before July 1. For this initial filing, we would use just one-day curves. We chose this timing to allow parties ample time to review the support behind our structured contracts and verify the forced outage rate calculations. Parties could also review market contracts and old contract pricing updates included in this estimate and preliminarily review the load forecast.

On or before October 1, we would provide a final load forecast and the final planned maintenance outages. As noted above, by early Fall, plant managers generally have firmed their plans for maintenance work in the following year. The only load change allowed after this date would be that necessary to reflect customer elections in September under Schedules

483 and 489. We envision that the parties would use the following six weeks to verify the load forecast and engage in any necessary review of the planned maintenance outages.

On or before November 15, we would provide a final MONET run for the following calendar year, updating market contracts through early November, any short-term transmission pricing, and using the averaged forward curves described above. This run would include any load changes resulting from Schedule 483 and 489 elections. During the following three weeks, parties could audit the forward curve calculations and review the final market contracts and transmission pricing included.

We anticipate a Commission order on rates for the Annual Update tariff on or around December 15.

Q. Does your proposed Annual Update change any of the risk allocations you discussed in Section II or create any new risk allocations?

A. We discussed above how this mechanism interacts with the risk of regulatory lag, with respect to power and fuel contracts. The cut-off of structured contracts as of July 1 heightens somewhat the risk of regulatory lag for PGE for any such contracts. For forced outages rates and planned maintenance outages, the Annual Update simply implements the risk allocation stemming from the methodology choice made in a GRC.

IV. Proposed Annual Variance Tariff

Q. What are the parameters of your proposed APCV mechanism?

A. Under the proposed APCV mechanism, PGE would:

- Track the difference between its actual NVPC for a given year and its forecast NVPC, resulting from the Annual Update;
- Neutralize the effects of load changes (increases or decreases) on that variance;
- Absorb 10% of the variance and design the remaining 90% into a per kWh rider per an amortization schedule set by the Commission; and
- Demonstrate each year that earnings in the prior year, with the effects of the Annual Update and Annual Variance tariffs, do not exceed a reasonable amount, sharing any earnings above a threshold ROE 50-50 between PGE and customers.

Q. Why have you included a retrospective AAC in your power cost framework?

A. We believe that, notwithstanding an annual update of forecast NVPC, a substantial probability remains that the actual incurred NVPC will differ significantly from the forecast most years and will do so in both a positive and negative manner, resulting in lower NVPC one year and higher NVPC another year. Without a retrospective mechanism in the framework, neither PGE nor customers will have the assurance they should have that prices reflect cost of service.

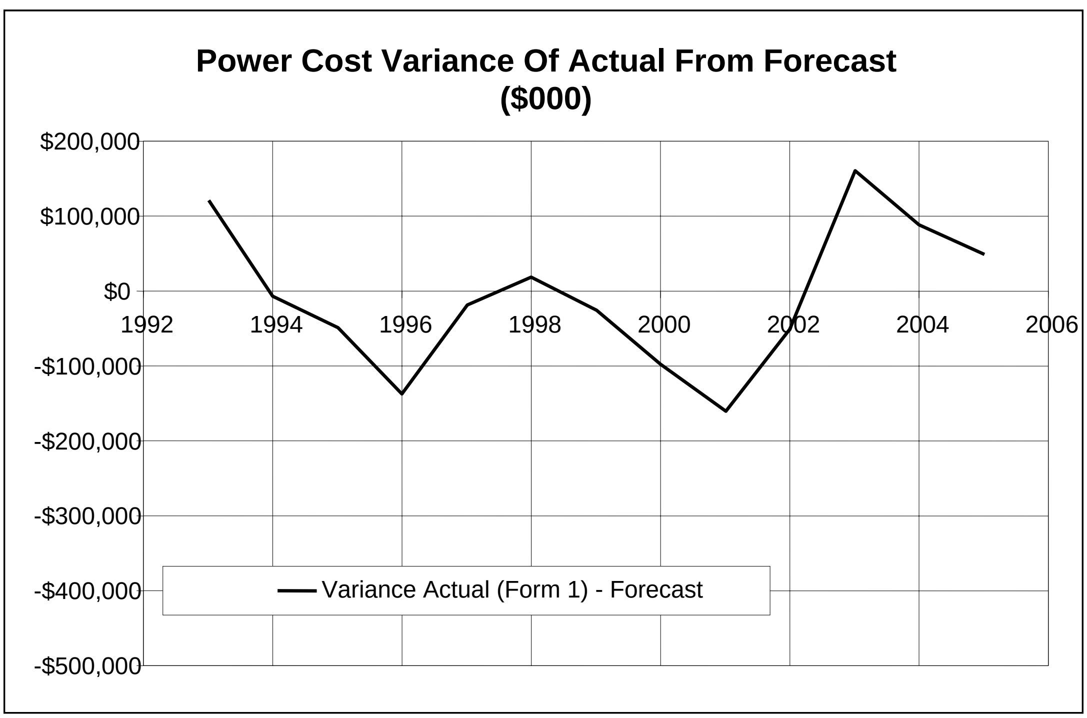
Q. Why does the Annual Variance tariff track variances between actual NVPC and forecast NVPC?

A. We have several reasons for proposing this construct. First, it is most consistent with the nature of our resource portfolio and how we operate the system. We work hard to minimize costs across the entire system and engage in much day-to-day activity to this end. Isolating the variance mechanism to a couple of cost components eliminates much of this activity from the mechanism and may distort the result. Second, and related, although we certainly know the uncertainty associated with hydro production, uncertainty – positive and negative – exists with respect to many other inputs to the MONET forecast even if hydro variations can swamp their effect. Third, during the last several years that we have wrestled with this issue with CUB, ICNU and OPUC Staff, we understand most have come to believe that a comprehensive mechanism is best. The disagreement lies in use of a dead-band and sharing, not in the scope of the mechanism.

Q. What has been the historical variance between forecast and actual NVPC?

A. Graph 1 below illustrates the variance between actual and forecasted net variable power costs from 1993 through 2005.

Graph 1



Graph 1 indicates that variances can be more than $150 million, both positive and negative.

Q. What do you cover in this section?

A. We first address, in Section A, how we propose to neutralize the outcome of the Annual Variance calculations to changes in load. Section B discusses why we included a sharing element in the proposal; Section C addresses why we did not, however, include a dead-band. In Section D we address the requirement of revenue neutrality the Commission suggested in its Order in UE 165. Section D discusses earnings tests, why we chose the form we did and how it would work. Last, in Section F, we address the process we would follow for the Annual Variance tariff.

A. Neutralizing Load Effects

Q. Why is it necessary to neutralize the effects of load changes on the variance tracked by the mechanism?

A. To fail to do so would create a mismatch between the NVPC component of rates and the actual costs incurred to serve customers.

Q. How will you neutralize these effects?

A. Because variable power costs are: 1) direct costs, 2) allocated to rate schedules on a kWh basis, and 3) included in energy charges that are billed on a kWh basis, it is relatively straightforward to determine the rate component associated with NVPC. In simple terms, it is the forecast NVPC divided by the forecast loads which we will call forecast unit NVPC. If actual load increases over forecast, NVPC will also increase, all else being equal. Likewise revenue associated with NVPC will increase by the forecast unit NVPC per kWh of load change. If loads decrease, the opposite will happen. Therefore, it is necessary to adjust for changes in loads by multiplying the load difference by the forecast unit NVPC.

Q. Are there other methodologies to achieve this neutralization?

A. There may be others, but they do not align actual NVPC incurred with revenues received.

Q. If customers respond to a prolonged period of tight power supply by reducing load, are they helped or hurt by this mechanism?

A. They are helped. In general, but especially during time of power shortage (e.g., a drought condition), we would expect the market value of power to exceed the forecast unit NVPC. Thus, a reduction in load would reduce what we call the "Power Cost Variance" (the difference between actual and forecast NVPC adjusted for load differences at the average unit NVPC) from what it would otherwise be.

Q. Please describe the Power Cost Variance as a formula.

A. The Power Cost Variance is equal to:

Actual NVPC - Forecast NVPC - (Actual Load - Forecast Load) * Forecast Unit NVPC

An algebraically equivalent way to express this is:

(Actual Unit NVPC - Forecast Unit NVPC) * Actual Load

(The proof is left to the reader.) This is the formulation included in our proposed tariff (PGE Exhibit 1302) and is the same as that used in our 1979-1987 PCA.

B. Sharing

Q. What purpose does a sharing feature serve?

A. To the extent the AAC is capturing variances between a forecast cost and an actual cost, the sharing percentages serve to align interests between the utility and customers, much as regulatory lag does. In other words, the utility experiences a direct financial effect of every decision made and action taken during the period over which the AAC is capturing the variance. This alignment of interests allows an assumption that the utility is acting prudently. Thus, while to some extent this feature works – as a dead-band does – to preclude the utility from recovery of some level of prudently incurred cost, it serves a regulatory purpose of aligning interests on decision-making and easing regulatory burdens associated with establishing prudence.

Q. What other states have used sharing as a feature of AACs for NVPC?

A. Colorado recently adopted a stipulated AAC that included sharing for Public Service Company of Colorado. Docket No. 02S-315EG. This AAC, in effect for 2004 through 2006, shares the first $15 million difference 50-50, the next $15 million is allocated 75% to customers and 25% to the utility and variances beyond that are 100% to customers. Order No. CO3-0670. The Commission explained in adopting the stipulation that: "This mechanism insures that the difference between ECA [energy cost adjustment] revenue paid by customers and prudently-incurred CPUC jurisdictional energy costs will never vary more that $11.25 million, either positive or negative." [p. 60.] The Order also notes that "[m]any parties filed testimony urging the Commission to adopt a 100% pass-through mechanism." [p. 59.]

Idaho uses a 90-10 sharing parameter in long-standing AACs in place for Avista and Idaho Power Company. Similarly, in 2005, Arizona approved an AAC for Arizona Public Service Company (APS) that includes 90-10 sharing. Docket No. E-01345A-03-0437. The Arizona Commission stated that it "agree[d] that the use of an adjustor when fuel costs are volatile prevents a utility's financial condition from deteriorating." [p. 16-17.] Because testimony indicated that APS required the AAC primarily for the cost of power purchased to serve load growth, however, rather than price volatility, the Commission limited the annual amount of NVPC that APS could use to calculate the AAC, thus requiring that APS file a rate case to reset the base if it deems necessary because the cap was reached. [p. 17.]

Sharing is also a parameter in Washington. We discuss this in Section C. below, on dead-bands.

Q. Has Oregon used sharing in AACs?

A. Yes, frequently. PGE's early PCA included sharing of the variances between the quarterly forecast NVPC and the actual NVPC 80% to customers and 20% to PGE. Since 1989, Oregon's PGAs also have included sharing. Historically, the PGA passed through 100% of any variances in the cost of purchased gas which, at that time, was typically from a sole interstate pipeline supplier. In 1989, it became possible for gas utilities to purchase from multiple suppliers. Gas costs were then approximately 56% of Northwest Natural Gas Company's total expenses. The Commission stated: "[I]t is obvious that changes in gas costs can have a significant effect on LDC earnings. The determinations in this order demonstrate that it is the intention of the Commission to continue to provide safeguards to LDCs and their customers regarding gas cost changes." Order No. 89-1046. The Commission adopted 80-20 sharing for the retrospective aspect of the PGA.

Q. How do the PGA's work?

A. Our understanding is that a PGA has two components, similar to those we propose for PGE: a forward-looking mechanism to reset base natural gas costs for a coming year and a retrospective mechanism which defers, for later inclusion in rates, 100% of the monthly difference between actual fixed costs and the base level and a portion of the monthly differences between actual commodity-related costs and the base level in rates. See Order

No. 99-272 at 2. As indicted above, this portion was 80-20 for all gas utilities starting in 1989. In the late 1990s, two of the Oregon gas utilities moved to 67-33 sharing, while one remains at 80-20. The sharing percentage triggers different applications of an earnings test. Order No. 99-272.

The base is set according to the cost of gas for a given gas utility for twelve months ending June 30 of each year. Volumes are not normalized to a prior rate case or for weather. This historical period can be adjusted for known and measurable changes in purchase contracts. See Order No. 89-1046. In other words, the base includes forward contracts. Only projected volumes not covered by forward contracts would be priced at the historical cost.

Based on this understanding, we perceive that the risk allocated between gas utilities and their customers is as follows:

1. Regulatory lag in adjusting the price of any “base” gas required for the following year and not purchased in advance. Gas utilities have this risk, but it is also largely within their control.

2. Variance risk between the volume of gas used in the prior year and, thus, used to set the base and the volume of gas actually needed. This risk is shared, either 67-33 or 80-20.

3. Variance risk between the price of gas needed to serve load greater than that in the base forecast and the price included in rates and, thus, recovered for the additional sales. This risk is also shared, either 67-33, or 80-20.

Q. Is the process of setting the forward-looking base for the PGA the same as you propose for the Annual Update?

A. No. There are two significant differences. First, we currently, and would in the future, use a normalized, forecasted load, not historical volumes. Second, both the Annual Update and Annual Variance mechanisms concern **net** variable power costs: we forecast sales of any power or fuel purchased in excess of the forecasted, normalized load and generating plant needs and would track the variance in sales as they actually occurred.

Q. Is there any other difference between natural gas and PGAs and NVPC and your proposed mechanisms that is worth noting?

A. Yes. PGE faces a much larger price variance that is not related to volume/load variance. Our NVPC is based on a resource stack at the bottom of which are resources with very low or zero variable costs. Changes in the delivery from these resources can profoundly affect our actual NVPC. It would be analogous to the gas utilities having access to natural gas supplies priced at nothing or very low prices – say, $0.50/MMBtu – but being unsure, day-to-day just how much of this gas they will receive in their system. In addition, we have single-source risk for both some of our plants and our purchases. In other words, we expect significant volumes from these sources raising the risks of default or production variations. Examples would be the Mid-C contracts, the Trans Alta contract, and our coal-fired generating plants.

Q. How did you choose the sharing percentage?

A. The sharing percentage is the same as used in Arizona and Idaho. It is also the same as being proposed by Avista for Washington, to match what is in place for them in Idaho.

C. Dead-bands

Q. Does your proposed Annual Variance tariff use a dead-band?

A. No.

Q. What has been Oregon's application of a dead-band to an AAC?

A. Oregon has applied a dead-band to an AAC only once: in the stipulated power cost adjustment mechanism adopted in UE 115. Because the tariff for this mechanism expired 15 months following its effective date, however, it is arguable that this tariff was more in the nature of a deferral than an AAC. Oregon does not apply any dead-band to the regulatory framework used for purchased gas adjustments (PGAs) for natural gas utilities nor did Oregon apply a dead-band to PGE 's 1980s PCA.

The Commission has also imposed a dead-band in one instance of a deferred accounting request.[1] Such requests are markedly different from AACs, however, because of their sporadic nature.

Q. What other states use a dead-band for AACs that apply to electric utility power costs?

A. Washington (through the Washington Utilities and Transportation Commission) has approved, in the instance of two stipulations offered to it, a dead-band for AACs that apply to NVPC. Within the last month, Wyoming also approved a stipulation filed with it in a PacifiCorp case that includes a power cost adjustment clause with a dead-band.

A dead-band parameter –$20 million plus or minus – appears in the AAC stipulated to by Puget Sound Energy (PSE) Company in 2002, along with sharing tiers of 50% for the next $20 million, 90%/10% for the next $80 million and anything over $120 million shared 95% to customers and 5% to PSE. Twelfth Supplemental Order Docket No. UE-011570. That stipulation also placed a cumulative $40 million, 4-year limit (7/1/02 through 6/30/06) on the amount of NVPC variances allocated either to customers or PSE, with sharing moving to 99% to customers and 1% to PSE for amounts over this. A dead-band – $9

[1] PGE stipulated to a dead-band in another deferred accounting request (Docket UM 1008/1009).

million plus or minus – also appears in the AAC stipulated to by Avista in 2002, with 90-10 sharing of all amounts outside of that. Fifth Supplemental Order, Docket No. UE-011195.

Q. Will Washington be reviewing the appropriateness of dead-bands in AACs for NVPC?

A. Yes. Both Avista (Docket No UE-060181) and PSE (Docket No. UE-060266) have filed cases requesting removal of the dead-bands from their power-cost related AACs. Avista proposes an AAC with 90-10 sharing. PSE proposes an AAC with 50-50 sharing of the first $25 million in positive or negative variance, with 90-10 sharing of the next $95 million in variance and 95-5 sharing of any remainder.

Q. Has Wyoming applied a dead-band parameter to an AAC for NVPC?

A. As noted above, Wyoming just approved a stipulation that included one for PacifiCorp. The NERA report indicates that Wyoming had previously approved a dead-band mechanism for Cheyenne Light, Fuel and Power Company (Cheyenne) but, based on our review of the matter, it is not clear that is the case. The August 2001 Order describes a stipulation regarding a long-standing NVPC AAC for Cheyenne. Docket No. 20003-ES-01-58. Because of costs incurred during the Western power market crisis, Cheyenne was proposing rate increases from 57.1% to 88.2%. In the Stipulation, the parties agreed to spread recovery of some of the already-incurred costs included in those increases over future years (through 2005) and Cheyenne agreed to fix capacity and energy prices for purposes of the AAC from February 24, 2001 through the end of 2002. After the end of 2002, the AAC would revert to passing through 100% of actual NVPC. This plan allowed Cheyenne to drop the proposed rate increases by about a half in 2001 with an additional round of increases in 2002.

Q. Does the NERA report also show Kansas as a state that has used a dead-band for utility power-cost related AACs?

A. Yes. Again, we reviewed the material and would not classify the approach as a dead-band. The state-wide policy, adopted in 1977, puts limits on certain costs, such as line losses.

Q. Why haven't you included a dead-band in your mechanism?

A. We have several reasons.

First, as noted above, Oregon has only applied a dead-band in a non-settlement matter for a deferred accounting request. A dead-band applied to PGE's stipulated 15-month PCA, but this was not an ongoing AAC. Oregon has never applied the dead-band concept to an indefinite AAC, of which the most comparable example is the PGA mechanisms.

Second, a dead-band interferes with the risk allocation of the forced outage rate methodology. This occurs because the dead-band, for positive or negative variances, will consume some of the amounts the methodology would otherwise allocate to PGE or to customers, depending on what other factors are causing NVPC to vary. Applying sharing does not cause this because the sharing is consistent across the five years the forced outage rate methodology requires to reach parity.

Third, a dead-band suggests that a utility's earnings opportunity must, first and foremost, be at risk to variances in costs over which the utility has little or no control and <u>must</u> incur to meet its obligation to serve. NVPC differ from fixed O&M both in the size of potential variance, which is much higher for NVPC, and the ability to delay or avoid expenditures, which is much greater for fixed O&M. Delaying significant amounts of fixed O&M can threaten the quality of customer service and, over some period, the health of the utility's system. Delaying the purchase of power customers demand could threaten the stability of the system, causing widespread outages.

Last, a dead-band is not necessary to prevent undue rate volatility. The Commission has control over the amortization of any variances accumulated through the mechanism. Small variances need not trigger a rate change and the Commission may spread large variances over several years.

Q. Are you aware of any regulatory policy reason for applying a dead-band?

A. No. Some argue that a retrospective AAC must include a dead-band to ensure that the utility bears some risk. However, most aspects of regulation, such as the concept of administratively-determined prudence, allocate risk to a utility. A dead-band that automatically works to preclude recovery of prudently-incurred costs a utility must incur, or to prevent customers from benefiting from the characteristics of resources such as hydro generation, is not a necessary step to ensure that a utility bears risk.

Q. Doesn't the Commission's Order in UE 165 suggest that an AAC for hydro variances include a dead-band?

A. The Commission stated that "unusual, but not necessarily extraordinary, events – should be used for hydro-related PCAs." Order No. 05-1261. It is not clear what the Commission would conclude with respect to a retrospective adjustment for all NVPC variances, as opposed to hydro-generation variances only. If this conclusion applied to a retrospective adjustment for comprehensive NVPC variances, it would suggest that there is some level of "usual" prudently incurred cost that a utility may not have an opportunity to recover. Moreover, this policy would preclude recovery simply because the cost is uncertain and, thereby, difficult to forecast. While utilities have traditionally borne responsibility for managing costs within their control, they have not borne responsibility for uncertainty. In some circumstances, a utility's NVPC may not be uncertain and such circumstances would support a regulatory framework that did not include a retrospective adjustment. That is not the case, however, for PGE.

Q. Has the Commission required a dead-band as described in UE 165 to Oregon PGA clauses?

A. No.

D. Revenue Neutrality

Q. What is your understanding of "revenue neutrality," a guideline the Commission recently suggested apply to a hydro-related AAC in UE 165?

A. We understand that the Commission's goal was "that operation of a hydro-related PCA should not bias the overall expected level of power cost recovery; i.e., the mechanism should be revenue neutral over time." Order No. 05-1261 at 10. We find this difficult to apply, however.

The reason regulatory practice has included AACs over the years is that some costs defy accurate forecasting. NVPC are such, both for individual components, such as hydro production, and overall. This is particularly the case in a resource portfolio that has resources with significantly different dispatch costs and in a region in which there is an active wholesale market in which utilities participate to achieve lower overall NVPC as the market-clearing heat rate changes, affecting planned dispatch decisions.

Thus, it is impossible to determine whether a given AAC will result in the same collection of costs from customers – revenue neutrality – whether it existed or not. This goal appears to suggest a long-term backward look, limiting recoveries from or refund to customers to equalize them over the period chosen. Such a practice, however, setting aside legal concerns, suggests that we know the costs covered by the AAC will distribute themselves over the period of years chosen in a manner that provides the utility and customers equal probabilities of the same amount of economic variance. We can think of no cost included within NVPC that meets such criteria, let alone that the overall resulting NVPC over a period of years would meet such criteria.

Until we can achieve a fuller understanding of the steps and pre-conditions necessary to apply this parameter, we will not attempt to do so. We cannot "show" that the retrospective APCV we propose, and the alternate, are "revenue neutral." We can assure, however, that customers pay no more than the actual cost of service related to NVPC as those rise and fall.

E. Earnings Tests

Q. How has Oregon applied earnings tests to AACs?

A. At some point in the 1990s, Oregon began to apply an earnings test to natural gas utilities' PGA mechanisms. Our understanding of how this earnings test works is as follows. In the Spring of each year, once audited results are available for the prior calendar year, the gas utilities make a filing of regulated earnings for that prior year. Using a formula, the parties derive an updated "allowed" ROE for the prior year. A portion of actual earnings a given number of basis points above the updated ROE are shared with customers. For example, it appears that this is 33% of earnings more than 300 basis points above the updated ROE for Northwest Natural. If a gas utility chooses 67-33, rather than 80-20, sharing for the retrospective portion of the PGC, the earnings test does not apply to deferred amounts. That the earnings test triggers, does not limit applying the PGA to create a new base natural gas cost for the following year, it simply generates a credit to customers that the utility amortizes in that following year. If an earnings test applies to the deferred amounts, and if adjusted earnings are above the threshold earnings levels and the deferrals would result in a surcharge to customers, the gas utility will return to customers the lesser of: (a) the amount of revenue in the readjusted test year representing 80% of the earnings above the threshold, or (b) the amount of revenue related to offsetting the purchased gas cost deferrals.

An earnings test did not apply to PGE's old PCA, nor did one apply to the SAVE mechanism.

Q. Has Oregon applied earnings tests to deferred accounting requests?

A. Yes. The statute that gives the Commission authority to use deferred accounting requires an earnings test in most instances. Nonetheless, in practice an earnings test is not always a factor. For example, the Commission did not perform an earnings test in passing through property tax reductions to customers (UM 374), the amount by which actual IT expenditures were less than its forecast (UE 115), or in allowing PGE to recover certain conservation expenses (UM 784).

During the early 1990s, when PGE's Trojan plant experienced prolonged outages and then we permanently closed it to achieve long-term lower costs for customers, the Commission authorized PGE to defer replacement power costs four times. Table 1 below shows the dockets, amount deferred, earnings test applied, and resulting recovery for each deferral.

Table 1
Trojan-Related Deferrals ($000)

Dockets	Period Covered	Customer Share	Earnings Test Year Ending	Power Cost Variance	Customer Share Before Earnings Test	Customer Share After Earnings Test	Effective Customer Share Percentage
UE 81, UE 82, UM 445	11/01/91 - 03/31/92	90%	04/01/92	26,112	23,501	23,501	90%
UM 529, UE 85	12/04/92 - 03/31/93	80%	04/01/93	56,714	45,371	45,371	80%
UM 594, UM 571, UE 93	07/01/93 - 03/31/94	50%	04/01/94	98,360	49,180	9,100	9%
UM 692, UE 93	01/01/95 - 03/31/95	40%	04/01/95	29,000	11,600	11,600	40%

Q. As a matter of regulatory policy, should earnings test considerations used for deferred accounting requests apply to AACs?

A. In general, no[2]. The two regulatory tools are different. As we noted above, the use of deferred accounting is infrequent and limited to temporary and extraordinary cost or revenue changes. Most AACs, in contrast, are an ongoing regulatory mechanism and features included in them directly affect the probability of cost recovery a utility can expect and that

[2] An exception may be applying an earnings test to the AACs adopted as a result of SB 408. Because various interpretations of SB 408 needed for the AACs could cause utilities severe financial harm, an earnings test may be the only means of achieving a reasonable result under the *Hope* test.

is important to determining whether the approved prices meet Constitutional and statutory requirements. For example, an AAC earnings test that routinely cut-off recovery of incurred costs at a point below a utility's authorized return on common equity (ROE) would affect the risk profile for the utility's entire cost structure. With such an earnings test, it could be impossible to conclude that the prices allowed the utility an opportunity to recover its costs and earn a return commensurate with firms facing comparable risks. It would lower investors' expected ROE, driving down the utility's market value and, ultimately, increasing its cost of raising capital. See PGE Exhibit 1100. Such an earnings test is a penalty, rather than a means of assuring reasonable prices.

An AAC should not, by its operation, cause prices to become unreasonable. The earnings test used for PGAs accomplishes that purpose. For an electric utility, however, because of the amounts involved in NVPC, sharing of earnings more than 100 basis points above an updated ROE may be more appropriate than the 300 basis points used for gas utilities.

Q. How would the earnings test apply?

A. PGE proposes to share evenly with customers the amount by which PGE's normalized actual ROE exceeds a threshold ROE. The threshold ROE is 100 basis points over a baseline ROE, calculated as follows:

- The baseline ROE for each year that is also a GRC test year will be the Commission authorized ROE as determined in that GRC.
- The baseline ROE for each year that is not a test year will be based on the difference between the risk free rate used to derive the Commission authorized ROE in the most recent GRC case and the actual risk free rate, based on actual

Treasury yield data and applying the same methods used to determine the risk free rate in the GRC.

The annual update to ROE will ensure that if interest rates change (up or down), the baseline ROE (and hence, threshold ROE) will move accordingly.

The normalized actual ROE will be determined based on PGE's actual financial results as reported in the Results of Operations report filed annually with the OPUC, adjusted for the following:

- Costs explicitly disallowed for recovery by the Commission in our last GRC, such as Category C advertising expenditures (these are not adjustments to forecasted expenditures).
- Removal of any non-utility costs inappropriately included in utility accounts.
- Removal of any prior period costs or revenues.
- Coordination of the interest deduction for tax purposes to reconcile to the cost of long-term debt financing of PGE's rate base.

Q. Does your proposed Annual Variance tariff use the earnings test the Commission suggested in its order in Docket UE 165?

A. No. The Commission's suggested earnings test mechanism would constrain any recovery by PGE to that which brought our earnings up to the bottom of a range calculated by subtracting 100 basis points from our authorized ROE and limit any refund by PGE to that which brought our earnings down to the top of a range calculated by adding 100 basis points to our authorized ROE. In other words, if PGE had experienced higher NVPC and managed to control other expenses or receive revenue to offset some of this loss, the earnings test would commensurately preclude recovery of the increased NVPC, ensuring that, at a minimum, PGE had to absorb all (or more – depending on net rate base) of the $15 million dead-band the Commission also suggested to be appropriate.

Even assuming an equal probability that NVPC will be lower or higher than the forecast, with an equal probability that the positive or negative variance will be the same, this unprecedented version of an earnings test would systematically and negatively interfere with the other risk allocations already made to the utility by the overall regulatory framework. Compounding this problem is what PGE has demonstrated in Docket UE 165: the variance between forecast and actual NVPC is not symmetric in probability and amount. Given the amount of hydro power in the NW, hydro conditions have the ability to move the market clearing heat rate across the WECC, with lower than average hydro raising the market clearing heat rate and higher than average hydro lowering it. Even if water conditions, over some period of years, produced a symmetric distribution of lower and higher than average production, the financial effects would not be symmetric because of how hydro affects the market.

Q. Has the Commission applied an earnings test such as the one suggested in UE 165 to Oregon PGA clauses or in any other instance?

A. No, not to our knowledge.

F. Process

Q. What process do you propose for the Annual Variance mechanism?

A. We propose to initiate the mechanism in June with a filing that contains:

- Calculation of the variance
- The earnings test
- Proposed rate adjustments

Assuming that the Commission could complete any necessary process with six months, PGE can make the price change on January 1 of the following year with ample advance notice to customers.

Q. Is it possible to make more timely rate changes for results of the Annual Variance mechanism?

A. Yes. PGE could estimate the result of the Annual Variance mechanism (although not the earnings test) for a given calendar year as of October of that year and include this estimate in the final stages of the Annual Update for the following year. As long as the Commission had authorized us to maintain a balancing account for this mechanism that we could credit or debit as need be for any reconciliation of the final to the estimate, PGE would be willing to do this.

Q. Would prudence be an issue in the Annual Variance proceeding?

A. Yes, actions or decisions that pre-date but affect the period of the variance and that were not the subject of regulatory scrutiny in the Annual Update process would be subject to a prudence review. An example of this would be maintenance decisions on PGE's generating facilities and forced outage rates. While a party could raise prudence issues with respect to decisions and actions during the period of the variance, the alignment produced by the sharing mechanism should limit such issues to a minimum.

V. MONET Changes

Q. What model changes have you made to MONET since your 2006 RVM (UE 172) filing?

A. We have made the following modeling changes:

- Inclusion of Boardman coal losses
- Change in definition of electric market from the PGE system to the Mid-C trading curve
- Inclusion of an electric exchange option
- Increase in stand-by generator ratings to full capacity
- Inclusion of net costs of Troutdale-Linneman wheeling
- Inclusion of wheeling cost for "excess" Montana Colstrip power

Q. Why have you changed the model to include consideration of the loss of coal during its transportation from Wyoming to Boardman?

A. We have documented (over the period 1999 through 2002) that we lose approximately 1% of the coal between the point where it is loaded in Wyoming to where it is fed into the Boardman boiler. The trip is approximately 1,121 miles. During transit, strong winds attack the coal from the cumulative effects of train speed, headwinds, and crosswinds. These winds blow coal out of the rail cars, which is called in-transit wind erosion. In the coal industry, in-transit wind erosion is a commonly accepted fact, much like the loss of electrical energy over transmission lines. Studies in the 1970s and early 1980s reported losses of up to 3%. The studies used several methods of measuring the amount of coal lost, including both measuring the change in the depth of the coal and the weight of the coal, before and after transit and wind tunnel tests. A study by K.H. Nimerick and O.P Laflin, "In-transit Wind Erosion Losses of Coal and Methods of Control", *Mining Engineering*, August (1979), 1236-1240, reported that coal loss can be as high as 1.675 tons (3,350 lbs.) per rail car when subjected to 58 mph winds for six hours.

We calculated our estimate of 1% by comparing the difference between coal purchased and coal burned and the actual physical change in our coal pile. In equation form:

Coal Loss = (Coal Purchased – Coal Burned) – (Change in Actual Coal Pile)

Our 1% coal loss figure is then total coal losses over 1999-2002 divided by total coal purchases over that same period.

Q. How does the inclusion of coal losses affect 2007 NVPC?

A. We presently estimate that this model change will increase NVPC by approximately $354,000 but this number will likely change as we update MONET.

Q. Why isn't PGE proposing a similar model change for coal transported to Colstrip?

A. Colstrip is located only six miles from the mine, so any coal loss due to in-transit wind erosion is minor. In fact, our study found that the coal losses were only 0.1%, which is insignificant.

Q. Why have you changed MONET's definition of the electric market from PGE system price to Mid-C prices?

A. Using Mid-C prices, rather than PGE system prices, removes the 1.9% adder for contractual losses over BPA's transmission system that we previously applied to purchases we forecasted we would make at Mid-C. We include losses in our load forecast, so this adder caused double-counting. Removing it is consistent with how we model losses from our thermal plants. This enhancement also removes a minor inconsistency in MONET's treatment of contract purchases vs. market purchases. Previously, when PGE purchased a contract at the current Mid-C price, the power incrementally displaced assumed forward market purchases in MONET at the PGE system price. In theory, there should be no change in power costs because both the contract and the market purchase were at the market price. This displacement did create a change in power costs in MONET, however, because of the loss adder on the forward market purchases. Suppose, for example, that PGE purchased a 100 MWa flat contract at the Mid-C for $50/MWh. We would input that contract into MONET, and MONET would reduce forward market purchases by 100 MWa, but at a PGE market curve price of approximately $51/MWh ($50 x 1.019 = 50.95). Forecasted power costs would fall because the adder did not apply to the contract.

Q. What effect does using Mid-C prices instead of PGE's system prices have on 2007 NVPC?

A. We currently estimate that using Mid-C prices decreases net variable power costs by approximately $7.0 million. This effect will diminish as we replace assumed forward market purchases with contracts through the year.

Q. How have you included the electric exchange option contract in MONET?

A. This contract is what we would call a structured contract, which is designed to achieve a particular result between the contracting parties. In this structured contract, the counterparty pays PGE an annual fee, and, in return, when the option is exercised by the counterparty, PGE must transmit (wheel) the counterparty's generation for them. Under normal conditions, we expect to use our existing BPA Point-To-Point transmission capacity with no incremental cost to PGE. However, we expect to incur incremental wheeling costs when simultaneously: (a) the counterparty exercises its option and (b) certain transmission paths are curtailed. This contract makes use of otherwise available capability on PGE's system. To include this contract in MONET, we modeled the incremental wheeling cost PGE expects to incur based on our expectation of how often the two conditions will occur simultaneously and included this estimate as well as the annual fee PGE receives from the counterparty. The forecasted net benefit to customers is approximately $1.1 million in 2007.

Q. Why did you change the stand-by generator ratings in MONET from partial-capacity to full capacity?

A. In prior MONET model runs, we significantly de-rated the capacities of the distributed standby generation (DSG) units at PGE customers' sites because of the annual run-time limits in their operating permits, which are typically a few hundred hours. Based on our observations of how PGE actually dispatches these DSG units, however, we believe this is too conservative. There might be only a few high-priced hours in a year when MONET dispatches a standby generator, and in reality the standby generator would then typically operate at its full capacity.

Going forward, we will monitor each DSG unit's run time to ensure that it stays within its annual limit. If a unit begins to exceed its annual limit, we will need to modify MONET to constrain its dispatch, probably by using a de-ration for certain months as needed. Under current conditions, we do not expect the annual run-time limits to limit DSG generation, but we do expect this enhancement to improve our power cost modeling.

Q. Does increasing the DSG units' capacities have any effect on NVPC in this proceeding?

A. No. With current oil prices and electric prices, we do not presently forecast to run any of these units in 2007. This is consistent with their peak resource nature.

Q. What change did you make to MONET to reflect the net wheeling costs related to the Troutdale-Linneman transmission facilities?

A. These costs relate to an old transmission contract between PGE and Pacific Power, under which we pay each other for wheeling rights on each other's transmission facilities. We overlooked this contract in UE 115 and first proposed to include it in MONET in the 2004 RVM proceeding. We have added this contract to MONET. Under the contract, PacifiCorp pays PGE a fixed $20,529 per month to use PGE's 230-kV Linneman-Bethel transmission line, and PGE pays PacifiCorp a fixed $8,646 per month to use PacifiCorp's Troutdale-Linneman 230-kV transmission line. The net effect is a fixed NVPC cost reduction of approximately $140,000 for 2007.

Q. Why have you modified MONET to include wheeling costs for "excess" power generated at the Colstrip plant in Montana?

A. This change corrects an omission on our part. There are times when our share of Colstrip's generation (296 MW at the busbar in the last several RVMs) exceeds our firm contract wheeling capacity on the Townsend-Garrison line in Montana (approximately 280 MW). We pay non-firm wheeling charges to deliver this power to the Garrison Substation, from which our BPA IR Contract wheels the power the rest of the way to our system. Because we include this excess power in MONET as part of our normal generation from Colstrip, the model should also include these "excess" wheeling costs. Our 2007 estimate is based on the 2002-2005 four-year average of actual excess wheeling payments to Northwestern Energy. This increases 2007 NVPC by approximately $205,000.

Q. Has more hydro output data become available since the Commission approved PGE's 2006 RVM filing?

A. Yes. We have historically based our hydro output forecasts on data that the Northwest Power Pool (NWPP) uses in its Headwater Benefits Studies (HBS). NWPP completed an

HBS in mid-2005, using data for the August 1928-July 1998 period, 70 Operating Years. The previous HBS used only 60 Operating Years, the August 1928-July 1988 period. The new HBS allowed us to construct a 69-calendar year data set.

Q. Has PGE added any new resources from the 2002 IRP Final Action Plan to MONET since the 2006 RVM filing?

A. Yes, we have added one such resource. The only new resource from the 2002 IRP Final Action Plan that is new since the 2006 RVM is Port Westward, commencing in March 2007

Q. How will Port Westward affect NVPC in 2007 when it begins commercial operation?

A. We expect that Port Westward's operation will lower NVPC because its favorable heat rate will displace higher cost contracts and assumed forward market purchases. We presently estimate these benefits, using the 2007 GRC MONET run, at approximately $11.7 million on an annualized basis.

After preparing this estimate, we became aware that the maximum operating capacity we used in MONET for Port Westward is too high and the heat rate is too low. We are working with the manufacturer to project Port Westward's operating parameters during the test year and will include heat rate and maximum capacity revisions in the updated MONET runs we do as this case proceeds. PGE Exhibit 300 discusses these parameter changes.

Q. What are your present expectations regarding 2007 planned maintenance outages (PMOs) for PGE's thermal plants?

A. Table 2 below shows both the 2006 and 2007 PMOs, the latter of which is based on the expectations of the respective PGE plant managers for Beaver, Boardman, and Coyote, and PP&L Montana, the plant operator for Colstrip.

Planned 2007 outages at Beaver include 16 days for the entire plant, and 21, 14, and 21 additional days for Units 6, 5, and 1, as we expect these units to need combustion turbine inspections and other work. Colstrip Unit 3 will be out for more than six weeks to complete an upgrade, which will increase PGE's output share by 4.8 MW. PP&L Montana does not plan a maintenance outage at Colstrip Unit 4 during 2007. The planned outage at Coyote relates to a hot gas path inspection and planned maintenance at Port Westward is for a combustion turbine inspection.

Table 2
Thermal Plant Scheduled Maintenance (Days/Year)

Plant	2006 RVM	2007 GRC
Beaver	28.5	See Text
Boardman	29	30
Colstrip 3	9	44
Colstrip 4	52	0
Coyote	16	16
Port Westward	NA	16

Q. What are your present expectations regarding 2007 PMOs for PGE's hydro plants?

A. Our planning includes the following hydro plant outages:

- Bull Run production decrease of more than two thirds in November and December – dismantlement begins
- Sullivan production decrease of approximately 15% from June 1 through November 9 – two units out for runner replacements
- River Mill production decrease of approximately 7% from April 15 through June 15, and during November – test spills for fish
- Round Butte production decrease of 10% in November – work on Selective Water Withdrawal Structure

Q. Have you changed the total capability and heat rate of Colstrip Units 3 and 4 for this filing?

A. Yes, because, consistent with our framework proposals, this type of change would appear in a GRC. We are updating for two types of changes at Colstrip for the 2007 GRC, which are updates to the existing capacity and heat rate of Units 3 and 4 and updates to reflect a turbine upgrade at each unit. Over the last 1-2 years, degradation in the capacity of Units 3 and 4 has been observed, reducing each unit's capacity from approximately 740 MW to 716 MW net. There is a minor update to the combined heat rate for Units 3 and 4, from 10,913 Btu/kWh to 10,842 Btu/kWh. Then, effective July 1, 2006 Colstrip 4 will have its high-pressure steam turbine upgraded, adding an estimated 24 MW of capacity with no additional fuel input. A year later, effective July 1, 2007, Unit 3 will be upgraded in the same manner. After the upgrade is complete, each unit's capacity will be increased by 24 MW, which is also coincidentally the approximate amount of observed capacity degradation over the last 1-2 years. Thus, after the upgrade is complete, each unit's capacity will be restored to about 740 MW net. The heat rate will also improve, to 10,490 Btu/kWh, because the upgrade capacity does not use additional fuel.

VI. Qualifications

Q. Mr. Niman, please describe your qualifications.

A. I received a Bachelor of Science degree in Mechanical Engineering from Carnegie-Mellon University and a Master of Science degree in Mechanical Engineering from the California Institute of Technology. I am a registered Professional Mechanical Engineer in the state of Oregon.

I have been employed at PGE since 1979 in a variety of positions including: Power Operations Engineer, Mechanical Engineer, Power Analyst, Senior Resource Planner, and Project Manager before entering into my current position as Manager, Financial Analysis in 1999. I am responsible for the economic evaluation and analysis of power supply including power cost forecasting, new resource development, least-cost planning, and avoided cost estimates. The Financial Analysis group supports the Power Operations, Business Decision Support, and Rates & Regulatory Affairs groups within PGE.

I. Introduction

Q. Please state your name and position.

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

Q. What is the purpose of your testimony?

A. In this testimony I:

- Summarize the projected 2007 Schedule 125 Resource Valuation Mechanism (RVM) update methodology, adjustment rates, and Energy Charges based on the power cost estimates provided in Exhibit 100 and;
- Describe the steps used to determine the projected 2007 RVM rates.

II. RVM Rate Summary

Q. Why are the RVM rates updated on January 1, 2007?

A. PGE is implementing the annual power cost update mechanism as approved in Order No. 01-777. This annual update, referred to as the RVM update (Resource Valuation Mechanism), provides that in mid-November of each year, PGE update and post the Energy Charges for each rate schedule and simultaneously post Schedule 125, RVM Part A and Part B rates for the upcoming year. With this filing PGE presents its current projections of those rates for 2007. These are only projections at this point and will change with future updates.

Q. Please describe the basis and overall methodology for updating power supply-related rates in this RVM filing.

A. The annual RVM update mechanism is designed to meet requirements originating in SB1149 that include unbundling costs into functional cost categories for recovery in rates. In addition, PGE is required to allow non-residential customers an opportunity to move to direct access service without adversely affecting other customers.

The annual RVM update is based on updated power supply costs and forward market prices for 2007. The methodology used to recover power supply costs through rates is built on two primary elements, the Energy Charge and the Schedule 125, Part A and Part B rates which, when summed, yield the cost of service rates. The following describes the Energy Charge and RVM rates and the basis of the rates:

- Rate schedule Energy Charges are set at the projected market value of power based on forward curves. While PGE has used the forward curve on February 23, 2006, for this filing, the actual Energy Charge rates for 2007 will be updated and finalized on November 15th based on the forward curve used for the November posting.

- RVM adjustment rates (Schedule 125) consist of two parts:
  - Part A – Long-term Resources. Part A rates (which may be a charge or credit) are determined as the difference between the projected production and fixed costs of PGE's long-term resources (resources with an initial term longer than five years) and the market value of the output of the Long-term resources. The projected market value utilizes the same forward curve used to set rate schedule Energy Charges described above.
  - Part B – Short-term Resources. Part B (which may be a charge or credit) is determined as the difference between the projected costs of power from Short-term resources (that is all resources not considered long-term resources) and the projected market value of the equivalent amount of power. The projected market value utilizes the same forward curve used to set rate schedule Energy Charges described above.

From the resulting Energy Charge and RVM Part A and Part B rates:

Power supply cost of service = Energy Rate + RVM Part A + RVM Part B, where RVM Parts A and B may be a charge or credit.

This approach allows PGE to accommodate different power supply options that customers may choose. For example, a large non-residential customer that elects to be served by an ESS will continue to receive the charge or credit of the Part A and Part B rates, but will not incur our Energy Charge. PGE also allows Schedule 83 customers to opt-out of the Part B rate entirely, but only with one year notice. PGE then effectively does not plan to serve that load and thus does not incur the associated power costs.

I provide a more detailed description of the steps and costs used to set the revised Energy Charge and Schedule 125, Part A and Part B rates below.

The applicable tariff sheets will be updated and filed on November 15th with final prices based on power costs resulting from this proceeding and then current market prices for 2007.

Q. Please summarize the projected Energy Charges and Schedule 125 RVM adjustment rates as updated for 2007.

A. The projected 2007 Energy Charges and Schedule 125 Part A and Part B rates applicable to rate schedules 7 through 93 are listed on Exhibit 201, Projected Energy and Schedule 125 Rates for 2007. As described above, the projected Energy Charge by rate schedule is derived from the power market forward curve for 2007. The projected RVM Part A and Part B rates are calculated based on the difference between Long and Short-term power costs and the market value of power. These projected rates will be updated and posted for the November 15th posting.

Q. How have the projected 2007 Energy Charge and Schedule 125 RVM adjustment rates changed from the equivalent final 2006 RVM update rates?

A. Table 1 below demonstrates, for a sample of our rate schedules, the development of the overall cost of service power supply rates which include the projected 2007 Energy Charge, Parts A and B rates, and the resulting net rates.

Table 1

2007 **Selected Schedules**	**Projected 2007 energy charge (cents/kWh)** **Energy Charge***	**Part A**	**Part B**	**Total**
Residential (Sch. 7)**				
Block 1	7.032	-1.390	0.084	5.726
Block 2	7.032	-1.390	0.084	5.726
Small Non-Residential (Sch. 32)	6.946	-1.267	0.017	5.696
Large Non-Residential Sch. 83-P, Primary				
Flat (< 1,000 kW)	6.621	-1.380	-0.017	5.224
On-Peak (> 1,000 kW)	7.011	-1.380	-0.017	5.614
Off-Peak (> 1,000 kW)	5.938	-1.380	-0.017	4.541
2006 **Selected Schedules**	**Current 2006 energy charge (cents/kWh)** **Energy Charge***	**Part A**	**Part B**	**Total**
Residential (Sch. 7)**				
Block 1	8.037	-1.984	-0.402	5.651
Block 2	7.756	-1.984	- 0.402	5.370
Small Non-Residential (Sch. 32)	7.754	-1.865	- 0.702	5.187
Large Non-Residential Sch. 83-P, Primary				
Flat (< 1,000 kW)	7.369	-2.105	-0.527	4.737
On-Peak (> 1,000 kW)	7.765	-2.105	-0.527	5.133
Off-Peak (> 1,000 kW)	6.714	-2.105	-0.527	4.082

"-" denotes the adjustment rate is a credit.
* Energy Charge does not include the system usage charge.
** Sch. 7 block rates do not include Sch. 102

Note that the above table does not include all charges applicable to the rate schedule.

The second portion of the table shows the current 2006 Energy Charges, Parts A and B rates, and resulting net rates for the same rate schedules. The changes in costs and forward curves between 2006 and projected 2007 can be noted.

The projected 2007 Energy Charges (column labeled Energy Charge), which are based on the forward curve, have decreased when compared to 2006. This indicates that the market price for power has decreased for 2007. In addition, the Part A credits are smaller reflecting the decrease in market prices and changes in costs. Part B rates for the most part are close to zero reflecting the large open position at this time. The Total column shows the sum of the Energy Charge and RVM Part A and B rates for the schedules. The results of this comparison show that the resulting net power costs have increased from the 2006 levels.

Q. Please describe the projected rate impacts for 2007 resulting from the RVM update.

A. Table 2 below summarizes the estimated rate impact for 2007 based on the power costs and market prices used in developing the updated RVM rates. The first column contains the estimated percentage changes in rates from Energy Charges and the Schedule 125 rates described above. The second column contains the estimated rate impacts with all supplemental schedules except the Low-Income Adjustment (LIA) and the Public Purpose Charge (PPC). Assumptions contained in the second column are as follows: BPA monetary benefits (Residential Exchange) of $15.59/MWh for 2007; termination of Schedule 107 DSM Refinancing; and minor changes to Schedule 105. PGE intends to provide updates to these rate impacts during the RVM process.

Table 2

	Estimated Rate Change (%) (w/Sch. 125, Part A and B, 102)*	**Estimated Rate Change (%) (w/all supplementals)********
Residential**	**2.9%**	**2.4%**
Small Non-Residential	**5.8%**	**5.0%**
Large Non-Residential, COS***	7**.0%**	**6.1%**
Overall	**4.9%**	**4.3%**

* includes base rates with Schedule 125.
** current rates assume BPA rate change October 1, 2006.
*** represents Cost of Service customers only**.**
**** includes all supplementals except LIA & PPC.

The Table 2 estimated rate change percentages as well as the prices that appear in Table 1 will change as RVM cost estimates are updated. In addition, the supplemental adjustment assumptions and associated rate impact estimates may change in upcoming updates.

III. Rates Determination

Q. Please describe how the updated Schedule 125 RVM Part A and Part B rates were developed.

A. The 2007 projected rates are determined by the following process, which is consistent with the methodology used to set 2006 rates:

1. Determine the market value of power for residential, small nonresidential, and large nonresidential customer classes.
2. Determine the costs of meeting each class's (residential, small nonresidential, large nonresidential) load requirements using Long-term and Short-Term resources. Because BPA Subscription Power deliveries terminate September 2006, the cost of Subscription Power is zero.
3. Allocate the market value of power for each class consistent with the percent of resources used to meet the class's load.
4. Calculate the differences between the allocated market value and the cost of each resource for each class.
5. Calculate the RVM Part A and B rates for each customer class.

Exhibit 202, RVM Adjustment Rate Development, provides the computations and steps used to compute the RVM adjustment rates. Pages 1 through 6 provide the detailed calculations of the market value of power for each rate schedule (Step 1). Page 7 presents the costs of meeting each class's power requirements using Long-term, Short-term and BPA Subscription Power (Step 2). Page 8 demonstrates how the market value of power for each class is allocated (Step 3). Page 9 summarizes both the production costs and the market value of power while page 10 details the calculation of the differences between the production costs and market value for each class (step 4). Page 11 summarizes the calculations of the rates for the RVM (step 5).

Q. Please describe the purpose and process for each of the steps for Part A and B rate development.

A. The 2007 update applies the same methodology as 2006 rates, but with revised power costs, load forecast data, and line loss estimates.

- Step 1: Determine the market value for each customer class by employing the energy consumption and load profiles of each schedule and the same forward price curve used to determine PGE's 2007 power costs. The forecast consumption of large residential customers who have "opted out" of Short-Term Resource Supply (the RVM Part B adjustment) is not part of the market value calculation.
- Step 2: Determine the power supply cost for each class consistent with the UE 115 Power Cost Stipulation resource stacking process. As in the market value of power calculation, the opt-out loads and associated wheeling costs are removed from the power cost calculations. The result is that the costs of the resources are separately identified for each customer class.
- Step 3: Allocate the market value of power for each customer class to Long-Term, and Short-Term resources consistent with the cost allocations from Step 2.
- Step 4: Calculate the difference between resource costs and the market value of power. This amount represents the total difference in dollars between costs of power and the market value determined from the forward price curve. This establishes the basis for Schedule 125's resource valuations.

- Step 5: Calculate the Schedule 125 rates from the dollar differences from Step 4. For rate calculations, the RVM Part A utilizes the consumption of PGE's total system less Schedule 483 loads. The revenues from Schedule 129 are subtracted from the dollar differences calculated in step 4 in order to appropriately calculate the RVM Part A rate. The RVM Part B rate is calculated with the opt-out loads removed. This ensures that the appropriate loads are used to determine rates and revenues. The resulting RVM rates reflect the difference between the market value of power and the cost of the resources.

Q. Do the calculated energy and RVM rates recover the target power costs.

A. Yes. Exhibit 203, Estimate of 2007 Energy Revenues, calculates the energy charge revenues of $1,029.4 million resulting from the projected load and calculated net energy rates for each rate schedule. Comparing these revenues to Exhibit 202, page 7, demonstrates that subject to rounding, PGE recovers its production costs.

IV. Qualifications

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

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

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

Q. Does this conclude your testimony?

A. Yes, it does.

List of Exhibits

PGE Exhibit	Description
201	Projected Energy and Schedule 125 Rates for 2007
202	RVM Adjustment Rate Development
203	Estimate of 2007 Energy Revenues

PORTLAND GENERAL ELECTRIC
Projected Energy Charge and Schedule 125 Rates for 2007

Grouping	Market-Based Energy mills/kWh	Schedule 125a mills/kWh	Schedule 125b mills/kWh
SCH 7 - Residential			
Block 1 (first 250 kWh)	70.32	(13.90)	0.84
Block 2 (over 250 kWh)	70.32	(13.90)	0.84
SCH 15 - Outdoor Area Lighting	66.50	(13.02)	0.36
SCH 32 - General Service <30 kW	69.46	(12.67)	0.17
SCH 38 - Opt Time-of-Day G.S. >30 kW			
On-peak	76.80	(13.80)	(0.17)
Off-peak	63.07	(13.80)	(0.17)
SCH 47 - Irrig. & Drain. Pump. - <30 kW			
First 50 kWh per kW	86.65	(12.67)	0.17
Over 50 kWh per kW	57.13	(12.67)	0.17
SCH 49 - Irrig. & Drain. Pump. - >30 kW			
First 50 kWh per kW	83.84	(13.80)	(0.17)
Over 50 kWh per kW	54.32	(13.80)	(0.17)
SCH 83-S General Service >30 kW			
Flat (less than 1,000 kW)	68.70	(13.80)	(0.17)
On-peak (greater than 1,000 kW)	72.71	(13.80)	(0.17)
Off-peak (greater than 1,000 kW)	61.66	(13.80)	(0.17)
SCH 83-P - Primary			
Flat (less than 1,000 kW)	66.21	(13.80)	(0.17)
On-peak (greater than 1,000 kW)	70.11	(13.80)	(0.17)
Off-peak (greater than 1,000 kW)	59.38	(13.80)	(0.17)
SCH 83-T - Subtransmission			
On-peak	69.19	(13.80)	(0.17)
Off-peak	58.50	(13.80)	(0.17)
SCH 91 - Street & Highway Lighting	66.67	(13.80)	(0.17)
SCH 92 - Traffic Signals	67.90	(13.80)	(0.17)
SCH 93 - Recreational Field Lighting	66.08	(13.80)	(0.17)

Note: System Usage Charges not included.

PORTLAND GENERAL ELECTRIC
RVM ADJUSTMENT RATE DEVELOPMENT
MARKET-BASED POWER SUPPLY COST CALCULATION
BY RATE SCHEDULE: COS LOADS
2007

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	12 Month Avg/Total
POWER PRICES (mills per kWh)[1]													
PGE Curve 15													
On-Peak	78.46	77.44	71.84	58.34	40.51	39.49	64.20	75.41	73.88	62.92	73.37	75.66	65.96
Off-Peak	70.06	68.02	59.36	50.19	31.84	28.79	50.19	62.92	61.39	54.01	61.14	68.53	55.54
Flat	74.76	73.40	66.61	54.72	36.69	34.97	57.72	70.17	68.05	59.18	67.93	72.36	61.38
Wheeling	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36
Market Prices													
On-Peak	80.82	79.80	74.20	60.70	42.87	41.85	66.56	77.77	76.24	65.28	75.73	78.02	68.32
Off-Peak	72.42	70.38	61.72	52.55	34.20	31.15	52.55	65.28	63.75	56.37	63.50	70.89	57.90
Flat	77.12	75.76	68.97	57.08	39.05	37.33	60.08	72.53	70.41	61.54	70.29	74.72	63.74
GROUPING[2]													
SCH 7 - Residential													
Total Energy (MWh)													
On-Peak	558,007	432,027	427,840	361,424	328,185	324,916	362,147	361,145	324,864	337,928	431,297	542,989	4,792,769
Off-Peak	310,531	278,590	234,329	205,457	197,349	181,055	191,457	213,559	178,456	207,488	245,025	295,850	2,739,148
Total	868,538	710,617	662,170	566,881	525,534	505,971	553,604	574,704	503,320	545,416	676,322	838,840	7,531,917
Loss Adjustment Factor: 6.28%													
Power Costs ($000)													
On-Peak	$47,930	$36,641	$33,739	$23,316	$14,953	$14,452	$25,618	$29,850	$26,323	$23,445	$34,713	$45,024	$356,006
Off-Peak	$23,901	$20,839	$15,371	$11,475	$7,173	$5,994	$10,693	$14,817	$12,091	$12,431	$16,536	$22,290	$173,610
Total	$71,831	$57,479	$49,110	$34,791	$22,126	$20,446	$36,311	$44,667	$38,414	$35,876	$51,250	$67,314	$529,616
SCH 15 - Outdoor Area Lighting													
Residential Portion													
Energy (MWh)													
On-Peak	279	200	154	84	51	29	34	61	124	199	243	292	1,750
Off-Peak	439	424	434	407	380	355	375	420	413	439	440	438	4,963
Total	717	624	588	490	431	384	409	481	537	638	683	729	6,713
Loss Adjustment Factor: 6.28%													
Power Costs ($000)													
On-Peak	$24	$17	$12	$5	$2	$1	$2	$5	$10	$14	$20	$24	$137
Off-Peak	$34	$32	$28	$23	$14	$12	$21	$29	$28	$26	$30	$33	$309
Total	$58	$49	$41	$28	$16	$13	$23	$34	$38	$40	$49	$57	$446
Commercial Portion													
Energy (MWh)													
On-Peak	692	498	384	209	128	73	86	152	310	500	611	733	4,377
Off-Peak	1,089	1,055	1,081	1,015	950	887	939	1,054	1,038	1,104	1,105	1,101	12,418
Total	1,780	1,553	1,465	1,224	1,078	961	1,025	1,207	1,348	1,604	1,717	1,834	16,796
Loss Adjustment Factor: 6.28%													
Power Costs ($000)													
On-Peak	$59	$42	$30	$14	$6	$3	$6	$13	$25	$35	$49	$61	$343
Off-Peak	$84	$79	$71	$57	$35	$29	$52	$73	$70	$66	$75	$83	$774
Total	$143	$121	$101	$70	$40	$33	$59	$86	$95	$101	$124	$144	$1,117

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RVM ADJUSTMENT RATE DEVELOPMENT
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BY RATE SCHEDULE: COS LOADS
2007

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	12 Month Avg/Total
Schedules 15R & 15C													
Total Energy (MWh)													
On-Peak	970	699	538	293	179	103	120	213	434	699	854	1,025	6,127
Off-Peak	1,527	1,479	1,515	1,421	1,331	1,242	1,314	1,475	1,451	1,543	1,545	1,539	17,382
Total	2,498	2,178	2,053	1,714	1,510	1,345	1,434	1,688	1,885	2,242	2,399	2,563	23,509
Loss Adjustment Factor:													
6.28%													
Power Costs ($000)													
On-Peak	$83	$59	$42	$19	$8	$5	$8	$18	$35	$49	$69	$85	$480
Off-Peak	$118	$111	$99	$79	$48	$41	$73	$102	$98	$92	$104	$116	$1,083
Total	$201	$170	$142	$98	$57	$46	$82	$120	$133	$141	$173	$201	$1,563
SCH 32 - Gen Serv - < 30 kW													
Total Energy (MWh)													
On-Peak	90,658	78,052	86,071	79,139	77,632	81,030	90,673	87,735	81,177	81,804	82,476	92,037	1,008,484
Off-Peak	46,773	43,210	41,690	38,036	40,214	36,737	40,194	43,424	38,028	41,299	40,408	45,646	495,658
Total	137,432	121,262	127,761	117,174	117,846	117,767	130,867	131,159	119,206	123,103	122,884	137,682	1,504,143
Loss Adjustment Factor:													
6.28%													
Power Costs ($000)													
On-Peak	$7,787	$6,620	$6,787	$5,105	$3,537	$3,604	$6,414	$7,252	$6,578	$5,676	$6,638	$7,632	$73,630
Off-Peak	$3,600	$3,232	$2,735	$2,124	$1,462	$1,216	$2,245	$3,013	$2,577	$2,474	$2,727	$3,439	$30,843
Total	$11,387	$9,852	$9,522	$7,230	$4,999	$4,820	$8,659	$10,264	$9,154	$8,150	$9,365	$11,071	$104,473
SCH 38 - Opt TOD G.S. > 30 kW													
Total Energy (MWh)													
On-Peak	6,175	6,033	6,132	5,727	4,982	5,416	5,367	6,123	6,914	6,028	6,057	6,139	71,092
Off-Peak	3,268	3,290	2,710	2,670	2,799	2,638	2,558	3,136	3,184	2,799	2,759	3,050	34,861
Total	9,443	9,323	8,842	8,397	7,781	8,054	7,924	9,259	10,098	8,827	8,815	9,189	105,952
Loss Adjustment Factor:													
6.28%													
Power Costs ($000)													
On-Peak	$530	$512	$484	$369	$227	$241	$380	$506	$560	$418	$487	$509	$5,224
Off-Peak	$252	$246	$178	$149	$102	$87	$143	$218	$216	$168	$186	$230	$2,173
Total	$782	$758	$661	$519	$329	$328	$522	$724	$776	$586	$674	$739	$7,397
SCH 47 - Irrig. & Drain. Pump. - < 30 kW													
Total Energy (MWh)													
On-Peak	179	230	161	214	918	1,332	2,600	2,808	1,236	410	179	162	10,429
Off-Peak	101	139	107	233	1,062	1,662	3,927	3,735	1,161	346	111	97	12,681
Total	280	369	268	446	1,981	2,994	6,527	6,543	2,397	755	290	259	23,110
Loss Adjustment Factor:													
6.28%													
Power Costs ($000)													
On-Peak	$15	$20	$13	$14	$42	$59	$184	$232	$100	$28	$14	$13	$735
Off-Peak	$8	$10	$7	$13	$39	$55	$219	$259	$79	$21	$8	$7	$724
Total	$23	$30	$20	$27	$80	$114	$403	$491	$179	$49	$22	$21	$1,459

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	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	12 Month Avg/Total
SCH 49 Irrig. & Drain. Pump. - > 30 kW													
Total Energy (MWh)													
On-Peak	327	510	516	733	2,557	4,369	7,258	8,203	3,969	1,293	482	326	30,543
Off-Peak	185	307	343	799	2,958	5,450	10,963	10,911	3,727	1,090	300	195	37,228
Total	512	816	860	1,532	5,516	9,819	18,220	19,113	7,696	2,383	782	521	67,770
Loss Adjustment Factor:													
6.28%													
Power Costs ($000)													
On-Peak	$28	$43	$41	$47	$117	$194	$513	$678	$322	$90	$39	$27	$2,139
Off-Peak	$14	$23	$23	$45	$108	$180	$612	$757	$253	$65	$20	$15	$2,114
Total	$42	$66	$63	$92	$224	$375	$1,126	$1,435	$574	$155	$59	$42	$4,253
SCH 83-S G.S. Second. > 30 kW													
Schedule 83-S LE 1,000 kW													
Energy (MWh)													
On-Peak	276,788	260,000	287,865	266,845	280,553	283,209	305,674	301,126	280,644	296,712	280,637	293,162	3,413,214
Off-Peak	159,959	147,720	160,184	147,595	154,273	155,473	167,025	162,892	154,624	160,513	155,776	165,998	1,892,033
Total	436,747	407,720	448,049	414,440	434,826	438,681	472,699	464,018	435,268	457,226	436,413	459,160	5,305,246
Schedule 83-S GT 1,000 kW													
Energy (MWh)													
On-Peak	32,065	29,571	34,766	32,583	34,003	34,793	42,092	43,271	40,129	39,980	35,320	34,783	433,356
Off-Peak	17,446	16,208	18,312	17,040	17,676	17,989	21,727	22,306	21,280	20,319	18,333	19,031	227,667
Total	49,511	45,779	53,078	49,623	51,679	52,782	63,819	65,577	61,409	60,299	53,653	53,814	661,023
Total Schedule 83-S													
On-Peak	308,853	289,571	322,631	299,428	314,556	318,002	347,766	344,397	320,772	336,692	315,957	327,945	3,846,570
Off-Peak	177,405	163,928	178,497	164,635	171,949	173,462	188,752	185,198	175,904	180,832	174,109	185,029	2,119,699
Total	486,258	453,499	501,127	464,063	486,505	491,464	536,518	529,595	496,676	517,525	490,066	512,974	5,966,269
Loss Adjustment Factor:													
6.28%													
Power Costs LE 1,000 kW($000)													
On-Peak	$23,775	$22,051	$22,701	$17,215	$12,783	$12,597	$21,623	$24,889	$22,740	$20,586	$22,587	$24,309	$247,855
Off-Peak	$12,312	$11,049	$10,507	$8,243	$5,607	$5,147	$9,328	$11,301	$10,476	$9,616	$10,513	$12,507	$116,608
Total	$36,087	$33,100	$33,208	$25,458	$18,390	$17,744	$30,952	$36,191	$33,216	$30,202	$33,100	$36,816	$364,464
Power Costs GT 1,000 kW($000)													
On-Peak	$2,754	$2,508	$2,742	$2,102	$1,549	$1,548	$2,978	$3,577	$3,252	$2,774	$2,843	$2,884	$31,509
Off-Peak	$1,343	$1,212	$1,201	$952	$642	$596	$1,213	$1,548	$1,442	$1,217	$1,237	$1,434	$14,037
Total	$4,097	$3,720	$3,943	$3,054	$2,192	$2,143	$4,191	$5,124	$4,693	$3,991	$4,080	$4,318	$45,546
Total Schedule 83-S													
On-Peak	$26,529	$24,559	$25,443	$19,317	$14,332	$14,144	$24,601	$28,466	$25,991	$23,360	$25,430	$27,193	$279,364
Off-Peak	$13,654	$12,262	$11,709	$9,195	$6,250	$5,743	$10,542	$12,849	$11,918	$10,834	$11,750	$13,940	$130,646
Total	$40,184	$36,821	$37,151	$28,512	$20,582	$19,887	$35,143	$41,315	$37,910	$34,193	$37,180	$41,134	$410,010

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2007

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	12 Month Avg/Total
SCH 83-P G.S. Primary													
Schedule 83-P LE 1,000 kW													
Energy (MWh)													
On-Peak	14,521	14,582	15,769	15,428	15,513	15,512	16,821	16,662	15,907	15,802	14,992	15,224	186,734
Off-Peak	8,996	8,881	9,397	9,067	9,003	9,115	9,835	9,530	9,533	9,067	8,829	9,243	110,496
Total	23,517	23,463	25,167	24,495	24,516	24,627	26,656	26,191	25,440	24,869	23,820	24,467	297,230
Sch 83-P GT 1,000 kW													
Energy (MWh)													
On-Peak	111,808	108,172	120,408	116,835	118,844	120,709	125,668	126,556	122,633	118,876	114,377	117,710	1,422,597
Off-Peak	77,055	74,243	80,494	78,204	79,726	81,802	83,613	84,018	82,170	78,463	77,694	79,444	956,926
Total	188,862	182,415	200,902	195,039	198,571	202,512	209,281	210,574	204,804	197,339	192,071	197,154	2,379,523
Total Energy (MWh)													
On-Peak	126,329	122,754	136,177	132,263	134,358	136,221	142,489	143,218	138,540	134,678	129,368	132,935	1,609,331
Off-Peak	86,050	83,124	89,891	87,271	88,729	90,918	93,448	93,548	91,703	87,530	86,523	88,687	1,067,422
Total	212,379	205,878	226,068	219,534	223,087	227,139	235,937	236,766	230,244	222,209	215,892	221,621	2,676,753
Loss Adjustment Factor:													
2.82%													
Power Costs LE 1,000 kW($000)													
On-Peak	$1,207	$1,196	$1,203	$963	$684	$667	$1,151	$1,332	$1,247	$1,061	$1,167	$1,221	$13,100
Off-Peak	$670	$643	$596	$490	$317	$292	$531	$640	$625	$526	$576	$674	$6,579
Total	$1,877	$1,839	$1,799	$1,453	$1,000	$959	$1,683	$1,972	$1,872	$1,586	$1,744	$1,895	$19,679
Power Costs GT 1,000 kW($000)													
On-Peak	$9,291	$8,876	$9,186	$7,292	$5,239	$5,194	$8,600	$10,120	$9,613	$7,979	$8,906	$9,443	$99,739
Off-Peak	$5,738	$5,373	$5,108	$4,226	$2,804	$2,620	$4,518	$5,639	$5,386	$4,548	$5,073	$5,791	$56,822
Total	$15,029	$14,248	$14,294	$11,517	$8,042	$7,814	$13,118	$15,759	$14,999	$12,527	$13,979	$15,233	$156,560
Total Schedule 83-P													
On-Peak	$10,498	$10,072	$10,389	$8,255	$5,922	$5,862	$9,751	$11,452	$10,860	$9,040	$10,073	$10,664	$112,839
Off-Peak	$6,408	$6,015	$5,705	$4,715	$3,120	$2,912	$5,049	$6,279	$6,011	$5,073	$5,649	$6,464	$63,401
Total	$16,905	$16,087	$16,094	$12,970	$9,042	$8,774	$14,801	$17,731	$16,871	$14,113	$15,723	$17,128	$176,239
SCH 83-T G.S. Subtransmission													
Calendar Energy (MWh)													
On-Peak	39,659	36,992	39,424	39,839	38,683	38,172	40,984	35,585	38,605	41,143	38,014	41,899	468,998
Off-Peak	28,844	26,434	28,223	28,685	28,462	27,575	29,512	26,079	27,585	29,449	27,169	27,172	335,189
Total	68,502	63,427	67,647	68,525	67,145	65,747	70,496	61,664	66,190	70,591	65,183	69,070	804,187
Loss Adjustment Factor:													
1.31%													
Power Costs ($000)													
On-Peak	$3,247	$2,991	$2,964	$2,450	$1,680	$1,618	$2,764	$2,804	$2,982	$2,721	$2,916	$3,312	$32,448
Off-Peak	$2,116	$1,885	$1,765	$1,527	$986	$870	$1,571	$1,725	$1,782	$1,682	$1,748	$1,951	$19,608
Total	$5,363	$4,875	$4,728	$3,977	$2,666	$2,489	$4,335	$4,528	$4,763	$4,403	$4,664	$5,263	$52,056

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	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	12 Month Avg/Total
SCH 91 - St & Highway Lighting													
Total Energy (MWh)													
On-Peak	4,063	2,909	2,233	1,202	726	411	486	876	1,787	2,924	3,598	4,343	25,557
Off-Peak	6,395	6,160	6,292	5,825	5,399	4,967	5,325	6,065	5,974	6,452	6,505	6,521	71,880
Total	10,459	9,069	8,525	7,027	6,125	5,378	5,810	6,941	7,761	9,376	10,103	10,864	97,437
Loss Adjustment Factor:													
6.28%													
Power Costs ($000)													
On-Peak	$349	$247	$176	$78	$33	$18	$34	$72	$145	$203	$290	$360	$2,005
Off-Peak	$492	$461	$413	$325	$196	$164	$297	$421	$405	$387	$439	$491	$4,492
Total	$841	$707	$589	$403	$229	$183	$332	$493	$550	$589	$729	$851	$6,496
SCH 92 - Traffic Signals													
Total Energy (MWh)													
On-Peak	287	283	282	286	282	282	277	278	290	275	289	281	3,394
Off-Peak	215	212	212	215	212	212	208	209	217	206	217	211	2,545
Total	502	496	494	501	494	494	486	487	507	482	506	492	5,939
Loss Adjustment Factor:													
6.28%													
Power Costs ($000)													
On-Peak	$25	$24	$22	$18	$13	$13	$20	$23	$23	$19	$23	$23	$247
Off-Peak	$17	$16	$14	$12	$8	$7	$12	$14	$15	$12	$15	$16	$157
Total	$41	$40	$36	$30	$21	$20	$31	$37	$38	$31	$38	$39	$403
SCH 93 - Rec Field Lighting													
Total Energy (MWh)													
On-Peak	15	15	21	24	32	49	33	30	58	56	25	16	374
Off-Peak	8	9	10	12	17	25	16	16	28	28	12	9	191
Total	24	23	31	36	49	73	50	47	86	85	37	25	565
Loss Adjustment Factor:													
6.28%													
Power Costs ($000)													
On-Peak	$1	$1	$2	$2	$1	$2	$2	$3	$5	$4	$2	$1	$26
Off-Peak	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$1	$1	$11
Total	$2	$2	$2	$2	$2	$3	$3	$4	$7	$6	$3	$2	$37

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	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	12 Month Avg/Total
TOTAL													
Energy (MWh)													
On-Peak	1,135,521	970,075	1,022,025	920,573	903,090	910,304	1,000,199	990,611	918,646	943,931	1,008,595	1,150,097	11,873,668
Off-Peak	661,303	606,881	583,820	535,259	540,482	525,942	567,674	587,353	527,420	559,063	584,683	654,004	6,933,883
Total	1,796,825	1,576,956	1,605,844	1,455,832	1,443,571	1,436,246	1,567,872	1,577,965	1,446,067	1,502,994	1,593,279	1,804,101	18,807,551
Power Costs ($000)													
On-Peak	$97,024	$81,788	$80,102	$58,990	$40,865	$40,212	$70,290	$81,355	$73,924	$65,052	$80,696	$94,844	$865,142
Off-Peak	$50,580	$45,100	$38,018	$29,661	$19,492	$17,271	$31,458	$40,454	$35,445	$33,240	$39,183	$48,961	$428,862
Total	$147,603	$126,888	$118,119	$88,651	$60,357	$57,483	$101,748	$121,809	$109,369	$98,292	$119,879	$143,805	$1,294,004
Average Power Costs													
On-Peak	85.44	84.31	78.38	64.08	45.25	44.17	70.28	82.13	80.47	68.92	80.01	82.47	72.86
Off-Peak	76.48	74.31	65.12	55.41	36.06	32.84	55.42	68.88	67.20	59.46	67.02	74.86	61.85
Total	82.15	80.46	73.56	60.89	41.81	40.02	64.90	77.19	75.63	65.40	75.24	79.71	68.80

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Avg/Total
Energy (MWh)													
Residential													
On-Peak	558,285	432,227	427,994	361,508	328,236	324,946	362,181	361,206	324,987	338,127	431,540	543,281	4,794,519
Off-Peak	310,970	279,014	234,763	205,863	197,730	181,410	191,832	213,979	178,870	207,927	245,464	296,288	2,744,111
													7,538,630
Small Non-residential													
On-Peak	91,529	78,781	86,615	79,561	78,679	82,435	93,359	90,695	82,724	82,714	83,266	92,932	1,023,291
Off-Peak	47,963	44,403	42,879	39,283	42,226	39,286	45,061	48,213	40,227	42,748	41,624	46,844	520,757
													1,544,048
Large non-residential													
On-Peak	485,707	459,068	507,415	479,504	496,175	502,923	544,659	538,710	510,935	523,090	493,789	513,884	6,055,858
Off-Peak	302,371	283,463	306,178	290,112	300,526	305,246	330,781	325,161	308,323	308,387	297,595	310,872	3,669,015
													9,724,874
												Totals	18,807,551
Market Value of Power ($000)													
Residential	$71,889	$57,528	$49,151	$34,819	$22,142	$20,459	$36,335	$44,701	$38,452	$35,916	$51,299	$67,372	$530,062
Small Non-residential	$11,554	$10,003	$9,643	$7,327	$5,120	$4,967	$9,121	$10,841	$9,428	$8,300	$9,511	$11,235	$107,049
Large non-residential	$64,161	$59,357	$59,325	$46,505	$33,095	$32,057	$56,293	$66,267	$61,489	$54,076	$59,069	$65,198	$656,892
Total	$147,603	$126,888	$118,119	$88,651	$60,357	$57,483	$101,748	$121,809	$109,369	$98,292	$119,879	$143,805	$1,294,004

[1] Forward curve prices of 2/23/06.
[2] On and off peak energy usages (Sunday-only off-peak basis) derived from load research data of average customers and grouping usage from 2007 Billing Determinants in workpapers, or specifics in Forecast SDEC05E07.

PORTLAND GENERAL ELECTRIC
RVM Adjustment Rate Development
Projected 2007 Power Costs[1]
Resource Stacking: Average Hydro Conditions
2/23/06 Forward Curve
($000)

Customer Class	2006 Total	Revised Total
Residential		
Long Term Resources		
VPC[2]	$101,992	$102,591
Fixed	$78,950	$78,950
Wheeling	$16,462	$16,558
Subtotal	$197,403	$198,099
Term Purchases[4]	$74,665	$75,104
Market Purchases/Sales	$157,473	$158,398
Subtotal	$232,139	$233,502
BPA Subscription[5]	$0	$0
Total	$429,542	$431,601
Sm. Non-Residential		
Long Term Resources		
VPC[2]	$19,840	$19,957
Fixed	$15,358	$15,358
Wheeling	$3,202	$3,221
Subtotal	$38,400	$38,535
Term Purchases[4]	$16,122	$16,216
Market Purchases/Sales	$32,805	$32,998
Subtotal	$48,927	$49,214
BPA Subscription[5]	$0	$0
Total	$87,327	$87,749
Lg. Non-Residential		
Long Term Resources		
VPC[2]	$153,378	$154,278
Fixed	$118,726	$118,726
Wheeling	$24,755	$24,901
Subtotal	$296,859	$297,905
Term Purchases[4]	$71,060	$71,477
Market Purchases/Sales	$139,868	$140,689
Subtotal	$210,928	$212,166
BPA Subscription[5]	$0	$0
Total	$507,787	$510,072
All Classes		
Long Term Resources		
VPC	$275,210	$276,826
Fixed[3]	$213,034	$213,034
Wheeling	$44,419	$44,680
Subtotal	$532,663	$534,540
Term Purchases	$161,847	$162,797
Market Purchases/Sales	$330,146	$332,086
Subtotal	$491,993	$494,883
BPA Subscription	$0	$0
Grand Total	$1,024,656	$1,029,423
Non-Fixed Costs - Total	$811,622	$816,389
Target Revenue Requirement of Non-Fixed Costs		$816,389
Revenue Sensitive Cost Factor[6]		0.59%

[1] Costs for VPC, Wheeling, Term Purchases, Market Purchases/Sales from Power Cost Model, Stacked, Resources to Meet Loads of Customer Classes.

[2] Comprised of PGE Hydro, Mid-C and PHP Hydro, Coal, Gas & Old Contracts

[3] 2007 Fixed Costs derived from spread of Non-VPC Production Revenue Requirement (annual) on Old Resource Allocation amounts. Amount adjusted for Order No. 02-772

[4] Term Purchases are new contracts and include wheeling expense.

[5] Excludes any BPA credits in lieu of power.

[6] From UE-115 Revenue Requirements model.

Note: Transmission and Distribution costs not included.

PORTLAND GENERAL ELECTRIC
RVM Adjustment Rate Development
Projected Market Value of Power
Resource Stacking: Average Hydro Conditions
2/23/06 Forward Curve

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Wgt Avg	Resource Pct of Class	Market Value ($000)
HOURS	744	672	743	720	744	720	744	744	720	744	721	744	8,760		
RESIDENTIAL															
Long Term Resources															
PGE Hydro	102	107	103	107	94	80	62	56	65	65	83	94			
Mid-C & PHP Hydro	147	147	120	140	140	150	139	118	91	103	123	136			
Coal	218	218	218	177	108	181	220	220	220	220	220	220			
Gas	81	77	(0)	(0)	(0)	(0)	4	79	78	2	77	82			
Old Contracts	73	76	79	87	87	87	79	74	61	69	68	67			
Subtotal	621	625	520	511	429	498	504	547	515	459	571	598	533	57.14%	$302,866
Net ST Purchases/Sales	644	521	446	343	337	264	302	291	243	336	446	624	400	42.86%	$227,196
BPA Subscription	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	$0
Total	1,266	1,147	966	854	766	762	807	838	758	795	1,017	1,223	932		$530,062
SMALL NON-RESIDENTIAL															
Long Term Resources															
PGE Hydro	20	21	20	21	18	16	12	11	13	13	16	18			
Mid-C & PHP Hydro	29	29	23	27	27	29	27	23	18	20	24	26			
Coal	42	42	42	34	21	35	43	43	43	43	43	43			
Gas	16	15	(0)	(0)	(0)	(0)	1	15	15	0	15	16			
Old Contracts	14	15	15	17	17	17	15	14	12	14	13	13			
Subtotal	121	122	101	99	83	97	98	106	100	89	111	116	104	54.27%	$58,092
Net ST Purchases/Sales	82	77	88	79	93	86	103	96	85	93	77	87	87	45.73%	$48,958
BPA Subscription	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	$0
Total	203	199	189	179	176	183	202	202	185	183	188	204	191		$107,049
LARGE NON-RESIDENTIAL															
Long Term Resources															
PGE Hydro	153	160	155	160	141	121	94	85	98	98	124	141			
Mid-C & PHP Hydro	221	221	180	210	211	226	209	177	137	155	185	205			
Coal	328	328	328	266	163	273	331	331	331	331	331	331			
Gas	122	116	(0)	(0)	(0)	(0)	6	119	117	2	116	124			
Old Contracts	110	115	119	131	130	130	119	111	92	104	103	100			
Subtotal	935	940	782	768	645	749	758	822	775	691	859	900	801	67.46%	$443,119
Net ST Purchases/Sales	199	241	389	375	500	452	501	420	442	505	315	286	386	32.54%	$213,773
BPA Subscription	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	$0
Total	1,133	1,182	1,171	1,143	1,145	1,201	1,259	1,243	1,217	1,196	1,174	1,186	1,188		$656,892
ALL CLASSES															
Long Term Resources															
PGE Hydro	275	288	279	288	253	217	168	152	175	176	223	252			
Mid-C & PHP Hydro	397	397	323	377	378	405	376	318	246	278	332	367			
Coal	589	589	589	478	293	489	594	594	594	594	594	594			
Gas	218	208	(1)	(1)	(1)	(1)	10	213	210	4	209	222			
Old Contracts	197	206	213	236	233	233	213	199	166	187	185	180			
Subtotal	1,677	1,687	1,404	1,378	1,157	1,344	1,361	1,476	1,391	1,239	1,542	1,615	1,437	62.20%	$804,077
Net ST Purchases/Sales	925	840	923	797	930	802	907	807	769	934	837	998	873	37.80%	$489,927
BPA Subscription	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	$0
Total	2,602	2,527	2,326	2,175	2,087	2,146	2,267	2,283	2,160	2,174	2,379	2,612	2,311		$1,294,004

PORTLAND GENERAL ELECTRIC
RVM Adjustment Rate Development
Projected Production Costs and Market Value of Power
Resource Stacking: Average Hydro
2/23/06 Forward Curve
($000)

Customer Class	Production Costs	Market Value of Power
Residential		
Long Term Resources	$198,099	$302,866
Term & Mkt Purchases & Sales	$233,502	$227,196
BPA Subscription	$0	$0
Total	$431,601	$530,062
Sm. Non-Residential		
Long Term Resources	$38,535	$58,092
Term & Mkt Purchases & Sales	$49,214	$48,958
BPA Subscription	$0	$0
Total	$87,749	$107,049
Lg. Non-Residential		
Long Term Resources	$297,905	$443,119
Term & Mkt Purchases & Sales	$212,166	$213,773
BPA Subscription	$0	$0
Total	$510,072	$656,892
All Classes		
Long Term Resources	$534,540	$804,077
Term & Mkt Purchases & Sales	$494,883	$489,927
BPA Subscription	$0	$0
Total	$1,029,423	$1,294,004

PORTLAND GENERAL ELECTRIC
RVM Adjustment Rate Development
Production Costs and Market Value of Power
Resource Stacking: Average Hydro
2/23/06 Forward Curve
($000)

		Revenues				
Customer Class	**Costs**	**Market Value**	**Sch 125a**	**Sch 125b**	**BPA Credit For Power**	**Total**
Residential						
Long Term Resources	$198,099	$302,866	($104,766)			$198,099
Term & Mkt Purchases & Sales	$233,502	$227,196		$6,306		$233,502
BPA Subscription	$0	$0			$0	$0
Total	$431,601	$530,062	($104,766)	$6,306	$0	$431,601
Sm. Non-Residential						
Long Term Resources	$38,535	$58,092	($19,556)			$38,535
Term & Mkt Purchases & Sales	$49,214	$48,958		$257		$49,214
BPA Subscription	$0	$0			$0	$0
Total	$87,749	$107,049	($19,556)	$257	$0	$87,749
Lg. Non-Residential						
Long Term Resources	$297,905	$443,119	($145,214)			$297,905
Term & Mkt Purchases & Sales	$212,166	$213,773		($1,606)		$212,166
BPA Subscription	$0	$0			$0	$0
Total	$510,072	$656,892	($145,214)	($1,606)	$0	$510,072
All Classes						
Long Term Resources	$534,540	$804,077	($269,537)			$534,540
Term & Mkt Purchases & Sales	$494,883	$489,927		$4,956		$494,883
BPA Subscription	$0	$0			$0	$0
Total	$1,029,423	$1,294,004	($269,537)	$4,956	$0	$1,029,423

PORTLAND GENERAL ELECTRIC
RVM ADJUSTMENT RATE DEVELOPMENT
SCHEDULE 125: PROJECTED RVM ADJUSTMENT RATES
2007

		Schedule 125a			Schedule 125b		Total	
Class/Schedule	Calendar Energy (MWh)	($000)	Rate (mills per kWh)	Calendar Energy (MWh)	($000)	Rate (mills per kWh)	($000)	Rate (mills per kWh)
RESIDENTIAL								
SCH 7 - Residential	7,531,917	($104,694)	(13.90)	7,531,917	$6,327	0.84	($98,367)	(13.06)
Portion of SCH 15 - Outdoor Area Lighting	6,713	($93)	(13.90)	6,713	$6	0.84	($88)	(13.06)
Subtotal	7,538,630	**($104,766)**	(13.90)	7,538,630	**$6,306**	0.84	**($98,455)**	(13.06)
SMALL NON-RESIDENTIAL								
Portion of SCH 15 - Outdoor Area Lighting	16,796	($213)	(12.67)	16,796	$3	0.17	($210)	(12.50)
SCH 32 - General Service <30 kW	1,504,143	($19,057)	(12.67)	1,504,143	$256	0.17	($18,802)	(12.50)
SCH 47 - Irrig. & Drain. Pump. - < 30 kW	23,110	($293)	(12.67)	23,110	$4	0.17	($289)	(12.50)
Subtotal	1,544,048	**($19,556)**	(12.67)	1,544,048	**$257**	0.17	**($19,301)**	(12.50)
LARGE NON-RESIDENTIAL								
SCH 38 - Opt Time-of-Day G.S. > 30 kW	105,952	($1,462)	(13.80)	105,952	($18)	(0.17)	($1,480)	(13.97)
SCH 49 - Irrig. & Drain. Pump. - > 30 kW	67,770	($935)	(13.80)	67,770	($12)	(0.17)	($947)	(13.97)
SCH 83-S General Service >30 kW	6,079,023	($83,891)	(13.80)	5,966,269	($1,014)	(0.17)	($84,905)	(13.97)
SCH 83-P - Primary	2,796,849	($38,597)	(13.80)	2,676,753	($455)	(0.17)	($39,052)	(13.97)
SCH 83-T - Subtransmission	1,365,349	($18,842)	(13.80)	804,187	($137)	(0.17)	($18,979)	(13.97)
SCH 91 - Street & Highway Lighting	97,437	($1,345)	(13.80)	97,437	($17)	(0.17)	($1,361)	(13.97)
SCH 92 - Traffic Signals	5,939	($82)	(13.80)	5,939	($1)	(0.17)	($83)	(13.97)
SCH 93 - Recreational Field Lighting	565	($8)	(13.80)	565	($0)	(0.17)	($8)	(13.97)
Schedule 129		($24)						
Mark-to Market of Part B Financials					$0			
Subtotal	10,518,884	**($145,191)**	(13.80)	9,724,874	**($1,606)**	(0.17)	**($146,814)**	(13.97)
TOTAL	**19,601,562**	**($269,513)**		**18,807,551**	**$4,956**		**($264,569)**	
TOTAL with Sch 76R & 483	**19,686,004**			**878,453**	(optout)			

Schedule 129 revenues are subtracted from 125a

PORTLAND GENERAL ELECTRIC
ESTIMATE OF 2007 ENERGY REVENUES

Grouping	2006 Cal Energy (MWH)	Energy Rate	Schedule 125a	Schedule 125b	Total Energy Rate	Revenues ($000)
SCH 7 - Residential						
Block 1 (first 250)	2,029,053	70.32	(13.90)	0.84	57.26	116,184
Block 2 (over 250)	5,502,864	70.32	(13.90)	0.84	57.26	315,094
SCH 15 - Outdoor Area Lighting						
Residential portion	6,713	66.50	(13.02)	0.36	53.84	361
Commercial portion	16,796	66.50	(13.02)	0.36	53.84	904
SCH 32 - General Service <30 kW	1,504,143	69.46	(12.67)	0.17	56.96	85,676
SCH 38 - Opt Time-of-Day G.S. >30 kW						
On-peak	52,019	76.80	(13.80)	(0.17)	62.83	3,268
Off-peak	53,934	63.07	(13.80)	(0.17)	49.10	2,648
SCH 47 - Irrig. & Drain. Pump. - <30 kW						
First 50 kWh per kW	4,693	86.65	(12.67)	0.17	74.15	348
Over 50 kWh per kW	18,417	57.13	(12.67)	0.17	44.63	822
SCH 49 - Irrig. & Drain. Pump. - >30 kW						
First 50 kWh per kW	19,114	83.84	(13.80)	(0.17)	69.87	1,335
Over 50 kWh per kW	48,656	54.32	(13.80)	(0.17)	40.35	1,963
SCH 83-S General Service >30 kW						
Flat (less than 1,000 kW)	5,305,246	68.70	(13.80)	(0.17)	54.73	290,356
On-peak (greater than 1,000 kW)	433,356	72.71	(13.80)	(0.17)	58.74	25,455
Off-peak (greater than 1,000 kW)	227,667	61.66	(13.80)	(0.17)	47.69	10,857
SCH 83-P - Primary						
Flat (less than 1,000 kW)	297,230	66.21	(13.80)	(0.17)	52.24	15,527
On-peak (greater than 1,000 kW)	1,422,597	70.11	(13.80)	(0.17)	56.14	79,865
Off-peak (greater than 1,000 kW)	956,926	59.38	(13.80)	(0.17)	45.41	43,454
SCH 83-T - Subtransmission						
On-peak	468,998	69.19	(13.80)	(0.17)	55.22	25,898
Off-peak	335,189	58.50	(13.80)	(0.17)	44.53	14,926
SCH 91 - Street & Highway Lighting	97,437	66.67	(13.80)	(0.17)	52.70	5,135
SCH 92 - Traffic Signals	5,939	67.90	(13.80)	(0.17)	53.93	320
SCH 93 - Recreational Field Lighting	565	66.08	(13.80)	(0.17)	52.11	29
Totals	18,807,551					$1,040,428
BPA Power Credit						$0
Schedule 125a revenues from optout loads						($10,957)
Schedule 129						($24)
Total Energy Revenues						$1,029,447

PORTLAND GENERAL ELECTRIC
Calculation of 2007 Wheeling Charge

Monthly Projected ESS Loads & Peaks: Load Forecast SDEC05E07

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann	12CP
System Peaks	10.1	11.0	11.9	11.3	11.2	11.0	14.0	15.1	13.0	11.6	10.6	10.4	15.1	11.8
System Busbar Energy	6,560	6,444	7,958	7,438	7,297	6,671	8,196	8,837	7,777	7,813	7,135	6,930	89,057	
Hours	744	672	744	720	743	720	744	744	720	744	721	744	8,760	
MWa	8.8	9.6	10.7	10.3	9.8	9.3	11.0	11.9	10.8	10.5	9.9	9.3	10.2	
System LF	87%	87%	90%	91%	88%	84%	79%	79%	83%	91%	93%	90%	67%	86.40%

MC of wheeling based on projected DA loads & 12CP

BPA PTP	1.487	kW-month
Hours	730	average per month
DA 12CP	11.8	
DA MWa	10.2	
LF	86.4%	
Wheeling Charge mills/kWh	**2.36**	

PORTLAND GENERAL ELECTRIC
SELECTED LOAD PROFILES BY SCHEDULE

Schedule 7

Schedule 7 Avg Cust Energy (kWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
On-peak	823	611	566	482	449	463	558	531	446	500	646	758	6,833
Off-peak	458	394	310	274	270	258	295	314	245	307	367	413	3,905
Total	1,281	1,005	876	756	719	721	853	845	691	807	1,013	1,171	10,738

Source: 2004 load research data

Schedule 7	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
On-peak percent	64.25%	60.80%	64.61%	63.76%	62.45%	64.22%	65.42%	62.84%	64.54%	61.96%	63.77%	64.73%	63.63%
Off-peak percent	35.75%	39.20%	35.39%	36.24%	37.55%	35.78%	34.58%	37.16%	35.46%	38.04%	36.23%	35.27%	36.37%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Schedule 15

Schedule 15 Burning Hour Percentages	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
On-peak percent	38.85%	32.08%	26.19%	17.10%	11.85%	7.64%	8.36%	12.62%	23.02%	31.19%	35.61%	39.98%	
Off-peak percent	61.15%	67.92%	73.81%	82.90%	88.15%	92.36%	91.64%	87.38%	76.98%	68.81%	64.39%	60.02%	
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

Schedule 32 Avg Cust Energy (kWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
On-peak	65.97%	64.37%	67.37%	67.54%	65.88%	68.81%	69.29%	66.89%	68.10%	66.45%	67.12%	66.85%	67.04%
Off-peak	34.03%	35.63%	32.63%	32.46%	34.12%	31.19%	30.71%	33.11%	31.90%	33.55%	32.88%	33.15%	32.96%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Source: 2004 load research data

Schedule 38	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
On-peak percent	65.39%	64.71%	69.36%	68.20%	64.02%	67.25%	67.72%	66.13%	68.47%	68.29%	68.71%	66.81%	67.14%
Off-peak percent	34.61%	35.29%	30.64%	31.80%	35.98%	32.75%	32.28%	33.87%	31.53%	31.71%	31.29%	33.19%	32.86%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Source: 2004 load research data

Schedule 47	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
On-peak percent	63.88%	62.45%	60.08%	47.87%	46.36%	44.49%	39.83%	42.92%	51.57%	54.25%	61.65%	62.54%	48.97%
Off-peak percent	36.12%	37.55%	39.92%	52.13%	53.64%	55.51%	60.17%	57.08%	48.43%	45.75%	38.35%	37.46%	51.03%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Schedule 49	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
On-peak percent	63.88%	62.45%	60.08%	47.87%	46.36%	44.49%	39.83%	42.92%	51.57%	54.25%	61.65%	62.54%	48.97%
Off-peak percent	36.12%	37.55%	39.92%	52.13%	53.64%	55.51%	60.17%	57.08%	48.43%	45.75%	38.35%	37.46%	51.03%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Source: 2004 load research data

PORTLAND GENERAL ELECTRIC
SELECTED LOAD PROFILES BY SCHEDULE

Schedule 83-S LT 1,000 kW

Schedule 83-S LT 1,000 kW	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
On-peak	285,804	280,335	281,499	271,466	269,800	281,158	287,782	298,899	296,896	287,639	281,391	285,443	3,408,110
Off-peak	165,169	159,273	156,642	150,150	148,361	154,347	157,249	161,688	163,578	155,605	156,195	161,628	1,889,883
Total	450,973	439,607	438,141	421,616	418,160	435,505	445,030	460,587	460,474	443,243	437,586	447,071	5,297,993

Source: 2007 load forecast

Schedule 83-S LT 1,000 kW	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
On-peak percent	63.37%	63.77%	64.25%	64.39%	64.52%	64.56%	64.67%	64.90%	64.48%	64.89%	64.31%	63.85%	64.33%
Off-peak percent	36.63%	36.23%	35.75%	35.61%	35.48%	35.44%	35.33%	35.10%	35.52%	35.11%	35.69%	36.15%	35.67%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Schedule 83-S GT 1,000 kW

Schedule 83-S GT 1,000 kW	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
On-peak (MWH)	33,083	31,825	34,013	33,135	32,723	34,545	39,672	42,959	42,392	38,787	35,413	33,887	432,435
Off-peak (MWH)	18,000	17,443	17,916	17,329	17,011	17,861	20,477	22,145	22,480	19,713	18,381	18,540	227,296
Total (MWH)	51,084	49,268	51,929	50,464	49,734	52,406	60,149	65,104	64,872	58,499	53,795	52,428	659,731

Source: 2007 load forecast

Schedule 83-S GT 1,000 kW	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
On-peak percent	64.76%	64.60%	65.50%	65.66%	65.80%	65.92%	65.96%	65.98%	65.35%	66.30%	65.83%	64.64%	65.55%
Off-peak percent	35.24%	35.40%	34.50%	34.34%	34.20%	34.08%	34.04%	34.02%	34.65%	33.70%	34.17%	35.36%	34.45%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Schedule 83-P LT 1,000 kW

Schedule 83-P LT 1,000 kW	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
On-peak	14,533	15,518	14,987	15,327	15,312	15,224	16,391	16,430	16,190	16,339	14,774	15,459	186,484
Off-peak	9,004	9,451	8,931	9,007	8,887	8,946	9,584	9,397	9,702	9,376	8,701	9,385	110,370
Total	23,537	24,968	23,918	24,334	24,199	24,170	25,975	25,827	25,892	25,715	23,474	24,844	296,853

Source: 2007 load forecast

Schedule 83-P LT 1,000 kW	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
On-peak percent	61.75%	62.15%	62.66%	62.99%	63.28%	62.99%	63.10%	63.62%	62.53%	63.54%	62.94%	62.22%	62.82%
Off-peak percent	38.25%	37.85%	37.34%	37.01%	36.72%	37.01%	36.90%	36.38%	37.47%	36.46%	37.06%	37.78%	37.18%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Schedule 83-P GT 1,000 kW

Schedule 83-P GT 1,000 kW	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
On-peak (MWH)	111,905	115,110	114,433	116,067	117,304	118,466	122,458	124,797	124,814	122,919	112,714	119,522	1,420,508
Off-peak (MWH)	77,121	79,005	76,499	77,690	78,693	80,282	81,477	82,850	83,631	81,131	76,565	80,666	955,611
Total	189,026	194,116	190,932	193,757	195,996	198,748	203,936	207,646	208,445	204,050	189,279	200,188	2,376,119

Source: 2007 load forecast

Schedule 83-P GT 1,000 kW	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
On-peak percent	59.20%	59.30%	59.93%	59.90%	59.85%	59.61%	60.05%	60.10%	59.88%	60.24%	59.55%	59.70%	59.78%
Off-peak percent	40.80%	40.70%	40.07%	40.10%	40.15%	40.39%	39.95%	39.90%	40.12%	39.76%	40.45%	40.30%	40.22%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

PORTLAND GENERAL ELECTRIC
SELECTED LOAD PROFILES BY SCHEDULE

Schedule 83-T	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
On-peak percent	57.89%	58.32%	58.28%	58.14%	57.61%	58.06%	58.14%	57.71%	58.32%	58.28%	58.32%	60.66%	58.32%
Off-peak percent	42.11%	41.68%	41.72%	41.86%	42.39%	41.94%	41.86%	42.29%	41.68%	41.72%	41.68%	39.34%	41.68%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Note: Schedule 83 profiles represent COS only

SCH 91 - St & Highway Lighting	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Burning Hour Percentages													
On-Peak	38.85%	32.08%	26.19%	17.10%	11.85%	7.64%	8.36%	12.62%	23.02%	31.19%	35.61%	39.98%	
Off-Peak	61.15%	67.92%	73.81%	82.90%	88.15%	92.36%	91.64%	87.38%	76.98%	68.81%	64.39%	60.02%	
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

Source: Burning hours study

SCH 92 - Traffic Signals	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Pct. Of Operation													
On-Peak	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	6.9
Off-Peak	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	5.1
Total	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	12.0

Schedule 93	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
On-peak percent	64.46%	63.03%	66.36%	66.62%	64.49%	66.49%	67.16%	65.13%	67.90%	66.53%	66.26%	65.30%	65.80%
Off-peak percent	35.54%	36.97%	33.64%	33.38%	35.51%	33.51%	32.84%	34.87%	32.10%	33.47%	33.74%	34.70%	34.20%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Source: 2004 load research data

PORTLAND GENERAL ELECTRIC

2007 Cycle Billing Determinants

Grouping	Basic Charge BD 1-phase	Basic Charge BD 3-phase	Vol. Trans & Related BD	Demand Transmission & Related BD	Volumetric Dist. BD-Block 1	Volumetric Dist. BD-Block 2	Facilities BD	Distribution Demand Block 1 BD	Distribution Demand Block 2 BD	Explicit & Implicit System Usage BD
Schedule 7	8,421,770	5,179	7,524,421	0	2,027,033	5,497,387	0	0	0	7,524,421
Schedule 15 Residential	6,348	0	6,684	0	6,684	0	0	0	0	6,684
Schedule 15 Commercial	9,864	0	16,812	0	16,812	0	0	0	0	16,812
Schedule 32	624,206	354,764	1,503,045	0	1,327,585	175,460	0	0	0	1,503,045
Schedule 38	1,644	13,410	105,829	0	105,829	0	0	0	0	105,829
Schedule 47	1,200	17,340	22,922	0	4,673	18,249	0	0	0	22,922
Schedule 49	48	8,412	67,951	0	19,426	48,525	0	0	0	67,951
Schedule 83-S COS	8,713	131,852	0	15,761,511	0	0	18,092,892	4,169,537	11,591,974	5,957,724
Schedule 83-S Market	36	1,824	0	253,074	0	0	292,488	55,702	197,372	112,624
Schedule 483-S	0	36	0	29,089	0	0	40,116	888	28,201	14,259
Schedule 91	2,472	0	97,806	0	97,806	0	0	0	0	97,806
Schedule 92	168	0	5,939	0	5,939	0	0	0	0	5,939
Schedule 93	0	324	565	0	565	0	0	0	0	565
Schedule 83-P COS		3,006	0	4,956,762	0	0	5,589,912	4,956,762	0	2,672,972
Schedule 83-P Market		84	0	249,142	0	0	272,040	249,142	0	119,861
Schedule 483-P		12	0	119,975	0	0	129,612	119,975	0	70,000
Schedule 83-T COS		84	0	1,420,507	0	0	1,480,680	1,420,507	0	803,359
Schedule 83-T Market		12	0	713,621	0	0	773,856	713,621	0	385,963
Schedule 75-T		12		231,000	0	0	231,000	231,000	0	168,900
Schedule 76R				0	0	0	0	0	0	0
Totals	9,076,469	536,351	9,351,974	23,734,681	3,612,352	5,739,622	26,902,596	11,917,134	11,817,547	19,657,637
COS Totals	9,076,433	534,371	9,351,974	22,138,780	3,612,352	5,739,622	25,163,484	10,546,806	11,591,974	18,786,030
Sch. 83 COS Totals	8,713	134,942	0	22,138,780	0	0	25,163,484	10,546,806	11,591,974	9,434,056
Sch. 83 Market Totals	36	1,980	0	1,595,901	0	0	1,739,112	1,370,328	225,573	871,607

PORTLAND GENERAL ELECTRIC

2007 Cycle Billing Determinants

Grouping	Block 1 Energy BD	Block 2 Energy BD	Flat Energy BD	On-peak Energy BD	Off-peak Energy BD	Wheeling Demand BD	Reactive BD	Fixed BD	125a BD	125b BD	Sch 129 BD
Schedule 7	2,027,033	5,497,387	0	0	0	0	0	0	7,524,421	7,524,421	0
Schedule 15 Residential	0	0	6,684	0	0	0	0	6,684	6,684	6,684	0
Schedule 15 Commercial	0	0	16,812	0	0	0	0	16,812	16,812	16,812	0
Schedule 32	0	0	1,503,045	0	0	0	0	0	1,503,045	1,503,045	0
Schedule 38	0	0	0	51,962	53,867	0	136,564	0	105,829	105,829	0
Schedule 47	4,673	18,249	0	0	0	0	98	0	22,922	22,922	0
Schedule 49	19,426	48,525	0	0	0	0	10,770	0	67,951	67,951	0
Schedule 83-S COS	0	0	5,297,993	432,435	227,296	0	1,984,708	0	5,957,724	5,957,724	0
Schedule 83-S Market	0	0	0	73,518	39,106	0	0	0	112,624	0	0
Schedule 483-S	0	0	0	8,901	5,358	29,089	7,953	0	0	0	14,259
Schedule 91	0	0	97,806	0	0	0	0	97,806	97,806	97,806	0
Schedule 92	0	0	5,939	0	0	0	0	0	5,939	5,939	0
Schedule 93	0	0	565	0	0	0	0	0	565	565	0
Schedule 83-P COS	0	0	296,853	1,420,508	955,611	0	1,114,867	0	2,672,972	2,672,972	0
Schedule 83-P Market	0	0	0	73,345	46,517	0	0	0	119,861	0	0
Schedule 483-P	0	0	0	42,308	27,692	119,975	40,178	0	0	0	70,000
Schedule 83-T COS	0	0	0	468,496	334,863	0	121,706	0	803,359	803,359	0
Schedule 83-T Market	0	0	0	211,424	174,538	0	0	0	385,963	0	0
Schedule 75-T	0	0	0	96,474	72,426	0	0	0	168,900	0	0
Schedule 76R	0	0	0	0	0	0	0	0	0	0	0
Totals	2,051,132	5,564,162	7,225,698	2,879,370	1,937,275	149,064	3,416,844	121,302	19,573,378	18,786,030	84,259
COS Totals	2,051,132	5,564,162	7,225,698	2,373,400	1,571,638	0	3,368,713	121,302	18,786,030	18,786,030	0
Sch. 83 COS Totals	0	0	5,594,847	2,321,439	1,517,771	0	3,221,281	0	9,434,056	9,434,056	0
Sch. 83 Market Totals	0	0	0	505,970	365,637	149,064	48,131	0	787,347	0	84,259

PORTLAND GENERAL ELECTRIC

2007 Cycle Billing Determinants

Grouping	Sch 102 Power BD	Sch 102 Monetary BD	Sch 101 BD	Sch 105 BD	Sch 107 BD	Sch 114 BD	Sch 126 BD
Schedule 7	2,027,033	5,497,387	7,524,421	7,524,421	7,524,421	7,524,421	7,524,421
Schedule 15 Residential	6,684	6,684	6,684	6,684	6,684	6,684	6,684
Schedule 15 Commercial	0	0	16,812	16,812	16,812	16,812	16,812
Schedule 32	232,854	232,854	1,503,045	1,503,045	1,503,045	1,503,045	1,503,045
Schedule 38	6,400	6,400	105,829	105,829	105,829	105,829	105,829
Schedule 47	21,296	21,296	22,922	22,922	22,922	22,922	22,922
Schedule 49	59,189	59,189	67,951	67,951	67,951	67,951	67,951
Schedule 83-S COS	295,265	295,265	5,957,724	5,957,724	5,957,724	5,957,724	5,957,724
Schedule 83-S Market	77	77	112,624	112,624	112,624	112,624	112,624
Schedule 483-S	704	704	14,259	14,259	14,259	14,259	14,259
Schedule 91	0	0	97,806	97,806	97,806	97,806	97,806
Schedule 92	0	0	5,939	5,939	5,939	5,939	5,939
Schedule 93	0	0	565	565	565	565	565
Schedule 83-P COS	9,398	9,398	2,672,972	2,672,972	2,672,972	2,672,972	2,672,972
Schedule 83-P Market	0	0	119,861	119,861	119,861	119,861	119,861
Schedule 483-P	0	0	70,000	70,000	70,000	70,000	70,000
Schedule 83-T COS	0	0	803,359	803,359	803,359	803,359	803,359
Schedule 83-T Market	0	0	385,963	385,963	385,963	385,963	385,963
Schedule 75-T	0	0	168,900	168,900	168,900	168,900	168,900
Schedule 76R	0	0	0	0	0	0	0
Totals	2,658,902	6,129,256	19,657,637	19,657,637	19,657,637	19,657,637	19,657,637
COS Totals	2,658,121	6,128,475	18,786,030	18,786,030	18,786,030	18,786,030	18,786,030
Sch. 83 COS Totals	304,664	304,664	9,434,056	9,434,056	9,434,056	9,434,056	9,434,056
Sch. 83 Market Totals	781	781	871,607	871,607	871,607	871,607	871,607