Portland General Electric Company
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March 30, 2012

Via Electronic Filing and US Mail
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Oregon Public Utility Commission
Attention: Filing Center
550 Capitol Street NE, #215
Salem OR 97301-2567

Re: UE ___ In the Matter of PORTLAND GENERAL ELECTRIC COMPANY'S 2013 Annual Power Cost Update Tariff (Schedule 125)

Attention Filing Center:

Enclosed for filing in the above-captioned docket please find the following:

Original and five copies of Direct Testimony of:
- **Mike Niman, Terri Peschka and Patrick G. Hager (PGE / 100)**
- **Robert Macfarlane and Bonnie Gariety (PGE / 200)**

Three copies on CD of:
- **Work Papers (non-confidential portions only)**

Original and two copies of:
- **Motion for Approval of Protective Order (with proposed Protective Order)**

PGE will submit the confidential exhibits and work papers after entry of a Protective Order. PGE is requesting expedited consideration of its Motion for Approval of Protective Order.

PGE's initial forecast of 2013 NVPC is $674.8 million. At this level of NVPC, PGE projects a base rate reduction effective January 1, 2013 of about 1.6%.

These documents are being filed electronically with the Filing Center. Hard copies will be sent via US Mail. An extra copy of this cover letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided.

Sincerely,

Randall J. Dahlgren
Director, Regulatory Policy & Affairs

RJD/jlt
encl.
cc: UE 228 Service List

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **PORTLAND GENERAL ELECTRIC COMPANY'S 2013 ANNUAL POWER COST UPDATE TARIFF OF DIRECT TESTIMONY AND WORK PAPERS (non-confidential portions only) and MOTION FOR PROTECTIVE ORDER** to be served by electronic mail to those parties whose email addresses appear on the attached service list from OPUC Docket No. UE 228.

Dated at Portland, Oregon, this 30th day of March, 2012.

Randall J. Dahlgren
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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE ___

Annual Update Tariff Filing
For Prices Effective January 1, 2013

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits

PGE

Portland General Electric

March 30, 2012

UE ___ / PGE / 100
Niman – Peschka - Hager

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Power Costs

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Mike Niman
Terri Peschka
Patrick G. Hager

Portland General Electric

March 30, 2012

Power Costs

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I. Introduction

Q. Please state your names and positions with Portland General Electric ("PGE").

A. My name is Mike Niman. My position at PGE is Manager, Financial Analysis.

My name is Terri Peschka. My position at PGE is General Manager, Power Operations.

My name is Patrick G. Hager. My position at PGE is Manager, Regulatory Affairs.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to provide the initial Annual Update Tariff ("AUT") forecast of PGE's 2013 Net Variable Power Costs ("NVPC"). We discuss several of the updates included in this initial forecast for 2013, as well as provide an update on PGE's efforts to comply with the Commission's directions in Order No. 11-432 (Docket No. UE 228). We also compare our initial forecast with PGE's final 2012 NVPC forecast and explain why the per unit expected NVPC have decreased by approximately $1.54 per MWh from the final 2012 AUT forecast to this initial 2013 AUT forecast.

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

A. Our 2013 AUT forecast is $674.8 million, based on contracts and forward curves as of February 23, 2012.

Q. What schedule in this docket do you propose for NVPC updates?

A. We propose the following schedule for the power cost updates:

- July - update power, fuel, and transportation/transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; and loads;

- September - update power, fuel, and transportation/transmission contracts, and related costs; gas and electric forward curves; planned hydro maintenance outages; and loads; and
- November - two updates: 1) forward curve updates, final updates of power contracts, fuel contracts, transportation/transmission contracts, long-term opt-outs and related costs; and 2) final gas and electric forward curves.

Q. Will the forecast from the final AUT update serve as the basis for the 2013 Power Cost Adjustment Mechanism ("PCAM") established by Order No. 07-015?

A. Yes, with one modification. In the UE 201 (2007 PCAM) Stipulation, parties supported a change in the language of Schedule 126 to clarify that adjustments to forecasted NVPC are made to reflect the impact of customer direct access enrollments under Schedules 515 through 594 that take place after the final Monet power cost run is filed in mid-November. If there is a change in the enrollments, a new Monet run reflecting those enrollment changes will form the baseline unit net variable power cost for the PCAM calculations.

Q. Are there Minimum Filing Requirements ("MFRs") associated with the AUT?

A. Yes. Order No. 08-505 adopted a list of MFRs for PGE in AUT filings and general rate case ("GRC") proceedings. The MFRs define the documents PGE will provide in conjunction with the NVPC portion of PGE's initial (direct case) and update filings of its GRC and/or AUT proceedings. PGE Exhibit 101 contains the list of required documents as approved by Order No. 08-505. The required MFRs are included as part of our electronic work papers, with the remainder of the MFRs to be filed within fifteen days of this filing (i.e. April 13, 2012).[1] In response to Commission Order No. 11-432, PGE has implemented a number of modifications in its process for producing the MFRs; we discuss these changes in Section IV below.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have six sections:

- Section II: Monet Model;
- Section III: Monet Updates;
- Section IV: Commission's Directives in Order No. 11-432;
- Section V: 2013 Load Forecast;
- Section VI: Comparison with 2012 NVPC Forecast; and
- Section VII: Qualifications.

[1] Per the UE 198 Stipulation, most of the MFRs will be filed on or before April 13, 2012. The summary MFRs are filed with this testimony.

II. Monet Model

Q. How did PGE forecast its NVPC for 2013?

A. As in previous dockets, we used our power cost forecasting model, called "MONET" (or Monet).

Q. Please briefly describe Monet.

A. We built this model in the mid-1990s and have since incorporated several refinements. In brief, Monet models the hourly dispatch of our generating units. Using data inputs, such as forecasted load and forward electric and gas curves, the model minimizes power costs by economically dispatching plants and making market purchases and sales. To do this, the model employs the following data inputs:

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

- Physical and financial electric contract purchases and sales; and
- Forward market curves for gas and electric power purchases and sales.

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

Q. How does PGE define NVPC?

A. NVPC include wholesale (physical and financial) power purchases and sales ("purchased power" and "sales for resale"), fuel costs, and other costs that generally change as power output changes. PGE records its net variable power costs to Federal Energy Regulatory Commission ("FERC") accounts 447, 501, 547, 555, and 565. Based on prior Commission decisions, we include some fixed power costs, such as excise taxes and transportation charges, because they relate to fuel used to produce electricity. We "amortize" these fuel-related costs even though, for purposes of FERC accounting, they appear in a balance sheet account (FERC 151). Variable chemical costs resulting from compliance with pollution control requirements at Boardman are also included based on our recent Advice filing, which we discuss in more detail below. We exclude some variable power costs, such as certain variable operation and maintenance costs ("O&M"), because they are already included elsewhere in PGE's accounting. However, variable O&M is used to determine the economic dispatch of our thermal plants. The "net" in NVPC refers to net of forecasted wholesale sales of electricity, natural gas, fuel and associated financial instruments.

Q. Do the MFRs provide more detailed information regarding the inputs to Monet?

A. Yes. The MFRs provide detailed work papers supporting the inputs used to develop this initial forecast of 2013 NVPC.

III. Monet Updates

Q. What updates are allowed under PGE's Schedule 125, Annual Power Cost Update (AUT) Tariff?

A. Schedule 125 states that the following updates are allowed in AUT 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;
- Thermal plant variable operation and maintenance;
- Changes in hedges, options, and other financial instruments used to serve retail load;
- Transportation contracts and other fixed transportation costs; and
- Chemical costs required for Boardman pollution controls, which are directly related to that plant's output. (PGE recently filed a revision to the allowable updates listed in Schedule 125. We discuss this revision in more detail below.)

Q. Which of these updates do you include in this initial filing?

A. We include all of the updates listed and address significant items below.

A. Physical Gas Modeling

Q. The Stipulation resolving some NVPC issues in UE 228 stated that PGE would "address the Rockies/Sumas basis issue in its initial 2013 AUT filing."[2] What is the Rockies/Sumas basis issue?

[2] Stipulation, UE 228, page 3 (Order No. 11-432, Appendix A, page 3).

A. The Rockies/Sumas basis issue was raised by Citizens' Utility Board ("CUB") in Docket No. UE 228 (2012 AUT). CUB stated that, under certain conditions, PGE could realize the price differential (the so-called "basis") between the Rockies and Sumas natural gas hubs by moving physical gas between the two locations. The stated conditions were: no gas financial contracts present in Monet, available pipeline capacity, and Sumas gas selling at a premium to Rockies gas.[3]

Q. Has PGE addressed this issue in its initial filing in this proceeding?

A. Yes. PGE has included modeling in Monet that seeks to capture the power cost benefits that could be attained by exploiting the price differential between the Rockies and Sumas hubs. PGE surveyed past transactions in order to determine the extent to which gas may have flowed from the Rockies to Sumas when this strategy was "in the money" given the price differential. These historical values dictate the volume that is modeled in Monet.

Q. In the UE 228 Stipulation referenced above, PGE agreed to match the volume of Rockies physical forward purchases with the corresponding financial contract volume. Will PGE continue this practice in the current proceeding?

A. Yes. PGE intends for the volume of physical Rockies purchases reflected in Monet to match the financial contract volume by the time of the first November update filing in this proceeding. For this initial forecast of 2013 NVPC, we use the final volumes of Rockies gas physical contracts for 2012 delivery from the November 15, 2011, filing in UE 228 as an approximation for the volume of Rockies gas physical contracts that are expected to be executed for 2013 delivery. PGE intends to continue using this volume in Monet until the first November update.

[3] Joint Testimony in Support of Stipulation, UE 228, pages 5–6

Q. What is the impact on PGE's forecast NVPC of these changes related to the Stipulation?

A. The changes to Rockies/Sumas basis modeling and matching the volume of physical to financial contracts decrease the 2013 NVPC forecast presented in this initial filing by approximately $700,000.

B. Wind Integration Day-Ahead Forecast Error

Q. Why did PGE update the wind integration day-ahead forecast error cost?

A. In this initial filing, PGE has updated the wind integration day-ahead forecast error cost based on the cost per MWh that was established in PGE's recent Wind Integration Study, Phase II. The cost previously used in Monet was the result of a Stipulation in UE 198, "due to the ongoing study of PGE's wind integration costs" at that time.[4] As PGE's Wind Integration Study has sufficiently advanced to the point of providing an estimate for the cost of day-ahead forecast error, we include that updated cost in this initial filing.

Q. Has PGE's Wind Integration Study been reviewed by stakeholders?

A. Yes. PGE engaged regional stakeholders in a public process that allowed for a full and thorough vetting of the study. PGE held three public stakeholder meetings in which all members of the service list from PGE's 2009 Integrated Resource Plan ("IRP") in Docket No. LC 48 were invited to attend. During these meetings, PGE provided detailed explanations of the modeling approach, methodology, data inputs, and assumptions.

Q. Were outside experts involved in the review process?

A. Yes. A technical review committee was also engaged by PGE. This committee was composed of industry members with expertise dealing with wind resources. The committee

[4] Stipulation, UE 198, page 3 (Order No. 08-505, Appendix A, Page 3).

members provided general guidance for the study development, as well as detailed recommendations on various aspects of the modeling. The final study report and the methodology employed by PGE were ultimately endorsed by the technical review committee.

The results of the Wind Integration Study will be used in PGE's forthcoming renewables request for proposals ("RFP") and the next IRP. The Wind Integration Study was completed in September 2011, and filed with PGE's 2011 IRP Update on November 23, 2011, in Docket No. LC 48. It is also provided as PGE Exhibit 103.

Q. What is the impact of this update on NVPC?

A. This change increases NVPC by approximately $4.3 million in this filing.

C. Boardman Pollution Control Chemicals

Q. Did PGE recently file a revised Schedule 125 and Schedule 126 in order to reflect a change to net variable power costs related to Boardman?

A. Yes. On March 29, 2012, PGE submitted a revised Schedule 125 and Schedule 126 in order to reflect the chemical costs of mercury and sulfur dioxide emission controls at Boardman as items that are eligible for update within the AUT and PCAM processes by including these costs in net variable power costs.

Q. What are these pollution control chemical costs at Boardman?

A. We have included the chemical costs for two distinct pollution control systems at Boardman as power costs in this initial filing: the mercury control system (activated carbon and calcium bromide injection) and the sulfur dioxide control system (dry sorbent injection or "DSI").

Q. When did PGE begin operating the mercury control system?

A. PGE began activated carbon injection and calcium bromide injection to achieve mercury emissions reductions at Boardman in 2011. Since that time, PGE has achieved significant reductions in the chemical usage rates and those improvements are reflected in the current 2013 forecast.

Q. Were chemical costs for the mercury control system at Boardman previously included in Monet?

A. Yes. These chemical costs were previously included in Monet as variable O&M for purposes of achieving the correct dispatch decision only; they were not included in power costs.

Q. How does PGE currently recover the mercury control chemical costs?

A. The revenue requirement related to the O&M expense is deferred as part of the four capital projects deferral (as stipulated in Docket No. UE 215). That deferral is Docket No. UM 1513.

Q. What is PGE proposing in this proceeding with respect to the mercury control chemical costs?

A. PGE is proposing that the expenses for chemicals associated with the mercury control system at Boardman be eligible for update in each power cost update filing and recovered in power costs, beginning in 2013. If this treatment is granted, we will exclude the costs from the 2013 deferral and from any subsequent years.

Q. Why is PGE installing the DSI system at Boardman?

A. The Regional Haze Rules established by the Oregon Department of Environmental Quality ("DEQ") mandate a maximum level of sulfur dioxide emissions that must be achieved beginning July 1, 2014. The DSI system is being installed in order to help achieve compliance with the DEQ requirements.

Q. What is DSI?

A. DSI is a pollution control system that reduces sulfur dioxide emissions by combining a dry alkaline reagent directly with the boiler exhaust gas stream. The reagent adsorbs sulfur dioxide and is then collected by the existing electrostatic precipitator. The sorbent material for the DSI system at Boardman is called "Trona."

Q. Why are the costs for DSI at Boardman included in this AUT?

A. The DSI system at Boardman is currently scheduled to be operational beginning in July 2013. At that point, testing of the system will take place and PGE will begin incurring the chemical costs for sulfur dioxide pollution control. Although not accounted for as fuel costs, the chemical costs of DSI are variable with the plant's production and, thus, appropriately included in PGE's 2013 net variable power cost forecast.

Q. Are the costs of either the mercury control chemicals or the sulfur dioxide control chemicals recovered by PGE in current rates?

A. No. Neither mercury nor sulfur dioxide control chemicals were included in base rates pursuant to PGE's last general rate case (Docket No. UE 215). As stated above, the revenue requirement associated with the cost of the mercury control chemicals is currently subject to deferred accounting in accordance with a stipulation in UE 215. PGE is not amortizing any deferred amounts for mercury control chemicals in 2012. The costs related to sulfur dioxide control chemicals is a cost that PGE expects to begin incurring in 2013; there is no consideration for this cost in PGE's current rates.

Q. Why is it appropriate to include the mercury control chemical costs and the DSI chemical costs in the AUT?

A. These costs are directly related to the plant's use of fuel and, thus, vary with production. PGE incurs these costs in order to meet emissions reduction requirements. Without such actions, we would not be allowed to continue operating the Boardman plant, which serves our customers as a reliable, low-cost resource.

Q. What effect does including the costs of the mercury and sulfur dioxide pollution control chemicals have on PGE's current 2013 NVPC forecast?

A. The inclusion of chemical costs arising due to mercury and sulfur dioxide pollution control at Boardman increases PGE's current 2013 NVPC forecast by approximately $3.1 million.

Q. Is PGE pursuing other means of lowering the sulfur emissions at Boardman as well?

A. Yes. In 2013, concurrent with the performance testing of the DSI system, PGE will be burning coal with reduced sulfur content. The sulfur content of the coal influences the amount of Trona needed (the feed rate) to achieve a given sulfur dioxide emission level. The chemical feed rate is varied in Monet dependent upon the sulfur content of the coal burned and the target sulfur dioxide emission level.

Q. Are there specific issues that PGE is monitoring for future power cost update filings in this proceeding?

A. Yes. One issue that PGE is currently watching is the on-going settlement process in the Northwest Pipeline rate case. PGE has included an estimate of the rate increase based on a settlement agreement filed with the Federal Energy Regulatory Commission. We will continue to monitor developments in the settlement process and plan to reflect any updates in future filings.

IV. Commission's Directives in Order No. 11-432

Q. The Commission's Order No. 11-432 discussed several issues that PGE should improve upon. Has PGE addressed those issues in this filing?

A. Yes. The issues identified by the Commission in Order No. 11-432 related to PGE's use of the confidential designation, and PGE's documentation supporting gas and power hedging transactions (including market liquidity). As we discuss below, PGE has implemented new procedures that become effective in 2012.

A. Confidential Designation

Q. What did the Commission state in Order No. 11-432 with regard to PGE's use of the confidential designation?

A. In that Order, the Commission indicated that PGE should, "be more deliberate and moderate in its use of the [confidential] designation in the future."[5]

Q. How has PGE altered its procedures regarding the designation of confidential material for this initial filing and the filing of the supporting MFR documents?

A. PGE performed a review of the MFR documents provided with this initial filing, as well as the documents to be provided in the April 13 MFR filing. The purpose of this review was to identify non-confidential materials and ensure that only documents containing sensitive information received the confidential designation. While this review was performed on a best-efforts basis given the voluminous nature of the MFR documents (PGE will provide nearly 1,700 documents, many of which are multi-page, in the April 13, 2012, filing), PGE will continue to review all supporting documents provided in update filings made in this proceeding and future power cost proceedings. In contrast to the prior practice of providing

[5] Order No. 11-432, page 3

all MFR documents on a single disk (DVD) labeled as "confidential," PGE now provides separate disks for confidential and non-confidential documents.

B. PGE's Mid-Term Strategy

Q. What is PGE's Mid-Term Strategy ("MTS")?

A. PGE's Mid-Term Strategy is the hedging policy whereby PGE secures power and gas hedges in the market by layering-in transactions over a 3-year window with tenors of 24 to 60 months in order to lower customers' rate volatility (i.e., PGE enters deals for delivery 24–60 months from the year of execution).

Q. What did Order No. 11-432 say with respect to market liquidity and documentation supporting the transactions executed under a hedging program, such as the MTS?

A. Commission Order No. 11-432 emphasized that utilities must be able to establish the existence of market liquidity for each transaction executed under their respective hedging programs. In the absence of objective evidence of market liquidity, a utility must provide contemporaneous documentation supporting the specific transactions. In that Order, the Commission also indicated that PGE must improve its documentation and record-keeping practices when executing transactions pursuant to its MTS hedging program.

Q. Will PGE establish and document the existence of market liquidity for MTS transactions with additional criteria going-forward?

A. Yes. In order to develop additional criteria for assessing market liquidity that could be coupled with PGE's existing practice of monitoring the price quotes received from counterparties, PGE surveyed the relevant market information that would be regularly available. Related criteria were developed for the natural gas and power markets.

Q. What additional criteria were developed to assess market liquidity for natural gas transactions?

A. PGE's MTS transactions for gas are primarily executed in the bilateral market. Data for these bilateral markets are infrequently reported or posted publicly. Therefore, publicly available data to track liquidity are not readily available. Consequently, beginning in 2012, PGE will look to the New York Mercantile Exchange ("NYMEX", a part of CME Group) natural gas transactions (for Henry Hub) as recorded by the Intercontinental Exchange ("ICE") as a proxy to track liquidity for natural gas. PGE will supplement this analysis with ICE data for specific basis pricing at our market hubs, as well as price quotes from our counterparties for each year within the three-year MTS window. (During 2012, the MTS window is 2014–2016). The NYMEX natural gas contract transactions provide an observable measure of liquidity in the overall natural gas market. Natural gas prices for all delivery locations in North America have two components: (1) a NYMEX price component and (2) a locational price component (the basis) expressed as a premium or discount to the relevant benchmark NYMEX contract. Basis markets can only be liquid if the NYMEX market is liquid.

A 3% threshold was established by PGE as necessary to establish the existence of a liquid market. That is, PGE would not transact for a given delivery year if PGE's cumulative transaction volume would exceed 3% of the cumulative market volume already executed for that same delivery year based on analysis of the dataset described above. This metric for gas will be calculated using a rolling 52-week window, updated bi-weekly to provide power operations personnel with the most current trade data and subsequent market liquidity measure. Three percent (3%) of the trailing 52-week volume reported on ICE was arrived at by PGE as a reasonable level for assessing liquidity as it is more conservative than a standard 5% level, but not as restrictive as the application of an extreme 1% threshold. Consideration was also given to the fact that the transactions reported on ICE represent just a portion of all transactions executed in the market.

Q. What criteria were developed to assess market liquidity for power transactions?

A. Similar to gas transactions, power transactions for mid-term durations are executed almost exclusively in the bilateral market. As discussed above, information that could be used for developing and implementing objective measures of liquidity are not readily available for the bilateral market. In order to establish the existence of liquidity for power transactions, PGE implemented the following criteria: the gas market must meet the liquidity threshold described above, and the implied market heat rate must be less than the heat rates of PGE's Coyote Springs and Port Westward generating facilities on a flat basis. (Coyote Springs and Port Westward are the only gas-fired facilities for which natural gas is procured under the MTS).

Q. If the 3% liquidity test is applied to the MTS transactions executed for 2013 delivery, what is the result?

A. PGE Exhibit 104C applies these liquidity criteria and demonstrates that PGE's gas financial transactions under the MTS for 2013 delivery were executed in a liquid market.

Q. Will PGE continue to monitor the information available for assessing liquidity in the gas and power markets?

A. Yes. PGE expects that the implementation of Dodd-Frank reforms by the Commodities and Futures Trading Commission will expand the amount of available transaction information and data. As more data become available, PGE will re-assess its liquidity metrics to ensure the use of the most relevant data.

Q. How is PGE improving its documentation and record-keeping practices for MTS transactions beginning in 2012?

A. PGE is improving its document retention practices in order to archive all relevant analyses, presentations, and supporting documents related to the MTS program and specific transactions. Additionally, PGE personnel will formally document the observed liquidity metrics discussed above (cumulative market volumes, and heat rates for power transaction) concurrent with each transaction, as well as 3 bids and offers for each transaction, and quoted prices. Market liquidity will be reviewed and documented bi-weekly. Structural developments in the market will be reviewed quarterly and presented to PGE's Risk Management Committee as well as stakeholders attending PGE's Quarterly Power Supply Update meetings.

Q. What types of supporting documents are provided with this filing?

A. PGE's Energy Risk Management Policies and Procedures ("ERMP&P") manual revised in November 2007, which governed PGE's practices in 2008, is provided as Exhibit 105C. Subsequent revisions to the ERMP&P are provided in the work papers accompanying this filing.

Prior to entering into an MTS transaction, Power Operations personnel must obtain approval from both PGE's Vice President of Power Operations and Resource Strategy and the General Manager of Risk Management. These pre-approval memos, along with documents supporting the request, for each transaction executed under the MTS are provided in our work papers.

Upon execution, the transaction details were either documented in a physical trade ticket or recorded electronically in PGE's WebTrader system (PGE began entering transaction information electronically in 2009). Deal capture in the WebTrader system links to PGE's BookRunner system. The information on the BookRunner deal input system mirrors that of a trade ticket. If a physical trade ticket was created for an MTS transaction, it is provided in our work papers. If a physical trade ticket does not exist for a given transaction, a "screen shot" from the BookRunner deal input system is provided.

Accompanying each of the trade tickets provided is either a Mid-Term Strategy execution document or a post-execution memo. These documents provide details on the specific transaction, as well as information regarding the net open position for the relevant period and PGE's assessment of the market conditions at the time the transaction was entered into. Also included on the Mid-Term Strategy execution document and post-execution memo are the quotes that PGE's Power Operations personnel obtained from potential counterparties while surveying the market prior to executing the gas transaction.

Q. What does all of this documentation demonstrate with respect to the transactions executed under PGE's MTS?

A. The hedging transactions executed under PGE's MTS are well-supported, as evidenced by the documentation provided with this initial filing. These transactions were consistent with all aspects PGE's hedging strategy. PGE's Power Operations personnel sought and received approval from PGE's Vice President of Power Operations and Resource Strategy and the General Manager of Risk Management before executing MTS transactions. After the deals were entered into, the terms of the transactions were reported back to those that provided the pre-approval, along with the conditions that were observed in the market. Quotes from multiple counterparties were documented for each gas transaction, and market gas prices and heat rates were recorded at the time of each power transaction.

V. 2013 Load Forecast

Q. Please summarize PGE's forecast for its 2013 retail load.

A. Table 1 below summarizes actual and forecast deliveries to various customer groups from 2010 through 2013 in million kWh at average weather conditions.

Table 1
Retail Energy Deliveries: 2010–2013
(cycle month energy in million kWh, average weather)

	2010 Actual *	2011 Actual *	(UE 228) 2012 Forecast	(UE __) 2013 Forecast
Residential	7,555	7,572	7,600	7,623
General Service	7,264	7,291	7,409	7,434
Industrial	3,991	4,204	4,026	3,960
Lighting	110	111	112	114
Total Retail	18,920	19,177	19,147	19,131

* The 2010 and 2011 actual loads are weather-adjusted.
Numbers may not total due to rounding.

Q. Does this 2013 forecast include all loads?

A. Yes. The forecast includes both PGE cost-of-service loads and deliveries of energy to customers under Schedules 485/489.

Q. Does PGE's cost-of-service load forecast assume that certain long-term opt-out customers return to a cost-of-service rate in 2013?

A. No, not for 2013. PGE's load forecast typically accounts for long-term opt-out customers who are either in the final year of a 3-year term or are on a 5-year term and have provided notice that they intend to return to cost-of-service. However, PGE currently has no 3-year opt-out customers or 5-year opt-out customers that have provided notice. Thus, the 2013 cost-of-service load forecast assumes no increase in load to serve opt-out customers returning to a cost-of-service rate.

Q. If customers select a long-term opt-out program for 2013, will PGE adjust the load forecast?

A. Yes. PGE will adjust the 2013 cost-of-service load forecast accordingly, as specified in Schedule 125.

Q. How does the initial 2013 load forecast differ from the final UE 228 forecast?

A. Table 1 shows PGE's historical weather-adjusted retail energy deliveries for 2010 and 2011, the final UE 228 forecast for 2012, and our current forecast for 2013. In UE 228, we projected total deliveries of 19,147 million kWh for 2012. We currently project 19,131 million kWh for 2013 under average weather conditions. Our 2013 load forecast is 0.1% lower than the forecast for 2012 used to develop power costs in UE 228. With the exclusion of two large customers, PGE's current forecast is for 1.2% and 1.3% load growth in 2012 and 2013, respectively.[6]

Q. Was the 2013 forecast developed using the same model that was used in UE 228?

A. Yes. The model specification remains the same as previous filings. Inputs to the model were updated reflecting actual loads through January. The load forecast will be updated (including parameter estimation) in the July and September filings as indicated in Section I above. PGE Exhibit 1400 in Docket UE 215 (specifically pages 6–10) explains the estimation procedures in detail.

[6] This detail will be provided in work papers filed by April 13, 2012.

Q. What load do you use in your 2013 test year power cost forecast?

A. The load listed in Table 1 represents total system load on a cycle month basis at the customer meter as used to calculate rates. The load used to generate power costs in Monet is the cost-of-service load on a calendar month-basis. Table 2 below reconciles the total system load in Table 1 with the cost-of-service load on a calendar month-basis.

Table 2
Total System Load on Cycle Month at Meter
to Cost-of-Service Load on Calendar Month at Meter: 2013
(million kWh)

Total System Load (cycle month)	19,131
Add: Cycle to Calendar Month Difference	25
Total System Load (calendar month)	19,155
Less: Schedules 485/489	(997)
Cost-of-Service Meter Load	18,159

Numbers may not total due to rounding.

Q. What is the corresponding initial cost-of-service busbar load forecast for 2013?

A. With the addition of line losses to Table 2, the initial busbar load forecast for 2013 is 19,530,860 MWh (19,530.8 million kWh), or 2,229.5 MWa. This load is the basis for the hourly Monet load input data.

VI. Comparison with 2012 NVPC Forecast

Q. Please restate your initial 2013 NVPC forecast.

A. The initial forecast is $674.8 million.

Q. How does the 2013 forecast compare with the 2012 forecast utilized to develop power costs in UE 228 and approved in Commission Order No. 11-432?

A. Based on PGE's final updated Monet run for the 2012 test year, the forecast was $702.9 million, or $36.09 per MWh. The initial 2013 forecast is $674.8 million, or $34.55 per MWh[7], which is approximately $1.54 per MWh less than the final forecast for 2012.

Q. What are the primary factors that explain the decrease in NVPC forecast for 2013 versus the NVPC forecast for 2012 in UE 228?

A. As Table 3 demonstrates on the following page, multiple factors contribute to the approximate $28.2 million decrease:

[7] These calculations are based on bus-bar cost-of-service load and include the fact that the 2013 cost-of-service load forecast is 12.3 MWa higher (2,229.5 – 2,217.3) than the 2012 cost-of-service load forecast used in UE 228.

Table 3
Factors in Forecast Power Cost Difference 2013 vs. 2012 ($ Million)

Element	Effect*
Hydro Cost and Performance	$4.0
Coal Cost and Performance	8.6
Gas Cost and Performance	-31.3
Wind Cost and Performance	3.2
Contract and Market Purchases	-21.4
Market Purchases for Cost of Service Load Increase	1.5
Transmission	1.3
Higher Market Price	5.9
Total	**-$28.2**

* Numbers may not total due to rounding.

Increased dispatch of gas-fired generation facilities along with lower contract costs contribute substantially to lower overall forecast power costs in this initial filing. Reduced hydro and coal output, along with slightly higher forward power market prices, partially offset the power cost decrease.

VII. Qualifications

Q. Mr. Niman, please describe your qualifications.

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

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

Q. Ms. Peschka, please state your educational background and experience.

A. I received a Bachelor of Arts degree in Finance from Portland State University. I have been employed at PGE since 1999 in the following positions: Risk Management Analyst, Manager of Risk Management Reporting & Controls, and my current position General Manager of Power Operations. Before joining PGE, I worked at PacifiCorp from 1980-1999 in various retail, wholesale, planning and mergers and acquisition positions. In my current position, I am responsible for managing the Power Operations group that coordinates the NVPC portfolio over the next five years.

Q. Mr. Hager, please describe your qualifications.

A. I received a Bachelor of Science degree in Economics from Santa Clara University in 1975 and a Master of Arts degree in Economics from the University of California at Davis in 1978. In 1995, I passed the examination for the Certified Rate of Return Analyst (CRRA). In 2000, I obtained the Chartered Financial Analyst (CFA) designation.

I have taught several introductory and intermediate classes in economics at the University of California at Davis and at California State University Sacramento. In addition, I taught intermediate finance classes at Portland State University. Between 1996 and 2004, I served on the Board of Directors for the Society of Utility and Regulatory Financial Analysts. Between 2002 and 2007, I served on the Advantis Credit Union Audit Committee and I now serve on the Board of Directors.

I have been employed at PGE since 1984, beginning as a business analyst. I have worked in a variety of positions at PGE since 1984, including power supply. My current position is Manager, Regulatory Affairs.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
101	List of MFRs per OPUC Order No. 08-505
102C	March 30 Initial Filing Monet Output Files and Assumptions Summary
103	PGE Wind Integration Study, dated September 30, 2011
104C	PGE Liquidity Threshold Analysis
105C	PGE Energy Risk Management Policies and Procedures, dated November 28, 2007

ORDER NO. 08-505

Minimum Filing Requirements
July 7, 2008

General

The Minimum Filing Requirements (MFRs) define the documents to be provided by PGE in conjunction with the Net Variable Power Cost (NVPC) portion of the Company's initial (direct case) and update filings of its General Rate Case (GRC) and/or Annual Update Tariff (AUT) proceedings.

The term "Supporting Documents and Work Papers" as used here means the documents used by the persons doing the NVPC forecasting at PGE to develop the final inputs to Monet and the final modeling in Monet for each filing. This may include such items such as contracts, emails, white papers, studies, PGE computer programs, Excel spreadsheets, Word documents, pdf and text files. This will not include intermediate developmental versions of documents that are not used to support the final filing. Documents will be provided electronically where practical.

In cases where systems change or are replaced in the future, such as BookRunner, the MFRs will continue to provide substantially the same information as provided in PGE's 2009 GRC (UE-198).

PGE will take reasonable steps to ensure that the MFRs can be made available to CUB and ICNU at the time of the filing, rather than these parties having to wait for the OPUC to approve the protective order in the case.

Delivery Timing

In either an AUT year (April 1 initial filing) or a GRC year (Feb. 28 initial filing), at a minimum the following portion of the Direct Case Filing MFRs will be delivered with the initial filing:

- Summary Documents (Items 1-6)
- Modeling Enhancements and New Item Inputs (Item 14) – not applicable in AUT year
- Miscellaneous Item 15d - re: Testimony and Exhibits provided on the CD

The remainder of the Direct Case Filing MFRs will be delivered with the initial filing if practical, or no later than fifteen days after the filing (e.g. March 15 in a GRC year, April 15 in an AUT year).

For all update filings, Update Filing MFRs will be delivered with the update filing with the following exception. For the April 1 GRC Update Filing in a GRC year, the delivery of Item 23 will be made with the filing if practical, or no later than fifteen days after the filing (e.g. April 15).

Direct Case Filing

Applicability

- Applies to GRC Initial Filing (e.g. February 28) in a GRC year
- Applies to AUT Initial Filing (i.e. April 1) in a non-GRC year

Summary Documents

1. Monet model for the final step
2. Hourly Diagnostic Reports for the final step
3. Step Log showing NVPC effects of modeling enhancements, modeling changes, addition of new items or removal of items from the prior year rate proceeding (GRC or AUT), and other major updates that PGE believes the parties would want to see identified separately, such as updating the hydro study.
4. Output/Assumptions Summary Report comparable to that provided for the 2009 GRC
5. Executable files, any other files needed to run Monet, and installation instructions
6. Identification of the operating system PGE uses to operate Monet

Supporting Documents and Work Papers for the Following

7. Forward Curve Inputs. Consists of:
    a. Electric curve extract from Trading Floor curve file
    b. Gas curve extract from Trading Floor curve file
    c. Canadian/US Foreign exchange rate (F/X Curve) from Risk Management
    d. Model run for hourly shaping of monthly on/off-peak electric curve (Lydia Program)
    e. Oil forward curve
8. Load Inputs. Consists of:
    a. Monthly load forecast from Load Forecast Group
    b. Hourly load forecast from Load Forecast Group
    c. Copy of the loss study used by Load Forecast Group to develop busbar load forecast
9. Thermal Plant Inputs
    a. Capacities
    b. Heat Rates
    c. Variable O&M

        This includes any other cost or savings components modeled as part of Variable O&M, such as incremental transmission losses, SO_2 emission allowances (emission allowance $/ton price forecast, plant emission factors lb/MMBtu), etc.
    d. Forced outage rates
    e. Maintenance outage schedules and derations
    f. Minimum capacities
    g. Operating constraints
    h. Minimum up times
    i. Minimum down times
    j. Plant testing requirements
    k. Oil usage volumes
    l. Coal commodity costs
    m. Coal transportation costs
    n. Coal fixed fuel costs classified as NVPC items

        Includes items such as: Colstrip Fixed Coal Cost and the following Boardman costs: Rail Car Mileage Tax, Coal Sampling, Rail Car Lease, Rail Car Maintenance, Trainset Storage Fee, and Coal Car Depreciation
10. Hydro Inputs
    a. Monthly energy for all Hydro Resources

        This will include the results of PGE's most current study using the Pacific Northwest Coordination Agreement (PNCA) Headwater Benefit Study. Note that this program is not the property of PGE and should be obtained from the Northwest Power Pool. Provide the PGE version of the PNCA model inputs, so that if the Parties obtain the PNCA model, they would have the inputs needed to reproduce PGE's study.
    b. Description of logic for hourly shaping where applicable
    c. Usable capacities where applicable
    d. Operating constraints modeled
    e. Hydro maintenance derations
    f. Hydro forced outage rates (not currently modeled)
    g. Hydro plant H/K factors
    h. Spreadsheet demonstrating how the hydro energy final output from the PNCA study is adjusted to arrive at the monthly energy output on the PwrAEOut sheet
11. Electric and Gas Contract Inputs
    a. Copy of contract for each long-term (5-year or greater term) or non-standard power contract modeled in Monet.

        For some contracts, this may consist of a term sheet rather than a full contract, depending on what was deemed reasonably necessary by the power modelers to model the contract in Monet.
    b. BookRunner extracts for the test year of:

        Electric Physical Contracts
        Electric Financial Contracts
        Gas Physical Contracts

Gas Financial Contracts
F/X Hedge Contracts

c. Copy of each firm gas transportation or storage contract modeled in Monet
d. List of the PURPA QF contracts modeled in Monet
e. List of the long-term (5-year or greater term) or non-standard contracts modeled in MONET that were not included in PGE's most recent GRC or AUT.
f. Gas transportation input spreadsheet or its successor/equivalent
g. Website snapshots input to the gas transportation spreadsheet
h. Other Supporting Documents and Work Papers for contracts modeled in Monet, including any items showing on the Monet Cost and/or Energy Output reports not covered above. Could include structured contracts, option contracts, etc.
i. Coal contracts: Covered above under Thermal Plant Inputs
j. Amortizations of regulatory assets or liabilities modeled in the Contracts section of Monet

12. Wheeling Inputs
    a. Supporting Documents and Work Papers for all wheeling items modeled in Monet
13. Wind Power Inputs. Includes but not limited to:
    a. Monthly energy
    b. Hourly energy
    c. Maintenance
    d. Forced outage rates
    e. Integration costs, royalties, other costs and elements modeled
14. Modeling Enhancements and New Item Inputs
    a. Supporting Documents and Work Papers for all modeling enhancements and new items modeled in Monet.
    b. Includes modeling or logic changes, changes to the methodology used to compute data inputs or other type of enhancement to the Monet model.
    c. Modeling revisions, refinements, clean-ups etc. that do not affect NVPC under any conditions will not be considered to be modeling enhancements.
15. Miscellaneous
    a. Line Item Adjustments to Monet such as OPUC orders, settlement stipulations, others
    b. Identification of all transactions modeled in Monet that do not produce energy
    c. Items in Monet not covered elsewhere above
    d. For all testimony and exhibits provided on the CD in pdf format, provide the testimony in searchable pdf format, and provide any exhibits created in Excel in the original Excel format when available to PGE.

Historical Operating Data

16. Hourly extract of data from PGE's Power Scheduling and Accounting System showing actual hourly energy values for the most recent Four-Year Calendar Period of the following:
    a. Generation from each coal, gas, hydro and wind generating plant modeled in Monet. Note that Colstrip Units 3 and 4 generation is aggregated in PGE's system, and the Mid-C contract generation is similarly aggregated.
    b. Long-term (>5 years) electric contract purchases, sales and exchanges modeled in Monet.
17. Table showing the actual monthly generation of each PGE coal, gas, hydro and wind generating plant modeled in MONET, from the period 1998 through the last calendar year.
18. Monthly compilations of actual NVPC produced by PGE for the most recent calendar year.

Update Filings

19. Monet model for the final step
20. Hourly Diagnostic Reports for the final step
21. Step Log showing effect on NVPC of each update step since the last filing
22. Output/Assumptions Summary Report comparable to that provided for the 2009 GRC
23. For each Monet update step:
    a. Text description of update, including identification and location of input changes within Monet.
    b. Excel file containing Monet standard output reports (PwrCsOut, PwrAEOut, PwrEnOut) and PC Input sheets.
    c. Supporting Documents and Work Papers for the update step
24. For all testimony and exhibits provided on the CD in pdf format, provide the testimony in searchable pdf format, and provide any exhibits created in Excel in the original Excel format when available to PGE.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Robert Macfarlane
Bonnie Gariety

Portland General Electric

March 30, 2012

Pricing

Table of Contents

I. Introduction and Summary

Q. Please state your name and position.

A. My name is Robert Macfarlane. I am an Analyst in the Pricing and Tariffs Department. My qualifications are listed in Section IV.

My name is Bonnie Gariety. I am an Analyst in the Pricing and Tariffs Department. My qualifications are also listed in Section IV.

Q. What is the purpose of your testimony?

A. This testimony describes the following:

- The estimated price impacts from this filing anticipated to occur on January 1, 2013.
- The calculation of Schedule 125 prices. PGE Exhibit 201 contains a draft of Schedule 125.

PGE will file the final Schedule 125 prices incorporating the final updates to Net Variable Power Costs (NVPC) on November 15.

II. Estimated Rate Impacts

Q. What are the base rate impacts of the proposed $30.6 million reduction in Schedule 125 prices?

A. Table 1 below summarizes the COS base rate impacts for 2013 for selected Schedules. Also, included in these inputs are proposed changes in System Usage charges for Schedules 85 and 89, and changes in the base rate portion of Schedule 122. These estimates are preliminary and subject to change due to among other items, market electric and gas prices.

Table 1
Estimated Base Rate Impacts

Schedule	Rate Impact
Sch 7 Residential	-1.6%
Sch 32 Small Non-residential 30 kW or less	-1.6%
Sch 83 Non-residential 31-200 kW	-1.9%
Sch 85 Secondary 201-1,000 kW	-1.3%
Sch 85 Primary 201-1,000 kW	-1.3%
Sch 89 Secondary Over 1,000 kW	-1.3%
Sch 89 Primary Over 1,000 kW	-1.4%
Sch 89 Subtransmission Over 1,000 kW	-1.4%
Overall	-1.6%

Q. What other price changes do you expect to occur on January 1, 2013?

A. We anticipate several changes on January 1, 2013, including:

- Schedule 105 Regulatory Adjustments.
- Schedule 122 Renewable Resources Automatic Adjustment Clause.
- Schedule 126 Annual Power Cost Variance Mechanism.
- System usage charge for Schedules 85 and 89 (as well as their direct access equivalents) based on changes in the Schedule 129 Long-term Transition Adjustment starting in 2013.

Updated estimates of these price changes will be provided later in the proceeding.

III. Calculation of Schedule 125 Prices

Q. Please describe how you calculated the Schedule 125 amount.

A. We determined the Schedule 125 amount of ($52.5) million by comparing the projection of 2013 NVPC to the amount of NVPC that is recovered through the combination of our current energy prices adjusted to exclude fixed generation cost recovery, multiplied by the 2013 load forecast by schedule. (The resulting revenues we reference as NVPC revenues). The difference between 2013 NVPC and NVPC revenues constitutes the change in NVPC. This amount, either positive or negative, is multiplied by 1.0338 to account for revenue sensitive costs such as uncollectibles and franchise fees. Page 1 of PGE Exhibit 202 provides a summary of the Schedule 125 amount of ($52.5) million and how it is spread to the respective schedules. Also included on page 1 are the proposed Schedule 125 prices.

Q. Please provide a more detailed description of how you calculate the NVPC revenues.

A. Page 2 of PGE Exhibit 202 demonstrates the calculation. We start with the tariff energy prices for each schedule and remove the portion of these energy prices that recovers the UE 215 fixed generation costs. We then multiply these prices by the respective energy billing determinants to calculate the amount of NVPC projected to be recovered for the 2013 test period. For 2013, we project NVPC revenues of $725.5 million. This amount is carried over to Page 1 of PGE Exhibit 202 in order to calculate the Schedule 125 amount.

Q. Please describe how you allocate the Schedule 125 amount to each rate schedule and how you calculate the Schedule 125 price.

A. We allocate and price the Schedule 125 amount consistent with Special Condition 1 of Schedule 125 which states:

> Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy based on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

Q. Where is the calculation of the basis of the Schedule 125 allocations, the 2012 Base Generation Revenues?

A. We present this calculation, which is simply the 2013 projected energy billing determinants times the tariff energy price, on page 2 of PGE Exhibit 202.

IV. Qualifications of Witnesses

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

A. I received a Bachelor of Arts business degree from Portland State University with a focus in finance.

Since joining PGE in 2008, I have worked as an analyst in the Rates and Regulatory Affairs Department. My duties at PGE have focused on pricing and regulatory issues.

From 2004 to 2008, I was a consultant with Bates Private Capital in Lake Oswego, OR where I developed, prepared, and reviewed financial analyses used in investor vs. broker litigation.

Q. Ms. Gariety, please state your educational background and qualifications.

A. I received a Bachelor of Science and a Master of Science degree in Economics from the University of Wyoming.

Since joining PGE in 2007, I have worked as an analyst in the Rates and Regulatory Affairs Department. My duties at PGE have focused on power costs; solar, load curtailment and electric vehicle programs; and various regulatory issues. Previously, I was an analyst with Iowa Utilities Board and the Office of Consumer Advocate under the Department of Justice. Also, I was an economist for the State of Oregon Employment Department.

Q. Does this complete your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
201	Proposed Schedule 125 Prices
202	Calculation of Proposed Schedule 125 Prices
203	Calculation of Proposed Generation and NVPC Revenues
204	Table 1 COS Base Rates – Estimated Effect on Total Electric Bills

SCHEDULE 125 (Continued)

FILING AND EFFECTIVE DATE

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

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

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

RATE ADJUSTMENT

The rate adjustment will be based on the Adjusted NVPC less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case applied to forecast loads used to determine changes in Net Variable Power Costs. NVPC prices are defined as the price component that recovers the level of NVPC from the Company's most recent general rate case contained in each Schedule's Cost of Service energy prices.

ADJUSTMENT RATES

Schedule		Part A ¢ per kWh
7		(0.312)
15		(0.250)
32		(0.291)
38	Large Nonresidential	(0.277)
47		(0.316)
49		(0.316)
75		
	Secondary	(0.263) (1)
	Primary	(0.253) (1)
	Subtransmission	(0.249) (1)
83		(0.285)

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

SCHEDULE 125 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule		Part A ¢ per kWh
85		
	Secondary	(0.271)
	Primary	(0.262)
89		
	Secondary	(0.263)
	Primary	(0.253)
	Subtransmission	(0.249)
91		(0.250)
92		(0.253)
93		(0.246)
94		(0.253)

SPECIAL CONDITIONS

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

PORTLAND GENERAL ELECTRIC
Calculation of Schedule 125 Prices

Schedules	2013 Calendar COS Energy MWH	2013 Base Generation Revenues	Generation Allocation	2013 Base NVPC Revenues	Sch 125 Allocation	2013 NVPC Revenues	2013 Sch 125 Rate mills/kWh	2013 Sch 125 Revenues	Cycle MWH	Cycle Revenues
Schedule 7	7,619,344	$518,894	45.32%	$328,791	($23,777)	$305,014	(3.12)	($23,772)	7,616,104	($23,762)
Schedule 15	23,112	$1,260	0.11%	$799	($58)	$741	(2.50)	($58)	23,112	($58)
Schedule 32	1,575,008	$100,108	8.74%	$63,426	($4,587)	$58,838	(2.91)	($4,583)	1,573,206	($4,578)
Schedule 38	34,708	$2,100	0.18%	$1,335	($96)	$1,239	(2.77)	($96)	34,678	($96)
Schedule 47	21,128	$1,459	0.13%	$923	($67)	$856	(3.16)	($67)	21,241	($67)
Schedule 49	67,524	$4,655	0.41%	$2,953	($213)	$2,740	(3.16)	($213)	67,407	($213)
Schedule 83-S	2,784,657	$173,484	15.15%	$109,883	($7,950)	$101,933	(2.85)	($7,936)	2,779,758	($7,922)
Schedule 85-S	2,109,484	$124,814	10.90%	$79,101	($5,719)	$73,382	(2.71)	($5,717)	2,103,528	($5,701)
Schedule 89-S	514,947	$29,586	2.58%	$18,762	($1,356)	$17,406	(2.63)	($1,354)	525,127	($1,381)
Schedule 85-P	281,195	$16,073	1.40%	$10,180	($737)	$9,443	(2.62)	($737)	272,768	($715)
Schedule 89-P	2,628,845	$145,256	12.69%	$92,127	($6,656)	$85,471	(2.53)	($6,651)	2,618,370	($6,624)
Schedule 89-T	384,765	$20,938	1.83%	$13,281	($959)	$12,321	(2.49)	($958)	384,765	($958)
Schedule 91	109,017	$5,944	0.52%	$3,767	($272)	$3,494	(2.50)	($273)	109,017	($273)
Schedule 92/94	4,439	$245	0.02%	$155	($11)	$144	(2.53)	($11)	4,439	($11)
Schedule 93	569	$31	0.00%	$19	($1)	$18	(2.46)	($1)	569	($1)
TOTAL	18,158,741	$1,144,846	100%	$725,501	($52,460)	$673,041		($52,428)	18,134,088	($52,361)
			Sch 125 TARGET ===>		($52,460)					

2013 NVPC (Monet Model Total Cost Output)	$674,756	
2013 NVPC Revenues	$725,501	(page 2 of Exhibit 202)
Change in NVPC	($50,745)	
Revenue Senstitive Adj. 3.38%	($1,715)	
Sch 125 Revenue Requirement ($000)	($52,460)	

PORTLAND GENERAL ELECTRIC
Calculation of Generation and NVPC Revenues

Schedule	2013 Calendar MWh	Energy Price	2013 Base Energy Revenues	UE 215 Rate Design Energy Price	Generation Energy Price	2013 Base Generation Revenues	UE 215 Fixed Gen. Price	NVPC Price	2013 NVPC Revenues
Sch 7									
Block 1	6,082,974	67.78	$412,304	1.42	66.36	$403,666	24.95	41.41	$251,896
Block 2	1,536,370	75.00	$115,228	0.00	75.00	$115,228	24.95	50.05	$76,895
Sch 15	23,112	54.52	$1,260		54.52	$1,260	19.97	34.55	$799
Sch 32	1,575,008	63.56	$100,108		63.56	$100,108	23.29	40.27	$63,426
Sch 38									
On-peak	18,537	66.33	$1,230		66.33	$1,230	22.03	44.30	$821
Off-peak	16,172	53.83	$871		53.83	$871	22.03	31.80	$514
Sch 47	21,128	69.07	$1,459		69.07	$1,459	25.39	43.68	$923
Sch 49	67,524	68.94	$4,655		68.94	$4,655	25.21	43.73	$2,953
Sch 83-S	2,784,657	62.30	$173,484		62.30	$173,484	22.84	39.46	$109,883
Sch 85-S									
On-peak	1,384,377	61.77	$85,513		61.77	$85,513	21.67	40.10	$55,514
Off-peak	725,107	54.20	$39,301		54.20	$39,301	21.67	32.53	$23,588
Sch 85-P									
On-peak	179,832	59.89	$10,770		59.89	$10,770	20.96	38.93	$7,001
Off-peak	101,363	52.32	$5,303		52.32	$5,303	20.96	31.36	$3,179
Sch 89-S									
On-peak	328,869	60.19	$19,795		60.19	$19,795	21.02	39.17	$12,882
Off-peak	186,078	52.62	$9,791		52.62	$9,791	21.02	31.60	$5,880
Sch 89-P									
On-peak	1,546,942	58.37	$90,295		58.37	$90,295	20.21	38.16	$59,031
Off-peak	1,081,903	50.80	$54,961		50.80	$54,961	20.21	30.59	$33,095
Sch 89-T									
On-peak	223,981	57.58	$12,897		57.58	$12,897	19.90	37.68	$8,440
Off-peak	160,784	50.01	$8,041		50.01	$8,041	19.90	30.11	$4,841
Sch 91	109,017	54.52	$5,944		54.52	$5,944	19.97	34.55	$3,767
Sch 92	4,439	55.26	$245		55.26	$245	20.24	35.02	$155
Sch 93	569	53.67	$31		53.67	$31	19.65	34.02	$19
Totals	18,158,741		$1,153,484			$1,144,846			$725,501

Note: See Attachment B page 52 of PGE UE 215 compliance work papers for source of fixed generation prices.

TABLE 1 BASE RATES
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CUSTOMERS' TOTAL ELECTRIC BILLS
2013 COS ONLY

CATEGORY	RATE SCHEDULE	Forecast SMAR12E13 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT Base Rates incl Sch 122a, Sch 125, System Usage	TOTAL ELECTRIC BILLS PROPOSED Base Rates incl Sch 122a, Sch 125, System Usage	Change AMOUNT	Change PCT.
Residential	7	727,199	7,616,104	$857,638,182	$843,929,194	($13,708,988)	-1.6%
Employee Discount				($939,264)	($924,046)	$15,218	
Subtotal				$856,698,918	$843,005,149	($13,693,770)	-1.6%
Outdoor Area Lighting	15	0	23,112	$4,310,646	$4,277,364	($33,281)	-0.8%
General Service <30 kW	32	87,904	1,573,206	$164,263,868	$161,620,881	($2,642,986)	-1.6%
Opt. Time-of-Day G.S. >30 kW	38	372	34,678	$4,204,537	$4,149,053	($55,484)	-1.3%
Irrig. & Drain. Pump. < 30 kW	47	3,266	21,241	$2,924,102	$2,885,232	($38,870)	-1.3%
Irrig. & Drain. Pump. > 30 kW	49	1,233	67,407	$6,550,648	$6,427,293	($123,355)	-1.9%
General Service >30 kW	83-S	10,920	2,779,758	$238,737,603	$234,178,800	($4,558,803)	-1.9%
General Service 201-1,000 kW							
Secondary	85-S	1,204	2,103,528	$162,985,584	$160,903,092	($2,082,493)	-1.3%
Primary	85-P	143	272,768	$20,020,438	$19,766,764	($253,674)	-1.3%
Schedule 89 > 1 MW							
Secondary	89-S	74	525,127	$38,524,315	$38,030,696	($493,619)	-1.3%
Primary	89-P	97	2,618,370	$168,740,556	$166,436,391	($2,304,166)	-1.4%
Subtransmission	89-T	7	384,765	$23,992,526	$23,665,475	($327,050)	-1.4%
Street & Highway Lighting	91	203	109,017	$18,023,843	$17,866,858	($156,984)	-0.9%
Traffic Signals	92	17	4,439	$345,639	$339,158	($6,480)	-1.9%
Recreational Field Lighting	93	24	569	$108,099	$107,291	($808)	-0.7%
TOTAL (CYCLE YEAR BASIS)		832,664	18,134,088	$1,710,431,321	$1,683,659,497	($26,771,824)	-1.6%
==============================							
CONVERSION ADJUSTMENT				$2,325,330	$2,288,934		
====================================							
TOTAL (CALENDAR YEAR BASIS)			**18,158,741**	**$1,712,756,651**	**$1,685,948,431**	**($26,808,221)**	-1.6%

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE _____

In the Matter of Portland General Electric Company's 2013 Annual Power Cost Update Tariff (Schedule 125)	**MOTION FOR APPROVAL OF PROTECTIVE ORDER [EXPEDITED CONSIDERATION REQUESTED]**

Pursuant to ORCP 36(C)(7) and OAR 860-001-0080, 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 is filing its annual power cost update pursuant to its tariff Schedule 125.

2. Some of the exhibits and work papers supporting the power cost filing contain confidential information regarding PGE's natural gas, electric and coal market activities as well as other confidential business matters. This information will include proprietary modeling code, PGE's timing of and expected prices for electricity purchases, PGE's timing of and expected prices for natural gas purchases, PGE's forward position for electricity, PGE's forward position for natural gas, and whether and the amount by which PGE is long or short for electricity and natural gas during various periods in 2013. This information is confidential commercial information and/or trade secrets under ORCP 36(C)(7).

3. PGE would like to file with the Commission, and provide to other parties, 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 will 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 discloses PGE's position, strategy and future needs to purchase and sell electricity, natural gas and coal. 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 30th day of March, 2012.

Respectfully submitted,

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**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE __

In the Matter of Portland General Electric Company's 2013 Annual Power Cost Update Tariff (Schedule 125)	**GENERAL PROTECTIVE ORDER**

DISPOSITION: MOTION FOR PROTECTIVE ORDER GRANTED

On March 30, 2012, Portland General Electric Company ("PGE") filed a motion for a general protective order with the Public Utility Commission of Oregon (Commission). PGE states that the order is needed to protect confidential customer information and confidential business plans and strategies. Specifically, PGE states that some of the work papers supporting its application will contain proprietary modeling code, PGE's timing of and expected prices for electricity purchases, PGE's timing of and expected prices for natural gas purchases, PGE's forward position for electricity, PGE's forward position for natural gas, and whether and the amount by which PGE is long or short for electricity and natural gas during various periods in 2013. PGE adds that the public release of this information could prejudice PGE and its customers. PGE also anticipates that there may be requests for further confidential information during this docket.

I find that good cause exists to issue a general protective order, which is attached as Appendix A. The order permits the broadest possible discovery consistent with the need to protect confidential information. It shields no specific documents and makes no judgment about whether any particular document contains a trade secret or commercially sensitive information. Rather, the order adopts a process for resolving discovery disputes that include sensitive information.

The order permits any party to designate information as confidential if the party reasonably believes that the information falls within the scope of ORCP 36(C)(7). The confidential designation must be made in good faith and be limited to only those portions of the document that qualify as a protected trade secret or other confidential research, development, or commercial information. Any other party may challenge the designation of information as confidential. The designating party bears the burden of showing that the challenged information is covered by ORCP 36(C)(7).

Confidential information may be disclosed only to a "qualified person" as defined in paragraph 3 of the general protective order. The authors of the confidential material, the Commission, Administrative Law Judges (ALJs), Commission Staff, and counsel of record for a party or persons directly employed by counsel are "qualified persons" and may review confidential information without individually signing the general protective order. Other persons wanting access to confidential information must become qualified under paragraph 10.

To receive confidential information, all parties except Commission Staff must sign the "consent to be bound" in section I of Appendix B. This includes the party that moved for issuance of the general protective order because any party may designate information as confidential under the order. By signing the "consent to be bound," a party agrees to be bound by the terms of the general protective order and certifies that it has an interest in the proceedings that is not adequately represented by other parties to the proceedings.

All persons given access to confidential information must monitor their own conduct to ensure compliance with the general protective order. Without the written permission of the designating party, no person may use or disclose the information for any purpose other than participating in these proceedings. All qualified persons must take reasonable precautions to keep confidential information secure. Questions regarding whether a particular person is a "qualified person" under the general protective order may be directed to the Administrative Hearings Division at (503) 378-6678.

ORDER

IT IS ORDERED that the General Protective Order, attached as Appendix A, governs the disclosure of confidential information in these proceedings.

Made, entered, and effective on ______________________________.

____
[Judge's name]
Administrative Law Judge

A party may appeal this order to the Commission under OAR 860-001-0420.

GENERAL PROTECTIVE ORDER
DOCKET NO. UE __

Scope of this Order:

1. This order governs the acquisition and use of Confidential Information in these proceedings.

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, addressee, or originator of Confidential Information;
b. A Commissioner, Administrative Law Judge (ALJ), or Commission Staff;
c. Counsel of record for a party;
d. A person employed directly by counsel of record; or
e. A person qualified under paragraph 10, including parties and their employees.

Designation of Confidential Information:

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

CONFIDENTIAL
SUBJECT TO GENERAL PROTECTIVE ORDER

To the extent practicable, the party may designate as confidential only the portions of the material covered by 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 Information must, when feasible, ensure that all copies of the information bear the above legend if requested by the designating party.

6. Any other party may challenge the designation of information as confidential by notifying the designating party. Once notified, the designating party bears the burden of showing that the challenged information is covered by ORCP 36(C)(7).

Information Given to the Commission:

7. Confidential Information filed or provided to the Commission or its Staff must be printed on yellow paper and placed in a sealed envelope or other appropriate container. **Only the portions of a document that fall within ORCP 36(C)(7) may be placed in the envelope/container.** The envelope/container must bear the legend:

> THIS ENVELOPE IS SEALED UNDER ORDER NO. _____ AND CONTAINS CONFIDENTIAL INFORMATION. THE INFORMATION MAY BE SHOWN ONLY TO QUALIFIED PERSONS AS DEFINED IN THE ORDER.

Disclosure of Confidential Information:

8. To receive Confidential Information, all parties except Commission Staff must sign the "consent to be bound" in section I of Appendix B. Confidential Information may not be disclosed to any person other than a Qualified Person. When feasible, Confidential Information must 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 ALJ.

9. A Qualified Person may disclose Confidential Information to any other Qualified Person associated with the same party, unless the designating party objects under paragraph 11.

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

a. Read a copy of this general 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 current, past, and expected clients.

Counsel must deliver a copy of the signed statement including the information in (d) and (e) to the designating party and to all parties of record. The notification may be made by electronic mail or facsimile. A person qualified under paragraph 3(e) may not have access to Confidential Information sooner than seven days after the designating party receives a copy of the signed statement.

11. All Qualified Persons may have access to Confidential Information unless the designating party objects as provided in this paragraph. The designating party must provide written notice to the Qualified Person and counsel for the party associated with the Qualified Person as soon as the designating 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 ALJ. After receipt of the written notice as required in this paragraph, the specific Confidential Information may not be disclosed to the Qualified Person until the issue is resolved.

Preservation of Confidentiality:

12. Without the written permission of the designating party, any person given access to Confidential Information under this order may not use or disclose Confidential Information for any purpose other than participating in these proceedings. All Qualified Persons must take reasonable precautions to keep Confidential Information secure. Disclosure of Confidential Information for purposes of business competition is strictly prohibited.

A Qualified Person may reproduce Confidential Information to the extent necessary to participate in these proceedings. A Qualified Person may disclose Confidential Information only to other Qualified Persons associated with the same party.

Duration of Protection:

13. The Commission will preserve the confidentiality of Confidential Information for a period of five years from the date of the final order in these proceedings, unless extended by the Commission at the request of the designating party. The Commission will notify the designating party at least two weeks prior to the release of Confidential Information.

Destruction After Proceedings:

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 these proceedings 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 must destroy or return it to the designating party within 90 days after final resolution of these proceedings unless the designating party consents in writing to retention of the Confidential Information. This paragraph does not apply to the Commission or its Staff.

Appeal to the Presiding Officer:

15. Any party may request that the ALJ conduct a conference to help resolve disputes related to this protective order.

A party challenging the designation of information as confidential may file an objection with the ALJ that identifies the information in dispute and includes a certification that reasonable efforts to achieve an informal resolution have been unsuccessful. Within seven days of the objection, unless otherwise ordered by the ALJ, the designating party must either remove the confidential designation or file a written response identifying the legal basis for the claim of confidentiality. The challenging party may file a written reply to any response within seven days. If the designating party does not timely respond to the motion, the Commission will remove the confidential designation from the challenged information.

Additional Protection:

16. If a designating party seeks additional protection for Confidential Information, the party may move for any of the remedies in ORCP 36(C). The motion must include:

a. The parties involved;
b. The exact nature of the information involved;
c. The legal basis for the claim that the information is protected under ORCP 36(C)(7) or the Public Records Law;
d. The exact nature of the relief requested;
e. The specific reasons the requested relief is necessary; and
f. A detailed description of the intermediate measures, including selected redaction, explored by the parties and why these measures are insufficient.

Pending the Commission's ruling on a motion for additional protection, the information involved need not be released.

SIGNATORY PAGE
DOCKET NO. UE __

I. Consent to be Bound:

This general protective order governs the use of Confidential Information in these proceedings.

________________________________ (Party) agrees to be bound by the terms of the general protective order and certifies that it has an interest in these proceedings that is not adequately represented by other parties to the proceedings.

Signature: ________________________________

Printed Name: ________________________________

Date: ________________________________

II. Persons Qualified under Paragraphs 3(a) through 3(d):

________________________________(Party) identifies the following person(s) automatically qualified under paragraphs 3(a) through (d).

PRINTED NAME	DATE

SIGNATORY PAGE
DOCKET NO. UE __

III. Persons Qualified under Paragraph 3(e):

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

By: Signature: ______________________ Date: ______________
Printed Name: ______________________
Address: ______________________
Employer: ______________________
Job Title: ______________________
☐ Paragraph 10(e) information also provided.

By: Signature: ______________________ Date: ______________
Printed Name: ______________________
Address: ______________________
Employer: ______________________
Job Title: ______________________
☐ Paragraph 10(e) information also provided.

By: Signature: ______________________ Date: ______________
Printed Name: ______________________
Address: ______________________
Employer: ______________________
Job Title: ______________________
☐ Paragraph 10(e) information also provided.

By: Signature: ______________________ Date: ______________
Printed Name: ______________________
Address: ______________________
Employer: ______________________
Job Title: ______________________
☐ Paragraph 10(e) information also provided.