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

August 10, 2012

Via Electronic Filing and US Mail
puc.filingcenter@state.or.us

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

Re: UE 250 - 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 Rebuttal Testimony and Exhibits of:

- **Mike Niman, Terri Peschka and Patrick G. Hager (PGE / 300)**

Three copies on CD of:

- **Work Papers**
- **Confidential Work Papers (subject to Protective Order No. 12-120)**

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,

Patrick G. Hager
Manager, Regulatory Affairs

PGH:jlt
encl.
cc: UE 250 Service List

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **UE 250 PORTLAND GENERAL ELECTRIC COMPANY'S REBUTTAL TESTIMONY** to be served by electronic mail to those parties whose email addresses appear on the attached service list and by First Class U.S. Mail, postage prepaid and properly addressed, to those parties on the attached service list who have not waived paper service for OPUC Docket No. UE 250.

DATED at Portland, Oregon, this 10th day of August, 2012.

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SERVICE LIST
OPUC DOCKET # UE 250

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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Power Costs

PORTLAND GENERAL ELECTRIC COMPANY

Rebuttal Testimony and Exhibits of

Mike Niman
Terri Peschka
Patrick G. Hager

Portland General Electric

August 10, 2012

Power Costs

Table of Contents

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 were previously provided in PGE Exhibit 100.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address the testimony of Oregon Public Utility Commission ("OPUC") Staff and the testimony of Industrial Customers of Northwest Utilities ("ICNU").

Q. What are the topics at issue in this docket?

A. The general issue being debated in this docket is whether PGE (or any other party) can propose a change to PGE's Annual Update Tariff ("AUT") as Schedule 125 outside of a general rate case ("GRC"). The specific issues in this docket are limited to those that PGE identified in its direct testimony: the inclusion of the costs of emission control chemicals at Boardman in the determination of PGE net variable power costs ("NVPC") and the update of the estimated wind integration cost of day-ahead forecast error.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have four sections:

- Section II: PGE Schedule 125;
- Section III: Boardman emission control chemicals;
- Section IV: Update wind integration day-ahead forecast error cost; and
- Section V: Natural gas transaction liquidity test.

II. PGE Schedule 125

Q. You stated that a general issue being debated in this docket is whether Schedule 125 can be modified outside of a GRC; can you please explain this statement?

A. On March 29, 2012, PGE proposed a change to Schedule 125 that allows for the estimated costs associated with pollution control chemicals at the Boardman generating plant to be updated in each power cost filing for inclusion in the forecast of PGE's NVPC (PGE Advice No. 12-08, Docket No. UE 251). Both Staff and ICNU oppose this proposed change on the premise that Schedule 125 can only be changed during a GRC (Staff Exhibit 100, page 11, and ICNU Exhibit 100, page 6, lines 21–22).

Q. Is there any basis for the statement that Schedule 125 <u>cannot</u> be updated outside of a GRC?

A. PGE could not locate any such restriction in prior Commission Orders. Rather, updates to any schedule are made pursuant to Oregon Revised Statute 757.215, without limitation to the update taking place during a GRC or otherwise. Commission Order No. 07-015 did note that "[m]odel changes or updates could be considered, not in the Annual Update process, but in a separate docket" (Order No. 07-015, page 19). PGE's request to modify Schedule 125 to include the pollution control chemical costs at Boardman was filed as a separate proceeding (Docket No. UE 251). That docket was ultimately consolidated with PGE's AUT as Docket No. UE 250.

PGE does agree that the scope of the AUT proceeding should generally be limited in order to allow parties to perform a complete review of the updates affecting NVPC in an efficient manner. However, any party should have the ability to propose that changes be made to Schedule 125. This is especially true when new costs, which vary with other factors modeled in Monet, arise as a result of a regulatory mandate. PGE commits an extensive amount of resources to produce complete, accurate, and well-organized documentation supporting each of its power cost update filings (the Minimum Filing Requirements or "MFRs") in order to provide the materials necessary for other parties to review PGE's NVPC forecast.

Q. Have other parties recommended that items should be included in PGE's modeling of NVPC outside of the scope that a strict reading of Schedule 125 would allow for?

A. Yes. In PGE's most recent AUT proceeding (Docket No. UE 228 - 2012 AUT), Citizens' Utility Board ("CUB") proposed that PGE begin modeling an estimate of the profit if the difference between the forward prices for Rockies and Sumas natural gas was realized. PGE agreed to incorporate this modeling change into its initial filing in the 2013 AUT, which resulted in a small reduction to PGE's forecast NVPC. This issue is also explained in Staff Exhibit 100 (Staff Exhibit 100, page 4, lines 3–11).

PGE's initial filing in Docket No. UE 228 included a revised method for calculating the imbalance premium paid to Bonneville Power Administration ("BPA") for Generation Imbalance Services. PGE agreed to this revision as part of a Stipulation in UE 215. This revised calculation method resulted in a reduction to PGE's forecast NVPC. Clearly, other parties have the opportunity to suggest that modeling changes beyond the scope of Schedule 125 should be included in Monet outside of a GRC. This example also illustrates that changes proposed by PGE and other parties can result in both increases and decreases to NVPC.

While we acknowledge that both of the modeling changes discussed above were prompted by Stipulations reached in the respective proceedings, we also note that, to PGE's knowledge, no party has expressed concerns related to their ability to perform a thorough and timely review of either change or to provide sufficient testimony.

III. Boardman Emission Control Chemicals

Q. Please briefly explain the costs that PGE is including in the AUT with respect to emission control chemicals at Boardman.

A. We include in our forecast of 2013 NVPC the costs of chemicals that PGE will use at Boardman in 2013 in order to achieve compliance with mercury emissions targets and perform testing to ensure compliance with future sulfur dioxide emissions targets. Additional information was provided in PGE Exhibit 100 (PGE Exhibit 100, pages 10–13).

Q. Has any party indicated in this proceeding that these pollution control costs should not be recovered by PGE?

A. No. No party has argued in this proceeding that these costs should not be recovered by PGE. Rather, the debate has focused on whether these costs should be included in PGE's forecast of 2013 NVPC in the AUT.

A. Nature of the Costs

Q. You stated that these costs relate to emissions compliance; has PGE previously presented to parties and the Commission the need to achieve these emissions targets at Boardman?

A. Yes. In the proceeding related to PGE's 2009 Integrated Resource Plan ("IRP" – Docket No. LC 48), PGE indicated that mercury and sulfur dioxide emission control systems would be installed at Boardman as part of a plan to cease coal-fired operations at the plant at the end of 2020 ("BART III proposal") (Order No. 10-457, pages 7–8). Stated elements of this proposal included the installation of mercury controls, and the installation and pilot testing of a dry sorbent injection ("DSI") system (Order No. 10-457, pages 7–8). The BART III proposal was acknowledged by the Commission in Order No. 10-457 (Order No. 10-457, pages 15–17). The mercury control costs were included in PGE's most recent GRC (Docket No. UE 215), where parties agreed that the recovery of the revenue requirement associated with these costs should be subject to deferred accounting (Order No. 10-478, page 6). Order No. 10-478 also adopted the Stipulation allowing PGE to recover the incremental revenue requirement associated with a shortened operating life for Boardman.

Q. Have other regulatory proceedings addressed PGE's plans to cease coal-fired operations at Boardman after 2020?

A. Yes. Pursuant to the Order and Stipulation in UE 215, PGE filed a tariff (Schedule 145), which was subsequently updated to reflect recovery of the incremental revenue requirement (depreciation and amortization, including revised decommissioning costs) based on a terminal retirement date of December 31, 2020 (Order No. 11-242).

Q. What effect does including these chemical costs have on PGE's 2013 NVPC forecast?

A. PGE's July 16, 2012, power cost update filing reflects the approximately $2.95 million NVPC effect of including these chemicals (mercury control chemicals account for approximately $1.29 million of this amount, while the DSI chemicals represent approximately $1.67 million).

B. The AUT is the Appropriate Proceeding

Q. Why is the AUT the appropriate proceeding for parties to consider the costs of these pollution control chemicals?

A. The AUT is the appropriate proceeding for review of these costs because they are directly related to the types and quantity of fuel used at Boardman when the chemicals are used to achieve an emission target.[1] Both the types and quantity of fuel estimated by PGE for use at Boardman in 2013 have been reviewed by parties to this AUT. As such, it makes sense for the pollution control chemicals that are directly dependent upon those factors to be reviewed at the same time. It is unclear to PGE how an examination of these costs in a proceeding outside of the context of power costs would be beneficial to customers, as it would result in a proceeding running both concurrently with and contingent upon the AUT.

Q. Staff stated that these costs should be treated in a manner similar to variable operations and maintenance expense ("O&M"). Do you agree?

A. No. It is not necessary to treat these costs in the same manner as O&M, where recovery is established and updated only in a GRC. The components of a plant's variable O&M cost are not each tracked individually relative to the associated cost driver. That is, precise variable O&M expense is not directly observable. Rather, for inclusion in Monet, variable O&M is generally estimated based on a measure of the expense incurred and expressed relative to a unit of the relevant cost driver (i.e., \$/MWh or \$/ton). The variable O&M established in this manner is included in Monet for dispatch purposes and is only updated in a GRC.

Q. How do these chemical costs differ from variable O&M?

A. These chemical costs differ because there is no ambiguity as to their causation; there is a direct correlation between the costs incurred to achieve a particular emission target and the quantity and type of fuel used at Boardman. Given that the quantity and type of fuel expected to be used at Boardman during 2013 are modeled directly in Monet, the resulting total chemical cost is the best estimate.

[1] A portion of PGE's 2013 DSI testing (reliability testing) will take place at a fixed chemical feed rate as described in the related MFRs provided by PGE on March 30, 2012, and April 13, 2012.

Q. In the context of wind integration costs, ICNU favors aligning costs and benefits (ICNU Exhibit 100, page 9). Does including these chemical costs in the AUT best match the costs with the benefits?

A. Yes. These costs represent a portion of the total costs that PGE will incur in order to operate Boardman as a coal-fired resource through 2020. As PGE's customers receive the benefits of the continued operation of Boardman as a low-cost baseload generating facility through 2020 (as reflected in NVPC), it makes sense for the costs of this operation to be included in NVPC as well.

Q. You mentioned above and in PGE Exhibit 100 that the revenue requirement associated with the cost of the mercury control chemicals is currently included in a deferral. Do you propose that the Commission modify the costs to be included in that Stipulation?

A. Yes. The revenue requirement related to the chemical expense is included as part of the "four capital projects" deferral (as stipulated in Docket No. UE 215). That deferral is Docket No. UM 1513. We simply request the Commission to direct that, beginning January 1, 2013, these chemical costs be included in PGE's NVPC rather than in the deferral.

IV. Wind Integration Day-Ahead Forecast Error Cost

Q. Please briefly explain the cost of day-ahead forecast error, with respect to wind integration.

A. The cost of day-ahead forecast error is the cost incurred to re-optimize PGE's portfolio in order to account for the difference between the day-ahead and the hour-ahead forecast for wind generation. These costs materialize in the form of market transactions (purchases and sales) and the re-dispatch of available generation resources.

Q. Was an estimate of this cost previously included in PGE's NVPC forecasts?

A. Yes. An estimate related to the cost of wind integration has been included in the NVPC forecast by PGE since the 2008 test year in Docket No. UE 188. The Order in that Docket (Order No. 07-573) stated that "[t]he parties also agreed that PGE would seek to model the integration costs of wind generation in its Monet power cost model. Accordingly, notwithstanding the Annual Power Cost Update permitted under Schedule 125, PGE could propose revisions to its Monet model to incorporate the integration of the BC project and other wind projects in the 2009 Annual Power Cost Update proceeding" (Order No. 07-573, page 3). Our update included in this filing is in compliance with that Order. PGE has included the same estimate of this specific cost since Docket No. UE 198 (the power cost portion of PGE's 2009 test year GRC).

Q. What was the basis for the estimate from UE 198?

A. The cost estimate previously included was the result of a stipulation in UE 198. In that proceeding, PGE proposed that the best estimate for the cost was $0.99/MWh. As noted in the settlement, parties agreed to $0.50/MWh (Order No. 08-505, page 3).

Q. Why is PGE now proposing an update to the estimated cost of day-ahead forecast error?

A. As described in our direct testimony in PGE Exhibit 100, the updated day-ahead forecast error cost estimate is an outcome from PGE's Wind Integration Study Phase II. That study was subject to extensive review both by stakeholders and an external technical review committee. The study was recognized by the Utility Variable-Generation Integration Group with the 2012 Technical Achievement Award.

Q. Has PGE updated the estimates for other elements of wind integration in the current proceeding?

A. Yes. In AUT proceedings, PGE typically includes any relevant updates of the BPA tariff and an estimate of the BPA imbalance premium.

Q. Does the fact that this update to day-ahead wind integration cost is derived in a model outside of Monet make it different from other routine updates to PGE's NVPC forecast?

A. No. Several other routine updates to Monet are also based on the output of an "outboard" model. An obvious example is the load forecast. The load forecast update is based on a very detailed econometric model that is completely external to Monet. Load shapes are also updated based on an outboard model. Hourly electric prices generated by PGE's Lydia model are produced every time Monet is updated for an AUT filing.

Q. Do you agree with ICNU's statement that day-ahead forecast error is something for which PGE, "does not actually incur any costs" (ICNU Exhibit 100, pages 24–25)?

A. No. To say that day-ahead uncertainty in wind generation does not increase PGE's costs is equivalent to asserting that there would be no advantage in knowing today the actual level of wind that will show up tomorrow. That does not make sense. If PGE had perfect foresight, it could schedule its generation resources and market transactions to exactly match its requirements for the next day, and would not have to make any adjustments to correct for forecast errors.

Q. Is ICNU's assertion true that PGE's methodology "does not even hold out reserves to deal explicitly with the uncertainty of wind on a day-ahead basis" (ICNU Exhibit 100, page 9)?

A. Yes.

Q. Is there a problem with this aspect of PGE's methodology?

A. No. The methodology employed by PGE is consistent with our operating experience. This methodology to isolate the cost of day-ahead uncertainty is also consistent with industry recommended best practice:

> Wind and solar never increase the amount of conventional generation that must be scheduled day-ahead (above that which would be required absent the wind and solar), but ignoring the wind and solar forecast can result in excessive amounts of conventional generation being brought on line (above what is actually required with the available wind and solar). This can result in inefficient operations with conventional plants operating well below their optimal outputs. ***Uncertainty in the wind and solar forecast can result in a change in the optimal scheduling mix, with flexible generation preferred over inflexible.***[2] [Emphasis added.]

[2] *Cost-Causation and Integration Cost Analysis for Variable Generation*, Michael Milligan, Erik Ela, Bri-Mathias Hodge, Brendan Kirby, and Debra Lew (National Renewable Energy Laboratory), Charlton Clark, Jennifer DeCesaro, and Kevin Lynn (U.S. Department of Energy), page 5. An electronic copy is included in PGE's Work Papers.

Q. Staff suggests that the bid-ask spreads (as provided in Table 6 of PGE's Wind Integration Study) should be modified (Staff Exhibit 100, page 16). Do you agree?

A. No. In response to a Staff data request, PGE provided a dataset that was meant to illustrate the order of magnitude of the "ask" spread paid historically when a thermal plant goes off-line unexpectedly (PGE's Response to OPUC Data Request No. 006). This dataset was meant to be illustrative of the fact that the spread widens as the transaction quantity increases, which is consistent with the assumptions summarized in Table 6 of PGE's Wind Integration Study.

Q. Why doesn't this dataset provide a good measure of the spread expected for transactions executed in response to wind fluctuations?

A. The loss of generation from a single thermal unit is not expected to "move the market" significantly. When shopping for power in response to a wind generation shortfall, however, we are typically facing a market in which wind has fallen off for many wind projects. We will not be the only shopper. Similarly, when our wind production picks up unexpectedly, we will be selling into a market that is trending down due to increased output from other wind generators.

Q. Staff requested that PGE provide an updated day-ahead forecast error cost utilizing the forward natural gas and power prices from PGE's initial filing in this docket (OPUC Data Request No. 005). Do you have an updated 2013 day-ahead forecast error cost estimate at this time?

A. Yes. As stated in PGE's Response to OPUC Data Request No. 005, it is not sufficient to update just one aspect of PGE's Wind Integration Study. Rather, all parameters used in the optimization must be consistent. As such, PGE has updated more than just the forward natural gas and power prices in order to derive an updated day-ahead forecast error cost estimate.

Q. What updates are included in this revised estimate?

A. The following updates are included:

- Forward natural gas prices – updated based on PGE's 06/07/2012 forward curve (Electricity prices were updated based on the updated gas prices);
- Load forecast – updated 2013 load forecast based on PGE's SJUN12 forecast;
- Wind penetration – updated to assume integration of Biglow Canyon only;
- BPA wind integration – updated to assume BPA provision of hour-ahead and within hour wind integration, consistent with Monet;
- Reserve calculations – updated to align with the load forecast update; and,
- Plant and contract parameters – updated to be consistent with expected 2013 operations.

PGE's Response to OPUC Data Request No. 005 explained that the forward electricity prices used in PGE's Wind Integration Model are derived values based on other model assumptions and inputs, rather than exogenous inputs to the model.

Q. What is PGE's updated estimate of the 2013 cost of day-ahead forecast error?

A. Our updated estimate is $1.24/MWh, much lower than the $3.36/MWh included in our initial filing. Based on PGE's July 16, 2012, power cost update filing, the reduction in the estimated 2013 cost of day-ahead forecast error results in a 2013 NVPC reduction of approximately $3.16 million (a net increase of approximately $1.11 million from the $0.50/MWh estimate previously used). PGE plans to use this updated cost estimate for the remaining power cost update filings in this proceeding.[3]

[3] Support for the revised estimated cost of day-ahead forecast error is included in PGE's Confidential Work Papers.

Q. Does PGE plan to take Staff's recommendations into account when filing its next GRC?

A. Yes. We plan to address Staff's recommendations that PGE provide an analysis of the least-cost method for integrating wind and, as also requested by Staff, we intend to propose a schedule for providing timely wind integration cost estimate updates in future AUT proceedings. PGE does not currently plan to modify the modeled bid-ask spread values in the current filing, but will work with Staff to explore alternatives for future AUT proceedings.

V. Natural Gas Transaction Liquidity Metric

Q. Do you have any comments regarding Staff's recommendation of an "incremental standard" (Staff Exhibit 100, pages 5–7) to assess liquidity in the market for natural gas swaps, as opposed to the cumulative standard presented in PGE Exhibit 100 (PGE Exhibit 100, pages 15–18)?

A. We have several comments regarding Staff's proposal. First, as noted in our opening testimony, this framework was implemented to govern transactions executed for PGE's Mid-Term Strategy beginning in 2012 (PGE Exhibit 100, pages 15–16). Although the 3% constraint has been satisfied (as noted in PGE Exhibit 100, page 17, and Staff Exhibit 100, page 4), we are not representing that this liquidity metric was applied to Mid-Term Strategy transactions for the 2013 test year, which are subject to review in this proceeding. Second, we will be happy to discuss any proposed refinements to PGE's recently implemented liquidity metric in a workshop setting in order to address the pros and cons of any change, as well as any potential implementation issues that might exist with a particular proposal.

Q. Does Staff's proposal face potential implementation issues?

A. Yes. As PGE understands the recommendation based upon the description provided in Staff Exhibit 100 (Staff Exhibit 100, pages 5–7), it is not clear that the Staff proposal could be implemented given the information currently available to PGE. Specifically, Staff's recommendation is contingent upon PGE knowing, either in real-time or ahead of time, the total volume of transactions executed in the market on a given day prior to executing our own transactions. However, PGE currently relies upon end-of-day market information to perform the liquidity assessment, which makes the incremental standard impossible to implement without additional refinement.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
301	PGE's Response to OPUC Data Request No. 005

May 9, 2012

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Randall Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 250
PGE Response to OPUC Data Request No. 005
Dated: April 25, 2012

<u>Request:</u>

The $3.44 (2014 dollars) figure used for the day-ahead forecast error component of wind integration costs was calculated under assumed gas and electric prices. How would this figure change, given the gas and electric price forecasts used in the Company's initial filing in this docket?

<u>Response:</u>

The exact effect of new gas prices and the corresponding power prices cannot be estimated without running the wind integration model. As indicated in PGE's Response to OPUC Data Request No. 004, wind integration costs resulting from day-ahead uncertainty are calculated as the difference in system costs between two model runs. It is important to note that simply "cutting and pasting" the gas and electric prices from the initial Monet filing is not consistent with the methodology employed in PGE's Wind Integration Study. In the Wind Integration Study, gas prices are an input ("exogenous") while the electric prices are derived values that depend on the assumed gas prices, the projected regional penetration of wind resources, and other factors. It is important that the electric prices used in the study be consistent with <u>all</u> of the parameters used in the optimization.

Running PGE's wind integration model is both time and labor intensive. PGE proposes one comprehensive update to the model that will include the requested updates to gas and electric prices as well as other updates that are expected to have material consequences for wind integration costs for 2013. To the extent practical, PGE will consider input from other parties if the input is received in a timeframe that will not delay the update process. PGE will make best efforts to report results of the update at the initial workshop in this docket scheduled for June 13, 2012, however, it is possible that updated and validated results will not be available at that time given the complexity of the model.