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

June 29, 2015

Via Electronic Filing
puc.filingcenter@state.or.us

Oregon Public Utility Commission
Attention: Filing Center
PO Box 1088
Salem, OR 97308-1088

Re: UE___ – 2014 Annual Power Cost Variance Mechanism

Attention Filing Center:

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

- **Alex Tooman and Greg Batzler (PGE/100-102, PGE/104)**
- **Work Papers (non-confidential portions only)**
- **Portland General Electric Company's Motion for Protective Order (with Proposed Protective Order)**

Exhibit **PGE/103C** is confidential and will be submitted, along with the confidential work papers, after entry of a Protective Order.

These documents are being filed electronically.

Thank you in advance for your assistance

Sincerely,

Patrick G. Hager
Manager, Regulatory Affairs

PGH:sp
Enclosures
cc: UE 291 Service List

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE ___
2014 PCAM

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits

Portland General Electric

June 29, 2015

Table of Contents

I. Introduction

Q. Please state your names and positions with PGE.

A. My name is Alex Tooman. I am a project manager at PGE.

My name is Greg Batzler. I am a business analyst at PGE.

Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is two-fold. First, we describe the 2014 Power Cost Variance (PCV), including base and actual power costs. Second, we describe how we determined the deferred amount for power costs using the Power Cost Adjustment Mechanism (PCAM) authorized by the Oregon Public Utility Commission (OPUC or Commission) in Order No. 07-015 (Docket UE 180) and established in PGE Schedule 126. In summary, because the Annual Variance of ($7.0 million)[1] (i.e., actual power costs were less than forecasted power costs) is entirely within the power cost deadbands, the 2014 PCV and deferral are zero.

Q. Please summarize the process used in the PCAM.

A. The first step in the process compares PGE's actual unit Net Variable Power Costs (NVPC) with our base unit NVPC and then multiplies the difference by actual load to determine an Annual Variance. We then apply asymmetrical power cost deadbands to the Annual Variance followed by 90-10 percent sharing between customers and shareholders to develop the PCV. After this, we apply a symmetrical Return on Equity (ROE) deadband to an earnings test to determine how much, if any, of the final PCV should be collected from or refunded to customers (see PGE Exhibit 101 for a summary of the PCV calculation). If

[1] In our testimony, any negative or credit amounts are signified as ($_____).

there is a collection from or refund to customers, this amount is then posted to PGE's PCV account where it will accrue interest at PGE's authorized rate of return, until the Commission approves amortization. Finally, if there is a collection from or refund to customers, PGE would amortize the PCV balance through Schedule 126, which is an Automatic Adjustment Clause as defined in ORS 757.210.

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

A. Yes. In PGE's 2007 PCAM (Docket No. UE 201), parties agreed to MFRs for future PCAMs. The MFRs specify that work papers to PGE's PCAM filing include the following:

- Monthly transaction-level detail by ledger number that is used to summarize actual power costs as provided in PGE Exhibit 103C.
- Detail regarding PGE's out-of-period adjustments.

As specified, confidential work papers to this filing include the required documentation.

Q. How is your testimony organized?

A. We begin by describing in greater detail how PGE calculated the PCV as determined by the Annual Variance and the power cost deadband. We then briefly describe PGE's PCAM earnings review although it is not applicable for 2014. The last section contains our qualifications.

II. Calculation of PCV

A. Base Power Costs

Q. What is the first step in calculating the PCV?

A. The first step is to identify PGE's baseline NVPC, which are based on the final power cost forecasts that PGE created for UE 266, the 2014 Annual Power Cost Update (AUT – Schedule 125) using our power cost forecasting model, Monet.[2] The Monet result establishes the unadjusted baseline NVPC of approximately $621.7 million for 2014.

Q. Did you apply any adjustments to derive these base costs?

A. Yes. From the unadjusted baseline NVPC, we reduced power costs by another $1.6 million to recognize steam sales from our Coyote Springs plant (as forecasted in UE 262). We applied this adjustment as directed by the Commission in Order No. 07-015 to achieve adjusted baseline power costs.

Q. Did you apply an adjustment for Ancillary Service Revenues as also directed by Commission in Order No. 07-015?

A. No. Because this revenue was incorporated directly into the Monet baseline power costs as filed in UE 266, there is no Ancillary Service adjustment necessary to calculate the 2014 PCV.

Q. Did you apply an adjustment related to direct access and variable price option load?

A. Yes. PGE reduced power costs related to the additional 32.7 MWa of 2014 direct access and variable price option load that had not been identified at the time the final Monet

[2] PGE has described the Monet model in the last eight general rate proceedings (i.e., UE 115, UE 180, UE 188, UE 197, UE 215, UE 262, UE 283, and UE 294) as well as previous RVM filings (Resource Valuation Mechanism – UE 139, UE 149, UE 161, and UE 172) and AUT filings (Annual Update Tariff – UE 192, UE 208, UE 228, and UE 250). Consequently, we incorporate those descriptions by reference.

forecast was prepared in November 2013. This reduced base power costs by another $9.7 million and, of course, it also reduced the base loads used to determine unit NVPC.

Q. Did you apply any other adjustments to the Monet output?

A. No.

Q. What were the final baseline NVPC?

A. After the adjustments described above, baseline NVPC for 2014 were approximately $610.4 million.

B. Actual Power Costs

Q. What is the next step in calculating the PCV?

A. The next step is to calculate PGE's actual NVPC for 2014. We begin this step by identifying PGE's variable power costs as charged to the following FERC accounts: 501, 547, 555, and 565. We then include the amount of sales for resale, as charged to FERC 447. For 2014, this net amount is approximately $617.9 million. To this amount, we apply a number of adjustments as listed in Table 1, and described below.

Table 1

Adjustments to Actual 2013 Power Costs ($000)

Actual NVPC per financial statements (see Exhibit 103C)		$617,944
Items to Exclude:		
FAS 133/71, mark-to-market deferrals	subtract	0
Credit reserve activity	subtract	37
Out of period items	subtract	0
Green power costs billed directly to customers	subtract	7,393
Direct access deferral amortization	subtract	537
Solar Payment Option - Sch205/206 avoided costs	subtract	581
Boardman additional 15% net benefits	subtract	(2,320)
Tucannon net benefits	subtract	(718)
Automated demand response pilot	subtract	366
Items to Include:		
Fuel Related:		
Gas resale margin	add	2,577
Oil resale	add	(808)
Coyote steam sales	add	(2,495)
Transmission resale revenues	add	(8,790)
Biglow availability (credit)/charge	add	327
Energy revenues for variable price option customers	add	(15,593)
Boardman test burn deferred to 2015	add	2,643
BPA settlement of wind curtailment	add	(350)
Chemical costs in O&M	add	4,670
Adjusted Actual NVPC*		$594,248

*May not sum due to rounding

Q. Please describe the adjustments PGE applies to exclude costs from its actual NVPC.

A. PGE excluded the following costs from actual NVPC:

- A charge of approximately $37,000 for reserve activity related to non-retail customers during the PCAM period.
- $7.4 million for green power expenses that are billed directly to customers through Schedules 7, 32, and 54. Consequently, they should not be included when calculating the PCV.
- A charge of approximately $0.5 million for the direct access deferral amortization. This charge was recorded to FERC account 447 and represents amortization of the deferral on the net gain on power costs associated with the large non-residential load shift true up. This charge is included in a supplemental schedule.

- A charge of approximately $0.6 million for the avoided costs associated with PGE's Solar Payment Option (SPO – Schedules 215, 216, and 217).[3] To eliminate double counting, this entry removes the increase to power costs that is associated with the avoided cost benefit that is applied to the SPO deferral.
- A credit of approximately ($0.7 million) for Tucannon River Wind Farm (Tucannon) net benefits. Because the 2014 costs and benefits of Tucannon were deferred according to the renewable adjustment clause provisions of Tariff Schedule 122, they are specifically excluded from the 2014 PCAM calculations (see also Commission Order No. 15-129 in Docket UE 288).
- A charge of approximately $0.4 million related to PGE's automated demand response pilot (ADR). Because ADR costs are collected through Schedule 135, we exclude them here to avoid double counting.
- A credit of approximately ($2.3 million) for the net benefits associated with PGE's 15% ownership increase of Boardman. Because the costs and benefits of PGE's additional 15% ownership share of Boardman were not included as part of PGE's 2014 NVPC filing (Docket No. UE 266[4]), they are specifically excluded from the 2014 PCAM calculations.

Q. Why did you include a credit for the net benefits associated with PGE's 15 percent ownership increase of Boardman?

A. We did so because Commission Order No. 14-169 authorizing PGE's 15 percent ownership share increase in Boardman was received after the final November 2013 Monet update for PGE's 2014 NVPC filing (Docket No. UE 266). As a result, the costs

[3] Previously known as the Solar Feed-in Tariff, Schedules 205 and 206.
[4] PGE did not receive authorization for the additional 15% ownership until May 2014 by Commission Order No. 14-169 (Docket No. UE 281), which occurred after PGE's final 2014 power cost forecast in November 2013.

and benefits of PGE's additional 15 percent ownership share of Boardman were not included as part of PGE's 2014 NVPC filing (Docket No. UE 266). In order to match PGE's baseline forecast, these net benefits are specifically excluded from the 2014 PCAM calculations.

Q. What adjustments did PGE make to include items in actual NVPC?

A. PGE included the following items in actual NVPC:

- A credit of approximately ($2.5 million) for actual steam sale revenues from the Coyote Springs 1 plant.
- A charge of approximately $2.6 million for gas resale margin.
- A credit of approximately ($0.8 million) for oil resale revenues. PGE's oil resale was the result of adjusting our oil inventory level to the established reliability reserve, which has not changed.
- A credit of approximately ($15.6 million) for energy revenues from variable price option customers.
- A charge of approximately $0.3 million for the Biglow Canyon availability adjustment. This charge effectively offsets lower purchased power costs due to Biglow Canyon having a higher availability factor than contracted.
- A charge of approximately $4.7 million for pollution control chemicals. In summary, these chemical costs are forecasted in the AUT, but recorded as operations and maintenance costs because the chemicals are injected after the fuel burn. Consequently, we add them to the PCAM to accurately match the components of actual and baseline power costs.

- A charge of approximately $2.6 million related to the scheduled Boardman biomass test burn. Because PGE postponed the test burn from 2014 to 2015, PGE is refunding the forecasted 2014 test burn costs as part of the 2015 AUT. Consequently, we add them to the 2014 PCAM to accurately match the components of actual and baseline power costs.
- A credit of approximately ($0.4 million) to recognize the generation-based portion (i.e., renewable energy certificate) of settlement proceeds related to the curtailment of Biglow wind generation in 2011.
- A credit of approximately ($8.8 million) for transmission resale revenues, net of lost transmission revenues from direct access customers.

Q. Why did you include a credit for transmission resale revenues in actual power costs?

A. We did so because it is similar to gas and oil resales. In all these categories, the associated fuel and wheeling expense is in power costs but the resale revenue is recorded in Other Revenue. To correctly reflect the <u>net</u> power costs associated with these categories, we adjust power costs to reflect the resale revenue.

Q. Are sales of ancillary services included in actual NVPC?

A. No. In 2014, there was no opportunity for these sales. Consequently, there was no revenue from the sales of ancillary services in FERC account 447.

Q. What is the final actual NVPC?

A. After all the adjustments described above, the final actual NVPC total is approximately $594.2 million.

C. Unit Power Costs and Annual Variance

Q. What is the next step in calculating the PCV?

A. The next step is to unitize the base and actual NVPC so as to calculate a unit NVPC variance. To accomplish this, we divide base NVPC and actual NVPC by base loads and actual loads, respectively. In both cases, we use retail cost of service loads. The unit NVPC variance is calculated by subtracting base unit NVPC from actual unit NVPC. We perform this step to eliminate the power cost variance that would arise from changes in load.

Q. What is the unit NVPC variance and how do you calculate the Annual Variance?

A. Although PGE Exhibit 101 lists the PCV on a monthly basis, the unit NVPC variance for purposes of the PCAM is based on annual amounts. For 2014, the unit NVPC variance is approximately ($0.45) per MWh (i.e., actual unit NVPC is less than base unit NVPC). We then calculate the Annual Variance by multiplying the unit NVPC variance times actual load. This produces an Annual Variance of approximately ($7.7 million).

D. PCV

Q. What is the final step in calculating the PCV?

A. The final step is to apply the deadband and sharing percentages, if applicable, to the Annual Variance. Because we focus on the earnings test and return on equity (ROE) deadband in the next section, we only discuss the power cost deadband here.

Q. What is the power cost deadband?

A. Beginning January 1, 2011, the power cost deadband is calculated based on Commission Order No. 10-478 (Appendix D, page 3 of 11), which specifies the following:

- $30 million for a positive Annual Variance; and
- ($15 million) for a negative Annual Variance.

This update is reflected in Schedule 126, which became effective January 1, 2011.

Q. What is the final PCV after application of the sharing percents?

A. Because PGE's Annual Variance of ($7.7 million) is within the deadband amount of ($15 million), we do not apply sharing percentages to determine a final PCV.

III. Earnings Review

Q. Has PGE performed an earnings review with which to calculate the ROE deadband?

A. Yes. We performed this review initially as part of our annual requirement to provide a Results of Operations (ROO) Report to the OPUC Staff, which we submitted on May 5, 2015. Because the ROO incorporates all aspects of the PCAM earnings review, PGE uses it as the basis for the ROE deadband. We include it as PGE Exhibit 102.

Q. What is the ROE deadband?

A. The ROE deadband is +/-100 basis points of PGE's authorized ROE, which for 2014 is 9.75% (Commission Order No. 13-459). If PGE's earnings are below 8.75%, then we would collect the PCV up to the point where the ROE is 8.75%. Alternatively, if PGE's earnings are above 10.75%, then we would refund the PCV down to the point where the ROE is 10.75%.

Q. What was PGE's final 2014 ROE including the PCV?

A. PGE's final 2014 ROE is 9.51%,[5] which is within the 8.75% to 10.75% deadband. As noted in Section II. D. above, the Annual Variance is within the power cost deadbands, so the PCV is not subject to the earnings review. Consequently, there is no customer collection (or refund) associated with the 2014 PCAM.

Q. Does PGE provide earnings test ROE results that separately identify the impact of the PCAM amount as specified in item 4 of the UE 201 stipulation (see Commission Order No. 08-551)?

A. Yes. PGE Exhibit 104 provides the stipulated ROE results; however, because the final 2014 PCAM amount equals zero, there is no impact from this entry.

[5] This is the earnings test result that includes the relevant adjustments from Commission Order No. 13-459 and the OPUC letter regarding the calculation of ROOs dated March 25, 1992.

Q. What is the rate impact of the 2014 PCAM?

A. Because the 2013 PCAM also entailed no refund to or collection from customers, there is no rate impact associated with the 2014 PCAM.

IV. Qualifications

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

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

Q. Mr. Batzler, please state your educational background and experience.

A. I received a Bachelor of Arts degree in Radio and Television from San Francisco State University in 1997 and a Master of Business Administration degree from Marylhurst University in 2011. I have been employed at PGE since 2006, working in various departments including Meter Reading and Human Resources. I have worked in the Rates and Regulatory Affairs department since 2012.

Q. Does this complete your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
101	Summary Calculation of PCV
102	2014 Results of Operations as filed May 5, 2015
103C	**Actual Power Costs by Month and FERC Account**
104	2014 Results of Operations with segregated PCAM amount

PGE Power Cost Variance Mechanism (PCAM)

December 2014

	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Total
BASE													
MONET NVPC ($000s)													
MONET (AUT/GRC) (Nov15, Pre-Selection)	$ 59,813	$ 52,535	$ 56,499	$ 45,065	$ 46,185	$ 44,782	$ 50,518	$ 50,411	$ 48,816	$ 50,450	$ 55,005	$ 61,644	$ 621,725
Adjust- from MONET to ORDER NVPC													
No outboard adjustments for 2014													$ -
ORDER NVPC (PRE-SELECTION)	$ 59,813	$ 52,535	$ 56,499	$ 45,065	$ 46,185	$ 44,782	$ 50,518	$ 50,411	$ 48,816	$ 50,450	$ 55,005	$ 61,644	$ 621,725
Adjust-from ORDER to BASE NVPC													
Coyote Steam Sales in AUT/GRC - Other Rev	$ (135)	$ (135)	$ (135)	$ (135)	$ (135)	$ (135)	$ (135)	$ (135)	$ (135)	$ (135)	$ (135)	$ (135)	$ (1,615)
Nov Opt-Outs to MONET NVPC	$ (867)	$ (751)	$ (773)	$ (617)	$ (533)	$ (475)	$ (928)	$ (1,092)	$ (899)	$ (908)	$ (896)	$ (982)	$ (9,720)
REVISED BASE NVPC (Post-Select, COS)	$ 58,811	$ 51,649	$ 55,592	$ 44,314	$ 45,518	$ 44,173	$ 49,456	$ 49,184	$ 47,783	$ 49,407	$ 53,975	$ 60,527	$ 610,390
BASE LOADS (MWHs)													
ORDER Retail Loads (Pre-Selection, COS)	1,682,722	1,453,202	1,518,354	1,376,132	1,361,924	1,327,578	1,449,331	1,447,438	1,330,484	1,390,825	1,499,647	1,699,609	17,537,247
Dec Opt-Outs to ORDER Retail Loads	(24,077)	(21,574)	(23,547)	(22,547)	(23,894)	(23,564)	(26,596)	(25,781)	(23,668)	(24,342)	(23,318)	(23,602)	(286,508)
BASE LOADS (Retail, w-DEC Opt-Outs, COS)	1,658,646	1,431,629	1,494,807	1,353,585	1,338,030	1,304,014	1,422,734	1,421,658	1,306,816	1,366,484	1,476,329	1,676,007	17,250,739
BASE UNIT NVPC	$ 35.46	$ 36.08	$ 37.19	$ 32.74	$ 34.02	$ 33.87	$ 34.76	$ 34.60	$ 36.56	$ 36.16	$ 36.56	$ 36.11	$ 35.38
ACTUALS	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	
Actual / Forecast NVPC (no Other Rev)	$ 61,984	$ 64,118	$ 40,754	$ 42,188	$ 41,866	$ 40,790	$ 52,916	$ 58,616	$ 51,707	$ 51,321	$ 53,557	$ 58,127	$ 617,944
EXCLUDE:													
Credit Reserve - Expense	$ 0	$ (5)	$ -	$ -	$ -	$ 20	$ -	$ -	$ -	$ -	$ -	$ 22	$ 37
FAS 133/71 - MTM/Deferral	$ -	$ (0)	$ -	$ 0	$ 0	$ -	$ 0	$ (0)	$ 0	$ -	$ (0)	$ 0	$ 0
Out-of-Period Adjustments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Direct Access deferral amortization - 4470004	$ (17)	$ 44	$ 47	$ 48	$ 48	$ 50	$ 52	$ 55	$ 57	$ 50	$ 50	$ 53	$ 537
Green Power expenses in 4171007 & 5550006	$ 735	$ 761	$ 639	$ 574	$ 535	$ 536	$ 374	$ 618	$ 625	$ 548	$ 604	$ 843	$ 7,393
Solar Pymt Option-SPO (was FIT) - avoided costs	$ 23	$ 14	$ 19	$ 31	$ -	$ 90	$ -	$ 51	$ 176	$ 78	$ 44	$ 56	$ 581
Net Benefits of 15% more Boardman gen	$ (578)	$ (376)	$ 39	$ 149	$ 189	$ 313	$ (87)	$ (384)	$ (442)	$ (448)	$ (386)	$ (310)	$ (2,320)
Auto Demand Response Pilot - 5550019	$ -	$ 167	$ (157)	$ 16	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 340	$ 366
Tucannon Wind - net benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (718)	$ (718)
Subtotal Exclusions	$ 164	$ 606	$ 588	$ 819	$ 772	$ 1,010	$ 339	$ 340	$ 415	$ 228	$ 312	$ 285	$ 5,878
INCLUDE:													
Coyote Steam Sales - 4560012	$ (208)	$ (194)	$ (222)	$ (167)	$ (128)	$ (170)	$ (245)	$ (256)	$ (280)	$ (208)	$ (207)	$ (210)	$ (2,495)
Gas Resale Margin - 4560008	$ (43)	$ (252)	$ 1,923	$ (22)	$ (9)	$ (15)	$ 524	$ (264)	$ 99	$ 24	$ (262)	$ 874	$ 2,577
Add Oil Sales - Revenue - 4560011	$ (584)	$ (56)	$ (168)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (808)
Biglow availability (damages)/bonus - 5530001	$ -	$ -	$ (8)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 336	$ 327
Energy Revenues from VPO customers	$ (1,898)	$ (1,706)	$ (983)	$ (816)	$ (830)	$ (1,026)	$ (1,433)	$ (1,605)	$ (1,551)	$ (1,383)	$ (1,217)	$ (1,145)	$ (15,593)
Transmission resale revenues	$ (86)	$ (437)	$ (888)	$ (924)	$ (927)	$ (869)	$ (855)	$ (791)	$ (743)	$ (721)	$ (757)	$ (792)	$ (8,790)
Pollution control chemicals in O&M	$ 472	$ 464	$ 449	$ 301	$ 150	$ 188	$ 282	$ 557	$ 357	$ 735	$ 274	$ 443	$ 4,670
Boardman Biomass test burn dfd to 2015(in Base)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,643	$ 2,643
BPA settlement of Biglow curtailment claim	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (350)	$ (350)
Subtotal Inclusions	$ (2,347)	$ (2,180)	$ 102	$ (1,628)	$ (1,744)	$ (1,891)	$ (1,728)	$ (2,359)	$ (2,119)	$ (1,553)	$ (2,169)	$ 1,799	$ (17,818)
REVISED ACTUAL NVPC	$ 59,473	$ 61,332	$ 40,268	$ 39,741	$ 39,350	$ 37,889	$ 50,849	$ 55,917	$ 49,173	$ 49,540	$ 51,076	$ 59,641	$ 594,248
ACTUAL LOADS (Retail-COS-Calendar)	1,621,086	1,498,722	1,410,415	1,280,090	1,277,867	1,247,117	1,483,573	1,490,787	1,321,084	1,323,514	1,465,458	1,591,550	17,011,264
ytd	1,621,086	3,119,808	4,530,223	5,810,314	7,088,181	8,335,298	9,818,871	11,309,659	12,630,742	13,954,256	15,419,714	17,011,264	
ACTUAL UNIT NVPC	$ 36.69	$ 40.92	$ 28.55	$ 31.05	$ 30.79	$ 30.38	$ 34.27	$ 37.51	$ 37.22	$ 37.43	$ 34.85	$ 37.47	$ 34.93
UNIT NVPC VARIANCE													
ACTUAL UNIT NVPC	$ 36.69	$ 40.92	$ 28.55	$ 31.05	$ 30.79	$ 30.38	$ 34.27	$ 37.51	$ 37.22	$ 37.43	$ 34.85	$ 37.47	$ 34.93
BASE UNIT NVPC	$ 35.46	$ 36.08	$ 37.19	$ 32.74	$ 34.02	$ 33.87	$ 34.76	$ 34.60	$ 36.56	$ 36.16	$ 36.56	$ 36.11	$ 35.38
ACTUALS ABOVE (BELOW) BASE UNIT NVPC	$ 1.23	$ 4.85	$ (8.64)	$ (1.69)	$ (3.23)	$ (3.49)	$ (0.49)	$ 2.91	$ 0.66	$ 1.27	$ (1.71)	$ 1.36	$ (0.45)
ANNUAL VARIANCE (AV) = UNIT NVPC VARIANCE X ACTUAL LOADS													
ACTUALS ABOVE (BELOW) BASE	$ 1,994	$ 7,262	$ (12,185)	$ (2,167)	$ (4,122)	$ (4,357)	$ (721)	$ 4,341	$ 868	$ 1,686	$ (2,502)	$ 2,164	$ (7,668)
ACTUALS ABOVE (BELOW) BASE - YTD	$ 1,994	$ 9,256	$ (2,930)	$ (5,097)	$ (9,219)	$ (13,576)	$ (14,297)	$ (9,956)	$ (9,087)	$ (7,401)	$ (9,903)		
Positive Deadband - Actuals ABOVE Base	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000
Negative Deadband - Actuals BELOW Base	$ (15,000)	$ (15,000)	$ (15,000)	$ (15,000)	$ (15,000)	$ (15,000)	$ (15,000)	$ (15,000)	$ (15,000)	$ (15,000)	$ (15,000)	$ (15,000)	$ (15,000)
Variance at 100%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	
ANNUAL POWER COST VARIANCE (PCV) = (ANNUAL VARIANCE - DEADBAND) X 90%													
YTD POWER COST VARIANCE (PCV) = (YTD VARIANCE - DEADBAND) X 90%								POSITIVE (NEGATIVE) PCV = ACTUALS ABOVE (BELOW) POWER COST DEADBANDS					$ -

NO PCAM BOOKED. YTD VARIANCE IS NOT OUTSIDE OF THE DEADBAND RANGE.	$ -
2290001 3000000295 - prior balance	$ -
Change to book	$ -

Post to:	4491001	$ -
Post to:	2290001	$ -

PORTLAND GENERAL ELECTRIC
OPUC REGULATORY REPORTING
RESULTS OF OPERATIONS
January 1, 2014 - December 31, 2014
(Thousands of Dollars)

Page 1

Regulatory adjustments based on **Docket UE 262, Order 13-459**	Actual Utility Results	Type I Accounting Adjustments	Regulated Utility Actuals	Type I Adjustments	Regulated Adjusted Results	Type II Adjustments	Pro Forma Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Operating Revenues							
Sales to Consumers	1,761,724	263	1,761,986	0	1,761,986	4,162	1,766,148
Sales for Resale	126,952	(126,952)	0	0	0	0	0
Other Operating Revenues	34,833	(9,867)	24,967	0	24,967	0	24,967
Total Operating Revenues	1,923,509	(136,556)	1,786,953	0	1,786,953	4,162	1,791,115
Operation & Maintenance							
Net Variable Power Cost	744,304	(136,818)	607,486	0	607,486	8,416	615,901
Total Fixed O&M	249,567	0	249,567	0	249,567	2,468	252,035
Other O&M	225,308	1,913	227,221	(13,128)	214,094	1,757	215,850
Total Operation & Maintenance	1,219,179	(134,905)	1,084,274	(13,128)	1,071,146	12,640	1,083,786
Depreciation & Amortization	299,522	(15,172)	284,350	20,219	304,568	2,402	306,970
Other Taxes / Franchise Fee	106,847	0	106,847	0	106,847	703	107,549
Income Taxes	63,367	7,689	71,057	(2,829)	68,227	(13,679)	54,548
Total Oper. Expenses & Taxes	1,688,915	(142,388)	1,546,527	4,262	1,550,788	2,065	1,552,854
Utility Operating Income	234,594	5,832	240,426	(4,262)	236,165	2,096	238,261
Rate of Return	7.55%		7.74%		7.60%		6.14%
Return on Equity	9.41%		9.79%		9.51%		6.76%
ROE based on actual capital structure.							
Average Rate Base							
Utility Plant in Service	7,225,239	0	7,225,239	108	7,225,347	1,023,137	8,248,484
Accumulated Depreciation	3,676,578	0	3,676,578	0	3,676,578	227,527	3,904,105
Accumulated Def. Income Taxes	532,464	0	532,464	0	532,464	34,350	566,814
Accumulated Def. Inv. Tax Credit	0	0	0	0	0	0	0
Net Utility Plant	3,016,197	0	3,016,197	108	3,016,305	761,260	3,777,565
Deferred Programs & Investments	20,677	1	20,678	0	20,678	6,515	27,194
Operating Materials & Fuel	75,984	0	75,984	0	75,984	6,328	82,313
Misc. Deferred Credits	(63,796)	0	(63,796)	0	(63,796)	(2,916)	(66,712)
Unamortized Ratepayer Gains	0	0	0	0	0	0	0
Working Cash	56,651	(206)	56,445	158	56,602	628	57,231
Total Average Rate Base	3,105,713	(205)	3,105,508	266	3,105,774	771,815	3,877,590

PGE Exhibit 103C is Confidential and will be provided upon execution of a Protective Order

PORTLAND GENERAL ELECTRIC
OPUC REGULATORY REPORTING
RESULTS OF OPERATIONS
January 1, 2014 - December 31, 2014
(Thousands of Dollars)

Regulatory adjustments based on **Docket UE 262, Order 13-459**	Actual Utility Results	Type I Accounting Adjustments	Regulated Utility Actuals	Type I Adjustments	Regulated Adjusted Results	2014 PCAM Accrual	Adjusted Results with PCAM
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Operating Revenues							
Sales to Consumers	1,761,724	263	1,761,986	0	1,761,986	0	1,761,986
Sales for Resale	126,952	(126,952)	0	0	0	0	0
Other Operating Revenues	34,833	(9,867)	24,967	0	24,967	0	24,967
Total Operating Revenues	1,923,509	(136,556)	1,786,953	0	1,786,953	0	1,786,953
Operation & Maintenance							
Net Variable Power Cost	744,304	(136,818)	607,486	0	607,486	0	607,486
Total Fixed O&M	249,567	0	249,567	0	249,567	0	249,567
Other O&M	225,308	1,913	227,221	(13,128)	214,094	0	214,094
Total Operation & Maintenance	1,219,179	(134,905)	1,084,274	(13,128)	1,071,146	0	1,071,146
Depreciation & Amortization	299,522	(15,172)	284,350	20,219	304,568	0	304,568
Other Taxes / Franchise Fee	106,847	0	106,847	0	106,847	0	106,847
Income Taxes	63,367	7,689	71,057	(2,829)	68,227	0	68,227
Total Oper. Expenses & Taxes	1,688,915	(142,038)	1,546,527	4,262	1,550,788	0	1,550,788
Utility Operating Income	234,594	5,832	240,426	(4,262)	236,165	0	236,165
Rate of Return	7.55%		7.74%		7.60%		7.60%
Return on Equity	9.41%		9.79%		9.51%		9.51%
ROE based on actual capital structure.							
Average Rate Base							
Utility Plant in Service	7,225,239	0	7,225,239	108	7,225,347	0	8,248,484
Accumulated Depreciation	3,676,578	0	3,676,578	0	3,676,578	0	3,904,105
Accumulated Def. Income Taxes	532,464	0	532,464	0	532,464	0	566,814
Accumulated Def. Inv. Tax Credit	0	0	0	0	0	0	0
Net Utility Plant	3,016,197	0	3,016,197	108	3,016,305	0	3,016,305
Deferred Programs & Investments	20,677	1	20,678	0	20,678	0	20,678
Operating Materials & Fuel	75,984	0	75,984	0	75,984	0	75,984
Misc. Deferred Credits	(63,796)	0	(63,796)	0	(63,796)	0	(63,796)
Unamortized Ratepayer Gains	0	0	0	0	0	0	0
Working Cash	56,651	(206)	56,445	158	56,602	0	56,602
Total Average Rate Base	3,105,713	(205)	3,105,508	266	3,105,774	0	3,105,774

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **2014 ANNUAL POWER COST VARIANCE MECHANISM, TESTIMONY, EXHIBITS, WORK PAPERS (CONFIDENTIAL EXCLUDED), AND MOTION FOR PROTECTIVE ORDER [WITH PROPOSED PROTECTIVE ORDER]** to be served by electronic mail to those parties whose email addresses appear on the attached service list for OPUC Docket No. UE 291, PGE's last PCAM docket.

DATED at Portland, Oregon, this 29th day of JUNE, 2015.

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