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Douglas C. Tingey
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April 1, 2005

Via E-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
2006 Resource Valuation Mechanism
OPUC Docket No. UE 172

Attention Filing Center:

Enclosed please find the original and five (5) copies of Portland General Electric's Direct Testimony (PGE Exhibits 100-103 and 200-203) and the original on CD and three (3) paper copies of Workpapers for filing in the above-referenced docket.

Exhibits 101-C and 102-C are designated as confidential, subject to Protective Order No. 05-156, entered on March 30, 2005.

Please date stamp the extra copy of this letter and return it in the postage-prepaid envelope provided. If you have any questions, please do not hesitate to call.

Sincerely,

DCT:am

cc without attachments: UE 161 Service List

CERTIFICATE OF SERVICE

I certify that I have caused to be served the non-confidential portions of the foregoing **TESTIMONY AND WORKPAPERS OF PORTLAND GENERAL ELECTRIC COMPANY** in OPUC Docket No UE 172, by U.S. Mail, to the following parties:

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Dated this 1st day of April, 2005.

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UE-172 / PGE Exhibit / 100
TINKER / NIMAN / TOOMAN

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

2006 RVM
UE-172

PORTLAND GENERAL ELECTRIC COMPANY

POWER COSTS

DIRECT TESTIMONY AND EXHIBITS

OF

Jay J. Tinker
Mike A. Niman
L. Alex Tooman

April 1, 2005

I. Introduction

Q. Please state your names and positions at PGE.

A. My name is Jay Tinker. My position is Project Manager in the Rates and Regulatory Affairs Department.

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

My name is Alex Tooman. I am also a Project Manager 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 2006 forecast of power costs. As we discuss in the next section, our current forecast of 2006 power costs is approximately $644 million, a $157 million (32.4%) increase from the 2005 RVM forecast in UE-161. However, approximately $68 million of this increase is the result of a higher cost of service load forecast for 2006. On a unit cost basis, PGE's power costs have increased from $26.21/MWh for 2005 to $32.31/MWh for 2006, an increase of 23.3%. 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 2006 forecast, the number and dates to be determined by the Administrative Law Judge (ALJ). We will file our final 2006 power cost forecast in November 2005.

Q. What is the rate impact of the $157 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 3.4% (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 Commission orders and stipulations that establish the scope of the 2006 RVM. Second, we summarize our load forecast for 2006, explaining the primary differences between the 2006 forecast and the load forecast that we provided in UE-161 for 2005. PGE's expected 2006 loads determine the amount of power that we must generate and/or purchase. Third, we discuss MONET (Monet), PGE's power cost forecasting model that we've used since the mid-1990s. We broadly describe Monet, including the forward price curves and other inputs. We then discuss the correction we've made to the Monet model since November 2004. We note that no new enhancements will be made to Monet for the 2006 RVM unless there is agreement among the parties or there is an Order by the Commission. We also discuss the updates that we've made to the input data since the final Monet run for the 2005 RVM in November 2004, and the updates to the input data that we intend to make before our final power cost forecast in November. The final section contains our qualifications.

Q. In the 2004 RVM, PGE proposed a Power Cost Adjustment (PCA) mechanism. Is PGE proposing a PCA for 2006 as part of the 2006 RVM?

A. No. Last year, we initiated a proceeding (OPUC Docket No. UE-165) in which PGE and parties are exploring possible approaches to hydro variability. The UE-165 proceeding is currently on-going and we expect a Commission Order in 2005.

Q. Does PGE have a schedule for updates to Monet for 2006 power costs?

A. No. We anticipate that the ALJ assigned to the 2006 RVM proceeding will establish the schedule of Monet updates based on discussion among and input by the parties.

Q. Has PGE made any scope changes or enhancements to the Monet model that are included in the 2006 RVM?

A. No. We have not made any scope changes or enhancements to the Monet model for the 2006 RVM. PGE has corrected the usable capacities of the Mid-Columbia hydro plants. This adjustment corrects an enhancement to the 2005 RVM Monet model that overstated the amount of discretionary capacity available for dispatch based on energy prices. Section III, Part C provides more detail regarding this correction.

Q. Are other witnesses providing testimony in the 2005 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 2006 retail load.

A. PGE Exhibit 103 provides PGE's forecast for retail loads in 2006 by customer class. We summarize the forecast and historical loads below in Table 1.

Table 1
Retail Load Forecast Comparison
(in million kWh)

	Actual 2001	Actual 2002	Actual 2003	Actual 2004	2005 RVM Forecast	Current Forecast (for 2005)	Current Forecast (for 2006)
Residential	7,118	7,063	7,201	7,440	7,615	7,624	7,784
Commercial	6,475	6,442	6,580	6,761	6,942	6,901	7,089
Industrial	5,302	5,014	4,553	4,286	4,415	4,409	4,485
Miscellaneous	202	207	202	199	209	206	208
Total Retail	19,097	18,726	18,537	18,686	19,181	19,141	19,566

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. PGE Exhibit 103 shows this breakdown by rate schedule for 2006. In PGE Exhibit 103 and elsewhere, we refer to the non cost of service load as "opt out" load.

Q. How does this forecast compare to the 2005 RVM (UE-161) forecast for 2005?

A. Table 1 shows PGE's actual weather-adjusted retail loads since 2001 and compares the UE-161 (October 2004) forecast with our current forecast of 2005 retail load and our forecast of retail loads by customer group for 2006. Our current 2005 retail load forecast, which included January 2005 weather-adjusted actual load, is 19,141 million kWh, approximately 0.1% lower than the UE-161 (RVM) forecast for 2005. We forecast retail load to increase 2.2% to 19,566 million kWh for 2006 from our current 2005 load estimate. Our expected

2006 load remains well below our UE-115 2002 test year estimate of 20,227 million kWh. Sector data shown in Table 1, primarily commercial and industrial, were calibrated to the North American Industry Classification System (NAICS).

PGE re-estimated the load model using the February 10, 2005 "benchmark" Oregon employment data while extending the sample period through December 2004. The new forecast is based on data input from: 1) the February 2005 U.S. economic forecast from Global Insight (formerly Wharton-DRI), 2) the March 2005 Oregon Economic and Revenue Forecast from the Oregon Office of Economic Analysis, and 3) the March 2005 California employment forecast.

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)

	2004 RVM	2005 RVM	2006 RVM
Total System Load	18,630	19,181	19,566
Part B Opt-Out	2,169	1,958	1,037
Cost of Service Load	16,461	17,223	18,529

While PGE's 2006 total system load forecast is projected to increase by only 2.1 percent from the 2005 RVM forecast, PGE's cost of service load is projected to increase by 7.6 percent, reflecting fewer Part B opt-out customers. Thus, PGE must plan for additional cost of service load in 2006.

III. PGE's Power Cost Forecast For 2006

A. Scope of the 2006 RVM

Q. What is the scope of the 2006 RVM?

A. The scope of the 2006 RVM is a review of PGE's expected net variable power costs (NVPC) for calendar year 2006 (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 on the development of rates for Schedule 125.

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

A. Net variable power costs include such costs as fuel, wholesale power purchases and sales ("purchased power" and "sales for resale"), and other costs of power that generally change as power output changes. PGE records its variable power costs to FERC accounts 501, 547, 555, 565, and 447.

Q. Has PGE's definition of net variable power costs changed since its last general rate case (OPUC Docket UE-115)?

A. No.

Q. Are all of the costs in "net variable power costs" actually variable?

A. No. Net variable power costs include some fixed power costs, such as Boardman taxes, and exclude some variable power costs, such as variable operation and maintenance costs. The net variable power costs that we model in this docket with Monet are consistent with the net variable power costs modeled in UE-115 and previous RVM filings (UE-139, UE-149, and UE-161).

Q. Why does PGE include some fixed power costs in Monet?

A. Some items, such as transportation charges and excise taxes, are included in Monet for FERC accounting reasons. These items are included in FERC Account 151, Fuel stock, which is a balance sheet account. However, as fuel is burned at the plant, these items are "amortized" on a MWh basis. Thus, these items belong in net variable power costs.

Q. Why does PGE exclude some variable power costs from Monet?

A. Other items, such as variable operation and maintenance, are already included elsewhere in PGE's accounting and are recovered outside of net variable power costs. Consequently, these items are not included in net variable power costs or the RVM process. However, some of these items do affect the economic dispatch cost of the plant and are included in the Monet model because they influence the plant dispatch decision, but the costs are not reported with NVPC.

Q. What changes can be made in the "annual update?"

A. The Commission directed PGE to include all proposed model enhancements to PGE's power cost forecast model, Monet, in our initial April 1 filing. A stipulation between PGE and other parties limits the model enhancements for the 2005 and 2006 RVMs to Coyote and Beaver dispatch logic and hydro modeling changes. The Commission approved the stipulation in the 2004 RVM (OPUC Order No. 03-535 at 3). The only changes allowed after the initial filing are updates for load forecasts, power purchase or sales contracts, fuel and fuel transportation contracts, and forward price curves for electricity and natural gas (OPUC Order No. 02-772 at 6). We also will update the Canadian/US dollar exchange rate, hedge contracts, and the price for oil that we use at our thermal plants and distributed standby generation. Finally, updates can reflect changes in PGE's resources resulting from the implementation of all or a portion of a Commission-approved Resource Plan, any

Commission approved resource change, or the catastrophic failure of a resource (OPUC Order No. 01-777, Appendix D, at 17).

Q. Does PGE's filing conform to the Commission's Order?

A. Yes. Our initial filing does not include any enhancements to Monet but does correct one enhancement that was in our 2005 RVM filing. We discuss this correction in Section C below. Our initial filing also includes our most recent 2006 retail load forecast, our contracts for wholesale power purchases and sales, fuel and fuel transportation contracts through March 8, and our forward curves as of March 8. We expect to update our 2006 RVM power cost forecast according to the schedule set by the ALJ.

B. The Monet Model

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

A. 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. PGE uses a model, built by us in the mid-1990s and refined since then, called Monet. Monet is capable of modeling the hourly dispatch of over 2000 generating units in the WECC, producing a "fundamentals" forecast. 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.

Monet is capable of producing hub market prices and area marginal power costs using its "fundamentals" methodology. Monet considers transmission constraints between areas, groups results by area (PGE, Canada, Pacific Northwest, BPA, Inland NW, Northern California, Southern California, and Desert SW), and computes its results by hour.

Since the emergence of forward markets, however, PGE has input the forward market curve for purchased power and gas, rather than use the "fundamentals" output of Monet. The 2006 results are based on operating Monet under the "dispatch to forward market curve" mode.

When we run Monet in "dispatch to forward market curve" mode, the model employs the following data inputs for PGE:

- Retail loads, on an hourly basis;
- Coal and oil prices;
- Fuel transportation costs;
- Thermal plants, with forced outage rates and scheduled maintenance outage rates, capacities, heat rates, and any variable operating and maintenance costs;
- Hydroelectric plants, with output based on 59 years of data reflecting current non-power operating constraints (such as fish issues) and peak, annual, seasonal, and hourly usage capabilities;
- Transmission (Wheeling) contract costs;
- Electric and gas contract purchases and sales; and
- Forward market curves for gas and electric power purchases and sales.

Using these data inputs, the model dispatches PGE resources to meet its loads based on the principle of economic dispatch. Thus, PGE's thermal plants are dispatched when the dispatch cost of the individual plant is below the market price. The plant may be operating at its maximum availability, ramping up to its maximum availability, starting up, shutting down, or off-line. Given thermal output, expected hydro generation, and contract purchases/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.

Q. What is the source of the forward curves that PGE inputs to Monet?

A. We use a one-day snapshot of trading curves to obtain forecasts for 2006 of natural gas prices at Sumas, Rockies, AECO, and Malin, and monthly on- and off-peak power prices at Mid-C and PGE system. The trading curves are supplied by the Power Operations Group, which purchases and sells wholesale electricity and gas for PGE, and validated by our Risk Management group.

Using this forecast, we create hourly wholesale prices for electric power. To create hourly prices, we begin with typical price profiles for winter, summer, and off-season, for weekdays, Saturdays, and Sundays, and use historical hourly price information. Because we model on-peak prices as independent from off-peak prices in a given month, we review price transitions from on-peak to off-peak hours to make sure they are appropriate. We also examine hourly prices for a typical weekday, Saturday, and Sunday for each month in the forecast period to make sure the prices are consistent between hours (e.g., Sunday prices lower than Saturday prices on-peak, for example). Hourly calculations take into account the number of on-peak and off-peak hours in each month of the forecast period to ensure hourly prices are consistent with the monthly prices. The results of this calculation are used directly in Monet.

Q. What is PGE's current forecast for power costs in 2006?

A. PGE's most recent forecast for 2006 power costs is approximately $644 million.

Q. Is the forecast of 2006 power costs directly comparable to PGE's current expected power costs in 2005 or to UE-115 power costs?

A. Yes and no. Our forecast for 2006 power costs, like our forecast for 2005 power costs, excludes power costs associated with serving customers who are not cost of service. For Monet modeling, we define non cost of service customers as those customers we anticipate will be served by an ESS under direct access or by PGE, but under one of our market pricing options, such as daily, monthly, or quarterly. These customers, representing approximately 124 MWa, have formally notified PGE that we should not plan to serve their 2006 load. We note, however, that the opt-out load for 2006 is significantly less than the 232 MWa assumed in the 2005 RVM.

The forecasts of 2002 power costs (i.e., the 2002 test year in UE-115) reflect the power costs to meet all load since no customers were eligible to leave cost of service for 2002. Thus, if we wish to compare the forecasted power costs across these four years, we must adjust the RVM forecasts to include the opt-out load.

Q. Could the November open enrollment process affect PGE's power costs in 2006?

A. Yes, all large non-residential customers, regardless whether they have "opted out" or not, will be able to receive service from PGE or from an ESS. If PGE's non-annual load is less than 124 MWa, PGE will have to purchase more energy in order to serve these customers. Conversely, if PGE's non-annual load exceeds 124 MWa, PGE will have to sell energy in order to maintain its relative position.

Q. Can PGE's 2005 and 2006 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 2005 and 2006 opt-out loads are supplied at the market prices in PGE's forward curves for 2005 and 2006, then we can compare the three forecasts. We refer to this power cost forecast as the "all loads" forecast.

Q. How does PGE's all loads power cost forecasts for 2005 and 2006 compare with PGE's forecasts for 2002 power costs?

A. The "all loads" forecast for 2006 power costs is $708 million. This is an increase of approximately $117 million above the 2005 "all loads" power cost estimate in UE-161 but still remains below 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 2006 and our final forecast will be submitted in November 2005. 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]	2004 All Loads	2005 All Loads	2006 All Loads	2004 RVM	2005 RVM	2006 RVM
Costs ($'000)	$766,882	$531,461	$591,007	$708,085	$444,776	$486,266	$643,737
Loads[2] ('000 MWh)	21,664	19,993	20,591	21,013	17,721	18,551	19,932
Unit Cost ($/MWh)	$35.40	$26.58	$28.70	$33.70	$25.10	$26.21	$32.30

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 2004, 2005, and 2006 RVM exclude non cost of service loads of approximately 259 MWa, 232 MWa, and 124 MWa respectively.

PGE Exhibit 101-C is the Monet output for the 2006 RVM forecast. The Monet forecast includes transmission costs for opt-out loads and must be adjusted to yield the appropriate 2006 RVM costs[1].

Q. Why are the RVM costs in 2006 higher than in 2005?

A. Our forecasted 2006 RVM costs are higher than our forecasted 2005 RVM costs for several reasons, as shown in Table 4.

Table 4
Changes in Power Costs

Item	Impact on 2006 RVM
Higher COS loads from reduced opt-out load	+ $47 million
Higher COS loads from load growth	+ $21 million
Higher wholesale electric and gas prices	+ $32 million
Lost 4th Qtr BPA Subscription Power Benefit	+ $17 million
Increased gas plant output	+ $27 million
Increased hydro contract costs	+ $11 million
Additional Wheeling Costs	+ $8 million
Increased coal costs	+ $7 million
Net benefit of increased gas plant dispatch	- $4 million
Klondike Wind, IRP Resource	- $2 million
Replace BPA Operating Reserves	- $1 million
Update Colstrip forced outage rate	- $2 million
Update Coyote performance parameters	- $1 million
Total	+ $160 million

Q. Please summarize the major factors causing higher power costs in the 2006 RVM.

A. There are seven major factors. First, the forecast of cost of service load is significantly higher in 2006 than 2005. For 2006, we estimate that our cost of service load will be approximately 1.4 million MWh (or 7.4%) higher in 2006 than in 2005. Of this increase,

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

945,000 MWh (or 68%) represents a reduction in opt-out load. The remaining increase is due to load growth of approximately 2.2% on the 2005 RVM load forecast. Second, wholesale electric market prices and gas prices are significantly higher for 2006 than 2005. For 2006, the flat electric forward curve is 56.69 mills/kWh while in 2005 the corresponding figure was 49.92 mills/kWh. For gas at Sumas, the forward curve for 2006 is $6.53/MMBtu while the corresponding curve for 2005 was $6.35/MMBtu. Third, PGE will lose its BPA subscription power benefit in the fourth quarter of 2006. PGE will need to make higher-cost power purchases to offset the loss. Fourth, the forecast calls for increased dispatch of PGE's gas plants resulting in increased gas costs compared to 2005 (at 2005 gas prices). Fifth, PGE will experience increased long-term hydro contract costs because our reduced share of Priest Rapids will be offset by Priest renewal displacement energy. Sixth, wheeling costs are higher because the BPA rate increase that becomes effective in October 2005, will be realized in all of 2006 rather than only the fourth quarter of 2005. Finally, coal costs will be higher in 2006.

Q. Are there any factors that mitigate power costs in the 2005 RVM?

A. Yes. Helping to mitigate these higher expected costs are four other factors. First, while PGE's gas costs will increase partly because we forecast increased dispatch in 2006 (see above), the increased output will displace higher-cost market purchases. Second, we have incorporated the Klondike Wind IRP resource, which is described in more detail in Section D below. Third, PGE will self-supply operating reserves, reducing wheeling costs by replacing BPA operating reserve contracts. The net reduction in costs is the difference between the cost savings resulting from cancellation of the BPA operating reserve contracts and the additional costs incurred when PGE supplies the operating reserves with its own resources. Fourth, updates to the Colstrip forced outage rate and Coyote performance parameters will reduce costs as described in Section D below.

Q. Do these factors explain all of the difference between the 2005 and 2006 RVM forecasts?

A. No, however, the factors explain the primary drivers of the increase in RVM forecasts.

C. Corrections to Monet

Q. Has PGE corrected Monet since the November 15, 2004 final 2005 RVM filing?

A. Yes. We corrected a 2005 RVM enhancement to Monet that incorporated discretionary dispatch of hourly Mid-C hydro. We did not make any enhancements to the 2005 RVM Monet model.

Q. Please describe the changes that you have made since last November.

A. We list all of the changes (and their impacts) we've made to Monet, whether corrections or updates, in the Monet "Step Log," found in our work papers. PGE Exhibit 101-C provides a summary of the correction and data updates to Monet.

Q. Please briefly describe the enhancement you made to the 2005 RVM regarding the hourly Mid-C hydro dispatch logic.

A. For the 2005 RVM we modified the hourly hydro dispatch algorithm in Monet to more accurately reflect the relationship between electric market prices and the dispatch of PGE's Mid Columbia (or Mid-C) hydro resources.

Q. Why did you decide to revise the hourly hydro dispatch logic in Monet?

A. The prior approach to hourly hydro dispatch understated the ability of PGE's hydro resources to respond to varying prices. In actual operations, PGE can (within operational constraints) allocate its limited hydro energy across the hours of the day to maximize the value of the hydro energy.

Q. Why was this enhancement an improvement over the prior modeling in Monet?

A. Prior to the enhancement, hourly hydro generation in Monet was determined by hourly "shaping factors" that allocate hydro generation over the hours of the day. These shaping factors represented typical daily shapes and were derived by averaging generation over the hours of the month. The hourly shapes used in the 2004 RVM were based on actual 1998 hourly generation data.

This model enhancement allocates PGE's "discretionary" Mid Columbia hydro resources to the higher priced hours in the month. This enhancement results in a better estimate of power costs and more accurately represents how PGE actually operates its system.

Q. What was the impact of this enhancement on the estimates of power costs and generation in Monet?

A. Total energy generated by the Mid Columbia projects did not change because this model logic only reallocates the available monthly energy - it does not alter the total energy available. Because the 2005 RVM enhancement to the hourly hydro dispatch logic in Monet increased the value of the Mid Columbia hydro resources, overall power costs declined.

Q. Did PGE believe revisions to the enhancement would be required?

A. Yes. While we felt that the logic was reasonable, due to time constraints in 2004, we were able to perform only limited testing to compare the revised hourly hydro dispatch logic to historical hourly generation for the 2005 RVM. At that time we stated that "more detailed comparisons may lead to additional modifications" (UE-161 - PGE Exhibit 100, page 27).

Q. Please describe the Correction to Mid-C hourly hydro dispatch logic.

A. PGE has not changed any of the program logic. Instead, we have corrected the maximum available capacity of the Mid-C projects. The new capacity levels are based on four-year historical averages of available capacity that incorporate forced outages, planned outages, and unit derations. These levels are more accurate and realistic, and more consistent with the treatment of our thermal plants, than using the theoretical maximum capacity of each project times PGE's share. The net effect of this correction is approximately $2.6 million increase in power costs.

D. 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 because doing so provides us with the best forecast for our power costs.

Q. Are these updates consistent with the stipulation signed in UE-149 and incorporated in Commission Order No. 03-535?

A. Yes. These updates are consistent with PGE Tariff Schedule 125, which Commission Order No. 03-535 identified as the basis for RVM model updates.

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.

Table 5
Major Resource Updates

	Data Update	Description
1	Update PGE and Mid-C Hydro Energy	Incorporate results from the 2003/04 PNCA Headwater Benefit Study.
2	Colstrip Unit 4 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	Klondike Wind	Add the new IRP resource.
4	PGE Hydro Planned Maintenance	Updates for planned maintenance at Sullivan and test spills for fish at North Fork, Faraday, and River Mill.
5	Update Boardman Heat Rate and Capacity	Refine updates introduced in the 2005 RVM to reflect actual results of the HP/IP upgrade and to reflect a change in boiler operating procedure.

Q. Please discuss the first resource update, which incorporates the 2003-2004 PNCA study of hydro operating constraints and conditions.

A. This update contains adjustments similar to those made to the 2002-2003 PNCA Headwater Benefits Study that was the basis for available hydro energy in the 2005 RVM. The adjustments to the 2003-2004 PNCA study used in the current filing reflect the most recent information regarding the Biological Opinion ("fish constraints") and other non-power constraints. Current adjustments included an increase to Bull Run's generation due to corrections to its maintenance factor and maintenance schedule. Bull Run's generation was also adjusted for an eight percent efficiency increase. In addition, we adjusted the energy for certain PGE hydro plants based on the ratio of the observed plant efficiency (H/K factor) to the efficiency assumed in the PNCA study. These updates and adjustments affected the hydro energy available from the PGE and Mid-C plants, with a resulting increase of 1.8

MWa, and a net decrease in power costs of approximately $677,000 (Monet update steps 41 and 56).

Q. Please discuss the second resource update, Colstrip Unit 4 HP/IP Turbine upgrade.

A. The project involves replacing the high pressure (HP) and intermediate pressure (IP) Turbines with a new fully bladed rotor and upgrading several related components. The HP/IP Turbine upgrade is expected to result in a 25 MW increase in the capacity of Unit 4 without any associated increase in fuel use. As a result, the heat rate of the facility also declines. PGE's share of the capacity increase is approximately 5 MW and the heat rate is expected to decline from 10,913 Btu/kWh to 10,556 Btu/kWh.

Q. Has PGE added any new IRP resources to the Monet model?

A. In December 2005, PGE will begin receiving energy from the new IRP resource, Klondike Wind Project. This resource has a 75 MW peak capacity and is forecast to operate with a 36 percent capacity factor. The project's 27 MWa output has a cost of $43.08/MWh for 2006.

Q. Please describe the updates related to planned maintenance outages at PGE hydro facilities.

A. PGE has significant planned maintenance outages for Sullivan, North Fork, Faraday and River Mill during 2006. The Sullivan facility will be shut down for 4 months to build fish migration structures. North Fork, Faraday, and River Mill are engaging in "test spills" during several months of the year to evaluate fish impacts. These test spills are modeled as scheduled maintenance derations in Monet. The 2005 RVM included a similar shut-down for Sullivan, but the maintenance was postponed until 2006. The test spills, however, are on-going projects to accumulate data regarding fish impacts.

Q. Please describe the update to the Boardman Heat Rate and Capacity.

A. In the 2005 RVM, PGE included a Boardman HP/IP Turbine upgrade as a resource update. In the 2006 RVM, we adjust this update to reflect the actual operational outcome of that project. Instead of the expected 32 MW capacity increase from the upgrade, we realized approximately a 30 MW increase. Boardman's net capacity declined an additional 2 MW because the plant "house load" increased by this amount. The combined effect of these updates is a capacity reduction of 4 MW, from 589 MW to 585 MW. Further, the heat rate increased from the 2005 RVM turbine upgrade expected level of 9,409 Btu/kWh to 9,725 Btu/kWh. A small part of that increase is due to achieving slightly less capacity from the upgrade than expected. The primary cause of the heat rate increase was that in 2004 we encountered hard ash in the furnace most likely due to an increase in the mineral content of our coal. This problem created a forced outage in the summer of 2004, which we addressed by increasing excess oxygen by one-half percent to produce softer ash, thus solving the hard ash operational problem but also increasing the heat rate.

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 2006 and provides a comparison to the 2005 RVM parameters.

Table 6
Thermal Performance Parameters

	Heat Rate		Capacity		Forced Outage		Planned Maintenance	
	2005 Btu/kWh	2006 Btu/kWh	2005 (MW)	2006 (MW)	2005 Rate	2006 Rate	2005 Days	2006 Days
Beaver	9,299	9,299	521	521	5.6%	8.7%	39	28.5
Boardman	9,409	9,725	383	380	6.5%	6.5%	32	29
Colstrip 3	10,642	10,913	148	148	14.5%	13.0%	7	9
Colstrip 4	10,642	10,913/10,556	148	148/153	14.5%	13.0%	7	52
Coyote	7,260	7,146	230	231	6.6%	6.8%	9	16

Q. What is the basis of the 2006 planned maintenance schedule?

A. For Beaver, Boardman, and Coyote, planned maintenance is based on the current expectations of the respective plant managers. For Colstrip, planned maintenance is based on the expectations of the plant operator, PP&L Montana.

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 2006, this average is calculated based on the actual forced outages experienced from 2001 through 2004.

Q. Why did the capacities and heat rates change from 2005 to 2006?

A. The Boardman and Colstrip 4 changes were discussed above as major resource updates. The improvements to Coyote's heat rate and capacity are due to 1) a new rotor and compressor, 2) refurbished gas turbine buckets, 3) steam turbine seal improvements, and 4) plant optimization and improved database.

Q. What items will PGE update after this April 1st filing?

A. PGE's updates will be limited to load forecasts, gas and electric forward curves, and contract updates consistent with the Commission's order in the UE-139 docket (OPUC Order No. 02-772).

IV. Qualifications

Q. Mr. Tinker, please describe your qualifications.

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

Q. Mr. 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. 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. Does this conclude your testimony?

A. Yes.

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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 and Stacking Model Cost to Serve Opt-Out Load
103	Delivery Forecast by Market Segment and Service Level Residential Building Permits, New Connects, Vacancy Rates and Occupied Accounts Forecast of Residential Use per Occupied Account and Ultimate Deliveries Commercial Deliveries Forecast by NAICS Cluster Industrial Deliveries Forecast by NAICS Cluster Forecast of Deliveries under Miscellaneous Secondary Rate Schedules Forecast 2006 PGE Net ("Cost of Service") and Opt-Out ("Non Cost of Service") Load

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PGE Exhibit 101-C is Confidential

See Confidential Exhibit Section under separate cover

PGE Exhibit 102-C is Confidential

See Confidential Exhibit Section under separate cover

Delivery Forecast by Market Segment and Service Level

(at normal weather)

	(in million kWh)				% Change[1]		
	2003	2004	2005	2006	2004	2005	2006
Schedule 7	7,196	7,433	7,617	7,778	3.3%	2.5%	2.1%
Residential Lighting et al	5	7[2]	7	7	26.8%	(0.5%)	(0.7%)
Total Residential	7,201	7,440	7,624	7,784	3.3%	2.5%	2.1%
Commercial[3]	6,580	6,761	6,901	7,089	2.7%	2.1%	2.7%
Manufacturing[3]	4,553	4,286	4,409	4,485	(5.9%)	2.9%	1.7%
Miscellaneous Customers	202	198	206	208	(1.7%)	3.9%	1.0%
Secondary Voltage[4]	6,942	7,194	7,375	7,601	3.6%	2.5%	3.1%
Total General Service	7,144	7,392	7,581	7,809	3.5%	2.6%	3.0%
Primary Voltage Service[5]	2,678	2,676	2,717	2,817	(0.1%)	1.5%	3.7%
Transmission Voltage Service[5]	1,514	1,178	1,218	1,155	(22.2%)	3.5%	(5.2%)
Total Retail	18,537	18,686	19,141	19,566	0.8%	2.4%	2.2%

1/ calculated from un-rounded numbers
2/ revised classification
3/ by North American Industry Classification System (NAICS) grouping
4/ current Schedules 32S & 83S
5/ current Schedule 83P
5/ current Schedules 83T & (old) Schedule 99

Residential Building Permits, New Connects, Vacancy Rates and Occupied Accounts

History and Forecast

	2003	2004	2005	2006
Building Permits [1]				
Single-Family	18,232	21,173	20,934	20,143
Multiple-Family	6,495	6,926	6,427	6,822
New Connects				
Single-Family	6,763	6,860	7,911	7,837
Multiple-Family	4,890	4,424	5,154	4,813
Manufactured Home	289	262	360	360
Other	228	244	240	240
Total Connects	12,170	11,790	13,665	13,250
Vacancy Rates (%)				
Single-Family	3.9%	4.1%	3.7%	3.7%
Multiple-Family	11.7%	11.8%	10.9%	10.2%
Mobile Home	9.5%	9.8%	9.5%	9.5%
Number of Occupied Accounts				
Single-Family Heat	103,191	103,421	104,424	104,775
Single-Family Non-Heat	299,802	304,682	312,099	318,621
Multiple-Family Heat	142,936	144,283	147,727	150,582
Multiple-Family Non-Heat	32,685	34,966	38,247	41,143
Mobile Home Heat	28,533	28,426	28,622	28,686
Mobile Home Non-Heat	3,608	3,606	3,640	3,647
Other	4,232	4,609	4,867	5,036
Total Occupied Accounts	614,988	623,994	639,626	652,489
Total Number of Customers [3]	658,232	668,830	681,738	694,024

1/ Oregon

2/ includes vacant accounts

Forecast of Residential Use per Occupied Account and Ultimate Deliveries

(at normal weather)

	2003[1]	2004[1]	2005	2006
Use Per Occupied Account (kWh)				
Single-Family Heat	17,063	17,366	17,368	17,437
Single-Family Non-Heat	10,872	11,119	11,182	11,205
Multiple-Family Heat	9,957	10,098	10,157	10,252
Multiple-Family Non-Heat	6,213	6,471	6,420	6,454
Mobile Home Heat	16,342	16,759	16,668	16,760
Mobile Home Non-Heat	11,283	11,718	11,779	11,805
Other	10,042	10,344	9,833	9,382
Average Use per Occupied Account	11,701	11,913	11,909	11,920
Ultimate Deliveries (millions of kWh)				
Single-Family Heat	1,761	1,796	1,814	1,827
Single-Family Non-Heat	3,259	3,388	3,490	3,570
Multiple-Family Heat	1,423	1,457	1,500	1,544
Multiple-Family Non-Heat	203	226	246	266
Mobile Home Heat	466	476	477	481
Mobile Home Non-Heat	41	42	43	43
Other	42	48	48	47
Schedule 7	7,196	7,433	7,617	7,778
Residential Lighting et al.	5	7	7	7
Total Residential Deliveries	7,201	7,440	7,624	7,784

1/ weather adjusted actual

Commercial Deliveries Forecast by NAICS Cluster

(at normal weather)

	(in million kWh)				% Change [1]		
	2003 [2]	2004 [2]	2005	2006	2004	2005	2006
Food Stores	478	496	505	516	3.7%	1.8%	2.1%
Govt. & Education	917	954	946	950	4.0%	(0.9%)	0.4%
Health Services	571	604	616	667	5.8%	1.9%	8.4%
Lodging	123	119	123	126	(3.4%)	2.9%	3.1%
Misc. Commercial	620	665	713	724	7.3%	7.2%	1.5%
Merchandise Stores/Malls	355	350	351	367	(1.4%)	0.4%	4.6%
Office & F.I.R.E [3]	887	940	962	981	6.0%	2.3%	1.9%
Other Services	814	786	795	819	(3.4%)	1.1%	3.1%
Other Trade	799	794	825	851	(0.6%)	3.9%	3.2%
Restaurants	440	438	449	459	(0.5%)	2.4%	2.2%
Trans., Comm. & Utility	575	614	616	628	6.7%	0.4%	1.9%
Total Commercial	6,580	6,761	6,901	7,089	2.7%	2.1%	2.7%

1/ calculated from un-rounded numbers

2/ weather-adjusted actual

3/ Finance, Insurance and Real Estate

Manufacturing Deliveries Forecast by NAICS Cluster

(at normal weather)

	(in million kWh)				% Change [1]		
	2003	2004	2005	2006	2004	2005	2006
Food & Kindred Products	246	232	235	239	(5.8%)	1.2%	2.0%
High Tech	1,523	1,524	1,643	1,749	0.0%	7.9%	6.4%
Lumber & Wood	156	169	153	154	8.4%	(9.7%)	1.0%
Primary & Fab. Metals	579	496	523	553	(14.3%)	5.5%	5.8%
Other Manufacturing	539	599	596	616	11.0%	(0.5%)	3.4%
Paper & Allied Products	1,315	1,071	1,059	969	(18.6%)	(1.1%)	(8.5%)
Transportation Equipment	194	196	200	203	0.8%	2.4%	1.4%
Total Manufacturing	4,553	4,286	4,409	4,485	(5.9%)	2.9%	1.7%

1/ calculated from un-rounded numbers

Forecast of Deliveries under Miscellaneous Secondary Rate Schedules

	(in million kWh)				% Change		
	2003	2004	2005	2006	2004	2005	2006
Secondary (Residential)							
Outdoor Area Lighting [1]	5.4	6.9	6.9	6.8	26.8%	(0.5%)	(0.7%)
Secondary (General Service)							
Outdoor Area Lighting [2]	18.4	16.7	16.7	16.7	(9.1%)	(0.1%)	(0.1%)
Farm Irrigation et al. [3]	80.3	79.3	86.2	87.6	(1.2%)	8.7%	1.6%
Service to Drainage [4]	1.8	0.7	1.1	1.3	(61.5%)	56.5%	14.1%
Street and Other Lighting [5]	101.4	101.7	102.2	102.7	0.3%	0.5%	0.5%
Total Misc. Commercial	201.9	198.5	206.2	208.2	(1.7%)	3.9%	1.0%
All Misc. Schedules [6]	207.4	205.4	213.1	215.0	(1.0%)	3.7%	0.9%

1/ Existing Schedule 14R
2/ Existing Schedules 14C & 15C
3/ Existing Schedules 47 & 49
4/ Existing Schedule 97
5/ Existing Schedules 91, 92 & 93

Forecast of 2006 PGE Net and Opt-Out Loads

(at normal weather)

(in million kWh)

	PGE Net [1]	Opt-Out [1]	Total [1]
Total Residential	7,784	0	7,784
Secondary Voltage	7,506	200	7,706
Primary Voltage Service	2,473	344	2,817
Transmission Voltage Service	663	492	1,155
Street Lights	103	0	103
Total Deliveries	18,529	1,037	19,566
Average MW [2]	2,275	124	2,399
Peak MW [3]	3,643	132	3,775

1/ cycle basis for PGE Net or "Cost of Service", Opt-out or "Non-Cost of Service" and Total Deliveries

2/ calendar basis

3/ co-incidental with winter system peak; "Opt-out" co-incidental peak of 157 MW is in June

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

2006 RVM
UE-172

PORTLAND GENERAL ELECTRIC COMPANY

PRICING

DIRECT TESTIMONY AND EXHIBITS

OF

Marc A. Cody

April 1, 2005

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:

1. Summarize the projected 2006 Schedule 125 Resource Valuation Mechanism (RVM) update methodology, adjustment rates, and Energy Charges based on the power cost estimates provided in Exhibit 100 and;
2. Describe the steps used to determine the projected 2006 RVM rates.

II. RVM Rate Summary

Q. Why are the RVM rates updated on January 1, 2006?

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 2006 so that customers may begin to evaluate their electricity supply arrangements and options. 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 2006. 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 March 8, 2005 for this filing, the actual Energy Charge rates for 2006 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.

The methodology recognizes that customer choices to take cost of service, direct access service, or one of our market-based pricing options as set out in Schedule 83 may have power supply impacts that could affect other customers, particularly if the choice was not planned for in the process of acquiring power. The RVM rate components help manage the rate impacts of these choices by valuing power at the current market prices (the Energy Charge) and tracking the differences between costs and market value (the RVM Part A and B rates) back to the customer classes causing the change in the power supply.

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 2006.

Q. Please summarize the projected Energy Charges and Schedule 125 RVM adjustment rates as updated for 2006.

A. The projected 2006 Energy Charges and Schedule 125 Part A and Part B rates applicable to rate schedules 7 through 97 are listed on Exhibit 201, Projected Energy and Schedule 125 Rates for 2006. As described above, the projected Energy Charge by rate schedule is derived from the power market forward curve for 2006. 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 2006 Energy Charge and Schedule 125 RVM adjustment rates changed from the equivalent final 2005 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 2006 Energy Charge, Parts A and B rates, and the resulting net rates.

Table 1

2006 Selected Schedules	**Projected 2006 energy charge (cents/kWh)** Energy Charge*	Part A	Part B	Total
Residential (Sch. 7)**				
Block 1	6.586	-1.218	-0.167	5.201
Block 2	6.586	-1.218	-0.167	5.201
Small Non-Residential (Sch. 32)	6.567	-1.176	-0.387	5.004
Large Non-Residential				
Sch. 83-P, Primary				
Flat (< 1,000 kW)	6.261	-1.350	-0.245	4.666
On-Peak (> 1,000 kW)	6.652	-1.350	-0.245	5.057
Off-Peak (> 1,000 kW)	5.627	-1.350	-0.245	4.032

2005 Selected Schedules	**Current 2005 energy charge (cents/kWh)** Energy Charge*	Part A	Part B	Total
Residential (Sch. 7)**				
Block 1	5.769	-0.920	-0.182	4.667
Block 2	5.769	-0.920	- 0.182	4.667
Small Non-Residential (Sch. 32)	5.733	-0.901	- 0.407	4.425
Large Non-Residential				
Sch. 83-P, Primary				
Flat (< 1,000 kW)	5.479	-0.993	-0.252	4.234
On-Peak (> 1,000 kW)	5.764	-0.993	-0.252	4.519
Off-Peak (> 1,000 kW)	4.871	-0.993	-0.252	3.730

"-" 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 and reflect rate design per UE-161.

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

The second portion of the table shows the current 2005 Energy Charges, Parts A and B rates, and resulting net rates for the same rate schedules. The changes in costs and forward curves between 2005 and projected 2006 can be noted.

The projected 2006 Energy Charges (column labeled Energy Charge), which are based on the forward curve, have increased when compared to 2005. This indicates that the market price for power has increased for 2006. In addition, the Part A credits have grown somewhat larger reflecting the increase in market prices. Part B rates have not changed much between the two years. 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 2005 levels.

Q. Please describe the projected rate impacts for 2006 resulting from the RVM update.

A. Table 2 below summarizes the estimated rate impact for 2006 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 plus the power portion of Schedule 102 (the BPA Subscription Power Credit). 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: Schedules 101, 114, and 126 terminate 12/31/05; BPA SN CRAC of approximately 4.1% with monetary benefits of $10.40/MWH for the fourth quarter of 2006; 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**	**6.9%**	**2.5%**
Small Non-Residential	**7.5%**	**3.9%**
Large Non-Residential, COS***	**8.0%**	**4.3%**
Overall	**7.3%**	**3.4%**

* includes base rates with Schedule 125 and BPA Power Credit.
** change assumes currently proposed BPA SN, LB, & FB Cost Recovery Adjustments have been incorporated into BPA rates in 2005 and 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 2006 projected rates are determined by the following process, which is consistent with the methodology used to set 2005 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, Short-term and BPA Subscription Power resources.
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 2006 update applies the same methodology as 2005 rates, but with revised power costs and load forecast data.

- 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 2006 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, Short-Term, and BPA Subscription Power 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 2006 Energy Revenues, calculates the energy charge revenues of $860.5 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 Masters of Science degree from Portland State University. Both degrees were in Economics. The Masters 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 2006
202	RVM Adjustment Rate Development
203	Estimate of 2006 Energy Revenues

PORTLAND GENERAL ELECTRIC
Projected Energy Charge and Schedule 125 Rates for 2006

Grouping	Market-Based Energy mills/kWh	Schedule 125a mills/kWh	Schedule 125b mills/kWh
SCH 7 - Residential			
Block 1 (first 250 kWh)	65.86	(12.18)	(1.67)
Block 2 (over 250 kWh)	65.86	(12.18)	(1.67)
SCH 15 - Outdoor Area Lighting	62.02	(11.88)	(3.23)
SCH 32 - General Service <30 kW	65.67	(11.76)	(3.87)
SCH 38 - Opt Time-of-Day G.S. >30 kW			
On-peak	71.80	(13.50)	(2.45)
Off-peak	58.07	(13.50)	(2.45)
SCH 47 - Irrig. & Drain. Pump. - <30 kW			
First 50 kWh per kW	87.73	(11.76)	(3.87)
Over 50 kWh per kW	58.21	(11.76)	(3.87)
SCH 49 - Irrig. & Drain. Pump. - >30 kW			
First 50 kWh per kW	82.38	(13.50)	(2.45)
Over 50 kWh per kW	52.86	(13.50)	(2.45)
SCH 83-S General Service >30 kW			
Flat (less than 1,000 kW)	65.20	(13.50)	(2.45)
On-peak (greater than 1,000 kW)	69.24	(13.50)	(2.45)
Off-peak (greater than 1,000 kW)	58.59	(13.50)	(2.45)
SCH 83-P - Primary			
Flat (less than 1,000 kW)	62.61	(13.50)	(2.45)
On-peak (greater than 1,000 kW)	66.52	(13.50)	(2.45)
Off-peak (greater than 1,000 kW)	56.27	(13.50)	(2.45)
SCH 83-T - Subtransmission			
On-peak	65.40	(13.50)	(2.45)
Off-peak	55.31	(13.50)	(2.45)
SCH 91 - Street & Highway Lighting	62.11	(13.50)	(2.45)
SCH 92 - Traffic Signals	64.41	(13.50)	(2.45)
SCH 93 - Recreational Field Lighting	63.81	(13.50)	(2.45)
SCH 97 - Drainage Districts			
On-peak	69.96	(13.50)	(2.45)
Off-peak	60.34	(13.50)	(2.45)

Note: System Usage Charges not included.

PORTLAND GENERAL ELECTRIC
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2006

	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	12 Month Avg/Total
POWER PRICES (mills per kWh)[1]													
PGE Curve 15													
On-Peak	71.84	68.53	62.41	52.73	47.13	46.36	67.25	69.04	64.07	57.57	59.87	65.22	61.00
Off-Peak	59.87	57.32	52.99	43.31	39.23	38.21	55.79	58.34	53.24	48.66	52.48	54.52	51.16
Flat	66.71	63.83	58.23	48.58	43.79	42.59	62.44	64.28	59.29	53.61	56.45	60.50	56.69
Wheeling	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80
Market Prices													
On-Peak	74.64	71.33	65.21	55.53	49.93	49.16	70.05	71.84	66.87	60.37	62.67	68.02	63.80
Off-Peak	62.67	60.12	55.79	46.11	42.03	41.01	58.59	61.14	56.04	51.46	55.28	57.32	53.96
Flat	69.51	66.63	61.03	51.38	46.59	45.39	65.24	67.08	62.09	56.41	59.25	63.30	59.49
GROUPING[2]													
SCH 7 - Residential													
Total Energy (MWh)													
On-Peak	558,009	439,177	439,966	391,055	356,191	327,896	368,438	353,680	346,688	399,573	438,784	552,579	4,972,034
Off-Peak	301,518	259,186	266,668	217,777	201,417	198,029	192,991	212,827	182,145	213,052	271,693	299,951	2,817,254
Total	859,527	698,363	706,634	608,832	557,608	525,925	561,429	566,506	528,833	612,625	710,476	852,529	7,789,288
Loss Adjustment Factor: 8.1%													
Power Costs ($000)													
On-Peak	$45,023	$33,864	$31,014	$23,474	$19,225	$17,425	$27,900	$27,466	$25,061	$26,076	$29,726	$40,631	$346,886
Off-Peak	$20,427	$16,844	$16,082	$10,855	$9,151	$8,779	$12,223	$14,066	$11,034	$11,852	$16,236	$18,586	$166,136
Total	$65,450	$50,708	$47,097	$34,329	$28,376	$26,204	$40,123	$41,533	$36,095	$37,928	$45,962	$59,217	$513,022
SCH 15 - Outdoor Area Lighting													
Residential Portion													
Energy (MWh)													
On-Peak	283	203	156	85	52	30	35	62	126	203	248	297	1,779
Off-Peak	445	431	441	413	387	361	382	428	421	447	448	446	5,049
Total	727	634	597	498	439	391	416	490	547	650	696	743	6,828
Loss Adjustment Factor: 8.1%													
Power Costs ($000)													
On-Peak	$23	$16	$11	$5	$3	$2	$3	$5	$9	$13	$17	$22	$127
Off-Peak	$30	$28	$27	$21	$18	$16	$24	$28	$26	$25	$27	$28	$296
Total	$53	$44	$38	$26	$20	$18	$27	$33	$35	$38	$44	$49	$424
Commercial Portion													
Energy (MWh)													
On-Peak	689	496	382	208	127	73	85	151	308	496	606	727	4,347
Off-Peak	1,084	1,050	1,075	1,008	944	881	932	1,046	1,030	1,095	1,096	1,092	12,333
Total	1,772	1,545	1,457	1,216	1,071	954	1,017	1,197	1,337	1,591	1,702	1,819	16,681
Loss Adjustment Factor: 8.1%													
Power Costs ($000)													
On-Peak	$56	$38	$27	$12	$7	$4	$6	$12	$22	$32	$41	$53	$311
Off-Peak	$73	$68	$65	$50	$43	$39	$59	$69	$62	$61	$66	$68	$723
Total	$129	$106	$92	$63	$50	$43	$65	$81	$85	$93	$107	$121	$1,035

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BY RATE SCHEDULE: COS LOADS
2006

	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	12 Month Avg/Total
Schedules 15R & 15C													
Total Energy (MWh)													
On-Peak	971	699	538	293	179	103	120	213	434	699	854	1,024	6,127
Off-Peak	1,529	1,480	1,516	1,422	1,331	1,242	1,314	1,474	1,451	1,542	1,544	1,538	17,382
Total	2,500	2,179	2,054	1,715	1,510	1,345	1,434	1,687	1,884	2,241	2,398	2,562	23,509
Loss Adjustment Factor:													
8.1%													
Power Costs ($000)													
On-Peak	$78	$54	$38	$18	$10	$5	$9	$17	$31	$46	$58	$75	$439
Off-Peak	$104	$96	$91	$71	$60	$55	$83	$97	$88	$86	$92	$95	$1,019
Total	$182	$150	$129	$88	$70	$61	$92	$114	$119	$131	$150	$171	$1,458
SCH 32 - Gen Serv - < 30 kW													
Total Energy (MWh)													
On-Peak	83,759	74,229	77,875	77,117	83,560	84,262	98,107	99,225	86,756	90,225	81,424	81,065	1,017,604
Off-Peak	39,818	36,565	41,500	36,782	38,886	42,541	45,956	43,734	41,697	39,458	38,901	42,557	488,396
Total	123,577	110,794	119,375	113,899	122,446	126,803	144,064	142,959	128,453	129,683	120,325	123,623	1,506,000
Loss Adjustment Factor:													
8.1%													
Power Costs ($000)													
On-Peak	$6,758	$5,724	$5,490	$4,629	$4,510	$4,478	$7,429	$7,706	$6,271	$5,888	$5,516	$5,961	$70,359
Off-Peak	$2,698	$2,376	$2,503	$1,833	$1,767	$1,886	$2,911	$2,890	$2,526	$2,195	$2,325	$2,637	$28,547
Total	$9,456	$8,100	$7,992	$6,463	$6,277	$6,364	$10,340	$10,596	$8,797	$8,083	$7,841	$8,598	$98,906
SCH 38 - Opt TOD G.S. > 30 kW													
Total Energy (MWh)													
On-Peak	2,197	1,963	2,278	2,283	2,526	2,515	2,447	2,607	2,404	2,486	2,302	2,282	28,290
Off-Peak	1,143	1,050	1,227	1,132	1,310	1,349	1,264	1,279	1,367	1,249	1,283	1,368	15,020
Total	3,340	3,013	3,505	3,415	3,836	3,864	3,711	3,886	3,771	3,735	3,585	3,650	43,309
Loss Adjustment Factor:													
8.1%													
Power Costs ($000)													
On-Peak	$177	$151	$161	$137	$136	$134	$185	$202	$174	$162	$156	$168	$1,944
Off-Peak	$77	$68	$74	$56	$60	$60	$80	$85	$83	$69	$77	$85	$874
Total	$255	$220	$235	$193	$196	$193	$265	$287	$257	$232	$233	$253	$2,817
SCH 47 - Irrig. & Drain. Pump. - < 30 kW													
Total Energy (MWh)													
On-Peak	125	130	176	447	1,235	2,560	2,985	3,197	1,938	612	236	104	13,746
Off-Peak	72	84	124	284	834	2,427	4,681	4,644	1,943	440	145	69	15,749
Total	198	214	300	732	2,069	4,987	7,666	7,841	3,882	1,053	381	173	29,495
Loss Adjustment Factor:													
8.1%													
Power Costs ($000)													
On-Peak	$10	$10	$12	$27	$67	$136	$226	$248	$140	$40	$16	$8	$940
Off-Peak	$5	$5	$7	$14	$38	$108	$296	$307	$118	$24	$9	$4	$936
Total	$15	$15	$20	$41	$105	$244	$523	$555	$258	$64	$25	$12	$1,876

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2006

	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	12 Month Avg/Total
SCH 49 Irrig. & Drain. Pump. - > 30 kW													
Total Energy (MWh)													
On-Peak	346	378	552	1,281	2,973	4,585	5,809	5,233	3,736	1,906	585	300	27,685
Off-Peak	200	245	388	814	2,007	4,348	9,111	7,603	3,745	1,371	359	201	30,391
Total	545	622	940	2,095	4,980	8,933	14,920	12,837	7,481	3,276	944	501	58,076
Loss Adjustment Factor: 8.1%													
Power Costs ($000)													
On-Peak	$28	$29	$39	$77	$160	$244	$440	$406	$270	$124	$40	$22	$1,879
Off-Peak	$14	$16	$23	$41	$91	$193	$577	$503	$227	$76	$21	$12	$1,794
Total	$41	$45	$62	$117	$252	$436	$1,017	$909	$497	$201	$61	$35	$3,673
SCH 83-S G.S. Second. > 30 kW													
Schedule 83-S LE 1,000 kW													
Energy (MWh)													
On-Peak	285,342	252,336	281,002	271,739	276,375	271,317	279,131	284,961	273,649	288,192	278,525	290,456	3,333,027
Off-Peak	156,609	136,479	154,826	148,017	152,553	153,880	169,927	169,273	159,444	164,725	154,993	160,372	1,881,097
Total	441,951	388,814	435,828	419,756	428,928	425,197	449,058	454,234	433,094	452,917	433,518	450,828	5,214,124
Schedule 83-S GT 1,000 kW													
Energy (MWh)													
On-Peak	38,753	35,364	39,282	35,563	33,654	31,276	32,625	34,578	33,472	36,230	34,982	38,595	424,373
Off-Peak	20,080	18,383	20,889	18,093	17,559	17,206	18,476	18,693	17,999	18,714	17,873	20,135	224,099
Total	58,833	53,747	60,171	53,655	51,213	48,482	51,101	53,272	51,470	54,945	52,854	58,730	648,472
Total Schedule 83-S													
On-Peak	324,095	287,700	320,285	307,302	310,029	302,593	311,755	319,539	307,121	324,423	313,507	329,051	3,757,400
Off-Peak	176,689	154,861	175,715	166,109	170,111	171,086	188,404	187,966	177,443	183,439	172,866	180,507	2,105,196
Total	500,783	442,561	495,999	473,411	480,141	473,679	500,159	507,505	484,564	507,862	486,373	509,559	5,862,596
Loss Adjustment Factor: 8.1%													
Power Costs LE 1,000 kW($000)													
On-Peak	$23,023	$19,457	$19,808	$16,312	$14,917	$14,418	$21,137	$22,130	$19,781	$18,807	$18,869	$21,357	$230,017
Off-Peak	$10,610	$8,870	$9,337	$7,378	$6,931	$6,822	$10,762	$11,188	$9,659	$9,163	$9,262	$9,937	$109,919
Total	$33,633	$28,327	$29,146	$23,690	$21,848	$21,240	$31,899	$33,317	$29,440	$27,971	$28,131	$31,294	$339,937
Power Costs GT 1,000 kW($000)													
On-Peak	$3,127	$2,727	$2,769	$2,135	$1,816	$1,662	$2,470	$2,685	$2,420	$2,364	$2,370	$2,838	$29,383
Off-Peak	$1,360	$1,195	$1,260	$902	$798	$763	$1,170	$1,235	$1,090	$1,041	$1,068	$1,248	$13,130
Total	$4,487	$3,922	$4,029	$3,037	$2,614	$2,425	$3,641	$3,921	$3,510	$3,405	$3,438	$4,086	$42,513
Total Schedule 83-S													
On-Peak	$26,150	$22,184	$22,578	$18,447	$16,734	$16,080	$23,607	$24,815	$22,201	$21,172	$21,239	$24,195	$259,401
Off-Peak	$11,970	$10,064	$10,597	$8,280	$7,729	$7,585	$11,933	$12,423	$10,749	$10,204	$10,330	$11,185	$123,049
Total	$38,120	$32,248	$33,175	$26,726	$24,463	$23,665	$35,540	$37,238	$32,950	$31,376	$31,569	$35,380	$382,450

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2006

	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	12 Month Avg/Total
SCH 83-P G.S. Primary													
Schedule 83-P LE 1,000 kW													
Energy (MWh)													
On-Peak	10,737	9,521	10,639	11,000	11,009	10,830	11,957	11,443	10,834	10,575	10,640	10,796	129,979
Off-Peak	6,900	5,778	6,756	6,622	6,716	6,657	8,443	7,567	7,116	6,712	6,629	6,584	82,481
Total	17,637	15,298	17,395	17,622	17,725	17,487	20,400	19,010	17,950	17,287	17,270	17,380	212,460
Sch 83-P GT 1,000 kW													
Energy (MWh)													
On-Peak	111,489	101,390	114,217	112,564	113,481	112,402	118,683	117,209	114,942	115,793	110,120	111,402	1,353,691
Off-Peak	74,163	67,610	76,836	74,234	77,210	75,933	83,225	79,392	78,438	77,483	73,029	75,129	912,683
Total	185,652	169,000	191,054	186,798	190,691	188,335	201,907	196,601	193,380	193,276	183,149	186,531	2,266,374
Total Energy (MWh)													
On-Peak	122,225	110,911	124,857	123,564	124,490	123,232	130,639	128,652	125,776	126,367	120,760	122,198	1,483,670
Off-Peak	81,063	73,388	83,592	80,856	83,926	82,590	91,668	86,960	85,554	84,196	79,658	81,713	995,164
Total	203,289	184,298	208,449	204,420	208,416	205,822	222,307	215,611	211,330	210,563	200,419	203,911	2,478,834
Loss Adjustment Factor:													
4.3%													
Power Costs LE 1,000 kW($000)													
On-Peak	$836	$708	$724	$637	$573	$555	$874	$857	$756	$666	$695	$766	$8,647
Off-Peak	$451	$362	$393	$318	$294	$285	$516	$483	$416	$360	$382	$394	$4,655
Total	$1,287	$1,071	$1,117	$956	$868	$840	$1,390	$1,340	$1,172	$1,026	$1,078	$1,160	$13,302
Power Costs GT 1,000 kW($000)													
On-Peak	$8,679	$7,543	$7,768	$6,519	$5,910	$5,763	$8,671	$8,782	$8,017	$7,291	$7,198	$7,903	$90,046
Off-Peak	$4,848	$4,239	$4,471	$3,570	$3,385	$3,248	$5,086	$5,063	$4,585	$4,159	$4,211	$4,492	$51,355
Total	$13,527	$11,783	$12,239	$10,090	$9,294	$9,011	$13,757	$13,845	$12,601	$11,450	$11,409	$12,395	$141,401
Total Schedule 83-P													
On-Peak	$9,515	$8,251	$8,492	$7,157	$6,483	$6,319	$9,545	$9,640	$8,772	$7,957	$7,893	$8,669	$98,693
Off-Peak	$5,299	$4,602	$4,864	$3,889	$3,679	$3,533	$5,602	$5,545	$5,001	$4,519	$4,593	$4,885	$56,010
Total	$14,814	$12,853	$13,356	$11,045	$10,162	$9,851	$15,147	$15,185	$13,773	$12,476	$12,486	$13,554	$154,703
SCH 83-T G.S. Subtransmission													
Calendar Energy (MWh)													
On-Peak	32,315	30,649	32,980	32,257	33,191	31,154	33,401	29,514	32,751	33,502	31,500	32,455	385,670
Off-Peak	23,286	22,081	23,907	23,281	24,106	22,465	24,157	21,638	23,607	24,057	22,712	23,652	278,948
Total	55,601	52,730	56,887	55,538	57,297	53,619	57,557	51,153	56,358	57,559	54,212	56,106	664,619
Loss Adjustment Factor:													
2.6%													
Power Costs ($000)													
On-Peak	$2,475	$2,243	$2,207	$1,838	$1,700	$1,571	$2,401	$2,175	$2,247	$2,075	$2,025	$2,265	$25,222
Off-Peak	$1,497	$1,362	$1,368	$1,101	$1,040	$945	$1,452	$1,357	$1,357	$1,270	$1,288	$1,391	$15,430
Total	$3,972	$3,605	$3,575	$2,939	$2,740	$2,517	$3,853	$3,533	$3,604	$3,345	$3,314	$3,656	$40,652

PORTLAND GENERAL ELECTRIC
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2006

	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	12 Month Avg/Total
SCH 91 - St & Highway Lighting													
Total Energy (MWh)													
On-Peak	4,014	2,872	2,202	1,184	715	404	478	862	1,757	2,876	3,538	4,272	25,173
Off-Peak	6,318	6,080	6,206	5,740	5,316	4,887	5,238	5,965	5,875	6,345	6,397	6,413	70,782
Total	10,332	8,952	8,408	6,925	6,031	5,292	5,716	6,827	7,632	9,221	9,935	10,685	95,955
Loss Adjustment Factor: 8.1%													
Power Costs ($000)													
On-Peak	$324	$221	$155	$71	$39	$21	$36	$67	$127	$188	$240	$314	$1,803
Off-Peak	$428	$395	$374	$286	$242	$217	$332	$394	$356	$353	$382	$397	$4,156
Total	$752	$617	$529	$357	$280	$238	$368	$461	$483	$541	$622	$712	$5,960
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: 8.1%													
Power Costs ($000)													
On-Peak	$23	$22	$20	$17	$15	$15	$21	$22	$21	$18	$20	$21	$234
Off-Peak	$15	$14	$13	$11	$10	$9	$13	$14	$13	$11	$13	$13	$148
Total	$38	$36	$33	$28	$25	$24	$34	$35	$34	$29	$33	$34	$383
SCH 93 - Rec Field Lighting													
Total Energy (MWh)													
On-Peak	13	13	18	26	29	41	30	30	69	67	26	14	375
Off-Peak	10	10	13	10	21	32	20	16	17	18	12	11	190
Total	24	23	31	36	49	73	50	47	86	85	37	25	565
Loss Adjustment Factor: 8.1%													
Power Costs ($000)													
On-Peak	$1	$1	$1	$2	$2	$2	$2	$2	$5	$4	$2	$1	$25
Off-Peak	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$11
Total	$2	$2	$2	$2	$2	$4	$4	$3	$6	$5	$2	$2	$36
SCH 97 Drain. Districts													
Total Energy (MWh)													
On-Peak	84	63	71	32	28	26	16	13	12	22	49	69	485
Off-Peak	124	141	120	90	67	30	14	11	10	19	50	109	785
Total	208	204	191	122	95	56	31	24	22	41	98	177	1,270
Loss Adjustment Factor: 8.1%													
Power Costs ($000)													
On-Peak	$7	$5	$5	$2	$2	$1	$1	$1	$1	$1	$3	$5	$34
Off-Peak	$8	$9	$7	$4	$3	$1	$1	$1	$1	$1	$3	$7	$47
Total	$15	$14	$12	$6	$5	$3	$2	$2	$1	$2	$6	$12	$81

PORTLAND GENERAL ELECTRIC
MARKET-BASED POWER SUPPLY COST CALCULATION
BY RATE SCHEDULE: COS LOADS
2006

	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	12 Month Avg/Total
TOTAL													
Energy (MWh)													
On-Peak	1,128,441	949,066	1,002,080	937,127	915,427	879,653	954,503	943,043	909,731	983,033	993,854	1,125,694	11,721,652
Off-Peak	631,985	555,384	601,186	534,513	529,544	531,239	565,026	574,327	525,072	555,392	595,836	638,299	6,837,803
Total	1,760,426	1,504,450	1,603,266	1,471,640	1,444,971	1,410,892	1,519,528	1,517,371	1,434,802	1,538,425	1,589,690	1,763,993	18,559,455
Power Costs ($000)													
On-Peak	$90,570	$72,759	$70,211	$55,895	$49,082	$46,432	$71,802	$72,768	$65,321	$63,752	$66,934	$82,335	$807,861
Off-Peak	$42,541	$35,854	$36,006	$26,442	$23,870	$23,371	$35,504	$37,684	$31,553	$30,663	$35,369	$39,298	$398,157
Total	$133,111	$108,613	$106,217	$82,337	$72,952	$69,803	$107,307	$110,452	$96,875	$94,414	$102,303	$121,633	$1,206,017
Average Power Costs													
On-Peak	80.26	76.66	70.07	59.64	53.62	52.78	75.22	77.16	71.80	64.85	67.35	73.14	68.92
Off-Peak	67.31	64.56	59.89	49.47	45.08	43.99	62.84	65.61	60.09	55.21	59.36	61.57	58.23
Total	75.61	72.19	66.25	55.95	50.49	49.47	70.62	72.79	67.52	61.37	64.35	68.95	64.98
Energy (MWh)													
Residential													Avg/Total
On-Peak	558,292	439,380	440,123	391,140	356,243	327,926	368,473	353,741	346,814	399,776	439,031	552,876	4,973,814
Off-Peak	301,963	259,617	267,109	218,190	201,804	198,390	193,373	213,255	182,566	213,499	272,141	300,396	2,822,303
													7,796,116
Small Non-residential													
On-Peak	84,573	74,855	78,432	77,772	84,922	86,894	101,177	102,573	89,002	91,334	82,267	81,896	1,035,697
Off-Peak	40,975	37,699	42,699	38,075	40,664	45,849	51,570	49,425	44,670	40,993	40,142	43,719	516,478
													1,552,175
Large non-residential													
On-Peak	485,576	434,831	483,525	468,215	474,262	464,833	484,853	486,729	473,915	491,924	472,556	490,922	5,712,141
Off-Peak	289,048	258,069	291,379	278,248	287,077	287,000	320,083	311,647	297,836	300,899	283,553	294,184	3,499,022
													9,211,163
												Totals	18,559,455
Market Value of Power ($000)													
Residential	$65,503	$50,752	$47,134	$34,355	$28,397	$26,222	$40,150	$41,566	$36,130	$37,966	$46,005	$59,266	$513,445
Small Non-residential	$9,600	$8,222	$8,104	$6,566	$6,431	$6,650	$10,928	$11,232	$9,140	$8,241	$7,972	$8,731	$101,817
Large non-residential	$58,008	$49,639	$50,979	$41,415	$38,124	$36,932	$56,229	$57,654	$51,605	$48,208	$48,326	$53,636	$590,755
Total	$133,111	$108,613	$106,217	$82,337	$72,952	$69,803	$107,307	$110,452	$96,875	$94,414	$102,303	$121,633	$1,206,017
	58,008	49,639	50,979	41,415	38,124	36,932	56,229	57,654	51,605	48,208	48,326	53,636	$590,755

[1] Forward curve prices of 3/8/05.

[2] On and off peak energy usages (Sunday-only off-peak basis) derived from 2001 & 2002 load research data of average customers and grouping usage from 2005 Billing Determinants in workpapers, or specifics in Forecast SMAR05G06.

PORTLAND GENERAL ELECTRIC
RVM Adjustment Rate Development
Projected 2006 Power Costs[1]
Resource Stacking: Average Hydro Conditions
3/8/05 Forward Curve
($000)

Customer Class	2006 Total	Revised Total
Residential		
Long Term Resources		
VPC[2]	$99,209	$99,791
Fixed	$78,950	$78,950
Wheeling	$15,579	$15,670
Subtotal	$193,737	$194,411
Term Purchases[4]	$55,798	$56,126
Market Purchases/Sales	$59,959	$60,311
Subtotal	$115,757	$116,437
BPA Subscription[5]	$44,851	$45,114
Total	$354,345	$355,963
Sm. Non-Residential		
Long Term Resources		
VPC[2]	$19,299	$19,412
Fixed	$15,358	$15,358
Wheeling	$3,030	$3,048
Subtotal	$37,687	$37,818
Term Purchases[4]	$19,271	$19,384
Market Purchases/Sales	$16,749	$16,847
Subtotal	$36,019	$36,231
BPA Subscription[5]	$1,741	$1,751
Total	$75,447	$75,800
Lg. Non-Residential		
Long Term Resources		
VPC[2]	$149,192	$150,068
Fixed	$118,726	$118,726
Wheeling	$23,428	$23,565
Subtotal	$291,346	$292,360
Term Purchases[4]	$69,392	$69,799
Market Purchases/Sales	$63,894	$64,270
Subtotal	$133,286	$134,069
BPA Subscription[5]	$2,346	$2,360
Total	$426,978	$428,789
All Classes		
Long Term Resources		
VPC	$267,699	$269,272
Fixed[3]	$213,034	$213,034
Wheeling	$42,037	$42,284
Subtotal	$522,770	$524,589
Term Purchases	$144,461	$145,309
Market Purchases/Sales	$140,602	$141,428
Subtotal	$285,063	$286,737
BPA Subscription	$48,938	$49,226
Grand Total	$856,771	$860,552
Non-Fixed Costs - Total	$643,737	$647,518
Target Revenue Requirement of Non-Fixed Costs		$647,518
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] 2006 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
3/8/05 Forward Curve

	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Wgt Avg	Resource Pct of Class	Market Value ($000)
HOURS	744	672	744	719	744	720	744	744	720	745	720	744	8,760		
RESIDENTIAL															
Long Term Resources															
PGE Hydro	107	102	99	96	91	74	56	51	52	59	82	100			
Mid-C & PHP Hydro	145	136	109	127	138	152	128	112	79	103	128	134			
Coal	227	227	227	204	72	186	229	229	229	229	229	229			
Gas	82	80	79	60	(0)	1	176	197	120	80	82	82			
Old Contracts	33	34	35	39	42	45	34	32	19	59	62	61			
Subtotal	594	579	549	526	343	458	622	621	498	530	582	604	542	56.36%	$289,365
Net ST Purchases/Sales	410	301	235	148	231	101	(34)	(27)	64	360	486	635	243	25.21%	$129,425
BPA Subscription	246	245	243	241	237	232	228	229	233	0	0	0	177	18.44%	$94,655
Total	1,250	1,124	1,028	916	811	790	816	824	795	890	1,068	1,240	962		$513,445
SMALL NON-RESIDENTIAL															
Long Term Resources															
PGE Hydro	21	20	19	19	18	14	11	10	10	11	16	19			
Mid-C & PHP Hydro	28	26	21	25	27	30	25	22	15	20	25	26			
Coal	44	44	44	40	14	36	45	45	45	45	45	45			
Gas	16	16	15	12	(0)	0	34	38	23	16	16	16			
Old Contracts	6	7	7	8	8	9	7	6	4	12	12	12			
Subtotal	116	113	107	102	67	89	121	121	97	103	113	118	105	55.06%	$56,064
Net ST Purchases/Sales	62	63	63	65	107	99	88	87	93	89	71	65	79	41.49%	$42,244
BPA Subscription	5	5	6	7	9	11	13	13	11	0	0	0	7	3.45%	$3,508
Total	182	181	176	174	182	199	222	221	201	192	184	183	192		$101,817
LARGE NON-RESIDENTIAL															
Long Term Resources															
PGE Hydro	161	154	149	144	137	111	84	76	78	88	123	150			
Mid-C & PHP Hydro	218	204	165	192	208	229	192	169	119	155	193	201			
Coal	342	342	342	307	109	279	344	344	344	344	344	344			
Gas	123	121	119	90	(0)	1	264	297	180	120	123	123			
Old Contracts	49	51	52	59	63	67	50	48	28	89	93	91			
Subtotal	893	871	826	792	516	688	935	934	748	797	875	909	815	72.69%	$429,397
Net ST Purchases/Sales	211	221	276	306	563	411	202	195	380	339	245	217	297	26.51%	$156,628
BPA Subscription	7	8	9	10	12	15	17	16	14	0	0	0	9	0.80%	$4,731
Total	1,111	1,100	1,111	1,107	1,091	1,114	1,154	1,145	1,143	1,135	1,120	1,126	1,122		$590,755
ALL CLASSES															
Long Term Resources															
PGE Hydro	290	276	268	259	245	200	151	137	139	158	220	269			
Mid-C & PHP Hydro	392	366	295	344	373	410	345	303	213	277	346	361			
Coal	613	613	613	551	195	501	617	617	617	617	617	617			
Gas	221	217	213	161	(1)	3	474	533	323	216	221	220			
Old Contracts	88	91	94	106	113	121	90	86	50	161	166	163			
Subtotal	1,603	1,562	1,483	1,420	926	1,235	1,678	1,676	1,343	1,429	1,571	1,631	1,463	64.30%	$774,826
Net ST Purchases/Sales	683	585	574	519	901	611	257	255	538	788	801	918	619	27.22%	$328,297
BPA Subscription	258	258	258	258	258	258	258	258	258	0	0	0	193	8.48%	$102,894
Total	2,543	2,405	2,315	2,198	2,085	2,103	2,192	2,190	2,139	2,217	2,372	2,548	2,275		$1,206,017

PORTLAND GENERAL ELECTRIC
RVM Adjustment Rate Development
Projected Production Costs and Market Value of Power
Resource Stacking: Average Hydro
3/8/05 Forward Curve
($000)

Customer Class	Production Costs	Market Value of Power
Residential		
Long Term Resources	$194,411	$289,365
Term & Mkt Purchases & Sales	$116,437	$129,425
BPA Subscription	$45,114	$94,655
Total	$355,963	$513,445
Sm. Non-Residential		
Long Term Resources	$37,818	$56,064
Term & Mkt Purchases & Sales	$36,231	$42,244
BPA Subscription	$1,751	$3,508
Total	$75,800	$101,817
Lg. Non-Residential		
Long Term Resources	$292,360	$429,397
Term & Mkt Purchases & Sales	$134,069	$156,628
BPA Subscription	$2,360	$4,731
Total	$428,789	$590,755
All Classes		
Long Term Resources	$524,589	$774,826
Term & Mkt Purchases & Sales	$286,737	$328,297
BPA Subscription	$49,226	$102,894
Total	$860,552	$1,206,017

PORTLAND GENERAL ELECTRIC
RVM Adjustment Rate Development
Production Costs and Market Value of Power
Resource Stacking: Average Hydro
3/8/05 Forward Curve
($000)

		Revenues				
Customer Class	Costs	Market Value	Sch 125a	Sch 125b	BPA Credit For Power	Total
Residential						
Long Term Resources	$194,411	$289,365	($94,953)			$194,411
Term & Mkt Purchases & Sales	$116,437	$129,425		($12,988)		$116,437
BPA Subscription	$45,114	$94,655			($49,541)	$45,114
Total	$355,963	$513,445	($94,953)	($12,988)	($49,541)	$355,963
Sm. Non-Residential						
Long Term Resources	$37,818	$56,064	($18,246)			$37,818
Term & Mkt Purchases & Sales	$36,231	$42,244		($6,013)		$36,231
BPA Subscription	$1,751	$3,508			($1,757)	$1,751
Total	$75,800	$101,817	($18,246)	($6,013)	($1,757)	$75,800
Lg. Non-Residential						
Long Term Resources	$292,360	$429,397	($137,037)			$292,360
Term & Mkt Purchases & Sales	$134,069	$156,628		($22,559)		$134,069
BPA Subscription	$2,360	$4,731			($2,371)	$2,360
Total	$428,789	$590,755	($137,037)	($22,559)	($2,371)	$428,789
All Classes						
Long Term Resources	$524,589	$774,826	($250,237)			$524,589
Term & Mkt Purchases & Sales	$286,737	$328,297		($41,560)		$286,737
BPA Subscription	$49,226	$102,894			($53,669)	$49,226
Total	$860,552	$1,206,017	($250,237)	($41,560)	($53,669)	$860,552

PORTLAND GENERAL ELECTRIC
RVM ADJUSTMENT RATE DEVELOPMENT
SCHEDULE 125: PROJECTED RVM ADJUSTMENT RATES
2006

	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	7,789,288	($94,874)	(12.18)	7,789,288	($13,008)	(1.67)	($107,882)	(13.85)
Portion of SCH 15 - Outdoor Area Lighting	6,828	($83)	(12.18)	6,828	($11)	(1.67)	($95)	(13.85)
Subtotal	7,796,116	($94,953)	(12.18)	7,796,116	($12,988)	(1.67)	($107,976)	(13.85)
SMALL NON-RESIDENTIAL								
Portion of SCH 15 - Outdoor Area Lighting	16,681	($196)	(11.76)	16,681	($65)	(3.87)	($261)	(15.63)
SCH 32 - General Service <30 kW	1,506,000	($17,711)	(11.76)	1,506,000	($5,828)	(3.87)	($23,539)	(15.63)
SCH 47 - Irrig. & Drain. Pump. - < 30 kW	29,495	($347)	(11.76)	29,495	($114)	(3.87)	($461)	(15.63)
Subtotal	1,552,175	($18,246)	(11.76)	1,552,175	($6,013)	(3.87)	($24,260)	(15.63)
LARGE NON-RESIDENTIAL								
SCH 38 - Opt Time-of-Day G.S. > 30 kW	43,309	($585)	(13.50)	43,309	($106)	(2.45)	($691)	(15.95)
SCH 49 - Irrig. & Drain. Pump. - > 30 kW	58,076	($784)	(13.50)	58,076	($142)	(2.45)	($926)	(15.95)
SCH 83-S General Service >30 kW	6,047,279	($81,638)	(13.50)	5,862,596	($14,363)	(2.45)	($96,002)	(15.95)
SCH 83-P - Primary	2,757,402	($37,225)	(13.50)	2,478,834	($6,073)	(2.45)	($43,298)	(15.95)
SCH 83-T - Subtransmission	1,138,753	($15,373)	(13.50)	664,619	($1,628)	(2.45)	($17,001)	(15.95)
SCH 91 - Street & Highway Lighting	95,955	($1,295)	(13.50)	95,955	($235)	(2.45)	($1,530)	(15.95)
SCH 92 - Traffic Signals	5,939	($80)	(13.50)	5,939	($15)	(2.45)	($95)	(15.95)
SCH 93 - Recreational Field Lighting	565	($8)	(13.50)	565	($1)	(2.45)	($9)	(15.95)
SCH 97 - Drainage Districts	1,270	($17)	(13.50)	1,270	($3)	(2.45)	($20)	(15.95)
Schedule 129		($31)						
Subtotal	10,148,549	($137,006)	(13.50)	9,211,163	($22,559)	(2.45)	($159,573)	(15.95)
TOTAL	19,496,840	($250,205)		18,559,455	($41,560)		($291,809)	
TOTAL with Sch 76R & 483	19,597,015			1,037,560	(optout)			

Schedule 129 revenues are subtracted from 125a

PORTLAND GENERAL ELECTRIC
ESTIMATE OF 2006 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)	2,006,310	65.86	(12.18)	(1.67)	52.01	104,348
Block 2 (over 250)	5,782,978	65.86	(12.18)	(1.67)	52.01	300,773
SCH 15 - Outdoor Area Lighting						
Residential portion	6,828	62.02	(11.88)	(3.23)	46.91	320
Commercial portion	16,681	62.02	(11.88)	(3.23)	46.91	782
SCH 32 - General Service <30 kW	1,506,000	65.67	(11.76)	(3.87)	50.04	75,360
SCH 38 - Opt Time-of-Day G.S. >30 kW						
On-peak	22,014	71.80	(13.50)	(2.45)	55.85	1,229
Off-peak	21,296	58.07	(13.50)	(2.45)	42.12	897
SCH 47 - Irrig. & Drain. Pump. - <30 kW						
First 50 kWh per kW	5,537	87.73	(11.76)	(3.87)	72.10	399
Over 50 kWh per kW	23,958	58.21	(11.76)	(3.87)	42.58	1,020
SCH 49 - Irrig. & Drain. Pump. - >30 kW						
First 50 kWh per kW	20,651	82.38	(13.50)	(2.45)	66.43	1,372
Over 50 kWh per kW	37,425	52.86	(13.50)	(2.45)	36.91	1,381
SCH 83-S General Service >30 kW						
Flat (less than 1,000 kW)	5,214,124	65.20	(13.50)	(2.45)	49.25	256,796
On-peak (greater than 1,000 kW)	424,373	69.24	(13.50)	(2.45)	53.29	22,615
Off-peak (greater than 1,000 kW)	224,099	58.59	(13.50)	(2.45)	42.64	9,556
SCH 83-P - Primary						
Flat (less than 1,000 kW)	212,460	62.61	(13.50)	(2.45)	46.66	9,913
On-peak (greater than 1,000 kW)	1,353,691	66.52	(13.50)	(2.45)	50.57	68,456
Off-peak (greater than 1,000 kW)	912,683	56.27	(13.50)	(2.45)	40.32	36,799
SCH 83-T - Subtransmission						
On-peak	385,670	65.40	(13.50)	(2.45)	49.45	19,071
Off-peak	278,948	55.31	(13.50)	(2.45)	39.36	10,979
SCH 91 - Street & Highway Lighting	95,955	62.11	(13.50)	(2.45)	46.16	4,429
SCH 92 - Traffic Signals	5,939	64.41	(13.50)	(2.45)	48.46	288
SCH 93 - Recreational Field Lighting	565	63.81	(13.50)	(2.45)	47.86	27
SCH 97 - Drainage Districts						
On-peak	444	69.96	(13.50)	(2.45)	54.01	24
Off-peak	826	60.34	(13.50)	(2.45)	44.39	37
Totals	18,559,455					$926,873
BPA Power Credit						($53,669)
Schedule 125a revenues from optout loads						($12,655)
Schedule 129						($31)
Total Energy Revenues						$860,519