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April 2, 2007

**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 COMPANY  
2008 Annual Power Cost Update Tariff (Schedule 125) filing**

Attention Filing Center:

Enclosed for filing in the captioned dockets are an original is the following:

Original and five copies of testimony of:

- **L. Alex Tooman, Jay Tinker, and Stephen Schue (Power Cost) (PGE/100-101); and**
- **Marc Cody (Pricing) (PGE/200-201).**

Two copies on CD and three paper copies of:

- **Work Papers (non-confidential portions only).**

Original and one copy of:

- **Portland General Electric Company's Motion for Protective Order.**

PGE will submit the confidential work papers after entry of a Protective Order.

PGE's initial forecast of 2008 NVPC is \$777 million. At this level of NVPC, PGE projects an overall rate reduction effective January 1, 2008 of 0.4%.

This document is being filed by electronic mail with the Filing Center. An extra copy of this cover letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided.

April 2, 2007  
Page 2

Thank you in advance for your assistance.

Sincerely,

A handwritten signature in black ink, appearing to read "D. Tingey".

DOUGLAS C. TINGEY

DCT:jbf  
Enclosure  
cc: Service List-UE 188

**CERTIFICATE OF SERVICE**

I hereby certify that I have this day caused the **DIRECT TESTIMONY AND WORK PAPERS (non-confidential portions only) and MOTION FOR PROTECTIVE ORDER OF PORTLAND GENERAL ELECTRIC COMPANY** to be served by electronic mail to those parties whose email addresses appear on the attached UE 188 service list, and by First Class US Mail, postage prepaid and properly addressed, to those parties on the attached service list who have not waived paper service.

Dated this 2nd day of April 2007.

  
\_\_\_\_\_  
DOUGLAS C. TINGEY

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**BEFORE THE PUBLIC UTILITY COMMISSION  
OF THE STATE OF OREGON**

# **Power Costs**

**PORTLAND GENERAL ELECTRIC COMPANY**

Direct Testimony and Exhibits of

*L. Alex Tooman- Jay Tinker – Stephen Schue*

April 2, 2007

**Power Costs**

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## I. Introduction

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

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

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

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

10 Our qualifications appear at the end of this testimony.

11 **Q. What is the purpose of your testimony?**

12 A. The purpose of our testimony is to provide the initial Annual Update Tariff (AUT) forecast  
13 of PGE's 2008 net variable power costs (NVPC) and compare this estimate with the 2007  
14 general rate case (GRC) NVPC approved in Order No. 07-105. We also explain why per  
15 unit NVPC have decreased slightly from 2007 to 2008, which translates into the rate  
16 reduction described in PGE Exhibit 200.

17 **Q. What is your AUT net variable power cost estimate?**

18 A. Our 2008 AUT forecast is \$777 million, based on contracts through and forward curves on  
19 January 25, 2007.

20 **Q. How is the remainder of your testimony organized?**

21 A. Our testimony includes the following sections:

- 22
  - Section II: Monet model

- 1       • Section III:       Load forecast
- 2       • Section IV:       Comparison with 2007 GRC NVPC estimate
- 3       • Section V:        Update schedule and relationship with other dockets
- 4       • Section VI:       Qualifications

## II. Monet Model

1 **Q. How did PGE model net variable power costs (NVPC) for the 2008 test year?**

2 A. We used our power cost forecasting model, called “MONET,” (or Monet)

3 **Q. Please describe Monet.**

4 A. We built this model in the mid-1990s and have since incorporated several refinements.

5 Monet models the hourly dispatch of our generating units. Each thermal unit has an  
6 individual profile that includes its capacity, heat rate, fuel costs, variable operation and

7 maintenance costs, and other characteristics. Monet models hydroelectric units with peak

8 capabilities and annual, monthly, and hourly usage factors, except the Mid-Columbia

9 facilities, for which Monet uses hourly dispatch logic. For the Biglow Canyon wind project,

10 Monet assumes an hourly output profile based on a numerical weather prediction model

11 simulation which was then calibrated against actual historical data. Since the emergence of

12 forward markets, PGE has input the forward market curves for purchased power and gas,

13 and then run its dispatchable resources, including its gas-fired plants, in Monet under a

14 “dispatch to forward market curve” mode.

15 **Q. How does Monet then forecast NVPC?**

16 A. Monet minimizes power costs by economically dispatching plants and making market

17 purchases and sales. To do this, the model employs the following data inputs:

18 • Forecasted retail loads, on an hourly basis;

19 • Physical and financial fuel contract prices and quantities, and related  
20 transportation costs;

21 • Thermal plants, with forced outage rates and scheduled maintenance outage days,  
22 maximum operating capabilities, heat rates, and any variable operating and

1 maintenance costs (although not part of net variable power costs for ratemaking  
2 purposes);

- 3 • Hydroelectric plants, with output reflecting current non-power operating  
4 constraints (such as for fish passage) and peak, annual, seasonal, and hourly  
5 maximum usage capabilities, except in the case of the Mid-Columbia facilities,  
6 for which Monet includes hourly dispatch logic;
- 7 • Wind turbines, with hourly output reflecting historical data if no related  
8 integration products have been purchased;
- 9 • Transmission (wheeling) contract costs;
- 10 • Physical and financial electric contract purchases and sales; and
- 11 • Forward market curves for gas and electric market purchases and sales.

12 Using these data inputs, Monet dispatches PGE resources to meet customer loads based  
13 on the principle of economic dispatch. Generally, any plant is dispatched when it is  
14 available and its dispatch cost is below the market electric price, subject to operational  
15 constraints, such as minimum unit commitment times. Specifically, plants can be operated  
16 in various stages – maximum availability, starting up, ramping up to maximum availability,  
17 shutting down, or off-line. Given thermal output, expected hydro generation, and contract  
18 purchases and sales, Monet fills any resulting gap between total resource output and PGE's  
19 retail load with market purchases (or sales) based on the forward market price curve.

20 **Q. Has PGE provided additional information on Monet in other dockets?**

21 A. Yes. PGE Exhibit 100 in our 2006 RVM filing (Docket UE 172) and PGE Exhibit 400 in  
22 our most recent general rate case (Docket UE 180) describe Monet in detail.

23 **Q. How does PGE define NVPC?**

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

11 **Q. Has PGE incorporated major changes to Monet in the 2008 test year NVPC estimates?**

12 A. No. For the AUT forecast, we limited changes to the five updates specified in Order  
13 No. 07-015. These are:

- 14 • Hourly loads for the forecast year.
- 15 • New physical and financial contracts and changes to existing contracts for power,  
16 fuel, fuel transportation, or transmission/wheeling.
- 17 • Forced outage rates, using the traditional four-year weighted, rolling-average  
18 methodology.<sup>1</sup>
- 19 • Planned maintenance outage days for the forecast year.
- 20 • Forward curves for long or short open power, natural gas, oil, or U.S./Canadian  
21 foreign exchange rate positions.<sup>2</sup>

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<sup>1</sup> This is consistent with the Order's direction to retain the current four-year rolling average methodology.

<sup>2</sup> The forward curves also impact MONET's modeling of plant dispatch.

1 **Q. You mention how you have incorporated an Order 07-015 provision for the forced**  
2 **outage rates. What did Order No. 07-015 require concerning the forecasted forced**  
3 **outage rates for PGE's plants?**

4 A. The Order calls for continuation of the current method – using the four-year rolling average  
5 forced outage rate (four-year average). This method bases the forecasted forced outage rate  
6 on historical data.

7 **Q. What did Order No. 07-015 require concerning Boardman's forced outage rate?**

8 A. The Order calls for removing the period November 18, 2005, through December 31, 2005,  
9 when calculating Boardman's four-year average for 2007. This four-year period is part of  
10 PGE's deferral request in UM 1234, and thus Order No. 07-015's forced outage rate  
11 provisions should apply. For the 2008 test year, we removed the period January 1 through  
12 February 5, 2006, also part of UM 1234, when calculating the four-year forced outage rate.

13 **Q. PGE committed to exclude the cost of a second outage beginning February 6, 2006.**  
14 **How did you make this adjustment?**

15 A. The UM 1234 deferral request concerned replacement power costs related to a forced outage  
16 caused by damage to Boardman's steam turbine rotor. On February 6, 2006, while returning  
17 the plant to service, the generator rotor was damaged, resulting in another extended forced  
18 outage. PGE, however, determined that it would not seek recovery of excess costs resulting  
19 from this second outage. In reference to this outage, from the UM 1234 Oral Arguments  
20 held October 3, 2006:

We didn't then and we don't now want to ask our customers to bear any responsibility for that. We're not seeking to defer those costs, and we won't seek to include those outage days in any future forecast, should we still use historical operations in creating that forecast.

1 This was reiterated in several of PGE's SEC filings. For example, PGE's  
2 September 30, 2006, 10-Q stated:

PGE did not file an application to defer incremental power costs related to the generator rotor outage (February 6, 2006 through late May 2006), and will not propose the inclusion of this outage in the 4-year rolling average of forced outages in its annual power cost update filings starting in 2008.

3 PGE eliminated the period February 6 through May 22, 2006, from Boardman's forced  
4 outage calculation in a manner consistent with the OPUC Staff calculation approved by  
5 OPUC Order No. 07-015.

6 **Q. Were there other outages related to the UM 1234 outage in 2006?**

7 A. Yes, after the second outage, Boardman operated generally at less than full power until  
8 May 25, 2006, when it was taken off-line because it was not economic to dispatch – PGE  
9 could purchase power at a cost lower than Boardman's incremental cost. PGE next  
10 dispatched Boardman on June 1, 2006. However, it was taken off-line to investigate excess  
11 bearing vibrations in the low-pressure rotor 1 (LP1). PGE attempted to correct the vibration  
12 over the next two days, but was unsuccessful. Boardman was removed from service on  
13 June 2 for repairs to a loose coupling at LP1. This issue is directly related to the UM 1234  
14 deferral outage (October 2005 through February 5, 2006) because it concerns LP1, the  
15 failure of which was the subject of UM 1234. Repairs were relatively simple, taking about  
16 16 labor hours. The work, however, had to wait for the turbine to cool down. Coupling  
17 repairs were completed on June 6 and the plant would then have returned to service had the  
18 plant operators not discovered another problem, a loose balance weight at the low pressure  
19 rotor 2 (LP2) end connected to the generator.

20 **Q. Was this LP2 loose balance weight issue related to either of the two previous outages?**

1 A. No. This LP2 issue, and the resulting outage, were independent of both of the preceding  
2 outages. The damaged balance weight was only discovered because the plant was off-line to  
3 repair the loose coupling. In fact, had the plant not been off-line, it is possible that the  
4 damage from the loose balance weight could have been much worse. Repairs to LP2 took  
5 approximately three weeks, with the plant returning to service on June 28, and released for  
6 dispatch on July 1, 2006.

7 **Q. How did PGE treat this third outage for purposes of this filing?**

8 A. As the third outage is partially due to UM 1234, we removed those hours related to  
9 UM 1234 from our forced outage calculations. PGE Exhibit 101 is a work order  
10 documenting repairs to the loose coupling which were completed on June 6, 2006. For  
11 forced outage rate calculations we assumed that the unrelated portion of the outage began on  
12 June 7, 2006.

13 **Q. What is the result of the above assumptions?**

14 A. We removed all hours from January 1 through June 6, 2006, for Boardman forced outage  
15 rate calculations in a manner consistent with the OPUC Staff calculation approved by OPUC  
16 Order No. 07-015. Boardman's four-year average is 10.3%, up somewhat from the 9.01%  
17 approved in UE 180.

18 **Q. Overall, how do the four-year averages for 2008 compare to those for 2007?**

19 A. The majority of PGE's thermal units have maintained, or improved their four-year averages  
20 for 2008. Table 1 below compares the 2007 and 2008 four-year averages used in our Monet  
21 modeling. Besides Boardman, as discussed above, Coyote Springs is the only plant with a  
22 higher average for 2008 than for 2007, and the increase is small, less than one half of one

- 1 percentage point. However, the Colstrip units and Beaver Units 1-7 show a large decrease,  
2 approximately four percentage points.

**Table 1**  
**Four-Year Rolling Forced Outage Rate – Thermal Units**

<b>Unit</b>	<b>2007</b>	<b>2008</b>
Boardman	*9.01%	10.30%
Colstrip Unit 3	12.40%	8.60%
Colstrip Unit 4	12.40%	8.60%
Coyote Springs - All States	7.20%	7.60%
Beaver Units 1-7	20.80%	16.60%
Beaver Unit 8	36.40%	36.40%
Port Westward	5.00%	5.00%

\* Per Order No. 07-015

**III. Load Forecast**

1 **Q. Please summarize PGE’s forecast for its 2008 retail load.**

2 A. Table 2 below summarizes actual and forecast deliveries to various customer groups from  
3 2005 through 2008 in million kWh at average weather conditions.

**Table 2**  
**Retail Deliveries: 2005 – 2008**  
**(Million kWh, average weather)**

	(Actual) <u>2005</u>	(Actual) <u>2006</u>	(UE 180/181) <u>2007</u>	(UE 188) <u>2008</u>
Residential	7,388	7,568	7,584	7,706
General Service	7,387	7,609	7,762	7,981
Industrial	3,983	4,085	4,144	4,208
Lighting	<u>104</u>	<u>105</u>	<u>108</u>	<u>110</u>
Total Retail	18,862	19,367	19,598	20,004

4 **Q. Does the forecast include all loads?**

5 A. Yes. The forecast includes both PGE cost-of-service loads and deliveries of energy to  
6 customers under Schedule 483/489. We sometimes refer to these deliveries as “non  
7 cost-of-service” loads.

8 **Q. How does this forecast differ from the UE 180/UE 181 forecast?**

9 A. Table 2 shows PGE’s actual weather-adjusted retail deliveries for 2005 and 2006, the  
10 UE 180/UE 181 (November 2006) forecast for 2007, and our current (UE 188) forecast by  
11 customer group for 2008. In UE 180/181 we projected total deliveries to all retail customers  
12 of 19,598 million kWh for 2007 and now forecast total deliveries of 20,004 million kWh for  
13 2008 under average weather conditions. This translates into a 1.2% annual increase in kWh  
14 delivery in 2007 from the actual weather-adjusted 2006 base and a 2.1% increase in 2008  
15 from the 2007 forecast base.

16 Our 2008 forecast is essentially an extension of the UE 180/181 delivery forecast filed  
17 with the Oregon Public Utility Commission on November 2, 2006. We applied the same

1 model and input assumptions that drive the UE 180/181 delivery forecast to develop our  
2 2008 delivery forecast. PGE Exhibit 1200 in Docket UE 180 (particularly pages 7 and 9)  
3 explains the estimation procedures in detail.

4 **Q. What load do you use in your 2008 test year power cost forecast?**

5 A. The load listed in Table 2 represents total system load at the customer meter and is used to  
6 calculate rates. The load used to generate power costs with Monet is based on  
7 cost-of-service load (i.e., total system load less Schedule 483/489 and less market price  
8 option load). This decomposition is listed below in Table 3.

**Table 3**  
**Total Retail Deliveries by Cost of Service Rates & Schedule 483/494: 2008**  
**(Cycle Month Energy in million kWh)**

Cost of Service Load	18,526
Schedules 483/489	1,465
Market Price Options	<u>13</u>
Total System Load	20,004

9 **Q. The Cost-of-Service load in Table 3 is at the customer meter. What is the**  
10 **corresponding busbar load?**

11 A. The busbar load is 2,275 MWa, or 19,984,340 MWh (or 19,984 million kWh). This load is  
12 the basis for the hourly Monet load input data.

**IV. Comparison with 2007 General Rate Case NVPC Forecast**

1 **Q. Please restate your 2008 AUT NVPC forecast.**

2 A. The AUT forecast is \$777 million.

3 **Q. What is this forecast on a per busbar MWh basis?**

4 A. Given forecasted loads of 19,984,340 MWh, the AUT forecast is \$38.88 per MWh.

5 **Q. How does the 2008 AUT forecast compare with the 2007 general rate case (GRC)**  
6 **forecast approved in Order No. 07-015?**

7 A. Based on PGE's final updated GRC Monet run for the 2007 test year and the requirements  
8 of Order No. 07-015, the 2007 forecast is \$767.1 million, or \$39.19 per MWh. The 2008  
9 cost-of-service load forecast is higher than the 2007 forecast by approximately 40 MWa  
10 (2,275 MWa in 2008 versus 2,235 in 2007). The higher load more than off-sets the  
11 approximately \$10 million increase in the power cost forecast, resulting in a small decrease  
12 in per MWh costs of approximately \$0.31.<sup>3</sup>

13 **Q. Which Order No. 07-015 requirements are included in the 2007 forecast?**

14 A. Order No. 07-015 required three reductions in net variable power costs. These are related  
15 to:

- 16 • Possible dispatch margins related to PGE's Super Peak capacity contract
- 17 • Lower forced outage rate assumption for PGE's Boardman plant
- 18 • 10-month versus 12-month differential in Port Westward dispatch benefits

19 **Q. Do you also include these elements in your 2008 NVPC forecast?**

20 A. Yes. We explicitly include the Super Peak contract margin estimate. The 2008 forced  
21 outage rate assumption for Boardman includes the adjustment that resulted in the specific

---

<sup>3</sup> This calculation includes the fact that 2008 is a leap year.

1 Order No. 07-015 dollar reduction. Finally, the Monet run for 2008 assumes that Port  
2 Westward is available for dispatch for the entire 2008 period (except for planned and forced  
3 outages).

4 **Q. Does this filing change the treatment of expected net revenues for the sale of ancillary**  
5 **services to the California Independent System Operator?**

6 A. No. Order No. 07-015 directed that “This adjustment is made to Other Revenues in revenue  
7 requirement.” (Order 07-015 at 16) Because this is not a general rate case filing, we do not  
8 propose changes to Other Revenues. Therefore, in 2008 customers will continue to benefit  
9 from approximately \$1.4 million of expected net ancillary service revenues through their  
10 inclusion in Other Revenues in UE 180.

11 **Q. What are the primary factors that explain the difference between the 2007 and 2008**  
12 **GRC (without Biglow) forecasts?**

13 A. As Table 4 shows, the \$10 million increase in overall power costs is due to numerous  
14 factors:

**Table 4**  
**Factors in Power Cost Differences**

<u>Element</u>	<u>Effect</u>
Hydro Cost and Performance	12
Coal Cost and Performance	(7)
Gas Cost and Performance	4
Gas Financials	(12)
Contract Costs	(21)
Market Purchases to Fill Contract Deficit	14
Market Purchases for Load Increase	25
Other	(5)
<b>Total</b>	<b>10</b>

15 With decommissioning of Bull Run and planned replacement of two turbines at  
16 Sullivan, we expect slightly less hydro production in 2008 and our purchased hydro contract  
17 costs increase, primarily due to payments under the Grant County Settlement Agreement

1 related to Priest Rapids. With lower forecasted forced outage rates at Colstrip Units 3 and 4,  
2 we expect slightly more coal output in 2008, although at a somewhat higher unit cost. With  
3 Port Westward available during the entire year, we expect greater output from our gas plants  
4 in 2008. However, there is also slight increase in per MWh costs for these plants. Gas  
5 financial exposure is less in 2008. Contract costs for 2008 are lower on a per MWh basis,  
6 but market purchases are needed to make up for a lesser quantity. Market purchases are also  
7 necessary to serve the approximately 40 MWa increase in cost-of-service loads from 2007 to  
8 2008.

9 **Q. Is this result, that per-unit NVPC change very little between 2007 and 2008, consistent**  
10 **with differences between the forward curves used in the forecasting process?**

11 A. Yes. Both the electric and gas forward curves used in the 2008 forecast are slightly higher  
12 than those used in the 2007 forecast. Therefore, the dispatch value of PGE's gas-fired plants  
13 changes very little. Coal plants continue to run whenever forecasted to be available and the  
14 value of our hydro resources does not change greatly. These factors combine to result in  
15 very little change in dispatch benefits for customers from PGE's overall resource portfolio.

16 Other factors, which are largely related to contract and market quantities and prices,  
17 generally off-set each other, resulting in only a small increase in overall forecasted NVPC  
18 from 2007 to 2008, and a small decrease on a per MWh basis.

19 **Q. Did you prepare a comparison of the 2008 AUT forecast with those of recent years?**

20 A. Yes. Table 5 below provides the comparison.

**Table 5**  
**Power Cost Forecast Summary**

	2005	2006	2007	2008
	RVM	RVM	GRC	AUT
Costs (\$000)	\$486,266	\$628,512	\$767,113	\$776,990
Busbar Cost of Service Loads (000 MWh)	18,551	19,556	19,575	19,984
Unit Cost (\$/MWh)	\$26.21	\$32.14	\$39.19	\$38.88

1            Table 5 includes the 2007 GRC to 2008 AUT comparison discussed above. It also  
2 includes data from the final Monet runs used in PGE’s 2005 and 2006 RVM filings. Unit  
3 power costs rose in both 2006 and 2007. However, as we discussed above, in 2008 there is a  
4 small decrease in forecasted unit power costs.

**V. Update Schedule and Relationship with Other Dockets**

1 **Q. When will PGE update its AUT forecast?**

2 A. We will update this forecast according to the schedule established by the parties to this  
3 docket. We expect the final update to be in November 2007.

4 **Q. Does this forecast include the expected net dispatch benefits from Phase 1 of the Biglow  
5 Canyon (Biglow) wind project?**

6 A. No. Biglow's 2008 costs and associated dispatch benefits are the primary subject of Docket  
7 UE 188. However, we expect to estimate the dispatch benefits of Biglow for use in UE 188,  
8 assuming our proposal in that docket is adopted.

9 **Q. Will the final AUT forecast update serve as the basis for the 2008 Power Cost  
10 Adjustment Mechanism established by Order No. 07-015?**

11 A. Yes.

**VI. Witness Qualifications**

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

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

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

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

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

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

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

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

5       **Q. Does this complete your testimony?**

6       A. Yes.

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF THE STATE OF OREGON**

# **Pricing**

**PORTLAND GENERAL ELECTRIC COMPANY**

Direct Testimony and Exhibits of

*Marc Cody*

**April 2, 2007**

**Pricing**

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**I. Introduction and Summary**

1 **Q. Please state your name and position.**

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

4 **Q. What is the purpose of your testimony?**

5 A. This testimony demonstrates how the prices contained in proposed Tariff Schedule 125 are  
6 calculated and provides an estimate of the 2008 base rate impacts from proposed Schedule  
7 125 for selected rate schedules. PGE will file the final rates incorporating the final updates  
8 to Net Variable Power Costs on November 15.

**II. Estimated Prices and Rate Impacts**

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

3 A. Table 1 below summarizes the preliminary price estimates and the base rate impacts for  
4 2008 for selected Schedules. The preliminary price estimates for all rate schedules are  
5 calculated per the provisions of Schedule 125 as the unit change in Net Variable Power  
6 Costs (NVPC) times a revenue sensitive cost factor of 1.0287 to account for franchise fees  
7 and uncollectables. A draft copy of Schedule 125 is included as Exhibit 201. Table 2  
8 contains the calculation of the Schedule 125 prices applicable to all customers except those  
9 on Schedules 76R, 483, and 489. The level of NVPC and the projected loads are discussed  
10 in PGE Exhibit 100.

11 **Q. What other price changes do you expect to occur on January 1, 2008?**

12 A. In addition to the Biglow Canyon filing (UE 188) and this AUT filing, I anticipate changes  
13 to Schedule 102 Regional Power Act Exchange Credit, Schedule 105 Regulatory  
14 Adjustments, Schedule 111 Advanced Metering Infrastructure (removal of the part B  
15 credits), and potential recovery of an increase in OPUC regulatory fees. These price  
16 changes were discussed in greater detail in PGE’s Biglow Canyon filing.

**Table 1**  
**Estimated Prices and Rate Impacts**

Schedule	Price (mills/kWh)	Rate Impact
Sch 7 Residential	-0.34	-0.3%
Sch 32 Small Non-residential	-0.34	-0.4%
Sch 83 Secondary	-0.34	-0.4%
Sch 83 Primary	-0.34	-0.5%
Sch 89 Secondary	-0.34	-0.5%
Sch 89 Primary	-0.34	-0.5%
Sch 89 Subtransmission	-0.34	-0.6%
Overall		-0.4%

**Table 2**  
**Calculation of Schedule 125 Price**

2007 NVPC (\$000)	767,112
2007 Calendar Loads (MWH)	18,165,207
2007 Unit NVPC	\$42.23
2008 NVPC (\$000)	776,990
2008 Calendar Loads	18,543,981
2008 Unit NVPC	\$41.90
Change in NVPC (dollars per MWh)	-\$0.33
Adjust for Revenue Sensitive Costs	-\$0.34
Schedule 125 Price (mills per kWh)	-0.34

**III. Qualifications of Witnesses**

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

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

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

8 **Q. Does this complete your testimony?**

9 A. Yes.

**SCHEDULE 125  
ANNUAL POWER COST UPDATE**

**PURPOSE**

The purpose of this adjustment schedule is to define procedures for annual rate revisions due to changes in the Company's projected Net Variable Power Costs. This schedule is an "automatic adjustment clause" as defined in ORS 757.210(1), and is subject to review by the Commission at least once every two years.

**APPLICABLE**

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

**NET VARIABLE POWER COSTS**

Net Variable Power Costs (NVPC) are the power costs for energy generated and purchased. NVPC are the net cost of fuel, fuel transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load.

**RATES**

This adjustment rate is subject to increases or decreases, which may be made without prior hearing, to reflect increases or decreases, or both, in NVPC.

**ANNUAL UPDATES**

The following updates will be made in each of the Annual Power Cost Update filings:

- Forced Outage Rates based on a four-year rolling average.
- Projected planned plant outages.
- Forward market prices for both gas and electricity.
- Projected loads.
- Contracts for the purchase or sale of power and fuel.
- Changes in hedges, options, and other financial instruments used to serve retail load.
- Transportation contracts.
- No other changes or updates will be made in the annual filings under this schedule.

**CHANGES IN NET VARIABLE POWER COSTS**

Changes in NVPC are defined as the projected per unit change in NVPC from the per unit NVPC used to develop the Energy Charge for the applicable rate schedules. Unit NVPC are defined as the total NVPC divided by the projected retail calendar loads. Projected retail calendar loads include the projected loads of all the Company's Customers except those served under Schedule 483 or Schedule 489.

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Advice No. 07-\_\_

Issued \_\_\_\_\_  
Pamela Grace Lesh, Vice President

Effective for service  
on and after \_\_\_\_\_

**SCHEDULE 125 (Continued)**

**FILING AND EFFECTIVE DATE**

On or before April 1<sup>st</sup> of each calendar year, the Company will file estimates of the adjustments to its NVPC to be effective on January 1<sup>st</sup> of the following calendar year.

On or before October 1<sup>st</sup> of each calendar year, the Company will file updated estimates with final planned maintenance outages, final load forecast, updated projections of gas and electric prices, power, and fuel contracts.

On November 15<sup>th</sup>, the Company will file the final estimate of NVPC and will calculate and file the final unit change in NVPC to be effective on the next January 1<sup>st</sup> with: 1) projected market electric and fuel prices based on the average of the Company's internally generated projections made during the period November 1<sup>st</sup> through November 7<sup>th</sup>, 2) load reductions from the October update resulting from additional participation in the Company's Long-Term Cost of Service Opt-out that occurs in September, 3) new market power and fuel contracts entered into since the previous updates, and 4) the final planned maintenance outages and load forecast from the October 1<sup>st</sup> filing.

**RATE ADJUSTMENT**

The rate adjustment will be the final unit change in NVPC times a revenue sensitive factor of 1.0287 to account for franchise fees and uncollectables applied to each of the above Schedules on an equal cents per kWh basis.

**ADJUSTMENT RATES**

Schedule		Part A ¢ per kWh
7		-0.034
15		-0.034
32		-0.034
38	Large Nonresidential	-0.034
47		-0.034
49		-0.034
75	Secondary	-0.034 <sup>(1)</sup>
	Primary	-0.034 <sup>(1)</sup>
	Subtransmission	-0.034 <sup>(1)</sup>
83	Secondary	-0.034
	Primary	-0.034
87	Secondary	-0.034
	Primary	-0.034
	Subtransmission	-0.034

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

Advice No. 07-\_\_\_\_  
Issued \_\_\_\_\_  
Pamela Grace Lesh, Vice President

Effective for service  
on and after \_\_\_\_\_

Portland General Electric Company  
P.U.C. Oregon No. E-18

First Revision of Sheet No. 125-3  
Canceling Original Sheet No. 125-3

**SCHEDULE 125 (Concluded)**

ADJUSTMENT RATES (Continued)

Schedule		Part A ¢ per kWh
89	Secondary	-0.034
	Primary	-0.034
	Subtransmission	-0.034
91		-0.034
92		-0.034
93		-0.034
94		-0.034

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Advice No. 07-\_\_\_  
Issued \_\_\_\_\_  
Pamela Grace Lesh, Vice President

Effective for service  
on and after \_\_\_\_\_

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF THE STATE OF OREGON**

# **Motion for Protective Order**

**PORTLAND GENERAL ELECTRIC COMPANY**

**April 2, 2007**

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

UE \_\_\_\_\_

**In the Matter of PORTLAND GENERAL  
ELECTRIC COMPANY**

**2008 Annual Power Cost Update Tariff  
(Schedule 125)**

**MOTION FOR APPROVAL OF  
PROTECTIVE ORDER**

**[EXPEDITED CONSIDERATION  
REQUESTED]**

Pursuant to ORCP 36(C)(7) and OAR 860-12-0035(1)(k), Portland General Electric Company (“PGE”) requests the issuance of a Protective Order in this proceeding. PGE believes good cause exists for the issuance of such an order to protect confidential market information and confidential business information, plans and strategies. In support of this Motion, PGE states:

1. Concurrent with the filing of this Motion, PGE has filed testimony and non-confidential work papers pursuant to PGE’s Annual Update Tariff.
2. Some of the work papers supporting the Annual Update Tariff filing contain confidential information regarding PGE’s fuel and electric market activities as well as other confidential business matters. This information is confidential commercial information and/or trade secrets under ORCP 36(C)(7).
3. PGE would like to file with the Commission a complete set of work papers as soon as possible, and requests expedited consideration of this motion.
4. PGE also anticipates that parties participating in this docket may make further requests for confidential information. PGE further anticipates it will be required to file periodic updates containing confidential information in this proceeding.

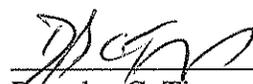
5. While PGE desires to provide parties with requested information, the information is of significant commercial value, and its public disclosure could be detrimental to PGE and its customers. The information contains proprietary modeling code, PGE's timing of and expected prices for electricity, natural gas and coal purchases, PGE's forward position for electricity, natural gas and coal in 2008, and whether PGE is long or short during 2008. If other parties involved in the wholesale electricity, natural gas and coal markets obtained this information, they could use it to the financial harm of PGE and its customers.

6. The Commission should therefore issue a Protective Order to protect the confidentiality of that material. The requested order, identical to the one that the Commission customarily issues, is attached.

For the reasons stated above, PGE requests that a protective order be issued in this proceeding.

DATED this 2<sup>nd</sup> day of April, 2007.

Respectfully submitted,



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Douglas C. Tingey, OSB No. 04436  
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Portland General Electric Company  
121 SW Salmon Street, 1WTC1301  
Portland, Oregon 97204  
(503) 464-8926 phone  
(503) 464-2200 fax  
doug.tingey@pgn.com

ORDER NO.

ENTERED

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

UE \_\_\_\_\_

In the Matter of PORTLAND GENERAL  
ELECTRIC COMPANY

2008 Annual Power Cost Update Tariff  
(Schedule 125)

**ORDER**

**DISPOSITION: MOTION FOR PROTECTIVE ORDER GRANTED**

On April 2, 2007, Portland General Electric Company ("PGE") filed a Motion for a Protective Order with the Public Utility Commission of Oregon ("Commission"). PGE states that good cause exists for the issuance of such an order to protect confidential business information, plans and strategies. Specifically, PGE states that some of the work papers supporting its Annual Update Tariff filing contain confidential information regarding PGE's natural gas, electric and coal market activities as well as other confidential business matters. This information is confidential commercial information and/or trade secrets under ORCP 36(C)(7).

Pursuant to OAR 860-012-0035(1)(k), I find that good cause exists to issue a Protective Order, attached as Appendix A. Under the terms of the order, a party may designate as confidential any information that falls within the scope of ORCP 36(C)(7).

Confidential information shall be disclosed only to a "qualified person" as defined in paragraph 3 of the Protective Order. Authors of the confidential material, the Commission or its Staff, and counsel of record for a party or persons directly employed by counsel are "qualified persons" who may review confidential information. Other persons desiring confidential information must become qualified pursuant to paragraph 10.

To receive confidential information, however, all parties—with the general exception of Staff—must sign the Consent to be Bound Form attached as Appendix B. This includes the party seeking the issuance of the protective order, because any party may designate information as confidential under this order.

The confidentiality of confidential information shall be preserved for a period of five years from the date of the final order in this docket, unless extended by the Commission at the request of the party desiring confidentiality.

ORDER NO.

All persons who are given access to confidential information have the duty to monitor their own conduct to ensure their compliance with the Protective Order. Such persons shall not use or disclose the information for any purpose other than the preparation for and conduct of this proceeding, and shall take all reasonable precautions to keep the confidential information secure. If any questions exist as to the status of any person to receive confidential information, the parties may contact the Administrative Hearings Division at (503) 378-6678.

**ORDER**

IT IS ORDERED that the Protective Order, attached as Appendix A, shall govern the disclosure of confidential information in this case.

Made, entered, and effective on \_\_\_\_\_.

\_\_\_\_\_  
[Judge]  
Administrative Law Judge

A party may appeal this order to the Commission pursuant to OAR 860-014-0091.

**PROTECTIVE ORDER**

DOCKET NO. UE \_\_\_\_

**Scope of this Order-**

1. This order governs the acquisition and use of “Confidential Information” in this proceeding.

**Definitions-**

2. “Confidential Information” is information that falls within the scope of ORCP 36(C)(7) (“a trade secret or other confidential research, development, or commercial information”).

3. A “qualified person” is an individual who is:

- a. An author(s), addressee(s), or originator(s) of the Confidential Information;
- b. A Commissioner or Commission staff;
- c. Counsel of record for a party;
- d. A person employed directly by counsel of record; or
- e. A person qualified pursuant to paragraph 10. This includes parties and their employees.

**Designation of Confidential Information-**

4. A party providing Confidential Information shall inform other parties that the material has been designated confidential by placing the following legend on the information:

CONFIDENTIAL  
SUBJECT TO PROTECTIVE ORDER

To the extent practicable, the party shall designate as confidential only those portions of the document that fall within ORCP 36(C)(7).

5. A party may designate as confidential any information previously provided by giving written notice to the other parties. Parties in possession of newly designated Confidential

ORDER NO.

Information shall, when feasible, ensure that all copies of the information bear the above legend to the extent requested by the party desiring confidentiality.

**Information Given to the Commission-**

6. Confidential Information that is: (a) filed with the Commission or its staff; (b) made an exhibit; (c) incorporated into a transcript; or (d) incorporated into a pleading, brief, or other document, shall be printed on yellow paper, separately bound and placed in a sealed envelope or other appropriate container. An original and five copies each separately sealed shall be provided to the Commission. **Only the portions of a document that fall within ORCP 36(C)(7) shall be placed in the envelope/container.** The envelope/container shall bear the legend:

THIS ENVELOPE IS SEALED PURSUANT TO ORDER NO. \_\_\_\_\_ AND CONTAINS CONFIDENTIAL INFORMATION. THE INFORMATION MAY BE SHOWN ONLY TO QUALIFIED PERSONS AS DEFINED IN THE ORDER.

7. The Commission's Administrative Hearings Division shall store the Confidential Information in a locked cabinet dedicated to the storage of Confidential Information.

**Disclosure of Confidential Information-**

8. Parties desiring receipt of Confidential Information shall sign the Consent to be Bound Form attached as Appendix B. This requirement does not apply to the Commission staff. Confidential Information shall not be disclosed to any person other than a "qualified person," as defined in paragraph 3. When feasible, Confidential Information shall be delivered to counsel. In the alternative, Confidential Information may be made available for inspection and review by qualified persons in a place and time agreeable to the parties or as directed by the Administrative Law Judge.

9. Qualified persons may disclose confidential information to any other qualified person, unless the party desiring confidentiality protests as provided in Section 11.

10. To become a qualified person under paragraph 3(e), a person must:

- a. Read a copy of this Protective Order;
- b. Execute a statement acknowledging that the order has been read and agreeing to be bound by the terms of the order;
- c. Date the statement;

- d. Provide a name, address, employer, and job title; and
- e. If the person is a consultant or advisor for a party, provide a description of the nature of the person's consulting or advising practice, including the identity of his/her current, past, and expected clients.

Counsel shall deliver a copy of the signed statement including the information in (d) and (e) above to the party desiring confidentiality and to all parties of record. Such notification may be made via e-mail or facsimile. A person qualified under paragraph 3(e) shall not have access to Confidential Information sooner than five (5) business days after receipt of a copy of the signed statement including the information in (d) and (e) above by the party desiring confidentiality.

11. All qualified persons shall have access to Confidential Information, unless the party desiring confidentiality protests as provided in this paragraph. The party desiring to restrict the qualified person(s) from accessing specific Confidential Information must provide written notice to the qualified person(s) and counsel for the party associated with the qualified person(s) as soon as the party becomes aware of reasons to restrict access. The parties must promptly confer and attempt to resolve any dispute over access to Confidential Information on an informal basis before filing a motion with the Administrative Law Judge. If the dispute cannot be resolved informally, either party may file a motion with the Administrative Law Judge for resolution. Either party may also file a motion if the other party does not respond within five days to a request to resolve the dispute. A motion must describe in detail the intermediate measures, including selected redaction, explored by the parties and explain why such measures do not resolve the dispute. After receipt of the written notice as required in this paragraph, the specific Confidential Information shall not be disclosed to the qualified person(s) until the issue is resolved.

**Preservation of Confidentiality-**

12. All persons who are given access to any Confidential Information by reason of this order shall not use or disclose the Confidential Information for any purpose other than the purposes of preparation for and conduct of this proceeding, and shall take all reasonable precautions to keep the Confidential Information secure. Disclosure of Confidential Information for purposes of business competition is strictly prohibited.

Qualified persons may copy, microfilm, microfiche, or otherwise reproduce Confidential Information to the extent necessary for the preparation and conduct of this proceeding. Qualified persons may disclose Confidential Information only to other qualified persons associated with the same party.

**Duration of Protection-**

13. The Commission shall preserve the confidentiality of Confidential Information for a period of five years from the date of the final order in this docket, unless extended by the Commission at the request of the party desiring confidentiality. The Commission shall notify the party desiring confidentiality at least two weeks prior to the release of confidential information.

**Destruction After Proceeding-**

14. Counsel of record may retain memoranda, pleadings, testimony, discovery, or other documents containing Confidential Information to the extent reasonably necessary to maintain a file of this proceeding or to comply with requirements imposed by another governmental agency or court order. The information retained may not be disclosed to any person. Any other person retaining Confidential Information or documents containing such Confidential Information must destroy or return it to the party desiring confidentiality within 90 days after final resolution of this proceeding unless the party desiring confidentiality consents, in writing, to retention of the Confidential Information or documents containing such Confidential Information. This paragraph does not apply to the Commission or its Staff.

**Appeal to the Presiding Officer-**

15. If a party disagrees with the designation of information as confidential, the party shall contact the designating party and attempt to resolve the dispute on an informal basis. If the parties are unable to resolve the dispute, the party desiring to use the information may move for exclusion of the information from the protection conferred by this order. The motion shall:

- a. Specifically identify the contested information, and
- b. Assert that the information does not fall within ORCP 36(C)(7) and state the reasons therefore.

The party resisting disclosure has the burden of showing that the challenged information falls within ORCP 36(C)(7). If the party resisting disclosure does not respond to the motion within ten (10) calendar days, the challenged information shall be removed from the protection of this order.

The information shall not be disclosed pending a ruling by the Administrative Law Judge on the motion.

**Additional Protection-**

16. The party desiring additional protection may move for any of the remedies set forth in ORCP 36(C). The motion shall state:

ORDER NO.

- a. The parties and persons involved;
- b. The exact nature of the information involved;
- c. The exact nature of the relief requested;
- d. The specific reasons the requested relief is necessary; and
- e. A detailed description of the intermediate measures, including selected redaction, explored by the parties and why such measures do not resolve the dispute.

The information need not be released and, if released, shall not be disclosed pending the Commission's ruling on the motion.

ORDER NO.

**SIGNATORY PAGE**

DOCKET NO. \_\_\_\_\_

**I. Consent to be Bound-**

This Protective Order governs the use of "Confidential Information" in this proceeding.

\_\_\_\_\_ PGE agrees to be bound by its terms of this Protective Order.

By: \_\_\_\_\_  
Signature & Printed Date

**II. Persons Qualified pursuant to Paragraphs 3(a) through 3 (d)**

\_\_\_\_\_ PGE identifies the following person(s) automatically qualified under paragraph 3(a) through (d).

_____	_____
Printed	Date
_____	_____
Printed	Date
_____	_____
Printed	Date
_____	_____
Printed	Date
_____	_____
Printed	Date
_____	_____
Printed	Date

**III. Persons Qualified pursuant to Paragraph 3(e) and Paragraph 10.**

I have read the Protective Order, agree to be bound by the terms of the order, and will provide the information identified in paragraph 10.

By: \_\_\_\_\_  
Signature & Printed Date

By: \_\_\_\_\_  
Signature & Printed Date

By: \_\_\_\_\_  
Signature & Printed Date

By: \_\_\_\_\_  
Signature & Printed Date