Portland General Electric
121 SW Salmon Street · Portland, Ore. 97204

July 1, 2020

Via Electronic Filing

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

Re: UE ___ PGE 2019 Annual Power Cost Variance Mechanism Dear

Filing Center:

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

- **Direct Testimony of Greg Batzler and Stefan Cristea (PGE/100)**
- **Non-confidential Exhibits, (PGE/101, PGE/102, PGE/104)**
- **Portland General Electric Company's Motion for a Protective Order with Proposed Protective Order**

Non confidential work papers will be emailed to puc.workpapers@state.or.us.

Exhibit **PGE/103C** is confidential and will be submitted to the filing center after approval of a Protective Order. Confidential work papers will be emailed to puc.workpapeers@state.or.us after the approval of a Protective Order.

Thank you,

/s/ *Jaki Ferchland*
Jaki Ferchland
Manager, Revenue Requirement

JF:np

Enclosures

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I. Introduction

Q. Please state your names and positions with PGE.

A. My name is Greg Batzler. I am a Regulatory Consultant at PGE.

My name is Stefan Cristea. I am a Senior Regulatory 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 2019 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 Public Utility Commission of Oregon (OPUC or Commission) in Order No. 07-015 (Docket No. UE 180) and established in PGE Schedule 126. In summary, because the Annual Variance of $5.4 million[1] (i.e., actual power costs are greater than forecasted power costs) is entirely within the power cost deadbands, the 2019 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 baseline 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 a 90-10 percent sharing between customers and shareholders to develop the PCV (PGE Exhibit 101 provides a summary of the PCV calculation). After this, we apply symmetrical Return on Equity (ROE) deadbands to an earnings review to determine how much, if any, of the final PCV should be collected from or refunded to customers. If there is

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

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 will 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 should include the following:

- Monthly transaction-level detail by ledger number that is used to summarize actual power costs as provided in PGE Exhibit 103C; and
- 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 deadbands. This includes a high-level summary comparing the differences between PGE's 2019 final NVPC forecast and 2019 PCAM results, as requested by the Commission in PGE's 2017 PCAM (Docket No. UE 346). We then briefly describe PGE's PCAM earnings review although it is not applicable for 2019. 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 2019 power cost forecast that PGE calculated in Docket No. UE 335 (UE 335), using our power cost forecasting model, MONET.[2] The MONET result establishes the unadjusted baseline NVPC of approximately $361.5 million for 2019.

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

A. Yes. First, from the unadjusted baseline NVPC, we reduced power costs by $1.7 million to recognize steam sales from our Coyote Springs plant (as forecasted in UE 335). 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 the Commission in Order No. 07-015?

A. No. Because this revenue was incorporated directly into the MONET baseline power costs as filed in UE 335, there is no Ancillary Service adjustment necessary to calculate the 2019 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 35.3 MWa of 2019 direct access and variable price option load that had not been identified at the time the final MONET forecast

[2] PGE has described the MONET model in the last ten general rate proceedings (i.e., UE 115, UE 180, UE 188, UE 197, UE 215, UE 262, UE 283, UE 294, UE 319, and UE 335) 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, UE 250, UE 308, and UE 359). Consequently, we incorporate those descriptions by reference.

was prepared in November 2019. This reduced base power costs by another $7.1 million and, it also reduced the baseline 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 baseline power costs by $0.9 million to recognize PGE's forecast of wind availability charges in UE 335. As wind availability damages/bonuses are included as an adjustment to actuals, to provide a comparable basis, we also include the UE 335 forecast as an adjustment to baseline NVPC.

Q. What was the final baseline NVPC estimate?

A. After the adjustments described above, baseline NVPC for 2019 were approximately $353.7 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 2019. 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 2019, this net amount is approximately $444.6 million. To this amount, we apply a number of adjustments as listed in Table 1 and described below.

Table 1
Adjustments to Actual 2019 Power Costs
($000)

Actual NVPC per financial statements (see Exhibit 103C)		$444,608
Items to Exclude:		
FAS 133/71, mark-to-market deferrals	subtract	0
Credit reserve activity	subtract	4,691
Out of period items	subtract	0
Direct access deferral amortization	subtract	515
Green power costs billed directly to customers	subtract	15,436
Solar Payment Option - Sch205/206 avoided costs	subtract	1,069
Automated demand response pilot	subtract	0
2019 amortization of 2015 net wheeling credit	subtract	(1,070)
Items to Include:		
Coyote steam sales	add	(1,874)
Gas resale margin	add	(17,302)
Wind availability (credit)/charge	add	693
Energy revenues for variable price option customers	add	(4,756)
Transmission resale revenues	add	(6,449)
Chemical costs in O&M	add	8,134
Production Tax Credits in Taxes	add	(44,037)
Adjusted Actual NVPC*		$358,376

*May not sum due to rounding

Q. Please describe the items PGE excluded from its actual NVPC.

A. PGE excluded the following costs from actual NVPC:

- A charge of approximately $4.7 million for reserve activity related to non-retail customers during the PCAM period.
- A charge 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 credit is included in a supplemental schedule.
- A charge of approximately $15.4 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 $1.1 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, which is applied to the SPO deferral.
- A credit of approximately ($1.1 million) to reverse the 2019 amortized portion of PGE's 2015 net payment[4] for acquiring BPA wheeling rights from two, third parties in 2015.

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 ($1.9 million) for actual steam sale revenues from the Coyote Springs 1 plant.
- A credit of approximately ($17.3 million) for gas resale margin.
- A charge of approximately $0.7 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
- A credit of approximately ($4.8 million) for energy revenues from variable price option customers.
- A credit of approximately ($6.4 million) for transmission resale revenues, net of lost transmission revenues from direct access customers.

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[3] Previously known as the Solar Feed-in Tariff, Schedules 205 and 206.
[4] Gross payment less fees to BPA to defer the rights for later use.

- A charge of approximately $8.1 million for pollution control chemicals. In summary, these chemical costs are forecasted in the AUT, but recorded as operation 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 credit of approximately ($44.0 million) for production tax credits (PTCs). As PTCs are forecast in NVPC consistent with the provisions of Oregon Senate Bill 1547, Section 18b,[5] we add them to the PCAM to accurately match the components of actual and baseline power costs.

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.

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

A. No. In 2019, there was no opportunity for these sales. Consequently, there was no revenue from the sale 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 $358.4 million.

[5] Senate Bill 1547 was signed into law by the governor on March 11, 2016.

C. Summary of NVPC Differences

Q. Please restate PGE's 2019 final baseline NVPC estimate and PGE's actual 2019 NVPC?

A. After applying the adjustments described on pages 3 and 4 above, PGE's baseline adjusted NVPC forecast for 2019 is approximately $353.7 million. After normalizing for load, PGE's 2019 baseline is further reduced to $352.9 million. This compares to the final actual NVPC of approximately $358.4 million, after applying the adjustments described on pages 5 through 7 of this testimony.

Q. Has PGE compared the changes between actual and forecast NVPC that explain the variance?

A. Yes. Pursuant to Commission Order No. 18-466, issued in PGE's 2017 PCAM, PGE has compared its 2019 PCAM results with its baseline 2019 forecast in order to determine and explain significant power cost variations for 2019.

Q. Please describe the drivers of the variance between baseline and actual 2019 NVPC.

A. As shown in Table 2 below, PGE's actual 2019 NVPC is approximately $4.7 million above forecast.[6] The $4.7 million variance is due to lower than forecast wind generation, resulting in a reduction to PTC benefits, and reduced PGE-owned resource generation leading to fuel savings, which are partially offset by increased net market purchases and sales. Additionally, PGE incurred lower wheeling expense in 2019 and higher overall NVPC expense related to a stipulated agreement in UE 335 (PGE's 2019 general rate case).

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[6] After normalizing for load, as discussed in Section II, D, below, the $4.7 million variance becomes the $5.4 million Annual Variance.

Table 2
2019 NVPC Reconciliation
($millions)

2019 Baseline NVPC	**$353.7**
Increase / (Decrease) to NVPC	
Wind PTCs	4.9
PGE-Owned Resources	(23.5)
Market Purchases and Sales	20.6
Wheeling	(1.6)
Stipulated Adjustments	4.5
Total Increase / (Decrease)[1]	**$4.7**
Adjusted Actual NVPC[2]	**$358.4**

[1]Prior to normalizing for load

[2] May not sum due to rounding

Q. Please describe the increase in NVPC related to wind PTCs.

A. PGE's 2019 wind generation was approximately 10%, or approximately 190 GWh, lower than forecasted resulting in reduced wind PTC benefits of approximately $4.9 million compared to baseline NVPC.

Q. Please describe the decrease in NVPC related to PGE-owned resource generation.

A. The ($23.5 million) decrease in NVPC associated with PGE's resource generation is due to lower than forecast coal and gas total generation in 2019 resulting in reduced fuel costs. While coal generation volume increased approximately 180 GWh, or 4% compared to baseline NVPC, gas generation volume decreased approximately 1,400 GWh, or 15% compared to 2019 baseline NVPC, due primarily to unplanned outages at Beaver, Carty, and Coyote Springs. Along with PGE's reduced total coal, gas, and wind generation in 2019, PGE-owned hydro generation was approximately 790 GWh lower than forecast (or 36%).

Q. Please describe the increase in NVPC related to market purchases and sales.

A. PGE experienced a $20.6 million increase in net market purchases and sales due primarily to increased energy purchases associated with replacement power for PGE's lower than forecast wind and hydro generation, and reduced gas generation due to unplanned outages.

D. 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 the baseline 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 baseline 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 2019, the unit NVPC variance is approximately $0.32 per MWh (i.e., actual unit NVPC is higher than baseline unit NVPC). We then calculate the Annual Variance by multiplying the unit NVPC variance times actual load. This produces an Annual Variance of approximately $5.4 million.

E. PCV

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

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

Q. What are the power cost deadbands?

A. Beginning January 1, 2011, the power cost deadbands are 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.

Q. What is the final PCV after application of the deadbands and sharing percentages?

A. Because PGE's Annual Variance of $5.4 million is within the upper deadband amount of $30 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 deadbands?

A. Yes. We perform this review initially as part of our annual requirement to provide a Results of Operations (ROO) Report to the OPUC Staff, which we will submit on or before July 1, 2020.[7] Because the ROO incorporates all aspects of the PCAM earnings review, PGE uses it as the basis for the ROE deadbands. We include it as PGE Exhibit 102.

Q. What are the ROE deadbands?

A. The ROE deadbands are ±100 basis points of PGE's authorized ROE, which for 2019 is 9.50% (see Commission Order No. 18-464). If PGE's earnings were below 8.50%, then we would collect the PCV above the power cost deadband up to the point where the ROE is 8.50%. Alternatively, if PGE's earnings were above 10.50%, then we would refund the PCV below the power cost deadband down to the point where the ROE is 10.50%.

Q. What was PGE's final 2019 ROE including the PCV?

A. PGE's final 2019 Regulated Adjusted ROE is 8.44%,[8] which is below the 8.50% to 10.50% earnings deadbands. As noted in Section II. D. above, the Annual Variance is also 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 2019 PCAM.

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[7] PGE was provided a 60-day extension to the May 1 due date for the 2019 Results of Operation filing through Order 20-140. PGE submitted the 2019 Results of Operations on June 30, 2020 in Docket NO. RE 119: https://edocs.puc.state.or.us/efdocs/HAQ/re119haq113750.pdf

[8] This is the earnings test result that includes the relevant adjustments from Commission Order No. 18-464 and the OPUC letter regarding the calculation of ROOs dated March 25, 1992.

Q. Does PGE provide earnings review 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 2019 PCAM amount equals zero, there is no impact from this entry.

Q. What is the rate impact of the 2019 PCAM?

A. Because the 2018 PCAM also entailed no refund to or collection from customers, there is no rate impact associated with the 2019 PCAM.

IV. Qualifications

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. Mr. Cristea, please state your educational background and experience.

A. I received a Bachelor of Arts degree in Regulatory Economics from the University of Calgary, Alberta, Canada. I began at PGE in 2016 as a regulatory analyst and was promoted to senior regulatory analyst in January 2019. I have worked on multiple PGE ratemaking, rulemaking, policy regulatory proceedings such as general rate cases (UE 319 and UE 335), Annual Updated Tariff (UE 359), or PCAM filings (UE 346, UE 362). Previously, I worked as an Operations Coordinator for Enterprise Holdings in Calgary, Alberta, Canada, overseeing the operations of approximately 50 car-rental offices. Prior to that, I owned and managed a construction business in France.

Q. Does this complete your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
101	Summary Calculation of 2019 PCV
102	2019 Results of Operations Report as filed June 30, 2020[9]
103C	2019 Actual Power Costs by Month and FERC Account
104	2019 Results of Operations with segregated PCAM amount

[9] PGE was provided a 60-day extension to the May 1 due date for the 2019 Results of Operation filing through Order 20-140.

PGE Power Cost Variance Mechanism (PCAM) ($000s) **December 2019**

	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total
BASE													
MONET NVPC ($000s)													
MONET (AUT/GRC) - Without PTCs	$ 43,524	$ 36,726	$ 35,014	$ 29,893	$ 30,608	$ 28,328	$ 28,694	$ 28,376	$ 29,913	$ 40,443	$ 37,275	$ 41,624	$ 410,419
Production Tax Credits (PTCs)	$ (2,689)	$ (3,684)	$ (4,610)	$ (5,610)	$ (5,048)	$ (5,573)	$ (5,423)	$ (3,821)	$ (3,149)	$ (3,144)	$ (3,042)	$ (3,100)	$ (48,892)
MONET (AUT/GRC) (Nov15, Pre-Selection)	$ 40,835	$ 33,042	$ 30,404	$ 24,284	$ 25,561	$ 22,756	$ 23,271	$ 24,555	$ 26,764	$ 37,299	$ 34,233	$ 38,524	$ 361,527
Nov Opt-Outs	$ (853)	$ (579)	$ (468)	$ (321)	$ (289)	$ (376)	$ (839)	$ (994)	$ (640)	$ (518)	$ (513)	$ (683)	$ (7,073)
NVPC (POST-SELECTION)	$ 39,982	$ 32,463	$ 29,935	$ 23,962	$ 25,271	$ 22,379	$ 22,432	$ 23,561	$ 26,124	$ 36,781	$ 33,720	$ 37,841	$ 354,454
Adjustments for BASE NVPC													
Coyote Steam Sales in GRC - Other Rev	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	$ (1,684)
Wind Availability Damages in GRC - O&M	$ -	$ -	$ 42	$ -	$ -	$ 42	$ -	$ -	$ 42	$ -	$ -	$ 769	$ 896
REVISED BASE NVPC (Post-Select, COS)	$ 39,842	$ 32,323	$ 29,837	$ 23,822	$ 25,131	$ 22,281	$ 22,292	$ 23,421	$ 26,026	$ 36,641	$ 33,580	$ 38,469	$ 353,665
BASE LOADS (MWHs)													
ORDER Retail Loads (Pre-Selection, COS)	1,659,807	1,425,973	1,477,440	1,341,328	1,334,713	1,325,331	1,471,650	1,488,433	1,334,777	1,369,334	1,466,678	1,704,952	17,400,415
Dec Opt-Outs to ORDER Retail Loads	(24,991)	(22,317)	(24,481)	(23,695)	(24,901)	(25,584)	(28,278)	(28,367)	(26,107)	(27,659)	(26,654)	(26,310)	(309,343)
BASE LOADS (Retail, w-DEC Opt-Outs, COS)	1,634,816	1,403,656	1,452,958	1,317,633	1,309,812	1,299,747	1,443,373	1,460,066	1,308,670	1,341,675	1,440,024	1,678,642	17,091,072
BASE UNIT NVPC	$ 24.37	$ 23.03	$ 20.54	$ 18.08	$ 19.19	$ 17.14	$ 15.44	$ 16.04	$ 19.89	$ 27.31	$ 23.32	$ 22.92	$ 20.69
ACTUALS / FORECAST	Actuals	Actuals	Actuals	Actuals	Actuals	Actuals	Actuals	Actuals	Actuals	Actuals	Actuals	Actuals	
Actual / Forecast NVPC (no Other Rev)	$ 39,151	$ 67,096	$ 35,244	$ 28,700	$ 28,966	$ 31,943	$ 31,208	$ 31,027	$ 29,795	$ 35,960	$ 42,386	$ 43,133	$ 444,608
EXCLUDE:													
FAS 133/71 - MTM/Deferral	$ -	$ -	$ -	$ -	$ -	$ 0	$ -	$ -	$ 0	$ -	$ -	$ (0)	$ 0
Credit Reserve - Expense	$ -	$ -	$ -	$ -	$ -	$ 21	$ -	$ -	$ 4,509	$ -	$ 143	$ 17	$ 4,691
Out-of-Period Adjustments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Direct Access deferral amortization - 4470004 & 5550005	$ (41)	$ 93	$ -	$ 93	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 515
Green Power expenses in 4171007 & 5550006	$ 1,509	$ 1,470	$ 1,493	$ 1,161	$ 1,009	$ 1,089	$ 1,283	$ 1,190	$ 1,188	$ 1,136	$ 1,285	$ 1,623	$ 15,436
Solar Pymt Option-SPO (was FIT) - avoided costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,045	$ 24	$ 1,069
2018 Trans amort-Revs in 2015 PCAM-Gamesa/EDF	$ (1,070)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,070)
Auto Demand Response deferred costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CalPX	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Carty Lateral Capital Lease reclass to O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal Exclusions	$ 399	$ 1,562	$ 1,493	$ 1,254	$ 1,055	$ 1,156	$ 1,329	$ 1,237	$ 5,744	$ 1,182	$ 2,520	$ 1,711	$ 20,641
INCLUDE:													
Coyote Steam Sales - 4560012	$ (164)	$ (125)	$ (151)	$ (122)	$ (111)	$ (127)	$ (243)	$ (201)	$ (180)	$ (150)	$ (140)	$ (161)	$ (1,874)
Gas Resale Margin - 4560008	$ 0	$ (3,111)	$ (10,081)	$ (1,020)	$ (1,733)	$ (107)	$ (255)	$ (18)	$ 27	$ (510)	$ (532)	$ 38	$ (17,302)
Wind availability (damages)/bonus - 5490001	$ -	$ 222	$ -	$ 470	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 693
Energy Revenues from VPO customers	$ (315)	$ (838)	$ (996)	$ (179)	$ (149)	$ (209)	$ (357)	$ (372)	$ (331)	$ (347)	$ (335)	$ (328)	$ (4,756)
Transmission resale revenues	$ (281)	$ (341)	$ (577)	$ (1,027)	$ (1,049)	$ (692)	$ (321)	$ (305)	$ (360)	$ (483)	$ (507)	$ (505)	$ (6,449)
Thermal plant chemicals in O&M	$ 408	$ 993	$ 1,115	$ 588	$ 193	$ 162	$ 595	$ 806	$ 680	$ 649	$ 748	$ 1,196	$ 8,134
Production Tax Credits-PTCs- in Taxes	$ (2,252)	$ (2,229)	$ (1,916)	$ (5,622)	$ (4,946)	$ (6,752)	$ (5,900)	$ (3,990)	$ (3,737)	$ (3,223)	$ (1,833)	$ (1,638)	$ (44,037)
Subtotal Inclusions	$ (2,604)	$ (5,428)	$ (12,604)	$ (6,911)	$ (7,795)	$ (7,725)	$ (6,481)	$ (4,080)	$ (3,902)	$ (4,063)	$ (2,599)	$ (1,396)	$ (65,591)
REVISED ACTUAL NVPC	$ 36,148	$ 60,106	$ 21,146	$ 20,535	$ 20,116	$ 23,061	$ 23,397	$ 25,710	$ 20,149	$ 30,714	$ 37,268	$ 40,026	$ 358,376
		SDEC17E FCST>>											
ACTUAL LOADS (Retail-COS-Calendar)	1,589,132	1,541,608	1,478,378	1,284,336	1,266,189	1,281,260	1,392,680	1,473,504	1,296,002	1,386,544	1,445,045	1,621,556	17,056,233
ytd	1,589,132	3,130,740	4,609,118	5,893,454	7,159,642	8,440,902	9,833,582	11,307,086	12,603,088	13,989,632	15,434,677	17,056,233	
ACTUAL UNIT NVPC	$ 22.75	$ 38.99	$ 14.30	$ 15.99	$ 15.89	$ 18.00	$ 16.80	$ 17.45	$ 15.55	$ 22.15	$ 25.79	$ 24.68	$ 21.01
UNIT NVPC VARIANCE													
ACTUAL UNIT NVPC	$ 22.75	$ 38.99	$ 14.30	$ 15.99	$ 15.89	$ 18.00	$ 16.80	$ 17.45	$ 15.55	$ 22.15	$ 25.79	$ 24.68	$ 21.01
BASE UNIT NVPC	$ 24.37	$ 23.03	$ 20.54	$ 18.08	$ 19.19	$ 17.14	$ 15.44	$ 16.04	$ 19.89	$ 27.31	$ 23.32	$ 22.92	$ 20.69
ACTUALS ABOVE (BELOW) BASE UNIT NVPC	$ (1.62)	$ 15.96	$ (6.23)	$ (2.09)	$ (3.30)	$ 0.86	$ 1.36	$ 1.41	$ (4.34)	$ (5.16)	$ 2.47	$ 1.77	$ 0.32
ANNUAL VARIANCE (AV)	= UNIT NVPC VARIANCE X ACTUAL LOADS												
ACTUALS ABOVE (BELOW) BASE	$ (2,580)	$ 24,606	$ (9,213)	$ (2,685)	$ (4,178)	$ 1,097	$ 1,888	$ 2,073	$ (5,625)	$ (7,152)	$ 3,571	$ 2,865	$ 5,432
ACTUALS ABOVE (BELOW) BASE - YTD	$ (2,580)	$ 22,026	$ 12,813	$ 10,127	$ 5,949	$ 7,046	$ 8,934	$ 11,007	$ 5,382	$ (1,770)	$ 1,801		
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					$ -

P O R T L A N D G E N E R A L E L E C T R I C
O P U C R E G U L A T O R Y R E P O R T I N G
R E S U L T S O F O P E R A T I O N S
January 1, 2019 - December 31, 2019
(Thousands of Dollars)

Regulatory adjustments based on **Docket UE 335, Order 18-464**	Actual Utility Results	Type I Accounting Adjustments	Regulated Utility Actuals	Type I Adjustments	Regulated Adjsuted Results	Type II Adjustments	Pro Forma Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Operating Revenues							
Sales to Consumers	1,879,149	(193)	1,878,956	0	1,878,956	8,789	1,887,746
Sales for Resale	193,611	(193,611)	0	0	0	0	0
Other Operating Revenues	67,909	(25,624)	42,285	0	42,285	0	42,285
Total Operating Revenues	2,140,669	(219,428)	1,921,241	0	1,921,241	8,789	1,930,031
Operation & Maintenance							
Net Variable Power Cost	639,644	(208,220)	431,424	0	431,424	(1,937)	429,487
Total Fixed O&M	321,344	0	321,344	0	321,344	5,863	327,207
Other O&M	286,942	1,337	288,279	(14,604)	273,674	3,057	276,732
Total Operation & Maintenance	1,247,929	(206,882)	1,041,047	(14,604)	1,026,442	6,983	1,033,425
Depreciation & Amortization	404,083	(3,698)	400,384	0	400,384	1,757	402,141
Other Taxes / Franchise Fee	132,405	0	132,405	0	132,405	1,181	133,586
Income Taxes	26,504	(2,605)	23,900	3,943	27,843	(286)	27,556
Total Oper. Expenses & Taxes	1,810,921	(213,185)	1,597,735	(10,662)	1,587,074	9,635	1,596,709
Utility Operating Income	329,749	(6,243)	323,506	10,662	334,168	(846)	333,322
Rate of Return	6.47%		6.54%		6.75%		6.74%
Return on Equity	7.89%		8.02%		8.44%		8.79%
ROE based on actual capital structure.							
Average Rate Base							
Utility Plant in Service	10,817,030	(150,540)	10,666,490	0	10,666,490	232,103	10,898,593
Accumulated Depreciation	5,127,261	0	5,127,261	(4)	5,127,257	252,451	5,379,711
Accumulated Def. Income Taxes	679,797	0	679,797	0	679,797	(8,700)	671,097
Accumulated Def. Inv. Tax Credit	0	0	0	0	0	0	0
Net Utility Plant	5,009,972	(150,540)	4,859,433	0	4,859,437	(11,648)	4,847,784
Deferred Programs & Investments	15,869	0	15,869	0	15,869	(893)	14,976
Operating Materials & Fuel	90,444	0	90,444	0	90,444	5,480	95,923
Misc. Deferred Credits	(76,630)	0	(76,630)	0	(76,630)	2,801	(73,829)
Unamortized Ratepayer Gains	0	0	0	0	0	0	0
Working Cash	60,233	232	60,464	(213)	60,252	1,255	61,507
Total Average Rate Base	5,099,887	(150,308)	4,949,579	(213)	4,949,370	(3,004)	4,946,362

Exhibit 103-C

Protected Information and will be submitted to the Filing Center upon approval of a Protective Order

PORTLAND GENERAL ELECTRIC
OPUC REGULATORY REPORTING
RESULTS OF OPERATIONS
January 1, 2019 - December 31, 2019
(Thousands of Dollars)

Regulatory adjustments based on **Docket UE 335, Order 18-464**	Actual Utility Results	Type I Accounting Adjustments	Regulated Utility Actuals	Type I Adjustments	Regulated Adjusted Results	2019 PCAM	Pro Forma Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Operating Revenues							
Sales to Consumers	1,879,149	(193)	1,878,956	0	1,878,956	0	1,878,956
Sales for Resale	193,611	(193,611)	0	0	0	0	0
Other Operating Revenues	67,909	(25,624)	42,285	0	42,285	0	42,285
Total Operating Revenues	2,140,669	(219,428)	1,921,241	0	1,921,241	0	1,921,241
Operation & Maintenance							
Net Variable Power Cost	639,644	(208,220)	431,424	0	431,424	0	431,424
Total Fixed O&M	321,344	0	321,344	0	321,344	0	321,344
Other O&M	286,942	1,337	288,279	(14,604)	273,674	0	273,674
Total Operation & Maintenance	1,247,929	(206,882)	1,041,047	(14,604)	1,026,442	0	1,026,442
Depreciation & Amortization	404,083	(3,698)	400,384	0	400,384	0	400,384
Other Taxes / Franchise Fee	132,405	0	132,405	0	132,405	0	132,405
Income Taxes	26,504	(2,605)	23,900	3,943	27,843	0	27,843
Total Oper. Expenses & Taxes	1,810,921	(213,185)	1,597,735	(10,662)	1,587,074	0	1,587,074
Utility Operating Income	329,749	(6,243)	323,506	10,662	334,168	0	334,168
Rate of Return	6.47%		6.54%		6.75%		6.75%
Return on Equity	7.89%		8.02%		8.44%		8.44%
ROE based on actual capital structure.							
Average Rate Base							
Utility Plant in Service	10,817,030	(150,540)	10,666,490	0	10,666,490	0	10,666,490
Accumulated Depreciation	5,127,261	0	5,127,261	(4)	5,127,257	0	5,127,257
Accumulated Def. Income Taxes	679,797	0	679,797	0	679,797	0	679,797
Accumulated Def. Inv. Tax Credit	0	0	0	0	0	0	0
Net Utility Plant	5,009,972	(150,540)	4,859,433	0	4,859,437	0	4,859,437
Deferred Programs & Investments	15,869	0	15,869	0	15,869	0	15,869
Operating Materials & Fuel	90,444	0	90,444	0	90,444	0	90,444
Misc. Deferred Credits	(76,630)	0	(76,630)	0	(76,630)	0	(76,630)
Unamortized Ratepayer Gains	0	0	0	0	0	0	0
Working Cash	60,233	232	60,464	(213)	60,252	0	60,252
Total Average Rate Base	5,099,887	(150,308)	4,949,579	(213)	4,949,370	0	4,949,370

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE ____

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY 2019 Annual Power Cost Variance Mechanism.	**MOTION FOR A GENERAL PROTECTIVE ORDER**

Pursuant to ORCP 36(C)(1) and OAR 860-001-0080, Portland General Electric Company ("PGE") requests the issuance of a General Protective Order in this proceeding. PGE believes good cause exists for the issuance of such an order to protect protected business information, plans, and strategies. In support of this Motion, PGE states:

1. Along with this motion, PGE has filed its 2019 Annual Power Cost Variance under Tariff Schedule 126. PGE has filed testimony regarding the power cost variance and the operation of the mechanism to the 2019 power cost variance. An exhibit to the testimony and certain work papers that support the testimony filed by PGE in this docket include protected, sensitive business information, including PGE's timing of and prices for electricity purchases and sales, fuel purchases and other contracts. PGE anticipates that there may be requests for further protected information during this docket as well. PGE desires to provide the information, but the information is protected, sensitive business information and of significant commercial value, and its public disclosure could be detrimental to PGE and its customers.

2. 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.

PGE requests expedited consideration of the Motion in order to allow PGE to file complete testimony, and for other parties to execute the protective order and obtain the confidential information.

DATED this 1st day of July, 2020.

Respectfully submitted,

/s/ *Douglas C. Tingey*

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(503) 464-2200 (Facsimile)
doug.tingey@pgn.com

ORDER NO.
ENTERED

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE ______

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY 2019 Annual Power Cost Variance Mechanism.	**GENERAL PROTECTIVE ORDER**

DISPOSITION: MOTION FOR PROTECTIVE ORDER GRANTED

On July 1st, 2020, Portland General Electric Company filed a motion for a general protective order to govern the acquisition and use of protected information produced or used in these proceedings. PGE states that the order is needed to protect certain information that falls within the scope of ORCP 36(C)(1). Specifically, PGE states that an exhibit to its filed testimony and certain work papers supporting the testimony include confidential, sensitive business information, including PGE's timing of, and prices for electricity purchases and sales, fuel purchases and other contracts. PGE adds that the public release of this information could prejudice PGE and its customers. PGE anticipates that there may be requests for further protected information during this docket as well as other business matters that are protected.

I find that good cause exists to issue a general protective order, which is attached as Appendix A. A party may appeal this order to the Commission under OAR 860-001-0110.

ORDER

IT IS ORDERED that the General Protective Order, attached as Appendix A, is adopted.

Made, entered, and effective on ____________________________.

____
[Judge]
Administrative Law Judge

GENERAL PROTECTIVE ORDER
DOCKET NO. [ ]

Scope of this Order:

1. This order governs the acquisition and use of Protected Information produced or used by any party to these proceedings.

Designation of Protected Information:

2. Any party may designate as Protected Information any information the party reasonably determines:

(a) Falls within the scope of ORCP 36(C)(1) (a trade secret or other confidential research, development, or commercial information); and
(b) Is not publically available.

3. To designate information as Protected Information, a party must place the following legend on the material:

PROTECTED INFORMATION
SUBJECT TO GENERAL PROTECTIVE ORDER

The party should make reasonable efforts to designate as Protected Information only the portions of the information covered by ORCP 36(C)(1).

4. Each page of a document containing Protected Information filed with the Commission or provided to Qualified Persons under this order 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)(1) may be placed in the envelope/container.* The envelope/container must bear the legend:

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

5. A party may designate as Protected Information any information previously provided by giving written notice to the Commission and other parties. Parties in possession of newly designated Protected Information must make reasonable efforts to ensure that all copies of the material containing the information bear the above legend if requested by the designating party.

6. A designating party must make reasonable efforts to ensure that information designated as Protected Information continues to warrant protection under this order. If designated information becomes publically available or no longer falls within the scope

of ORCP 36(C)(1), the designating party should make reasonable efforts to remove the protected designation and provide written notice to the Commission and other parties.

Challenge to Designation of Information as Protected:

7. A party may informally challenge any designation of Protected Information 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)(1). Any party may request that the ALJ hold a conference to help resolve disputes about proper designation.

8. If the dispute cannot be resolved informally, the challenging party may file a written objection with the ALJ. The objection need only identify the information in dispute and certify that reasonable efforts to achieve informal resolution have failed.

9. Within five business days of service of the objection, the designating party must either remove the protected designation or file a written response. A written response must identify the factual and legal basis of how the challenged information is protected under the Oregon Public Records Act, ORS 192.410 et seq, or the Uniform Trade Secrets Act, ORS 646.461(4). Broad allegations unsubstantiated by specific facts are not sufficient. If the designating party does not timely respond to the objection, the Commission will remove the protected designation from the challenged information.

10. The challenging party may file a written reply to any response within five business days of service of an objection. The designating party may file a sur-reply within three business days of service of a response. The ALJ will make all reasonable efforts to resolve the matter within 10 business days of service of the last filing.

Access to Protected Information:

11. Only Qualified Persons may access Protected Information designated by another party under this Protective Order. Persons automatically bound by this protective order and qualified to access Protected Information are:

a. Commission employees; and
b. Assistant Attorneys General assigned to represent the Commission.

12. Persons qualified upon a party signing the Consent to be Bound section of Appendix B are:

a. Counsel for the party;
b. Any person employed directly by counsel of record; and
c. An employee of the Regulatory Division at the Citizens' Utility Board of Oregon.

A party must identify all these persons in section 2 of Appendix B when consenting to be bound by the order, and must update this list throughout the proceeding to ensure it accurately identifies Qualified Persons

13. A party bound by the protective order may seek to qualify other persons to access Protected Information by having those persons complete and sign Appendix C, and submitting that information to the Commission and all parties. Within five business days of receiving a copy of Appendix C, the designating party must either provide the requested access to Protected Information or file an objection under Paragraph 14.

Objection to Access to Protected Information:

14. All Qualified Persons have access to Protected Information unless the designating party objects as provided in this paragraph. As soon as the designating party becomes aware of reasons to restrict access to a Qualified Person, the designating party must provide the Qualified Person and his or her counsel notice stating the basis for the objection. The parties must promptly confer and attempt to resolve the dispute on an informal basis.

15. If the parties are unable to resolve the matter informally, the designating party must file a written objection with the ALJ. The requesting party may file a response to the motion within 5 business days of service of an objection. The ALJ will make all reasonable efforts to resolve the matter within 10 business days of the last filing. Pending the ALJ's decision, the specific Protected Information may not be disclosed to the person subject to the objection.

Use of Protected Information:

16. All Qualified Persons must take reasonable precautions to keep Protected Information secure. A Qualified Person may reproduce Protected Information to the extent necessary to participate in these proceedings. A Qualified Person may discuss Protected Information obtained under this order only with other Qualified Persons who have obtained the same information.

17. Without the written permission of the designating party, any Qualified Person given access to Protected Information under this order may not disclose Protected Information for any purpose other than participating in these proceedings.

18. Nothing in this protective order precludes any party from independently seeking through discovery in any other administrative or judicial proceeding information or materials produced in this proceeding under this protective order.

19. Counsel of record may retain memoranda, pleadings, testimony, discovery, or other documents containing Protected 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 only be disclosed to

Qualified Persons under this order. Any other person retaining Protected 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 Protected Information. This paragraph does not apply to the Commission or its Staff.

Duration of Protection:

20. The Commission will preserve the designation of information as protected 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 Protected Information.

ORDER NO.
ENTERED

CONSENT TO BE BOUND
DOCKET NO. [ ]

I. Consent to be Bound:

This general protective order governs the use of Protected 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 Paragraph 12:

______________________________(Party) identifies the following person(s) qualified under paragraph 12.

PRINTED NAME	DATE

ORDER NO.
ENTERED

QUALIFICATION OF OTHER PERSONS
DOCKET NO. [ ]

III. Persons Seeking Qualification under Paragraph 13:

I have read the general protective order, agree to be bound by the terms of the order, and provide the following information.

Signature:		**Date:**
Printed Name:		
Physical Address:		
Email Address:		
Employer:		
Associated Party:		
Job Title:		
If not employee of party, description of practice and clients:		