Portland General Electric Company
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portlandgeneral.com

June 29, 2021

Via Electronic Filing

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

Re: UE ___ 2020 Annual Power Cost Variance Mechanism

Attention 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 Portland General Electric Company (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 2020 Power Cost Variance (PCV), including baseline 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 ($13.7) million[1] (i.e., actual power costs are lower than forecasted power costs) is entirely within the power cost deadbands, the 2020 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 a collection from or refund to customers, this amount is then posted to PGE's PCV account

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

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 2020 final NVPC forecast and 2020 PCAM results, as required 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 2020. The last section contains our qualifications.

II. Calculation of PCV

A. Baseline 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 2020 power cost forecast that PGE calculated in Docket No. UE 359 (UE 359), using our power cost forecasting model, MONET.[2] The MONET result established the unadjusted baseline NVPC of approximately $393.5 million for 2020.

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 Docket No. UE 335, PGE's most recent general rate case). 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 359, there is no Ancillary Service adjustment necessary to calculate the 2020 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 24.1 MWa of 2020 direct access and variable price option load that had not been identified at the time the final MONET forecast

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[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, UE 359, and 377). Consequently, we incorporate those descriptions by reference.

was prepared in November 2019. This reduced baseline power costs by another \$6.3 million and, it also reduced the baseline loads used to determine baseline 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 2020 were approximately \$386.4 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 2020. 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 2020, this net amount is approximately \$545.5 million. To this amount, we apply a number of adjustments as listed in Table 1 and described below.

Table 1
Adjustments to Actual 2020 Power Costs
($000)

Actual NVPC per financial statements (see Exhibit 103C)		$545,535
Items to Exclude:		
Out of period items	subtract	2,504
August Trading Losses	subtract	127,310
Wheatridge Wind	subtract	871
Direct access deferral amortization	subtract	400
Green power costs billed directly to customers	subtract	17,062
Solar Payment Option - Sch205/206 avoided costs	subtract	592
2020 amortization of 2015 net wheeling credit	subtract	(2,250)
Items to Include:		
Coyote steam sales	add	(1,419)
Gas resale margin	add	(442)
Wind availability (credit)/charge	add	1,114
Energy revenues for variable price option customers	add	(1,507)
Transmission resale revenues	add	(6,717)
Chemical costs in O&M	add	5,209
Production Tax Credits in Taxes	add	(43,137)
North Mist Depreciation and Interest	add	15,850
Merchandise Processing Fee for Canadian Gas Imports	add	165
EIM-related imbalance credits/debits in other revenue	add	(491)
Adjusted Actual NVPC*		$367,671

*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 $2.5 million related to out of period items. This charge reflects the reversal of two items recorded in 2020 that pertain to prior years:
  - Approximately $2.2 million related to the 2019 Qualifying Facilities Track and True Up Mechanism, and
  - Approximately $0.3 million related to Solar Payment Options amounts recorded incorrectly in 2018 and 2019.
- A charge of approximately $127.3 million related to trading losses realized by PGE in 2020. The adjustment reflects the removal of NVPC impacts associated with losses resulting from PGE's August 2020 trading activities.

- A charge of approximately $0.9 million related to the Wheatridge wind facility. For 2020, costs and benefits associated with the Wheatridge wind facility are included in customer prices through PGE Schedule 122 (Renewable Resources Automatic Adjustment Clause).
- A charge of approximately $0.4 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 $17.1 million for green power expenses that are billed directly to customers through PGE Schedules 7, 32, and 54. Consequently, they should not be included when calculating the PCV.
- 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, which is applied to the SPO deferral.
- A credit of approximately ($2.2 million) to reverse the 2020 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:

[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 credit of approximately ($1.4 million) for actual steam sales revenues from the Coyote Springs 1 plant.
- A credit of approximately ($0.4 million) for gas resale margin.
- A charge of approximately $1.1 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 ($1.5 million) for energy revenues from variable price option customers.
- A credit of approximately ($6.7 million) for transmission resale revenues, net of lost transmission revenues from direct access customers.
- A charge of approximately $5.2 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 ($43.1 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.
- A charge of approximately $15.8 million related to North Mist Gas Storage facility. North Mist Gas storage facility expenses are forecasted in the AUT but recorded as depreciation and interest expenses for SEC compliance. Consequently, we reclassify

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

the depreciation and other interest expense related to the North Mist Gas Storage facility to net variable power cost, consistent with the recording of these costs for FERC regulatory accounting purposes and add them to the PCAM to accurately match the components of actual and baseline power costs.

- A charge of approximately $0.2 million for merchandise processing fees associated with gas imports from Canada. These fees are forecasted in the AUT but recorded as generation, transmission and distribution expenses for SEC compliance.
- A credit of approximately ($0.5 million) for EIM- related imbalance credits and debits that are recorded as other revenue for SEC compliance but are forecasted in the AUT as part of the EIM net benefits.

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 the actual NVPC?

A. No. In 2020, 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 $367.7 million.

C. Summary of NVPC Differences

Q. Please restate PGE's 2020 final baseline NVPC estimate and PGE's actual 2020 NVPC?

A. After applying the adjustments described on pages 3 and 4 above, PGE's baseline adjusted NVPC forecast for 2020 is approximately $386.4 million. After normalizing for load, PGE's 2020 baseline is further reduced to $381.4 million. This compares to the final actual NVPC of approximately $367.7 million, after applying the adjustments described on pages 5 through 9 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 2020 PCAM results with its baseline 2020 forecast in order to determine and explain significant power cost variations for 2020.

Q. Please describe the drivers of the variance between baseline and actual 2020 NVPC.

A. As shown in Table 2 below, PGE's actual 2020 NVPC is approximately ($18.8 million) below forecast, before normalizing for load. After normalizing for load, as described in Section II-D, the Annual Variance decreases to ($13.7 million) below forecast. The Annual Variance is primarily due to the following factors:

1. Higher than forecast wind generation, resulting in an increase to PTC benefits.

2. Reduced PGE-owned resource generation leading to fuel savings, which are partially offset by increased net market purchases and sales.

3. Lower than forecast wheeling expense in 2020.

4. Higher forecasted NVPC expense related to a stipulated agreement adopted by Commission Order No. 19-329 (Docket No. UE 359, PGE's 2020 AUT).

Table 2
2020 NVPC Reconciliation
($millions)

2020 Baseline NVPC	**$386.4**
Increase / (Decrease) to NVPC	
Wind PTCs	($7.0)
PGE-Owned Resources	($59.5)
Market Purchases and Sales	$41.5
Wheeling	($0.9)
Stipulated Adjustments	$7.0
Total Increase / (Decrease)[1]	**($18.8)**
Adjusted Actual NVPC[2]	**$367.7**

[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 2020 wind generation was approximately 17%, or approximately 298 GWh, higher than forecasted resulting in increased wind PTC benefits of approximately $7.0 million compared to baseline NVPC.

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

A. The ($59.5 million) decrease in NVPC associated with PGE's resource generation is due to lower than forecast coal and gas total generation in 2020 resulting in reduced fuel costs. While coal generation volume was lower than forecast by approximately 690 GWh, or 18% compared to baseline NVPC, gas generation volume was lower than forecast by approximately 2,618 GWh, or 25% compared to 2020 baseline NVPC. Along with PGE's reduced total coal and gas generation in 2020, PGE-owned hydro generation was approximately 878 GWh lower than forecast (or 42%).

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

A. PGE experienced a $41.5 million increase in net market purchases and sales due primarily to increased energy purchases associated with replacement power for PGE's lower than forecast gas, coal, and hydro generation.

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 baseline and actual NVPC so as to calculate a unit NVPC variance. To accomplish this, we divide the baseline NVPC and actual NVPC by baseline 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 2020, the unit NVPC variance is approximately ($0.80) per MWh (i.e., actual unit NVPC is lower 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 ($13.7 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 ($13.7 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 deadbands?

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 21, 2021 and supplemented on April 22, 2021. 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 are the ROE deadbands?

A. The ROE deadbands are ±100 basis points of PGE's authorized ROE, which for 2020 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 2020 ROE including the PCV?

A. PGE's final 2020 Regulated Adjusted ROE is 9.65%,[6] which is within the 8.50% to 10.50% earnings deadbands. 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 2020 PCAM.

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)?

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[6] 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.

A. Yes. PGE Exhibit 104 provides the stipulated ROE results; however, because the final 2020 PCAM amount equals zero, there is no impact from this entry.

Q. What is the rate impact of the 2020 PCAM?

A. Because the 2019 PCAM also entailed no refund to or collection from customers, there is no rate impact associated with the 2020 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 have been employed at PGE in the Rates and Regulatory Affairs department since 2016. I have served as a witness to or lead analyst for numerous PGE ratemaking, rulemaking, policy regulatory proceedings such as general rate cases (UE 319 and UE 335), annual power cost updates (UE 359 and UE 377), and Power cost adjustment mechanism filings (UE 346, UE 362, and UE 381). 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

Exhibit	**Description**
101	Summary Calculation of 2020 PCV
102	2020 Results of Operations Report as filed April 22, 2021
103C	2020 Actual Power Costs by Month and FERC Account
104	2020 Results of Operations with segregated PCAM amount

PGE Power Cost Variance Mechanism (PCAM) ($000s) Final 2020

	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
BASE													
MONET NVPC ($000s)													
MONET (AUT/GRC) - Without PTCs	$ 44,253	$ 39,159	$ 37,544	$ 32,462	$ 33,510	$ 31,935	$ 30,550	$ 31,153	$ 31,965	$ 34,573	$ 36,823	$ 45,796	$ 429,723
Production Tax Credits (PTCs)	$ (2,090)	$ (3,345)	$ (2,896)	$ (4,138)	$ (3,701)	$ (4,201)	$ (4,161)	$ (2,762)	$ (1,915)	$ (2,291)	$ (2,350)	$ (2,325)	$ (36,175)
MONET (AUT/GRC) (Nov15, Pre-Selection)	$ 42,163	$ 35,814	$ 34,647	$ 28,324	$ 29,809	$ 27,734	$ 26,390	$ 28,390	$ 30,050	$ 32,282	$ 34,473	$ 43,471	$ 393,548
Nov Opt-Outs	$ (606)	$ (523)	$ (389)	$ (314)	$ (260)	$ (340)	$ (758)	$ (850)	$ (584)	$ (484)	$ (479)	$ (742)	$ (6,329)
NVPC (POST-SELECTION)	$ 41,557	$ 35,291	$ 34,258	$ 28,010	$ 29,549	$ 27,394	$ 25,632	$ 27,540	$ 29,466	$ 31,798	$ 33,994	$ 42,729	$ 387,219
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)	$ 41,417	$ 35,151	$ 34,160	$ 27,869	$ 29,409	$ 27,297	$ 25,491	$ 27,400	$ 29,368	$ 31,658	$ 33,853	$ 43,357	$ 386,431
BASE LOADS (MWHs)													
ORDER Retail Loads (Pre-Selection, COS)	1,701,034	1,506,215	1,498,692	1,341,400	1,323,833	1,318,202	1,469,136	1,513,018	1,349,626	1,355,058	1,468,341	1,739,527	17,584,083
Dec Opt-Outs to ORDER Retail Loads	(18,313)	(16,331)	(16,860)	(16,897)	(18,030)	(18,196)	(19,672)	(18,582)	(17,405)	(17,363)	(16,217)	(17,320)	(211,188)
BASE LOADS (Retail, w-DEC Opt-Outs, COS)	1,682,721	1,489,884	1,481,832	1,324,502	1,305,803	1,300,006	1,449,464	1,494,436	1,332,221	1,337,694	1,452,124	1,722,207	17,372,895
BASE UNIT NVPC	$ 24.61	$ 23.59	$ 23.05	$ 21.04	$ 22.52	$ 21.00	$ 17.59	$ 18.33	$ 22.04	$ 23.67	$ 23.31	$ 25.18	$ 22.24
ACTUALS / FORECAST	Actuals	Actuals	Actuals	Actuals	Actuals	Actuals	Actuals	Actuals	Actuals	Actuals	Actuals	Actuals	Total
Actual / Forecast NVPC (no Other Rev)	$36,559	$38,096	$31,913	$27,034	$29,281	$25,799	$39,302	$162,951	$33,148	$35,287	$41,966	$44,199	$ 545,535
EXCLUDE:													
Out-of-Period Adjustments	$ -	$ 2,234	$ -	$ -	$ -	$ -	$ -	$ 270	$ -	$ -	$ -	$ -	$ 2,504
August Energy Trading Losses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 127,310	$ -	$ -	$ -	$ -	$ 127,310
Wheatridge											$ -	$ 871	$ 871
Direct Access deferral amortization - 4470004 & 5550005	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 400
Green Power expenses in 4171007 & 5550006	$ 1,631	$ 1,456	$ 1,433	$ 1,347	$ 1,149	$ 1,161	$ 1,233	$ 1,392	$ 1,370	$ 1,151	$ 1,343	$ 2,396	$ 17,062
Solar Pymt Option-SPO (was FIT) - avoided costs	$ 15	$ 21	$ 36	$ 40	$ 33	$ 47	$ 108	$ 135	$ 83	$ 38	$ 26	$ 12	$ 592
2019 Trans amort-Revs in 2015 PCAM-Gamesa/EDF	$ -	$ (1,750)	$ -	$ -	$ (500)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,250)
Subtotal Exclusions	$ 1,679	$ 1,995	$ 1,502	$ 1,420	$ 715	$ 1,241	$ 1,374	$ 129,139	$ 1,486	$ 1,223	$ 1,402	$ 3,312	$ 146,489
INCLUDE:													
Coyote Steam Sales - 4560012	$ (148)	$ (110)	$ (106)	$ (107)	$ (79)	$ (69)	$ (89)	$ (190)	$ (152)	$ (110)	$ (127)	$ (133)	$ (1,419)
Gas Resale Margin - 4560008	$ (68)	$ (1)	$ 71	$ (40)	$ (37)	$ 181	$ 377	$ (341)	$ 97	$ (122)	$ (224)	$ (335)	$ (442)
Wind availability (damages)/bonus - 5490001	$ 481	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 634	$ 1,114
Energy Revenues from VPO customers	$ (233)	$ (102)	$ (110)	$ (104)	$ (76)	$ (45)	$ (91)	$ (162)	$ (175)	$ (145)	$ (121)	$ (142)	$ (1,507)
Transmission resale revenues - 4560007	$ (298)	$ (386)	$ (365)	$ (645)	$ (815)	$ (725)	$ (491)	$ (535)	$ (505)	$ (875)	$ (863)	$ (214)	$ (6,717)
Thermal plant chemicals in O&M	$ 738	$ 321	$ 461	$ 437	$ 219	$ 18	$ 212	$ 1,011	$ 937	$ 259	$ 227	$ 369	$ 5,209
Production Tax Credits-PTCs- in Taxes	$ (4,768)	$ (4,965)	$ (4,122)	$ (4,290)	$ (3,950)	$ (4,839)	$ (4,514)	$ (3,029)	$ (1,957)	$ (2,993)	$ (1,700)	$ (2,011)	$ (43,137)
North Mist Depreciation and Interest	$ 1,321	$ 1,321	$ 1,321	$ 1,321	$ 1,321	$ 1,321	$ 1,321	$ 1,321	$ 1,321	$ 1,321	$ 1,321	$ 1,321	$ 15,850
Merchandise Processing Fee for Canadian Gas Imports	$ 25	$ 25	$ 0	$ 44	$ 24	$ 1	$ 31	$ 12	$ 0	$ 0	$ -	$ 2	$ 165
EIM-related imbalance credits/debits in other revenue	$ 411	$ 195	$ 87	$ (398)	$ 29	$ (380)	$ (93)	$ (164)	$ (602)	$ (1,056)	$ 627	$ 851	$ (491)
Subtotal Inclusions	$ (2,539)	$ (3,701)	$ (2,761)	$ (3,782)	$ (3,364)	$ (4,537)	$ (3,338)	$ (2,078)	$ (1,036)	$ (3,722)	$ (860)	$ 342	$ (31,375)
REVISED ACTUAL NVPC	$ 32,341	$ 32,400	$ 27,650	$ 21,832	$ 25,201	$ 20,022	$ 34,590	$ 31,734	$ 30,626	$ 30,343	$ 39,705	$ 41,229	$ 367,671

PGE Power Cost Variance Mechanism (PCAM) ($000s) Final 2020

	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
	JRV74	JRV74	JRV74	JRV74	JRV74	JRV74	JRV74	JRV74	JRV74	JRV74	JRV74	JRV74	
ACTUAL LOADS (Retail-COS-Calendar)	1,584,149	1,467,304	1,482,962	1,261,880	1,262,944	1,259,678	1,454,888	1,489,236	1,353,584	1,380,297	1,514,289	1,635,878	17,147,088
ytd	1,584,149	3,051,453	4,534,415	5,796,294	7,059,238	8,318,916	9,773,804	11,263,040	12,616,625	13,996,921	15,511,210	17,147,088	
ACTUAL UNIT NVPC	$ 20.42	$ 22.08	$ 18.65	$ 17.30	$ 19.95	$ 15.89	$ 23.78	$ 21.31	$ 22.63	$ 21.98	$ 26.22	$ 25.20	$ 21.44
UNIT NVPC VARIANCE													
ACTUAL UNIT NVPC	$ 20.42	$ 22.08	$ 18.65	$ 17.30	$ 19.95	$ 15.89	$ 23.78	$ 21.31	$ 22.63	$ 21.98	$ 26.22	$ 25.20	$ 21.44
BASE UNIT NVPC	$ 24.61	$ 23.59	$ 23.05	$ 21.04	$ 22.52	$ 21.00	$ 17.59	$ 18.33	$ 22.04	$ 23.67	$ 23.31	$ 25.18	$ 22.24
ACTUALS ABOVE (BELOW) BASE UNIT NVPC	$ (4.20)	$ (1.51)	$ (4.41)	$ (3.74)	$ (2.57)	$ (5.10)	$ 6.19	$ 2.97	$ 0.58	$ (1.68)	$ 2.91	$ 0.03	$ (0.80)
ANNUAL VARIANCE (AV) = UNIT NVPC VARIANCE X ACTUAL LOADS													
ACTUALS ABOVE (BELOW) BASE	$ (6,650)	$ (2,219)	$ (6,537)	$ (4,720)	$ (3,243)	$ (6,428)	$ 9,004	$ 4,429	$ 787	$ (2,324)	$ 4,402	45	$ (13,737)
ACTUALS ABOVE (BELOW) BASE - YTD	$ (6,650)	$ (8,868)	$ (15,405)	$ (20,125)	$ (23,367)	$ (29,795)	$ (20,792)	$ (16,363)	$ (15,576)	$ (17,899)	$ (13,497)	(13,452)	
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)

YTD POWER COST VARIANCE (PCV) — POSITIVE (NEGATIVE) PCV = ACTUALS ABOVE (BELOW) POWER COST DEADBANDS

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Regulatory adjustments based on **Docket UE 335, Order 18-464**	Actual Utility Results	Type I Accounting Adjustments	Regulated Utility Results	Type I Regulatory Adjustments	Regulated Adjusted Results	PCAM Reversal	Regulated Adjusted Post PCAM Results	Type 2 Pro Forma Adjustments	Pro Forma Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			(1+2)		(3+4)		(5+6)		(7+8)
Operating Revenues									
Sales to Consumers	1,930,462	(163)	1,930,299	0	1,930,299	0	1,930,299	7,667	1,937,965
Sales for Resale	179,806	(179,806)	0	0	0	0	0	0	0
Other Operating Revenues	42,154	(12,864)	29,290	0	29,290	0	29,290	2,745	32,035
Total Operating Revenues	2,152,421	(192,832)	1,959,589	0	1,959,589	0	1,959,589	10,412	1,970,001
Operation & Maintenance									
Net Variable Power Cost	723,445	(300,617)	422,827	103	422,930	13,538	436,468	1,689	438,157
Total Fixed O&M	285,909	0	285,909	15,642	301,551	0	301,551	4,217	305,768
Other O&M	281,971	(6,043)	275,928	(1,672)	274,256	0	274,256	1,742	275,999
Total Operation & Maintenance	1,291,325	(306,661)	984,665	14,073	998,738	13,538	1,012,276	7,649	1,019,924
Depreciation & Amortization	429,563	(5,458)	424,105	(500)	423,605	0	423,605	2,570	426,175
Other Taxes / Franchise Fee	136,443	0	136,443	0	136,443	0	136,443	1,051	137,494
Income Taxes	6,218	39,077	45,295	(3,662)	41,633	(3,654)	37,979	(1,554)	36,425
Total Oper. Expenses & Taxes	1,863,549	(273,042)	1,590,507	9,911	1,600,419	9,884	1,610,303	9,716	1,620,019
Utility Operating Income	288,872	80,210	369,081	(9,911)	359,170	(9,884)	349,286	696	349,982
Rate of Return	5.51%		7.33%		7.13%		6.93%		6.66%
Return on Equity	6.42%		10.04%		9.65%		9.26%		9.07%
ROE based on actual capital structure.									
Average Rate Base									
Utility Plant in Service	11,222,500	(195,010)	11,027,490	0	11,027,490	0	11,027,490	(276,785)	10,750,706
Accumulated Depreciation	5,400,963	(1,011)	5,399,952	0	5,399,952	0	5,399,952	(496,067)	4,903,885
Accumulated Def. Income Taxes	665,491	9,919	675,410	0	675,410	0	675,410	(14,925)	660,486
Accumulated Def. Inv. Tax Credit	0	0	0	0	0	0	0	0	0
Net Utility Plant	5,156,046	(203,918)	4,952,128	0	4,952,128	0	4,952,128	234,207	5,186,335
Deferred Programs & Investments	14,045	0	14,045	0	14,045	0	14,045	(955)	13,090
Operating Materials & Fuel	95,472	0	95,472	0	95,472	0	95,472	(23,663)	71,810
Misc. Deferred Credits	(82,082)	0	(82,082)	0	(82,082)	0	(82,082)	1,872	(80,210)
Unamortized Ratepayer Gains	0	0	0	0	0	0	0	0	0
Working Cash	61,927	(3,617)	58,309	(179)	58,131	0	58,131	2,946	61,076
Total Average Rate Base	5,245,408	(207,536)	5,037,872	(179)	5,037,694	0	5,037,694	214,407	5,252,101

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Regulatory adjustments based on **Docket UE 335, Order 18-464**	Actual Utility Results	Type I Accounting Adjustments	Regulated Utility Results	Type I Regulatory Adjustments	Regulated Adjusted Results	2020 PCAM	Regulated Adjusted Post PCAM Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
			(1+2)		(3+4)		(5+6)
Operating Revenues							
Sales to Consumers	1,930,462	(163)	1,930,299	0	1,930,299	0	1,930,299
Sales for Resale	179,806	(179,806)	0	0	0	0	0
Other Operating Revenues	42,154	(12,864)	29,290	0	29,290	0	29,290
Total Operating Revenues	2,152,421	(192,832)	1,959,589	0	1,959,589	0	1,959,589
Operation & Maintenance							
Net Variable Power Cost	723,445	(300,617)	422,827	103	422,930	0	422,930
Total Fixed O&M	285,909	0	285,909	15,642	301,551	0	301,551
Other O&M	281,971	(6,043)	275,928	(1,672)	274,256	0	274,256
Total Operation & Maintenance	1,291,325	(306,661)	984,665	14,073	998,738	0	998,738
Depreciation & Amortization	429,563	(5,458)	424,105	(500)	423,605	0	423,605
Other Taxes / Franchise Fee	136,443	0	136,443	0	136,443	0	136,443
Income Taxes	6,218	39,077	45,295	(3,662)	41,633	0	41,633
Total Oper. Expenses & Taxes	1,863,549	(273,042)	1,590,507	9,911	1,600,419	0	1,600,419
Utility Operating Income	288,872	80,210	369,081	(9,911)	359,170	0	359,170
Rate of Return	5.51%		7.33%		7.13%		7.13%
Return on Equity	6.42%		10.04%		9.65%		9.65%
ROE based on actual capital structure.							
Average Rate Base							
Utility Plant in Service	11,222,500	(195,010)	11,027,490	0	11,027,490	0	11,027,490
Accumulated Depreciation	5,400,963	(1,011)	5,399,952	0	5,399,952	0	5,399,952
Accumulated Def. Income Taxes	665,491	9,919	675,410	0	675,410	0	675,410
Accumulated Def. Inv. Tax Credit	0	0	0	0	0	0	0
Net Utility Plant	5,156,046	(203,918)	4,952,128	0	4,952,128	0	4,952,128
Deferred Programs & Investments	14,045	0	14,045	0	14,045	0	14,045
Operating Materials & Fuel	95,472	0	95,472	0	95,472	0	95,472
Misc. Deferred Credits	(82,082)	0	(82,082)	0	(82,082)	0	(82,082)
Unamortized Ratepayer Gains	0	0	0	0	0	0	0
Working Cash	61,927	(3,617)	58,309	(179)	58,131	0	58,131
Total Average Rate Base	5,245,408	(207,536)	5,037,872	(179)	5,037,694	0	5,037,694