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

June 6, 2016

Via Email /FedEx
puc.filingcenter@state.or.us

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

Re: UE___ – 2015 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,

Stefan Brown
Manager, Regulatory Affairs

SB/sp

Enclosures
cc: UE 299 Service List

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE ___
2015 PCAM

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits

PGE

Portland General Electric

June 6, 2016

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 2015 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 ($2.6 million)[1] (i.e., actual power costs were less than forecasted power costs) is entirely within the power cost deadbands, the 2015 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 2015. 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 2015 power cost forecast that PGE created for UE 286, using our power cost forecasting model, Monet.[2] The Monet result establishes the unadjusted baseline NVPC of approximately $562.3 million for 2015.

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

A. Yes. From the unadjusted baseline NVPC, we reduced power costs by another $1.9 million to recognize steam sales from our Coyote Springs plant (as forecasted in UE 283). 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 286, there is no Ancillary Service adjustment necessary to calculate the 2015 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 32.2 MWa of 2015 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 2014. This reduced base power costs by another $9.9 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. Yes. Similar to the treatment of steam sales, we increased power costs by $1.1 million, from the unadjusted baseline NVPC, to recognize PGE's forecast of wind availability charges in UE 283. While PGE has included wind availability damages/bonus as an adjustment to PCAM actuals since 2008,[3] UE 283 is the first general rate case in which PGE has forecast this cost/benefit. Therefore, in order to provide a comparable basis for PCAM actuals, PGE has included the UE 283 forecast as an adjustment to baseline NVPC.

Q. What was the final baseline NVPC estimate?

A. After the adjustments described above, baseline NVPC for 2015 were approximately $551.7 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 2015. 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 2015, this net amount is approximately $573.3 million. To this amount, we apply a number of adjustments as listed in Table 1, and described below.

[3] Beginning in UE 211 (2008 PCAM), PGE has included wind availability damages as an adjustment to PCAM actuals as they represent an offset to either higher or lower purchased power costs due to PGE's wind plants having a higher or lower availability factor than contracted.

Table 1

Adjustments to Actual 2015 Power Costs ($000)

Actual NVPC per financial statements (see Exhibit 103C)		$573,332
Items to Exclude:		
FAS 133/71, mark-to-market deferrals	subtract	0
Credit reserve activity	subtract	50
Out of period items	subtract	0
Green power costs billed directly to customers	subtract	8,980
Direct access deferral amortization	subtract	(499)
Solar Payment Option - Sch205/206 avoided costs	subtract	266
Tucannon transmission credit	subtract	0
Portland Public Schools solar avoided costs	subtract	(1)
Automated demand response pilot	subtract	540
Items to Include:		
Fuel Related:		
Gas resale margin	add	1,172
Oil resale	add	0
Coyote steam sales	add	(2,555)
Transmission resale revenues	add	(6,205)
Wind availability (credit)/charge	add	103
Energy revenues for variable price option customers	add	(13,476)
Boardman test burn deferred to 2016	add	2,655
REC sales paid in 2015	add	(794)
BPA wheeling rights net benefit	add	(8,131)
Chemical costs in O&M	add	6,226
Adjusted Actual NVPC*		$542,989

*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 $50,000 for reserve activity related to non-retail customers during the PCAM period.
- $9.0 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 credit of approximately ($0.5 million) for the direct access deferral amortization. This credit 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 $0.3 million for the avoided costs associated with PGE's Solar Payment Option (SPO – Schedules 215, 216, and 217).[4] To eliminate double counting, this entry removes the increase to power costs that is associated with the avoided cost benefit, which is applied to the SPO deferral.
- A charge of approximately $0.5 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 ($1,000) to reflect the avoided costs associated with the Portland Public Schools Solar Project (PPS Solar). Because the 2015 costs and benefits of PPS Solar were deferred according to the renewable adjustment clause provisions of Tariff Schedule 122, they are specifically excluded from the 2015 PCAM calculations (see also Commission Order No. 15-304 in Docket UE 297).

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 ($2.6 million) for actual steam sale revenues from the Coyote Springs 1 plant.
- A charge of approximately $1.2 million for gas resale margin.
- A credit of approximately ($13.5 million) for energy revenues from variable price option customers.
- A charge of approximately $0.3 million for the wind availability adjustment. This charge effectively offsets lower purchased power costs due to PGE's wind plants having a higher availability factor than contracted.

[4] Previously known as the Solar Feed-in Tariff, Schedules 205 and 206.

- A charge of approximately $6.2 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 $2.7 million related to the scheduled Boardman biomass test burn. Because PGE postponed the test burn from 2015 to 2016, PGE is refunding the forecasted 2015 test burn costs as part of the 2016 AUT. Consequently, we add them to the 2015 PCAM to accurately match the components of actual and baseline power costs.
- A credit of approximately ($0.8 million) to recognize renewable energy certificate sales PGE made in 2015 but not recorded until 2016. The 2016 entry will then be reversed in the 2016 PCAM.
- A credit of approximately ($6.2 million) for transmission resale revenues, net of lost transmission revenues from direct access customers.
- A credit of approximately ($8.1 million) to reflect the net payment[5] for PGE acquiring BPA wheeling rights from two third-parties in 2015.

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 net power costs associated with these categories, we adjust power costs to reflect the resale revenue.

[5] Gross payment less fees to BPA to defer the rights for later use.

Q. Why did you include a credit for BPA wheeling rights?

A. Because PGE acquired and paid for the BPA wheeling rights in 2015, it is appropriate to reflect the net benefit of these rights in 2015 as a credit to power costs. For accounting purposes, PGE recorded the payment as a regulatory asset and will amortize the balance upon taking the transmission service as an offset to incurred costs. As PGE begins to use the wheeling rights and the regulatory asset is amortized, we will reverse the accounting amortization entries from applicable PCAM filings.

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

A. No. In 2015, 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 $543.0 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 2015, the unit NVPC variance is approximately ($0.15) 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 ($2.6 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 ($2.6 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 April 29, 2016. 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 2015 is 9.68% (Commission Order No. 14-422). If PGE's earnings were below 8.68%, then we would collect the PCV up to the point where the ROE is 8.68%. Alternatively, if PGE's earnings were above 10.68%, then we would refund the PCV down to the point where the ROE is 10.68%.

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

A. PGE's final 2014 ROE is 8.18%,[6] which is below the 8.68% earnings deadband. However, 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 2015 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 2015 PCAM amount equals zero, there is no impact from this entry.

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[6] This is the earnings test result that includes the relevant adjustments from Commission Order No. 14-422 and the OPUC letter regarding the calculation of ROOs dated March 25, 1992.

Q. What is the rate impact of the 2015 PCAM?

A. Because the 2014 PCAM also entailed no refund to or collection from customers, there is no rate impact associated with the 2015 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	2015 Results of Operations as filed April 29, 2016
103C	**Actual Power Costs by Month and FERC Account**
104	2015 Results of Operations with segregated PCAM amount

PGE Power Cost Variance Mechanism (PCAM)

2015	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Total
BASE													
MONET NVPC ($000s)													
MONET (AUT/GRC) (Nov15, Pre-Selection)	$ 55,990	$ 48,166	$ 49,923	$ 42,448	$ 40,601	$ 39,584	$ 44,358	$ 45,302	$ 44,338	$ 45,820	$ 48,625	$ 57,153	$ 562,308
Nov Opt-Outs	$ (939)	$ (797)	$ (799)	$ (665)	$ (620)	$ (584)	$ (905)	$ (993)	$ (912)	$ (804)	$ (861)	$ (973)	$ (9,854)
NVPC (POST-SELECTION)	$ 55,051	$ 47,369	$ 49,123	$ 41,783	$ 39,981	$ 38,999	$ 43,453	$ 44,309	$ 43,426	$ 45,016	$ 47,764	$ 56,180	$ 552,454
Adjustments for BASE NVPC													
Coyote Steam Sales in AUT/GRC - Other Rev	$ (156)	$ (156)	$ (156)	$ (156)	$ (156)	$ (156)	$ (156)	$ (156)	$ (156)	$ (156)	$ (156)	$ (156)	$ (1,874)
Wind Availability (damages)/bonus in AUT/GRC - O&M	$ -	$ 194	$ -	$ -	$ -	$ -	$ -	$ -	$ 908	$ -	$ -	$ -	$ 1,102
REVISED BASE NVPC (Post-Select, COS)	$ 54,895	$ 47,407	$ 48,967	$ 41,626	$ 39,825	$ 38,843	$ 43,297	$ 44,153	$ 44,178	$ 44,860	$ 47,608	$ 56,024	**$ 551,682**
BASE LOADS (MWHs)													
ORDER Retail Loads (Pre-Selection, COS)	1,704,096	1,463,827	1,528,867	1,380,214	1,364,156	1,328,172	1,444,650	1,449,172	1,327,219	1,392,116	1,499,136	1,715,876	17,597,500
Dec Opt-Outs to ORDER Retail Loads	(23,724)	(21,218)	(23,500)	(22,471)	(23,708)	(23,341)	(25,978)	(25,684)	(23,802)	(23,379)	(22,882)	(22,591)	(282,278)
BASE LOADS (Retail, w-DEC Opt-Outs, COS)	1,680,372	1,442,609	1,505,367	1,357,742	1,340,448	1,304,831	1,418,672	1,423,488	1,303,417	1,368,736	1,476,254	1,693,285	**17,315,221**
BASE UNIT NVPC	$ 32.67	$ 32.86	$ 32.53	$ 30.66	$ 29.71	$ 29.77	$ 30.52	$ 31.02	$ 33.89	$ 32.77	$ 32.25	$ 33.09	**$ 31.86**
ACTUALS / FORECAST	**Actuals**	**Actuals**	**Actuals**	**Actuals**	**Actuals**	**Actuals**	**Actuals**	**Actuals**	**Actuals**	**Actuals**	**Actuals**	**Actuals**	
Actual / Forecast NVPC (no Other Rev)	**$ 52,790**	**$ 43,422**	**$ 45,303**	**$ 41,438**	**$ 39,185**	**$ 50,072**	**$ 57,001**	**$ 49,733**	**$ 44,980**	**$ 45,187**	**$ 50,195**	**$ 54,026**	$ 573,332
EXCLUDE:													
Credit Reserve - Expense	$ -	$ -	$ -	$ -	$ -	$ 24	$ -	$ -	$ -	$ -	$ -	$ 26	$ 50
FAS 133/71 - MTM/Deferral	$ 0	$ 0	$ (0)	$ 0	$ (0)	$ -	$ -	$ -	$ -	$ -	$ 0	$ (0)	$ 0
Out-of-Period Adjustments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Direct Access deferral amortization - 4470004	$ 37	$ (50)	$ (47)	$ (46)	$ (45)	$ (47)	$ (52)	$ (52)	$ (49)	$ (43)	$ (47)	$ (58)	$ (499)
Green Power expenses in 4171007 & 5550006	$ 846	$ 756	$ 692	$ 661	$ 618	$ 634	$ 766	$ 758	$ 711	$ 625	$ 729	$ 1,182	$ 8,980
Solar Pymt Option-SPO (was FIT) - avoided costs	$ -	$ 43	$ -	$ -	$ -	$ 224	$ -	$ -	$ -	$ -	$ -	$ -	$ 266
Auto Demand Response Pilot - 5550019	$ -	$ (197)	$ -	$ 312	$ -	$ -	$ -	$ -	$ -	$ 291	$ -	$ 133	$ 540
Tucannon transmission credit deferral - 5650001	$ (395)	$ 395	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PPS - Ptld Public Schools solar avoided costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1)	$ (1)
Subtotal Exclusions	$ 488	$ 948	$ 645	$ 928	$ 573	$ 835	$ 714	$ 706	$ 661	$ 873	$ 683	$ 1,281	$ 9,336
INCLUDE:													
Coyote Steam Sales - 4560012	$ (301)	$ (280)	$ (369)	$ (212)	$ (145)	$ (161)	$ (211)	$ (169)	$ (195)	$ (163)	$ (175)	$ (175)	$ (2,555)
Gas Resale Margin - 4560008	$ 546	$ 188	$ 266	$ (92)	$ 26	$ 225	$ 1	$ 57	$ (91)	$ (13)	$ (7)	$ 66	$ 1,172
Oil Sales - Revenue - 4560011	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wind availability (damages)/bonus - 5530001	$ -	$ (18)	$ (205)	$ (3)	$ -	$ -	$ -	$ -	$ -	$ -	$ 329	$ -	$ 103
Energy Revenues from VPO customers	$ (1,112)	$ (717)	$ (877)	$ (1,143)	$ (1,434)	$ (1,673)	$ (1,489)	$ (1,371)	$ (1,229)	$ (1,412)	$ (734)	$ (284)	$ (13,476)
Transmission resale revenues	$ (634)	$ (589)	$ (676)	$ (564)	$ (548)	$ (1,467)	$ (460)	$ (471)	$ (456)	$ (434)	$ (449)	$ 541	$ (6,205)
Thermal plant chemicals in O&M	$ 850	$ 289	$ 559	$ 259	$ 289	$ 412	$ 236	$ 406	$ 391	$ 361	$ 896	$ 1,277	$ 6,226
Boardman 100% biomass burn dfd to 2016(in Base)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,655	$ 2,655
BPA wheeling rights net benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (8,131)	$ (8,131)
REC sales paid in 2015	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (794)	$ (794)
Subtotal Inclusions	$ (650)	$ (1,127)	$ (1,303)	$ (1,755)	$ (1,813)	$ (2,664)	$ (1,923)	$ (1,548)	$ (1,580)	$ (1,661)	$ (139)	$ (4,846)	$ (21,007)
REVISED ACTUAL NVPC	$ 51,651	$ 41,348	$ 43,355	$ 38,756	$ 36,799	$ 46,573	$ 54,364	$ 47,479	$ 42,739	$ 42,653	$ 49,373	$ 47,899	$ 542,989
ACTUAL LOADS (Retail-COS-Calendar)	1,560,793	1,314,219	1,373,896	1,317,839	1,301,396	1,434,046	1,575,700	1,496,233	1,296,987	1,329,947	1,481,339	1,641,627	17,124,024
ytd	1,560,793	2,875,012	4,248,908	5,566,747	6,868,143	8,302,190	9,877,890	11,374,123	12,671,110	14,001,057	15,482,396	17,124,024	
ACTUAL UNIT NVPC	$ 33.09	$ 31.46	$ 31.56	$ 29.41	$ 28.28	$ 32.48	$ 34.50	$ 31.73	$ 32.95	$ 32.07	$ 33.33	$ 29.18	$ 31.71
UNIT NVPC VARIANCE													
ACTUAL UNIT NVPC	$ 33.09	$ 31.46	$ 31.56	$ 29.41	$ 28.28	$ 32.48	$ 34.50	$ 31.73	$ 32.95	$ 32.07	$ 33.33	$ 29.18	$ 31.71
BASE UNIT NVPC	$ 32.67	$ 32.86	$ 32.53	$ 30.66	$ 29.71	$ 29.77	$ 30.52	$ 31.02	$ 33.89	$ 32.77	$ 32.25	$ 33.09	$ 31.86
ACTUALS ABOVE (BELOW) BASE UNIT NVPC	$ 0.42	$ (1.40)	$ (0.97)	$ (1.25)	$ (1.43)	$ 2.71	$ 3.98	$ 0.72	$ (0.94)	$ (0.70)	$ 1.08	$ (3.91)	$ (0.15)
ANNUAL VARIANCE (AV) = UNIT NVPC VARIANCE X ACTUAL LOADS													
ACTUALS ABOVE (BELOW) BASE	$ 663	$ (1,840)	$ (1,335)	$ (1,647)	$ (1,866)	$ 3,884	$ 6,275	$ 1,070	$ (1,222)	$ (936)	$ 1,602	$ (6,416)	$ (2,601)
ACTUALS ABOVE (BELOW) BASE - YTD	$ 663	$ (1,177)	$ (2,513)	$ (4,160)	$ (6,026)	$ (2,142)	$ 4,133	$ 5,203	$ 3,981	$ 3,046	$ 4,647		
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. $ -

PORTLAND GENERAL ELECTRIC
OPUC REGULATORY REPORTING
RESULTS OF OPERATIONS
January 1, 2015 - December 31, 2015
(Thousands of Dollars)

Regulatory adjustments based on **Docket UE 283, Order 14-422**	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	1,772,978	231	1,773,209	0	1,773,209	7,506	1,780,715
Sales for Resale	104,940	(104,940)	0	0	0	0	0
Other Operating Revenues	32,187	(8,384)	23,803	0	23,803	0	23,803
Total Operating Revenues	1,910,105	(113,093)	1,797,012	0	1,797,012	7,506	1,804,518
Operation & Maintenance							
Net Variable Power Cost	677,028	(121,455)	555,573	0	555,573	4,654	560,227
Total Fixed O&M	261,587	0	261,587	0	261,587	3,014	264,601
Other O&M	238,813	1,685	240,498	(13,593)	226,905	2,134	229,039
Total Operation & Maintenance	1,177,428	(119,771)	1,057,657	(13,593)	1,044,065	9,802	1,053,867
Depreciation & Amortization	303,668	(19,147)	284,522	25,461	309,982	2,006	311,988
Other Taxes / Franchise Fee	114,644	0	114,644	0	114,644	1,231	115,875
Income Taxes	46,343	12,520	58,863	(4,744)	54,120	(1,590)	52,530
Total Oper. Expenses & Taxes	1,642,083	(126,397)	1,515,687	7,124	1,522,810	11,449	1,534,260
Utility Operating Income	268,021	13,304	281,325	(7,124)	274,201	(3,943)	270,259
Rate of Return	6.68%		7.02%		6.84%		6.84%
Return on Equity	7.88%		8.54%		8.18%		8.13%
ROE based on actual capital structure.							
Average Rate Base							
Utility Plant in Service	8,478,837	0	8,478,837	0	8,478,837	160,395	8,639,232
Accumulated Depreciation	3,978,721	0	3,978,721	0	3,978,721	185,027	4,163,748
Accumulated Def. Income Taxes	592,028	0	592,028	0	592,028	25,214	617,242
Accumulated Def. Inv. Tax Credit	0	0	0	0	0	0	0
Net Utility Plant	3,908,088	0	3,908,088	0	3,908,088	(49,846)	3,858,243
Deferred Programs & Investments	27,910	0	27,910	0	27,910	2,645	30,555
Operating Materials & Fuel	93,634	0	93,634	0	93,634	(10,795)	82,839
Misc. Deferred Credits	(76,636)	0	(76,636)	0	(76,636)	(1,959)	(78,595)
Unamortized Ratepayer Gains	0	0	0	0	0	0	0
Working Cash	56,841	(484)	56,358	264	56,621	334	56,955
Total Average Rate Base	4,009,837	(484)	4,009,353	264	4,009,617	(59,620)	3,949,997

Exhibit 103C

Confidential

PORTLAND GENERAL ELECTRIC
OPUC REGULATORY REPORTING
RESULTS OF OPERATIONS
January 1, 2015 - December 31, 2015
(Thousands of Dollars)

Regulatory adjustments based on **Docket UE 283, Order 14-422**	Actual Utility Results	Type I Accounting Adjustments	Regulated Utility Actuals	Type I Adjustments	Regulated Adjusted Results	2015 PCAM Accrual	Pro Forma Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Operating Revenues							
Sales to Consumers	1,772,978	231	1,773,209	0	1,773,209	0	1,773,209
Sales for Resale	104,940	(104,940)	0	0	0	0	0
Other Operating Revenues	32,187	(8,384)	23,803	0	23,803	0	23,803
Total Operating Revenues	1,910,105	(113,093)	1,797,012	0	1,797,012	0	1,797,012
Operation & Maintenance							
Net Variable Power Cost	677,028	(121,455)	555,573	0	555,573	0	555,573
Total Fixed O&M	261,587	0	261,587	0	261,587	0	261,587
Other O&M	238,813	1,685	240,498	(13,593)	226,905	0	226,905
Total Operation & Maintenance	1,177,428	(119,771)	1,057,657	(13,593)	1,044,065	0	1,044,065
Depreciation & Amortization	303,668	(19,147)	284,522	25,461	309,982	0	309,982
Other Taxes / Franchise Fee	114,644	0	114,644	0	114,644	0	114,644
Income Taxes	46,343	12,520	58,863	(4,744)	54,120	0	54,120
Total Oper. Expenses & Taxes	1,642,083	(126,397)	1,515,687	7,124	1,522,810	0	1,522,810
Utility Operating Income	268,021	13,304	281,325	(7,124)	274,201	0	274,201
Rate of Return	6.68%		7.02%		6.84%		6.94%
Return on Equity	7.88%		8.54%		8.18%		8.13%
ROE based on actual capital structure.							
Average Rate Base							
Utility Plant in Service	8,478,837	0	8,478,837	0	8,478,837	0	8,639,232
Accumulated Depreciation	3,978,721	0	3,978,721	0	3,978,721	0	4,163,748
Accumulated Def. Income Taxes	592,028	0	592,028	0	592,028	0	617,242
Accumulated Def. Inv. Tax Credit	0	0	0	0	0	0	0
Net Utility Plant	3,908,088	0	3,908,088	0	3,908,088	0	3,858,243
Deferred Programs & Investments	27,910	0	27,910	0	27,910	0	30,555
Operating Materials & Fuel	93,634	0	93,634	0	93,634	0	82,839
Misc. Deferred Credits	(76,636)	0	(76,636)	0	(76,636)	0	(78,595)
Unamortized Ratepayer Gains	0	0	0	0	0	0	0
Working Cash	56,841	(484)	56,358	264	56,621	0	56,955
Total Average Rate Base	4,009,837	(484)	4,009,353	264	4,009,617	0	3,949,997