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June 26, 2020

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PORTLAND GENERAL ELECTRIC CO.
2021 Annual Power Cost Update Tariff
Docket No. UE 377

Dear Filing Center:

Please find enclosed the redacted version of the Opening Testimony and Exhibits of Lance D. Kaufman (AWEC/100 – 102) on behalf of the Alliance of Western Energy Consumers ("AWEC") in the above-referenced docket.

Please note that AWEC's testimony and exhibits contain protected information that is being handled in accordance with Order No. 20-100. The confidential portions of AWEC's filing have been encrypted with 7-zip software and are being transmitted electronically to the Commission and qualified persons, consistent with the Commission's Order No. 20-088.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the **confidential portions of the Opening Testimony and Exhibits of Lance D. Kaufman** upon the parties shown below via electronic mail, consistent with Commission Order No. 20-088.

Dated at Portland, Oregon, this 26th day of June, 2020.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 377

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
2021 Annual Power Cost Update Tariff.	)
	)

OPENING TESTIMONY OF DR. LANCE D. KAUFMAN

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

(REDACTED VERSION)

June 26, 2020

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EXHIBIT LIST

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Lance Kaufman. I am the principal economist of Aegis Insight. My qualifications are included in Exhibit AWEC/101.

Q. ON WHOSE BEHALF YOU ARE TESTIFYING?

A. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are large energy users in the Western United States, including customers receiving electrical services from Portland General Electric ("PGE" or "Company") in Oregon.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address issues related to PGE's 2021 net variable power cost forecast ("NVPC").

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I make the following recommendations:

1. Replace the 2018 Colstrip forced outage rate with the 20-year average.
2. Remove Beaver gas constraints from MONET. Make a similar adjustment to the 2021 PCAM.
3. Remove infant mortality forced outage rates from Carty's 4-year average and replace with PGE's 2020 operational forecast for Carty's forced outages.
4. Modify the market depth calculations of Energy Imbalance Market ("EIM") benefits to reflect only hours with increments, and only hours with decrements for average increments and decrements, respectively.

5. Use the 4-year average of transmission resale revenues when forecasting transmission resales.
6. Credit the 2021 NVPC forecast with the value of the 2015 BPA wheeling rights purchases, amortized over the expected expense of the purchased rights. Make an equal adjustment to the 2021 PCAM.

The impact of these recommendations is summarized in the figure below.

Figure 1: Summary of AWEC Recommendations

[redacted]

II. COLSTRIP FORCED OUTAGE RATE

Q. HOW DOES PGE MODEL THE FORCED OUTAGE RATE ("FOR") FOR COLSTRIP?

A. PGE uses the average FOR from the previous four years. This method was approved in Commission Order 10-414 in Docket UM 1355, which developed a method for calculating the FOR for coal-fired generating resources.

Q. IS PGE COMPLYING WITH ALL OF THE REQUIREMENTS OF ORDER 10-414 IN MODELING COLSTRIP?

A. No. The Commission-approved methodology includes exceptions to using the most recent four-year average in modeling the FOR. Specifically, if the FOR falls outside of the 10^{th} or 90^{th} percentile for comparable NERC coal units in a year, that year is considered an "outlier year," is removed from the four-year average, and is replaced by the 20-year rolling average FOR.[1] Similarly, if a plant outage is determined to be due to utility imprudence, it is excluded and replaced in the same manner.[2] In this case, Colstrip experienced an extended outage and deration in 2018 because the plant exceeded its permit limits for Particulate Matter of 0.030 lbs/MMBtu, which informs the plant's compliance with the Mercury and Air Toxics Standards (collectively, "MATS PM"). This outage and deration was due to imprudence on the part of all of the Colstrip owners, including PGE.

Q. WHY DO YOU CONCLUDE THAT THE 2018 COLSTRIP OUTAGE AND DERATION WAS DUE TO IMPRUDENCE?

A. This was the finding of the Washington Utilities and Transportation Commission ("WUTC"), which held an investigation into this outage. This investigation, docketed as UE-190882, included each of the investor-owned utilities subject to the WUTC's jurisdiction: Puget Sound Energy, Avista Corp., and PacifiCorp ("IOUs"). The WUTC concluded that each of these utilities had failed to demonstrate that they acted prudently in addressing MATS PM violation and taking action to avoid this violation:

> Regulated companies bear the burden of proving their decisions were prudent. Here, the record contains insufficient contemporaneous documentation of the [IOUs'] decision making in the period between the Q1 and Q2 MATS PM Testing. Accordingly, we base our decision on the [IOUs'] failure to sufficiently demonstrate the prudence of their actions and decisions leading up to the 2018 Colstrip outage.[3]

The WUTC's final order includes a thorough and detailed description of the facts leading up to the MATS PM violation that required Colstrip to be taken offline and later run at a derated level.[4]

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[1] Docket UM 1355, Order No. 10-414 at 5 (Oct. 22, 2010).
[2] Id.
[3] WUTC Docket UE-190882, Final Order 05 ¶ 43 (Mar. 20, 2020).
[4] Id. ¶¶ 22-39.

Q. PLEASE SUMMARIZE THESE FACTS AS THE WUTC FOUND THEM.

A. Quarterly testing of MATS PM at Colstrip consistently showed levels below permitted limits until Q1 of 2018 when testing showed levels at the permitted limit of 0.030 lb/MMBtu.[5/] PGE confirmed that this is the limit.[6/] The results of the Q1 2018 test were revealed to the Colstrip owners at the February 21, 2018 Owner & Operator ("O&O") Committee meeting.[7/] Subsequent O&O Committee meetings were held on March 21, April 18, May 16, June 20, July 18, August 15, and September 19 of 2018.[8/] The WUTC also stated that Talen, the Colstrip operator, at times "communicated to the [IOUs] its expectation and recurring recommendation that Colstrip would pass its second quarterly (Q2) MATS PM Testing."[9/] However, as discussed below, any such communications between the February 21, 2018 and June 20, 2018 O&O Committee meetings are not apparent from the documents PGE provided in discovery in this case.

Q2 MATS PM testing revealed a site-wide emissions rate of 0.047 lb/MMBtu, "an unprecedented exceedance of the site's 0.030 lb/MMBtu limit."[10/] Units 3 and 4 went offline on June 28th and June 29th, respectively.[11/] The units went back online on July 8th and July 17th, respectively, but only for purposes of "inspection, evaluation, corrective action, and in-stack testing to determine compliance with emissions limits."[12/] The units were not brought fully back into service until September 2018.[13/]

5/ Id. ¶¶ 27, 28.
6/ AWEC/102 at 19 (PGE Response to AWEC DR 036).
7/ WUTC Docket No. UE-190882, Final Order 05 ¶ 28-29.
8/ Id. ¶ 29.
9/ Id. ¶ 30.
10/ Id. ¶ 33.
11/ Id. ¶ 35.
12/ Id.
13/ Id. ¶ 36

Q. WHAT DO THE DOCUMENTS PGE PROVIDED IN DISCOVERY REVEAL REGARDING THE OWNERS' ATTENTION TO MATS PM LEVELS?

A. The documents PGE provided align with the WUTC's conclusions. The WUTC found that the Colstrip owners failed to keep sufficient contemporaneous documentation to demonstrate their decision-making and attention to the elevated MATS PM levels. PGE provided meeting minutes and agendas from each of the O&O Committee meetings from February through June 2018.[14/] It also provided notes from each of these meetings except for the February meeting, citing an inability to locate these notes due to staff turnover.[15/] None of these agendas, minutes, or notes mention MATS PM testing until the June meeting, let alone indicate an effort to discover the cause of the increase in MATS PM emissions, or identify an action plan or any other strategy the owners were considering to reduce MATS PM emissions. This is despite PGE's notes from the January 2018 meeting stating that "[redacted]."[16/] This is also in contrast to the August meeting notes, which state that "[redacted]."[17/]

The only indication that MATS PM testing was discussed at the O&O Committee meetings between the Q1 and Q2 tests are PGE's notes from the June meeting, which reference the upcoming Q2 testing and state that [redacted]

14/ AWEC/102 at 19-48 (PGE Response to AWEC DR 36).
15/ Id. at 20. PGE also only provided meeting agendas for the January, February, and March meetings, and minutes for the January and February meetings.
16/ Id. at 26.
17/ Id. at 47.

[redacted].[redacted][18] PGE's notes do not indicate that it or any other owner pushed for proactive remedial efforts to minimize emissions and limit the impact to Colstrip operations.

Q. WHAT DO YOU CONCLUDE FROM THIS INFORMATION?

A. The WUTC's conclusions appear to be sound and founded on evidence consistent with that provided by PGE in this proceeding. If any owner, including PGE, took any action to minimize or prevent the risk of a MATS PM permit violation that would result in penalties and shutdown of the plant, there is no evidence of it. Accordingly, I agree with the WUTC that, like the Washington IOUs, PGE has failed to demonstrate the prudence of its actions leading up to the 2018 Colstrip outage and, therefore, this outage should be removed from the four-year average in forecasting the FOR for Colstrip in this case.

Order 10-414 states that:

> If the Commission finds that any plant outage in the previous four years was due to utility imprudence, the FOR(s) for the year(s) of the outage shall be replaced in the four-year rolling average by the historical average FOR as determined in step 5 above. Further, for any determination of imprudence related to an outage occurring during the period of the historical average, the year(s) of the outage shall not be included in calculating the historical average FOR.[19]

I recommend the Commission find this outage imprudent and treat 2018 consistent with Order 10-414.

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[18] AWEC/102 at 44 (PGE Response to AWEC DR 36).
[19] Docket No. UM 1355, Order No. 10-414 at 5.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Replacing 2018 with the 20-year historic average reduces the 4-year forced outage rate to [redacted] percent for Colstrip 3 and 4, respectively. This reduces the NVPC forecast by $1.1 million.

III. PORT WESTWARD COMPLEX GAS SUPPLY

Q. PLEASE SUMMARIZE THIS ISSUE.

A. PGE constrains the dispatch of Beaver in MONET due to gas supply constraints at the Port Westward complex.[20] Beaver's operation is constrained in every month in MONET. This reduces Beaver's ability to serve PGE's peak loads and to operate when marginal energy costs are high. PGE invested in Port Westward 2 to support a capacity shortfall, incurring substantial capital costs. PGE's insufficient gas supply for the Port Westward complex renders the Port Westward 2 ineffective. I recommend the Commission find PGE's 2021 gas supply decisions for the Port Westward complex imprudent and that the 2021 NVPC forecast be made assuming no gas constraint for the Port Westward complex. This reduces the 2021 power cost forecast by $3.4 million.

Q. HOW GREAT IS THE CURTAILMENT OF BEAVER IN MONET?

A. The figure below summarizes the number of hours Beaver is constrained in MONET. On average Beaver is restricted to run [redacted] per day in 2021.[21] Curtailment is most extreme in [redacted].

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[20] AWEC/102 at 4 (PGE Response to AWEC DR 22, part d).
[21] PGE MFR workpaper #M610PUC10-00i-2021 AUT.xlsm sheet "Gas Storage".

Figure 2: Confidential MONET Dispatch Constraints for Beaver Plant

[redacted]

Q. WHY DOES PGE NOT HAVE SUFFICIENT GAS TO OPERATE THE PORT WESTWARD COMPLEX AT FULL CAPACITY?

A. AWEC requested that PGE explain the reason for insufficient gas supply to meet the increased demand of the Port Westward complex. PGE responded that the 2009 IRP, which identified the capacity need supporting Port Westward 2, assumed sufficient gas supply for the project. PGE noted that it models Port Westward 2 at full capacity and did not explain why there is insufficient gas supply for the Port Westward complex as a whole, including for Beaver.[22]

Q. ARE YOU CHALLENGING THE PRUDENCE OF PORT WESTWARD 2?

A. No. The Commission has accepted the prudence of Port Westward 2. However, that prudence appears to rest on the assumption that there is sufficient gas. Port Westward 2 was acquired to add capacity to PGE's system. However, PGE is serving the gas needs of Port Westward 2 by reducing the capacity of Beaver. This capacity reduction offsets

[22] AWEC/102 at 3-4 (PGE Response to AWEC DR 22).

Port Westward 2's capacity contribution. Customers are paying the full cost of the Port Westward 2 investment, but do not receive the originally projected benefit because PGE does not have sufficient gas supply.

Q. IS PGE CURRENTLY ACQUIRING CAPACITY RESOURCES?

A. Yes. PGE supplemented its filing in this case on June 8, 2020 to request inclusion of a new capacity resource, the Douglas PPA, in the 2021 NVPC forecast.

Q. IS IT POSSIBLE THAT THE COST OF SUPPLYING GAS TO BEAVER EXCEEDS THE BENEFIT?

A. Yes, it is possible; however that should not be the basis for evaluating prudence of the gas supply. Prudence of the gas supply should include consideration of the incremental capacity costs of new capacity resources that PGE is acquiring, such as the Douglas PPA.[23/] Without the gas constraint, PGE may have been able to avoid acquiring this incremental capacity, or could have acquired a lower amount of capacity.

Q. ARE THERE OTHER REASONS WHY PGE'S INABILITY TO MAXIMIZE ITS EXISTING CAPACITY RESOURCES IS CONCERNING?

A. Yes. PGE has raised alarms in several recent dockets about diminishing capacity in the West and the impact this may have on resource adequacy requirements.[24/] Yet, PGE itself does not appear to have taken the actions necessary to maximize its existing resources' capacity contribution.

23/ PGE/300, Seulean – Kim – Batzler/4.

24/ See, e.g., Docket UE 258, PGE/100, Sims-Tinker/4:23-8:15; Docket No. UM 2024, PGE Phase 1 Opening Comments at 4-5 (Mar. 16, 2020).

Q. HAVE YOU EVALUATED THE COST OF SUPPLYING SUFFICIENT GAS AND THE CAPITAL COST OF PORT WESTWARD 2 AGAINST THE RELATIVE BENEFIT OF AVOIDING THE DOUGLAS PPA AND THE INCREMENTAL NVPC BENEFITS?

A. No, it did not become apparent to me that PGE was curtailing Beaver due to gas supply limits until after participating in the PGE AUT workshop on June 5, 2020 and reviewing PGE's response to Staff DR 4.[25] The full cost of not having sufficient capacity did not become apparent until PGE filed supplemental testimony on June 8, 2020 requesting cost recovery for the Douglas PPA. This allowed time for only one round of discovery requests on the issue. Based on the data available there is sufficient cause to question the prudence of not supplying Beaver with gas. PGE should bear the burden of demonstrating that the lack of gas is prudent, particularly considering the late filing of PGE's supplemental testimony requesting costs for a capacity resource.

Q. WHAT IS YOUR RECOMMENDATION FOR BEAVER GAS CONSTRAINTS?

A. I recommend removing the Beaver gas constraints in MONET. This reduces NVPC by $3.4 million. I also recommend that the effects of actual gas constraints at Beaver be removed from NVPC in the PCAM by adding a credit equal to the difference between the Beaver operating cost and the cost of replacement power in hours where PGE constrains Beaver.

IV. CARTY FORCED OUTAGE RATE

Q. PLEASE SUMMARIZE THIS ISSUE.

A. PGE models the forced outage rate of Carty using two years of actual outage data and two years of an "Initial" outage rate. The initial outage rate is [redacted] percent. The two years of actual outages rates are [redacted] percent and [redacted] percent in 2018 and 2019,

[25] AWEC/102 at 49 (PGE Response to Staff DR 4).

respectively. PGE states that the initial rate is high to account for infant mortality. Infant mortality is a term that refers to higher outage rates during the first few "infant" years of operation for a new plant. However, PGE admits that Carty will be past the infant mortality stage in the middle of the power cost forecast year because it will have operated for more than five years.[26] I recommend replacing PGE's forced outage rate with an outage rate calculated using PGE's 2018 through May 2020 actuals and June 2020 through December 2020 forecasted rate. This results in a forced outage rate of [redacted] percent. My recommendation reduces the 2021 NVPC forecast by $520,000.

Q. PLEASE EXPLAIN HOW PGE NORMALLY FORECASTS GAS FORCED OUTAGE RATES.

A. PGE normally forecasts gas outage rates using a plant-specific four-year moving average of the historic equivalent forced outage rate. PGE uses the methodology as a reasonable predictor of future plant outages. PGE studied alternative approaches to forecasting forced outages as part of the Commission's forced outage investigation in Docket No. UM 1355. PGE found that 3- and 4-year rolling averages produced the lowest forecast error compared to other years.[27]

Q. IS THE FOUR-YEAR ROLLING AVERAGE METHOD INTENDED TO INCORPORATE HISTORIC ABNORMAL EVENTS INTO FUTURE NVPC FORECASTS?

A. No. The method was intended to generate an accurate forward-looking forecast of normalized forced outage rates. PGE stated in Docket No. UM 1355 that it was appropriate to remove outlying outage events.[28]

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[26] AWEC/102 at 15 (PGE Response to AWEC DR 034).
[27] Docket No. UM 1355, PGE/100, Hager - Tinker/13, lines 4 and 5.
[28] Docket No. UM 1355, PGE/100, Hager - Tinker/13.

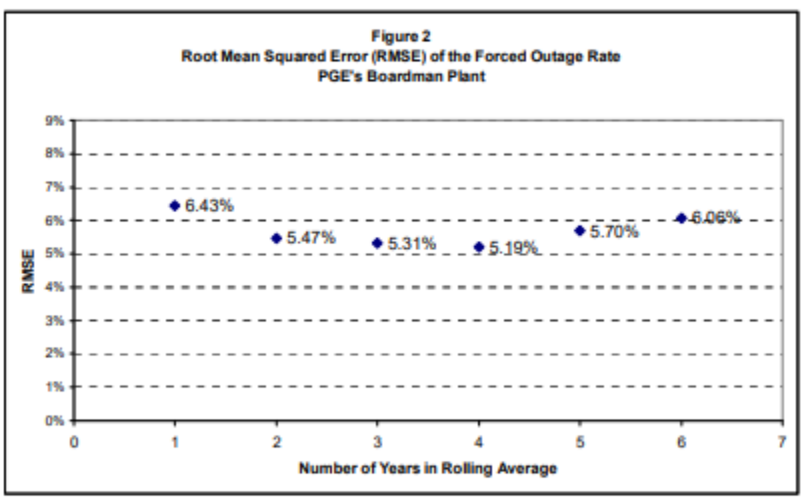
Q. WILL INCLUDING CARTY'S "INFANT MORTALITY" OUTAGE RATE IN THE 4-YEAR AVERAGE RESULT IN AN ACCURATE AND NORMALIZED FORECAST OF CARTY'S OUTAGES?

A. No, PGE admits that Carty is past the infant mortality stage. Using two years of "infant mortality" outage rates in the 4-year average will result in a forecast that is biased and high.

Q. WHY DO YOU RECOMMEND USING PGE'S 2018 THROUGH MAY 2020 ACTUALS AND JUNE 2020 THROUGH DECEMBER 2020 FORECASTED RATE?

A. PGE also provided a Carty forced outage rate forecast for 2020 in response to AWEC DR 34.[29] In Docket No. UM 1355 PGE showed that a 3-year average was as effective as a 4-year average. PGE's analysis also showed that a 2-year average was also a good predictor of forced outages. PGE's analysis is reproduced below.[30]

Figure 3: UM 1355 PGE Analysis of Forced Outage Rate Accuracy



Using more recent data over a shorter period will prove more accurate than using a longer period that includes outlying outages which are not expected in the future.

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[29] AWEC/102 at 15-18 (PGE response to AWEC DR 34 Confidential Attachment CARTY REPORT_AVAILABILITY_2020YTD.xlsx).

[30] Docket No. UM 1355, PGE/100, Hager - Tinker/13.

Q. DOES PGE USE THE INFANT MORTALITY OUTAGE RATES IN OPERATIONAL (I.E., NON-AUT) DOCUMENTS?

A. No. PGE provided an internal forecast of forced outage rate for Carty for 2020 in response to AWEC DR 34.[31/] This forecast did not reflect future infant mortality and was more consistent with the 2-year historic average.

Q. PLEASE RESTATE YOUR RECOMMENDATION FOR THIS ISSUE.

A. I recommend replacing PGE's forced outage rate with an outage rate calculated using PGE's 2018 through May 2020 actuals and June 2020 through December 2020 forecasted rate. This results in a forced outage rate of [redacted] percent. My recommendation reduces the 2021 NVPC forecast by $520,000.

V. EIM BENEFIT

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH PGE'S EIM BENEFIT ESTIMATION.

A. PGE has modified its EIM Benefit calculation method in all but one AUT since entering the EIM. Each variant of PGE's method has underestimated benefits. PGE's proposed changes this year reduce the benefit forecast by $3.8 million relative to what it would be if PGE continued to use the method PGE proposed in the 2020 AUT.[32/] PGE's proposed methodology has a critical flaw that prevents it from being an accurate and meaningful model. When this flaw is corrected, PGE's proposed methodology is consistent with the 2020 AUT, i.e., both methods result in similar predicted benefits.

[31/] AWEC/102 at 15-18 (PGE response to AWEC DR 34 Confidential Attachment CARTY REPORT_AVAILABILITY_2020YTD.xlsx).

[32/] AWEC/102 at 5-11 (PGE response to AWEC DR 26 Attachment E (summary sheet)) and PGE/100, Seulean – Kim – Batzler/10.

PGE's proposed model calculates the "market depth" of the EIM market within any given hour as the hourly average historic increments and decrements within the month. The critical flaw is that PGE averages increments across all hours within the month, and decrements across all hours within the month, rather than averaging only within hours where an actual increment or decrement occurs. This results in a large and biased underestimate of the depth of the EIM market. I recommend modifying the market depth calculations to reflect average volumes during periods of increments and decrements separately.

Q. PLEASE SUMMARIZE PGE'S PAST EIM BENEFIT FORECASTS.

A. In the 2017 AUT, PGE forecast no EIM benefit due to uncertainty.[33/] In the 2018 and 2019 AUTs, PGE relied on a third-party study to forecast EIM benefits.[34/] In the 2020 AUT PGE proposed using historical values. PGE also introduced an additional benefit, greenhouse gas revenues, which PGE received since the outset of EIM participation but did not include in previous forecasts.[35/] In this filing, PGE proposes a sub-hourly dispatch model to forecast EIM benefits. PGE's forecast and actual benefits are summarized below.

Figure 4: PGE Forecast and Actual EIM Benefit

[redacted]

[33/] Docket No. UE 308, PGE/400, Niman - Peschka - Hager/20.
[34/] Docket No. UE 319, PGE/300, Niman - Peschka - Rodehorst/17; Docket No. UE 335, PGE/300, Niman – Kim – Batzler/10.
[35/] Docket No. UE 359, PGE/100, Niman – Kim – Batzler/10-11.

PGE consistently under forecasts EIM benefits. This suggests that PGE is overly conservative when forecasting EIM benefits.

Q. DID PARTIES RAISE CONCERNS WITH PGE'S EIM BENEFIT FORECAST IN PAST CASES?

A. Yes, parties noted that PGE's forecast in previous dockets appeared too low.

Q. WHAT IS YOUR MAIN CONCERN WITH THE 2021 EIM BENEFIT FORECAST?

A. PGE developed a model that substantially underestimates EIM benefits. PGE created a sub-hourly dispatch model to estimate EIM benefits. PGE uses historic EIM transactions to measure the market depth of this model. The market depth is used to limit the size of increments and decrements. However, PGE uses the incorrect denominator when calculating average historic increments and decrements.

Q. WHAT ARE INCREMENTS AND DECREMENTS?

A. Increments and decrements form the basic operations of the EIM. Increments are market transactions where PGE is paid to increase generation. Decrements are market transactions where PGE is paid to reduce generation. PGE calculates the average hourly size of an increment by dividing total increments in a month by the number of hours in the month. This underrepresents the average size of an increment because it includes hours where no increment is made.

Q. CAN YOU GIVE AN EXAMPLE THAT EXPLAINS WHY THIS APPROACH IS NOT CORRECT?

A. The market depth measure is intended to measure the average size of a transaction. Suppose you asked how much gas you purchased in an average transaction last year. The correct answer is to add all gas purchases over the year and divide by the number of transactions. The PGE approach is to take total gas purchases over the year and divide by

8760 hours. PGE's approach will clearly underrepresent the size of an average transaction.

Q. WHAT IS PGE'S ARGUMENT TO SUPPORT THEIR APPROACH?

A. PGE argues that its method is appropriate because it helps to normalize historic transactions. PGE states:

> With respect to the increment and decrement amounts, PGE elected to use the total number of hours within each month in order to estimate the reasonable level of transactional volume that PGE could execute under normal market conditions, and the total number of hours is one approach for smoothing out the impacts from hours that had non-normal market conditions.[36/]

However, PGE's rationale is incorrect. PGE is not only smoothing transactions, PGE is also shrinking transactions. Consider the treatment of forced outages. Historic forced outages are normalized by averaging the annual outage rate across four years. The annual outage rate *does not include all hours in the year.* For example, if a unit has a planned outage, these hours are not included in the denominator when calculating the outage rate.

Consider a coal plant that has a three-month planned maintenance outage and a three-month unplanned outage. PGE's "all hours of the year" method would result in an outage rate of 3/12 = 25 percent. The correct method, and the method used in this case for forced outages, excludes the months of planned outages, and results in an outage rate of 3/9 = 33 percent. In other words, including hours in the denominator that are not relevant biases the estimate low.

[36/] AWEC/102 at 13-14 (PGE response to AWEC DR 27, subpart c).

Q. WHAT IS YOUR RECOMMENDATION FOR THIS ISSUE?

A. I recommend that historic average increments be calculated by dividing the total increments within a month by the number of hours in that month that increments were made. I recommend that historic average decrements be calculated by dividing the total decrements within a month by the number of hours in that month that decrements were made. This increases the EIM benefit forecast by $4.6 million.

Q. HOW DOES YOUR METHOD COMPARE TO THE ACTUAL HISTORIC BENEFIT PROPOSED BY PGE IN UE 359?

A. The gross EIM benefit of the sub hourly dispatch model, after my adjustment, remains lower than the historic actual benefit method proposed by PGE in UE 359. The values are compared in the figure below.

Figure 5: AWEC Proposed EIM Benefit Vs. UE 359 Method

[redacted]

VI. TRANSMISSION SALES REVENUE

Q. PLEASE SUMMARIZE THIS ISSUE.

A. PGE forecasts [redacted] in transmission revenue for the 2021 NVPC forecast.[37/] The figure below compares actual to forecasted transmission revenue from the last 10 years. There is a clear history of under forecasting transmission resale revenue. I recommend the Commission use the most recent four-year average transmission revenue.

[37/] MFR workpaper #M610PUC10-00i-2021 AUT output.xlsm sheet "PwrCsOut" cell N322.

Figure 6: Confidential Transmission Resale Revenue

[redacted]

Q. HOW DID PGE FORECAST TRANSMISSION RESALE REVENUES IN ITS INITIAL FILING?

A. In response to AWEC DR 17, PGE states:

> For the 2021 NVPC modeling the transmission resale revenue forecast assumes that PGE has 300 MW of transmission capacity available for resale for Q1, Q2, and Q4 of 2021.[38/]

Q. HOW DID PGE FORECAST TRANSMISSION RESALE REVENUES IN PREVIOUS FILINGS?

A. In response to AWEC DR 17, PGE states:

> PGE's transmission resale forecast for 2021 is similar to PGE's 2018 and 2019 forecasts. In the 2015 through 2017 NVPC forecasts PGE was modeling transmission resale revenues based on the long-term transmission resale agreement with Shell Energy North America, LP (Shell). The Shell agreement expired in December 2017. PGE did not model transmission resales in the NVPC forecasts between 2010 and 2014.[39/]

38/ AWEC/102 at 1 (PGE Response to AWEC DR 17).
39/ Id. at 2 (PGE Response to AWEC DR 17).

Q. HOW DOES PGE EXPLAIN THE DISCREPANCY BETWEEN FORECASTED AND ACTUAL RESALES?

A. PGE states that actual resale revenues in Figure 6 above do not account for incremental costs associated with transmission resale, and that these costs are also not included in the NVPC forecast. For example:

> PGE would pursue transmission resales in the event a plant is placed in an extended forced outage, if the transmission wasn't needed for replacement power. In that case PGE would incur significant costs for replacement power that would potentially more than outweigh the transmission resale revenues. Moreover, PGE also incurs costs associated with short term transmission purchases that are not modeled in MONET and flow through the PCAM construct.[40/]

Q. DO YOU AGREE THAT ACTUAL TRANSMISSION RESALE VALUES DO NOT ACCOUNT FOR INCREMENTAL COSTS ASSOCIATED WITH FORCED OUTAGES?

A. No. Forced outages are modeled in the AUT through a four-year average of forced outages. To the extent that the four-year average transmission resale revenue is associated with additional forced outage costs, these costs are accounted for through the forced outage mechanism in MONET.

Q. DO YOU AGREE THAT ACTUAL TRANSMISSION RESALE VALUES DO NOT ACCOUNT FOR SHORT-TERM TRANSMISSION PURCHASES THAT ARE NOT MODELED IN MONET?

A. I cannot confirm or deny PGE's assertion at this time. I requested that PGE provide data necessary to compare actual transmission resales to forecast transmission resales. This should have included information about the alleged short-term purchases. PGE did not provide this information. To the extent that PGE believes it bears costs not included in the AUT, PGE should propose methodologies to capture such costs.

40/ AWEC/102 at 2 (PGE Response to AWEC DR 17).

Q. WHAT IS YOUR RECOMMENDATION FOR THIS ISSUE?

A. I recommend the Commission increase transmission net resale revenue forecast by $4.5 million as calculated in the table below. This decreases NVPC by an equal amount.

Figure 7:Transmission Resale Adjustment

[redacted]

VII. BPA TRANSMISSION RIGHTS PURCHASE

Q. PLEASE SUMMARIZE THIS ISSUE.

A. PGE acquired BPA transmission rights in 2015. This transaction involved a large payment from the previous owners to PGE. The previous owners paid PGE because the previous owners were not utilizing the rights and were being charged a deferral payment by BPA. PGE assumed financial responsibility for the deferral payments to BPA in exchange for the up-front payment by the previous owners. This transaction resulted in an expected net gain for PGE of $8.1 million dollars, calculated as the upfront payments from the previous owners less the expected deferral payments to BPA. PGE recorded the full amount of this gain in 2015 as a credit to net power costs. PGE should have amortized the net amount over the life of the transmission contracts to match costs with benefits.

Q. WHAT WAS THE IMPACT OF PGE'S TREATMENT OF THE PAYMENT IN 2015?

A. PGE executed a contract in 2015 that obligated customers to future power cost expense. As part of this contract PGE experienced an expected $8.1 million gain. The gain was fully recorded in the 2015 PCAM as a credit to customers; however, due to the PCAM mechanisms, none of this credit flowed through to customers. The transaction resulted in an $8.1 million dollar windfall for PGE shareholders and a multimillion-dollar incremental cost to rate payers in the following years.

Q. WHY IS THIS ISSUE BEING RAISED NOW, FIVE YEARS AFTER THE FACT?

A. PGE informed the Commission about this transaction on June 6, 2016 in its initial filing for the 2015 PCAM, UE 310. However, PGE provides a very brief description of the transaction:

> **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.[41/]

PGE incorrectly stated "PGE acquired and paid for the BPA wheeling rights in 2015." PGE did not pay for the transaction in 2015, PGE was paid for the transaction. Parties to UE 310 were not presented with a clear explanation about how PGE received a large payment in 2015, nor that this payment was tied to expense that would occur the following years.

I am raising this issue now because customers are being asked to pay expenses in this year's power costs associated with the wheeling rights, but did not receive any of the benefits of the 2015 payment to PGE.

Q. WHAT IS CORRECT TREATMENT OF THE NET GAIN FROM THE 2015 TRANSACTION?

A. The full payment for the transaction should have been recorded as a regulatory liability and returned to customers proportionately to the expense of the contract. For example, if

[41/] UE 310, PGE/100, Tooman-Batzler/8.

the expenses associated with the contract were evenly spread over the following 10 years, the gains from the payment should have been evenly spread over the following 10 years and the unamortized balance of the contract should have reduced PGE's ratebase.

Q. WHAT IS YOUR RECOMMENDATION FOR THIS ISSUE?

A. I recommend that the final 2021 NVPC forecast be reduced by the amount that customers would have received had PGE correctly recorded and amortized this transaction. In addition, the 2021 PCAM should include a credit of equal amounts. This treatment should be continued in future AUT and PCAM filings. I need additional data from PGE to complete the calculations for this adjustment.

Q. ARE YOU RECOMMENDING THAT GAINS THAT SHOULD HAVE FLOWED THROUGH TO CUSTOMERS IN PREVIOUS YEARS UNDER YOUR PROPOSED METHODOLOGY BE REFLECTED IN THIS OR FUTURE AUT PROCEEDINGS?

A. No, the rule against retroactive ratemaking prevents those gains from flowing through to customers now. My recommendation only proposes to flow gains through to customers that should be realized in 2021 and onward.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 377

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
2021 Annual Power Cost Update Tariff.	)
	)

EXHIBIT AWEC/101

CURRICULUM VITAE OF LANCE D. KAUFMAN

CURRICULUM VITAE

LANCE KAUFMAN
Aegis Insight
4801 W. Yale Ave.
Denver, Colorado 80219
(541) 515-0380
lance@aegisinsight.com

EDUCATION:

University of Oregon	Ph.D.	Economics	2008 – 2013
University of Oregon	M.S.	Economics	2006 – 2008
University of Anchorage Alaska	B.B.A.	Economics	2001 – 2004

CERTIFICATIONS:

Certified Depreciation Professional	Society of Depreciation Professionals	2018

PROFESSIONAL EXPERIENCE:

Principal Economist	Aegis Insight	2014 – Present
Senior Economist	Oregon Public Utility Commission	2015 – 2018
Public Utility Advocate	Alaska Department of Law	2014 – 2015
Senior Economist	Oregon Public Utility Commission	2013 – 2014
Instructor	University of Oregon	2008 – 2012
Research Assistant	University of Alaska Anchorage	2003 – 2008

PROFESSIONAL MEMBERSHIPS:

Society of Depreciation Professionals	2015 – Present
American Economics Association	2017 – Present

RESEARCH, CONSULTING, AND ECONOMETRIC ANALYSIS:

- Jester, Gibson & Moore, Denver, CO 2019
  Retained as an expert witness for plaintiffs regarding lost earnings in an ADEA wrongful termination matter.
- Albrechta & Coble, Ltd. Fremont, OH 2019
  Retained as an expert witness for plaintiff regarding lost earnings in a race related wrongful termination matter.
- Conrad Law, PC, Salt Lake City, UT 2019
  Retained as an expert witness for Ellis-Hall Consultants, LLC. regarding economic damages in Ellis-Hall Consultants, LLC. et. al. v. George B. Hofmann IV, United States District Court, District of Utah, Central Division.
- Davison Van Cleve, PC, Salem, OR 2019
  Retained as an expert witness for Alliance of Western Energy Consumers regarding net variable power cost calculations in PORTLAND GENERAL ELECTRIC COMPANY, 2020 Annual Power Cost Update Tariff Public Utility Commission of Oregon Docket No. UE 359.

- Sanger Law, PC, Salem, OR, 2019
  Testified as an expert witness for Renewable Energy Coalition and Rocky Mountain Coalition for Renewable Energy regarding Qualified Facility avoided costs in Application of Rocky Mountain Power for a Modification of Avoided Cost Methodology and Reduced Term of PURPA Power Purchase Agreements Public Service Commission of Wyoming Docket No. 20000-545-ET-18
- Sanger Law, PC, Salem, OR, 2019
  Retained to provide analysis of Portland General Electric wind production costs in support of the Northwest & Intermountain Power Producers Coalition comments in Oregon HB 2857.
- Sanger Law, PC, Salem, OR, 2019
  Retained as an expert witness for Cafeto Coffee Company regarding the necessity, design, and location of transmission lines in SPRINGFIELD UTILITY BOARD Petition for Certificate of Public Convenience and Necessity Public Utility Commission of Oregon Docket No. PCN 3.
- King & Greisen, LLP, Denver, CO 2018 –
  Provided statistical analysis of age disparity in re Raymond et. al. v. Spirit Aerosystems, Inc. Civil Action No. 6:16-cv-01282-EFM-GEB.
- Baumgartner Law, LLC, Denver, CO, 2018 – 2019
  Retained as an expert witness for plaintiffs re calculation of economic harm due to injury in re Eric Bowman, v. Top Tier Colorado, LLC,, Case No. 18CV31359, United States District Court, District of Colorado.
- Cohen Milstein Sellers & Toll PLLC, Washington DC, 2018 –
  Retained as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in re Isaac Harris et al. v. Medical Transportation Management, Inc., Civil Action No. 17-1371, United States District Court, District of Columbia.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2018 –
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in re Vicky Maldonado and Carter v. Apple Inc., AppleCare Services Company, Inc., and Apple CSC, Inc., Case No. 3:16-cv-04067-WHO, United States District Court, District of California.
- Hagens Berman Sobol Shapiro, LLP, Phoenix, Arizona, 2018 –
  Deposed and testified as an expert witness for plaintiffs re calculation of unpaid mileage for truck drivers in re Swift Transportation Co., Inc., Civil Action No. CV2004-001777, Superior Court of the State of Arizona, County of Maricopa.
- Killmer, Lane, and Newman, LLP, Denver, Colorado, 2018
  Retained as expert witness for plaintiffs re reasonable attorney fees in re Jeanne Stroup and Ruben Lee, v. United Airlines, Inc., Case No. 15-cv-01389-WYD-STV, United States District Court, District of Colorado.
- Klein and Frank, PC, Denver, Colorado, 2018
  Retained as expert witness for plaintiffs re potential jury bias in re Gail Goehrig and Chris Goehrig v. Core Mountain Enterprises, LLC, Case No. 2016CV030004, San Juan County District Court.
- Robert Belluso, Pennsylvania, 2017

Retained as expert witness for plaintiff re lost profit in re Robert Belluso D.O. v Trustees of Charleroi Community Park, PHRC Case No. 201505365, Pennsylvania Human Relations Commission.

- Lowery Parady, LLC, Denver, Colorado, 2017
  Analyzed payroll data and calculated unpaid overtime and unpaid hours for plaintiff class action in re Violeta Solis, et al. v. The Circle Group, LLC, et al., Case No. 1:16-cv-01329-RBJ, United States District Court, District of Colorado.
- Sawaya & Miller Law Firm, Denver, Colorado, 2017
  Provided data processing and analysis of employment records.
- Financial Scholars Group, Orinda, California, 2017
  Provided analysis of risk profile in bundled real estate and personal loans in re Old Republic Insurance Company v. Countrywide Bank et al., Circuit Court of Cook County, Illinois, Chancery Division.
- Financial Scholars Group, Orinda, California, 2017
  Provided consultation and analysis of financial market transactions in preparation of settlement claims filings in re Laydon v. Mizuho Bank, Ltd., et al. and Sonterra Capital Master Fund Ltd., et al v. UBS AG et al.
- Clean Energy Action, Boulder, Colorado, 2016 – 2017
  Provided consultation on the appropriate discounting methodology used in energy resource planning in the Public Service Company of Colorado application for approval of the 2016 Electric Resource Plan, Proceeding No. 16A-0396E, Public Utilities Commission of the State of Colorado.
- Confidential Client, 2016
  Provided analysis and report on the probability that distinct crimes are independent events based on geographical analysis of crime rates.
- Christine Lamb and Kevin James Burns, Denver, Colorado, 2016
  Provided data analysis for defendant of the impact of ethnicity on termination decisions in re Aragon et al v. Home Depot USA, Inc., Case No. 1:15-cv- 00466-MCA-KK, United States District Court, District of New Mexico.
- Steptoe & Johnson LLP, Washington, DC, 2015 – 2016
  Programmed analysis of internet traffic data for plaintiffs applying a proprietary probability model developed to identify and verify accounts responsible for repeated infringements of asserted copyrights by defendants' internet subscribers in re BMG Rights Management (US) LLC, and Round Hill Music LP v. Cox Enterprises, Inc., et al., Case No. 1:14-cv-1611(LOG/JFA), United States District Court Eastern District of Virginia, Alexandria Division.
- Hagens Berman Sobol Shapiro, LLP, Phoenix, Arizona, 2014 –
  Programmed analysis for plaintiffs to calculate unpaid mileage for truck drivers in re Swift Transportation Co., Inc., Civil Action No. CV2004-001777, Superior Court of the State of Arizona, County of Maricopa.
- Padilla & Padilla, PLLC, Denver, Colorado, 2014 – 2016
  Provided research and analysis for plaintiffs re the impact on minority applicants from use of the AccuPlacer Test by the City and County of Denver, and estimated damages in re Marian G. Kerner et al. v. City and County of Denver, Civil Action No. 11-cv-00256-MSK-KMT, United States District Court, District of Colorado.

- U.S. Equal Employment Opportunity Commission, 2013 –
  Provided statistical analysis of EEOC filings.

REGULATORY PROCEEDINGS:

- Portland General Electric 2016 Annual Power Cost Variance Docket No. UE 329.
- PacifiCorp 2016 Power Cost Adjustment Mechanism Docket No. UE 327.
- Public Utility Commission of Oregon Staff Investigation into the Treatment of New Facility Direct Access Charges Docket No. UM 1837
- PacifiCorp Oregon Specific Cost Allocation Investigation Docket No. UM 1824.
- PacifiCorp 2018 Transition Adjustment Mechanism Docket No. UE 323.
- Portland General Electric 2018 General Rate Case Docket No. UE 319.
- Avista Corp. 2017 General Rate Case Docket No. UG 325.
- Portland General Electric Affiliated Interest Agreement with Portland General Gas Supply Docket No. UI 376.
- Portland General Electric 2017 Automated Update Tariff Docket No. UE 308
- PacifiCorp 2017 Transition Adjustment Mechanism Docket No. UE 307
- Portland General Electric 2017 Reauthorization of Decoupling Adjustment Docket No. UE 306
- Northwest Natural Gas Investigation of WARM Program Docket No. UM 1750.
- PacifiCorp Investigation into Multi-Jurisdictional Allocation Issues Docket No. UM 1050.
- Idaho Power Company 2015 Power Supply Expense True Up Docket No. UE 305
- Homer Electric Association 2015 Depreciation Study U-15-094
- Submitted prefiled testimony regarding the depreciation study.
- Chugach Electric Association 2015 Rate Case U-15-081
- Developed staff position regarding margin calculations.
- ENSTAR 2014 Rate Case U-14-111
- Submitted prefiled testimony regarding sales forecast.
- Alaska Pacific Environmental Services 2014 Rate Case U-14-114/115/116/117/118
  Submitted prefiled testimony regarding cost allocations, cost of service, cost of capital, affiliated interests, and depreciation.
- Alaska Waste 2014 Rate Case U-14-104/105/106/107
  Submitted prefiled testimony regarding cost of service study, cost of capital, operating ratio, and affiliated interest real estate contracts.
- Fairbanks Natural Gas 2014 Rate Case U-14-102
  Submitted prefiled testimony regarding cost of service study and forecasting models.
- Avista 2015 Rate Case U-14-104
  Submitted analysis supporting OPUC Staff settlement positions regarding Avista's sales and load forecast, decoupling mechanisms and interstate cost allocation methodology. Represented Staff in settlement conferences on November 21, November 26, and December 4, 2013.
- Portland General Electric 2015 Rate Case
  Submitted pre-filed opening testimony addressing PGE's sales forecast, printing and mailing budget forecast, mailing budget, marginal cost study, line extension policy and reactive demand charge. Represented OPUC Staff in settlement conferences on May 20, May 27, and June 12, 2014.

- Portland General Electric 2014 General Rate Case
  Submitted analysis supporting OPUC Staff settlement positions regarding PGE's sales and load forecast, revenue decoupling mechanism, and cost of service study. Represented OPUC Staff in settlement conferences on May 29, June 3, June 6, July 2, and July 9 of 2013. Submitted testimony in support of partial stipulation, pre-filed opening testimony addressing PGE's decoupling mechanism, and testimony in support of a second partial stipulation.
- PacifiCorp 2014 General Electric Rate Case
  Submitted analysis supporting OPUC Staff settlement positions regarding PacifiCorp's sales and load forecast and cost of service study. Represented Staff in settlement conferences on June 12 through June 14, 2013.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 377

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
2021 Annual Power Cost Update Tariff.	)
	)

EXHIBIT AWEC/102

PACIFICORP RESPONSES TO DATA REQUESTS

(REDACTED VERSION)

June 22, 2020

TO: Jesse O. Gorsuch
Alliance of Western Energy Consumers

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to AWEC Data Request No. 017
Dated June 8, 2020

Request:

Please refer to the MFR file "#M610PUC10-00i-2021 AUT output.xlsm" Sheet "PwrCsOut", line 322. Please also refer to UE 362 PGE/100, Batzler - Cristea/5 at Table 1.

a. Are transmission resales in Table 1 directly comparable to transmission resales on sheet "PwrCsOut" of the corresponding years' net power cost forecast? If no, why not?
b. Please provide final NVPC forecast MONET output for each year from 2010 to present.
c. Please provide the actual transmission resales amount for each year from 2010 to present.
d. Please explain the variance, if any, between forecasts and actuals.
e. Please include all additional data required to compare forecasted to actual resale revenues from 2010 to present.
f. Please explain how transmission resale amounts are forecasted in the 2021 power cost forecast and identify any differences between the current method and the methods used for 2010 to 2020.

Response:

a. No. PGE's transmission resale forecast assumes a fixed amount of transmission capacity is available to for resale. The modeling is based on an agreement between stipulating parties in Docket No. UE 262 providing that beginning with its 2015 NVPC filing, PGE would include a proposed forecast of transmission resale revenue. Consequently, starting with the 2015 NVPC forecast, PGE has been including transmission resales revenues in the MONET modeling. For the 2021 NVPC modeling the transmission resale revenue forecast assumes that PGE has 300 MW of transmission capacity available for resale for Q1, Q2, and Q4 of 2021. PGE does not assume any transmission available to resale in Q3 due to expected transmission needs for PGE's load service obligation or PGE's Market Sales Obligation (Delivery to the market hub).

In actual operations PGE does not have a secured long-term transmission resale agreement and all transmission resales are pursued on a short-term basis (less than one year). Often this represents an instrument to optimize PGE's transmission needs to reliably serve our load and is based on the economics of PGE's generation plants. For example, PGE would pursue transmission resales in the event a plant is placed in an extended forced outage, if the transmission wasn't needed for replacement power. In that case PGE would incur significant costs for replacement power that would potentially more than outweigh the transmission resale revenues. Moreover, PGE also incurs costs associated with short term transmission purchases that are not modeled in MONET and flow through the PCAM construct.

b. Confidential Attachment 017-A provides the NVPC MONET final output for each year from 2010 to 2020.

c. Attachment 017-B provides the actual transmission resales reported in PGE's PCAM filings.

d. Please see PGE's response to part a.

e. PGE objects to this request on the basis that it is vague and overly broad. Subject to and without waiving this objection PGE responds as follows:

   Please see PGE's responses to parts a through d. PGE does not have a secured long-term transmission resale agreement in real operations compared to the AUT assumption that PGE has a fixed 300 MW transmission available for resale.

f. PGE's transmission resale forecast for 2021 is similar to PGE's 2018 and 2019 forecasts. In the 2015 through 2017 NVPC forecasts PGE was modeling transmission resale revenues based on the long-term transmission resale agreement with Shell Energy North America, LP (Shell). The Shell agreement expired in December 2017. PGE did not model transmission resales in the NVPC forecasts between 2010 and 2014.

Attachment 017-A is protected information subject to Protective Order No. 20-100.

June 22, 2020

TO: Jesse O. Gorsuch
Alliance of Western Energy Consumers

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to AWEC Data Request No. 022
Dated June 8, 2020

Request:

Please refer to PGE's response to Staff DR 4.

a. Has PGE been unable to dispatch Port Westward or Beaver at full capacity due to gas constraints in December or January?

b. Please provide the hourly generation of Port Westward and Beaver by unit from 2016 to present.

c. Please provide the capacity of Port Westward and Beaver.

d. In the 2021 NVPC forecast, does PGE restrict the dispatch of Port Westward or Beaver units to reflect gas constraints in December or January? If yes, please indicate where these constraints appear in the model. If no, why not?

e. Which IRPs included supported the acquisition of Port Westward 2? Did the modeling in these IRPs limit the dispatch or gas availability for Port Westward 2? If no, why not? If yes, why does PGE not have sufficient gas supply to operate Port Westward 2 at full capacity?

Response:

a. Yes, at times PGE has limited the Beaver dispatch in December or January to address gas supply constraints. PGE has not, however, limited the dispatch of Port Westward to address gas supply constraints. PGE does not specifically track when the Port Westward / Beaver complex has been unable to dispatch at full capacity due to firm gas supply constraints. In typical operations, if PGE experienced issues with gas supply PGE would limit the output of Beaver and fuel first Port Westward and Port Westward 2 (PW2). PGE has sufficient firm natural gas transportation rights to support the full dispatch capacity of Port Westward.

b. For hourly generation from 2016 to 2019 please refer to PGE's MFRs filed April 15, Vol 11 - Historical Data\Actual Hourly Energy for 2016-2019\Gas Plants. Confidential

Attachment 022-A provides hourly generation of Port Westward and Beaver from January 1, 2020 to May 31, 2020.

c. Please refer to cells K606:V606 (Port Westward) and K604:V604 (Beaver) on the "PC Input" worksheet in the MONET model for monthly capacity values.

d. The 2021 NVPC forecast reflects gas constraints for Beaver. The gas storage optimization in Step 0i estimates the available fuel supply for Beaver based on forecasted values for total available fuel supply at the Port Westward / Beaver complex, less the expected fuel demand for Port Westward and Port Westward 2. The 2021 NVPC forecast does not restrict the dispatch of Port Westward to reflect gas constraints. Please refer to cells C60:N104 on the "Gas Storage" worksheet in the MONET model for the fuel calculations.

e. PGE's 2009 IRP action plan in Docket No. LC 48 identified the need for approximately 200 MW of flexible capacity to fulfill the dual purpose of meeting load during peak customer demand events as well as providing flexible capacity to follow both load and wind fluctuations. The ensuing 2012 Request for Proposal resulted in the selection of the PW2 project as the least cost, least risk bid. With information available at that time, PGE's 2009 IRP assumed that PGE's gas rights on the KB pipeline, future gas pipeline expansions planned for the area, and the pipeline connection to the Mist gas storage facility would meet the gas demand at PW2. Therefore, PGE did not limit the dispatch of PW2 in the 2009 IRP modeling. PGE is not limiting the PW2 dispatch for gas supply constraints in the current MONET modeling.

Attachment 022-A is protected information subject to Protective Order No. 20-100.

June 22, 2020

TO: Jesse O. Gorsuch
Alliance of Western Energy Consumers

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to AWEC Data Request No. 026
Dated June 8, 2020

Request:

Please refer #M610PUC10-00d-2021 AUT output.xlsm cells F2096 to F2100.

a. Do the referenced cells provide the 2020 AUT EIM benefit estimates, or the 2021 AUT EIM benefit calculated using the 2020 AUT methodology but with updated values?

b. Please provide all workpapers used to calculate the 2020 AUT EIM benefit.

c. Please provide the 2021 AUT EIM benefit calculated using the 2020 AUT methodology but with updated values. Please include all workpapers, including but not limited to workpapers aggregating EIM transactions from the real-time level.

d. Please provide the actual GHG revenues by month from PGE's start of participation in EIM to present. Please include all workpapers, including but not limited to workpapers aggregating EIM transactions from the real-time level.

e. Please provide historic EIM sub-hourly dispatch benefits by month from PGE's start of participation in EIM to present. Please include all workpapers, including but not limited to workpapers aggregating EIM transactions from the real-time level.

f. If PGE declines to provide any part of this request, please provide the data necessary to make such calculations.

Response:

a. Cells F2096 to F2100 are the 2020 AUT EIM benefits that PGE submitted as part of its net variable power cost filing in OPUC Docket No. UE 359. They are not 2021 AUT EIM benefits.

b. Attachments 026-A through 026-D contain the workpapers submitted as part of PGE's Minimum Filing Requirements in OPUC Docket No. UE 359.

Attachment 026-A summarizes the benefit data, which is identified in part a of this response.

Attachment 026-B includes PGE's measurement of 2018 sub-hourly dispatch actuals with bid cost recovery included. See PGE's response to OPUC Data Request No. 070 for additional discussion on Bid Cost Recovery.

Attachment 026-C includes PGE's measurement of 2018 hydro GHG revenue that was used as the basis for the GHG benefit forecast.

Attachment 026-D includes PGE's measurement of grid management charges in 2018.

c. PGE objects to this request on the basis that it requires is overly broad, unduly burdensome, and requires new analysis. Without waiving and notwithstanding this objection PGE responds as follows:

Attachment 026-E provides a calculation of 2021 EIM benefit using the approach PGE utilized for its forecast of 2020 EIM benefits. Attachment 026-E includes a result with gross bid cost recovery dollars included in the calculation and a result with gross bid cost recovery dollars excluded. The result with gross bid cost recovery dollars included is consistent with the approach PGE utilized for its forecast of 2020 benefits (i.e., PGE included gross bid cost recovery dollars CAISO paid to PGE participating resources). However, allowing bid cost recovery dollars from 2019 to contribute to the creation of a 2021 EIM benefit forecast is unsuitable for several reasons. These reasons include:

1. PGE's participating resources received bid cost recovery dollars during the first quarter of 2019 that are not representative of the existing CAISO real-time market. During the first quarter of 2019, CAISO initiated a market software change that was impacting unit commitment logic in a manner that resulted in bid cost recovery dollars being assigned to PGE's participating resources. CAISO resolved the error in its unit commitment logic in March 2019, and the assignment of bid cost recovery dollars to PGE's participating resources was also reduced. PGE described the details of this impact in OPUC Docket No. UE 359.[1]

2. Bid Cost Recovery dollars received by PGE's participating resources can be offset by the Bid Cost Recovery charges PGE's EIM Entity is required to pay to CAISO. The EIM Entity is charged Bid Cost Recovery dollars, because PGE is often an importer in the EIM and importers bear the cost of the Bid Cost Recovery dollars paid to the resources committed by the market but not made whole by energy prices. See also PGE's Response to OPUC Data Request No. 98.

Since the use of bid cost recovery dollars is not appropriate for use in 2021 benefit forecasting, PGE included a second calculation with bid cost recovery dollars excluded in Attachment 026-E. See also PGE's response to OPUC Data Request No. 070.

Finally, PGE notes that its proposal in the 2020 AUT to use PGE's measurement of 2018 actual EIM benefits as a basis for forecasting 2020 benefits relied on the fact that the calendar year benefits were similar to normalized benefits produced from previous modeling efforts (which relied on production cost modeling). However, as PGE also

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[1] See PGE Exhibit 400, pages 13 and 14.

emphasized in OPUC Docket No. UE 359, its use of prior calendar year benefit measurements (i.e., dollars saved) will be an inappropriate basis for forecasting future dollars saved if the calendar year includes extraordinary (i.e., 'non-normal') events. PGE's calendar year 2019 benefit measurement includes extraordinary events.

d. See PGE's Response to OPUC Data Request No. 076 for GHG revenues by month. Attachment 026-F provides revenue data at an interval level, but the data will differ slightly from the results reported in OPUC Data Request No. 076, because the interval level data is rounded when it is retrieved from PGE's PCI software.

e. See PGE's Response to OPUC DR 70 for sub-hourly dispatch savings by month.

Workpapers used to calculate the sub-hourly dispatch savings by month include:

2020: Attachment 026-G includes the calculation of PGE's 2020 sub-hourly dispatch benefit by month with and without bid cost recovery dollars assigned to participating resources. The data is from January 1, 2020 through March 31, 2020. Attachment 026-H includes real-time level data from January 1, 2020 through March 31, 2020.

2019: Attachment 026-I includes the calculation of PGE's 2019 sub-hourly dispatch by month with and without bid cost recovery dollars assigned to participating resources. Attachment 026-J includes real-time level data from January 1, 2019 through December 31, 2019.

2018: See PGE's Response to AWEC DR 33 for 2018 real-time interval data.

2017: PGE does not have October 1, 2017 through December 31, 2017 data in a format comparable to data in 2018 and later, because prior to January 1, 2018 PGE's benefit estimation analysis was not fully integrated into its current software analytics tools.

In Attachments 026-H and 026-J the detail for thermal resources includes:

1. Base Schedule (MWh)
2. FMM Incr (MWh)
3. RTD Incr (MWh)
4. UIE Incr (MWh)
5. FMM EN Rev
6. RTD EN Rev
7. RTD UIE Rev
8. BCR

In Attachments 026-H and 026-J the detail for hydro resources includes:

1. Base Schedule (MWh)
2. FMM Incr (MWh)
3. RTD Incr (MWh)
4. UIE Incr (MWh)

5. FMM EN Rev
6. RTD EN Rev
7. UIE Rev
8. BCR
9. Cost
10. P&L (Profit and Loss)

Throughout the year, PGE completed its benefit measurements after CAISO's T+12 settlement activity was complete for the relevant trading month. Since that time, T+55 settlement activity has been processed and results reported in Attachments 026-G and 026-I will not precisely match the real-time transaction level detail provided in this response.

f. See parts a through e

Attachments 026-B, 026-C, 026-D, 026-F, and 026-G through 026-J are protected information subject to Protective Order No. 20-100.

UE 377

Attachment 026-E

Provided in Electronic Format

PGE's Calculation of 2021 EIM Benefit Using the 2020 AUT EIM Benefit Forecast Method

Bid Cost Recovery Included

		2019 $ Actuals	AWEC DR 026 Request Result for Part C	Notes	Escalator	2.5%
1	Western EIM Gross Benefit	$8,981,619	$9,436,314	2019 $ Actual sourced from Attachment 026-I 2021 $ escalates 2019 $ Actual by 2.5 percent		
2	Settlement Charges	($1,024,744)	($1,076,622)	2019 $ Actual sourced from 2019 GMC Charges 2021 $ escalates 2019 $ Actual by 2.5 percent		
3	Net EIM Benefit	$7,956,875	$8,359,692			
4	Hydro GHG Benefit	$2,476,217	$1,430,789	2019 $ is 2019 Hydro FMM Revenue 2021 $ reduces 2019 $ Actual by 50% for quantity reduction and escalates by 7.5% for inflation and real GHG price escalation		
	Total Gross Benefit	$11,457,836	$10,867,102			
	Total Net Benefit	$10,433,091	$9,790,480			

Bid Cost Recovery Excluded

		2019 $ Actuals	AWEC DR 026 Request Result for Part C	Notes	Escalator	2.5%
1	Western EIM Gross Benefit	$6,310,449	$6,629,916	2019 $ Actual sourced from Attachment 026-I 2021 $ escalates 2019 $ Actual by 2.5 percent		
2	Settlement Charges	($1,024,744)	($1,076,622)	2019 $ Actual sourced from 2019 GMC Charges 2021 $ escalates 2019 $ Actual by 2.5 percent		
3	Net EIM Benefit	$5,285,705	$5,553,294			
4	Hydro GHG Benefit	$2,476,217	$1,430,789	2019 $ is 2019 Hydro FMM Revenue 2021 $ reduces 2019 $ Actual by 50% for quantity reduction and escalates by 7.5% for inflation and real GHG price escalation		
	Total Gross Benefit	$8,786,666	$8,060,704			
	Total Net Benefit	$7,761,921	$6,984,082			

Resource Summary

PositionName	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
BNP1_5_BOARDMAN	$22,666	$15,324	($8,362)	$0	$305	$0	$7,815	$31,252	$58,134	($6,395)	$12,552	$3,863	$137,154
BRP1_2_BEAVER1-7	$1,291	$77,593	$23,485	($335)	$34,459	($53,778)	($84,913)	($61,323)	($109,009)	($73,277)	$155,530	$272,851	$182,573
CSP1_5_COYOTE1	$7,702	($406,336)	$45,885	$14,216	$15,102	$85,934	$65,851	$68,701	$54,916	$34,882	$14,478	$18,151	$19,482
CYP1_5_CARTY1	$360,841	$555,610	$111,300	$89,143	$10,135	$94,561	($69,570)	($24,482)	($82,512)	($29,125)	$5,447	$1,818	$1,023,168
* MIDC_5_PGESHARE	$103,853	$465,781	$217,566	$68,167	$94,744	$62,044	$51,976	$82,955	$110,525	$122,046	$59,229	$95,909	$1,534,795
* MIDC_7_DOPDPGESHARE	$41,069	$172,209	$196,624	$84,944	$89,284	$69,602	$39,165	$44,580	$60,056	$139,083	$61,975	$40,053	$1,038,644
* PNP-RBP_2_PELRB	$203,352	$697,009	$558,508	$226,181	$288,338	$255,333	$74,367	$142,594	$175,077	$256,679	$102,656	$97,140	$3,077,234
PWP1_2_PORTWEST1	$19,306	($1,165)	$196,323	$65,628	($32,708)	$10,186	($477)	$5,368	($44,957)	($76,622)	($65,421)	$49,318	$124,778
PWP2_2_RECIP1-6	$22,999	$159,313	($115,330)	$33,507	$85,370	$41,495	$103,247	$49,863	$25,688	$31,598	$64,839	$365,095	$867,685
PWP2_2_RECIP7-12	$26,394	$155,014	($27,651)	$60,826	$67,197	$128,293	$95,905	$65,119	$31,544	$47,040	$104,241	$222,183	$976,106
Total	**$809,473**	**$1,890,352**	**$1,198,347**	**$642,276**	**$652,227**	**$693,671**	**$283,365**	**$404,627**	**$279,462**	**$445,908**	**$515,529**	**$1,166,382**	**$8,981,619**

Note(s)
* Hydro benefits measured as EIM revenues against Powerdex hourly prices

Resource Summary Breakdown by Category

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Bid Cost Recovery	$347,662	$536,002	$222,141	$36,508	$80,514	$59,670	$289,051	$121,802	$168,102	$147,279	$278,063	$384,376	$2,671,170
Sub-Hourly Dispatch Measurement (i.e., fuel cost savings)	$461,811	$1,354,350	$976,206	$605,768	$571,713	$634,001	-$5,686	$282,825	$111,360	$298,629	$237,466	$782,006	$6,310,449
Total	**$809,473**	**$1,890,352**	**$1,198,347**	**$642,276**	**$652,227**	**$693,671**	**$283,365**	**$404,627**	**$279,462**	**$445,908**	**$515,529**	**$1,166,382**	**$8,981,619**

Reconciliation with OPUC DR 070

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Sub-Hourly Dispatch Measurement (i.e., fuel cost savings)	**$461,811**	**$1,354,350**	**$976,206**	**$605,768**	**$571,713**	**$634,001**	**($5,686)**	**$282,825**	**$111,360**	**$298,629**	**$237,466**	**$782,006**	**$6,310,449**

2019 Sub-Hourly Dispatch Benefit (No Bid Cost Recovery Reported)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
PGE Response to OPUC DR 070	**$461,811**	**$1,354,350**	**$976,206**	**$605,768**	**$571,713**	**$634,001**	**($5,686)**	**$282,825**	**$111,360**	**$298,629**	**$237,466**	**$782,006**	**$6,310,449**

Bid Cost Recovery

PositionName	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
BNP1_5_BOARDMAN	13,115	0	0	0	0	0	7,629	853	1,989	0	2,080	1,224	26,890
BRP1_2_BEAVER1-7	1,673	54,718	104,979	16,494	38,159	15,755	160,585	28,394	36,694	8,399	25,245	84,209	575,304
CSP1_5_COYOTE1	0	0	0	0	0	358	4	7	0	0	0	0	369
CYP1_5_CARTY1	301,088	461,759	84,032	0	0	13,497	38,933	31,153	441	6,746	234	12,098	949,981
MIDC_5_PGESHARE	0	0	0	0	0	0	0	0	0	0	0	0	0
MIDC_7_DOPDPGESHARE	0	65	0	0	0	0	0	0	0	0	0	0	65
PNP-RBP_2_PELRB	0	0	0	0	0	0	0	0	0	0	0	0	0
PWP1_2_PORTWEST1	23,105	8,076	0	0	0	0	1,103	3,940	0	0	0	2,965	39,189
PWP2_2_RECIP1-6	5,153	5,111	8,611	7,121	21,442	19,497	52,567	30,367	47,243	53,178	92,295	178,048	520,633
PWP2_2_RECIP7-12	3,528	6,273	24,519	12,893	20,913	10,563	28,230	27,088	81,735	78,956	158,209	105,832	558,739
Total	**$347,662**	**$536,002**	**$222,141**	**$36,508**	**$80,514**	**$59,670**	**$289,051**	**$121,802**	**$168,102**	**$147,279**	**$278,063**	**$384,376**	$2,671,170

Benefit - Net of BCR

PositionName	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
BNP1_5_BOARDMAN	9,551	15,324	(8,362)	0	305	0	186	30,399	56,145	(6,395)	10,472	2,639	110,264
BRP1_2_BEAVER1-7	(382)	22,875	(81,494)	(16,829)	(3,700)	(69,533)	(245,498)	(89,717)	(145,703)	(81,676)	130,285	188,642	(392,731)
CSP1_5_COYOTE1	7,702	(406,336)	45,885	14,216	15,102	85,576	65,847	68,694	54,916	34,882	14,478	18,151	19,113
CYP1_5_CARTY1	59,753	93,851	27,268	89,143	10,135	81,064	(108,503)	(55,635)	(82,953)	(35,871)	5,213	(10,280)	73,187
MIDC_5_PGESHARE	103,853	465,781	217,566	68,167	94,744	62,044	51,976	82,955	110,525	122,046	59,229	95,909	1,534,795
MIDC_7_DOPDPGESHARE	41,069	172,144	196,624	84,944	89,284	69,602	39,165	44,580	60,056	139,083	61,975	40,053	1,038,579
PNP-RBP_2_PELRB	203,352	697,009	558,508	226,181	288,338	255,333	74,367	142,594	175,077	256,679	102,656	97,140	3,077,234
PWP1_2_PORTWEST1	(3,799)	(9,241)	196,323	65,628	(32,708)	10,186	(1,580)	1,428	(44,957)	(76,622)	(65,421)	46,353	85,589
PWP2_2_RECIP1-6	17,846	154,202	(123,941)	26,386	63,928	21,998	50,680	19,496	(21,555)	(21,580)	(27,456)	187,047	347,052
PWP2_2_RECIP7-12	22,866	148,741	(52,170)	47,933	46,284	117,730	67,675	38,031	(50,191)	(31,916)	(53,968)	116,351	417,367
Total	**$461,811**	**$1,354,350**	**$976,206**	**$605,768**	**$571,713**	**$634,001**	**-$5,686**	**$282,825**	**$111,360**	**$298,629**	**$237,466**	**$782,006**	$6,310,449

FMM Inc MWh

PositionName	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
BNP1_5_BOARDMAN	(2,943)	(2,873)	(8,488)	0	0	0	(10,641)	(10,470)	(18,878)	(848)	(6,716)	522	(61,335)
BRP1_2_BEAVER1-7	63	1,034	1,281	1,494	(3,395)	(4,637)	(16,856)	(6,002)	(15,522)	(9,439)	(4,399)	(11,541)	(67,919)
CSP1_5_COYOTE1	954	(8,141)	1,666	1,596	1,070	10,097	7,674	5,206	4,737	4,080	2,915	3,115	34,969
CYP1_5_CARTY1	(406)	(1,705)	(1,621)	6,088	260	11,432	4,289	2,597	(4,610)	(2,863)	(2,753)	(1,188)	9,520
MIDC_5_PGESHARE	(13,234)	(16,351)	(8,504)	722	3,007	(1,472)	(9,973)	(7,973)	(12,314)	(10,508)	(3,206)	(8,754)	(88,560)
MIDC_7_DOPDPGESHARE	(4,175)	(5,268)	(7,314)	(5,089)	2,705	(3,749)	(5,044)	(4,157)	(8,195)	(12,542)	(6,468)	(3,238)	(62,534)
PNP-RBP_2_PELRB	(30,795)	(38,363)	(30,441)	(8,181)	(17,045)	(11,521)	(18,322)	(14,015)	(16,632)	(18,361)	(15,783)	(12,969)	(232,428)
PWP1_2_PORTWEST1	2,307	(4,203)	(2,866)	9,858	0	12,339	4,756	4,596	(3,315)	(8,742)	(12,278)	(6,256)	(3,804)
PWP2_2_RECIP1-6	498	1,192	3,137	7,323	1,006	2,341	(679)	1,145	(6,189)	(6,542)	(10,477)	(15,337)	(22,582)
PWP2_2_RECIP7-12	1,033	(1,223)	1,666	3,595	1,466	5,497	1,295	1,287	(8,855)	(15,181)	(19,298)	(5,722)	(34,440)
Total	**(46,698)**	**(75,901)**	**(51,484)**	**17,406**	**(10,926)**	**20,327**	**(43,501)**	**(27,786)**	**(89,773)**	**(80,946)**	**(78,463)**	**(61,368)**	**(529,113)**

FMM EN Rev ($)

PositionName	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
BNP1_5_BOARDMAN	(65,073)	(146,372)	(227,981)	0	0	0	(263,811)	(218,828)	(450,778)	(15,814)	(159,977)	8,596	(1,540,038)
BRP1_2_BEAVER1-7	1,059	134,718	63,442	58,475	(74,145)	(160,206)	(561,160)	(198,090)	(462,107)	(331,912)	(116,155)	(471,007)	(2,117,088)
CSP1_5_COYOTE1	59,964	(361,836)	91,389	32,402	24,507	177,017	140,207	108,458	105,527	89,166	77,089	88,798	632,688
CYP1_5_CARTY1	347	125,822	44,064	134,696	9,162	175,126	51,221	50,515	(96,968)	(64,106)	(76,536)	(27,628)	325,715
MIDC_5_PGESHARE	(368,554)	(808,223)	(272,460)	5,015	50,108	(29,944)	(232,694)	(192,332)	(277,853)	(248,703)	(86,830)	(250,446)	(2,712,916)
MIDC_7_DOPDPGESHARE	(113,624)	(238,060)	(209,333)	(72,279)	57,148	(70,923)	(111,670)	(96,508)	(188,468)	(299,086)	(166,641)	(92,949)	(1,602,393)
PNP-RBP_2_PELRB	(831,894)	(2,028,725)	(884,059)	(83,267)	(240,281)	(286,061)	(431,530)	(349,205)	(412,009)	(330,942)	(425,606)	(309,991)	(6,613,570)
PWP1_2_PORTWEST1	70,656	(191,023)	33,728	241,589	(39)	196,676	81,303	91,848	(70,235)	(223,424)	(323,059)	(198,392)	(290,372)
PWP2_2_RECIP1-6	27,723	210,542	118,833	216,803	64,884	63,448	6,969	51,371	(136,559)	(169,609)	(320,806)	(444,389)	(310,790)
PWP2_2_RECIP7-12	47,700	41,711	55,168	119,365	70,147	211,895	60,727	67,625	(218,376)	(397,285)	(596,314)	(136,982)	(674,619)
Total	**($1,171,696)**	**($3,261,446)**	**($1,187,209)**	**$652,799**	**($38,509)**	**$277,028**	**($1,260,438)**	**($685,146)**	**($2,207,826)**	**($1,991,715)**	**($2,194,835)**	**($1,834,390)**	**($14,903,383)**

RTD Incr (MWh)

PositionName	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
BNP1_5_BOARDMAN	(1,257)	15	(373)	0	0	0	(964)	457	(317)	164	(206)	(402)	(2,883)
BRP1_2_BEAVER1-7	(126)	(449)	(767)	(379)	(500)	(364)	(1,434)	(52)	(1,062)	(401)	(582)	(347)	(6,463)
CSP1_5_COYOTE1	(3,132)	(4,184)	(5,306)	(520)	(681)	(1,288)	(596)	335	(470)	(1,501)	(1,453)	(801)	(19,597)
CYP1_5_CARTY1	1,688	66	(1,678)	(1,165)	(393)	(162)	(7,896)	(4,736)	(77)	218	3,240	(662)	(11,557)
MIDC_5_PGESHARE	(530)	(2,790)	(1,819)	(1,076)	(1,924)	(994)	(1,296)	(1,162)	(920)	(2,070)	(1,066)	(1,642)	(17,289)
MIDC_7_DOPDPGESHARE	(336)	(1,049)	(1,494)	(913)	(1,606)	(1,246)	(881)	(726)	(716)	(1,500)	(567)	(633)	(11,667)
PNP-RBP_2_PELRB	(2,293)	(3,323)	(3,358)	(3,004)	(4,078)	(1,037)	(2,636)	(2,832)	(1,404)	(4,176)	(2,957)	(2,907)	(34,005)
PWP1_2_PORTWEST1	901	523	(594)	427	25	163	428	(36)	(169)	(93)	(473)	(526)	576
PWP2_2_RECIP1-6	(108)	(1,180)	(872)	(838)	(718)	(769)	(607)	(436)	(721)	(1,015)	(855)	(1,322)	(9,441)
PWP2_2_RECIP7-12	(282)	(1,506)	(515)	(487)	(259)	(164)	(194)	(369)	(522)	(1,241)	(1,124)	(1,432)	(8,095)
Total	**(5,475)**	**(13,877)**	**(16,776)**	**(7,955)**	**(10,134)**	**(5,861)**	**(16,076)**	**(9,557)**	**(6,378)**	**(11,615)**	**(6,043)**	**(10,674)**	**(120,421)**

RTD EN Rev ($)

PositionName	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
BNP1_5_BOARDMAN	(26,279)	3,660	(6,529)	0	0	0	(22,729)	7,575	(5,741)	1,807	(1,269)	(5,982)	(55,487)
BRP1_2_BEAVER1-7	(2,575)	(54,791)	(43,764)	(3,189)	(23,462)	(10,222)	(29,227)	(201)	(32,974)	(6,515)	(19,161)	(643)	(226,724)
CSP1_5_COYOTE1	(65,155)	(161,465)	(82,096)	(5,897)	(5,865)	(30,315)	(3,491)	7,313	(3,500)	(24,277)	(25,183)	(11,841)	(411,772)
CYP1_5_CARTY1	47,335	6,285	(34,054)	901	(1,941)	(33,460)	(190,303)	(112,776)	952	8,582	85,826	(13,977)	(236,630)
MIDC_5_PGESHARE	2,151	(37,349)	4,727	28,586	19,938	16,580	(19,588)	(21,957)	(1,687)	(42,595)	(23,080)	(33,188)	(107,462)
MIDC_7_DOPDPGESHARE	(3,649)	(16,790)	46,321	59,475	17,026	17,963	(12,120)	(13,679)	(9,664)	(23,265)	178	(12,638)	49,158
PNP-RBP_2_PELRB	(21,403)	299	52,902	94,865	119,118	157,309	(46,219)	(53,943)	37,116	(44,519)	28,091	98,780	422,396
PWP1_2_PORTWEST1	27,466	26,071	19,862	4,886	(1,236)	730	13,699	(917)	(2,044)	1,754	(12,328)	(14,429)	63,514
PWP2_2_RECIP1-6	(1,024)	(57,250)	(32,826)	(32,909)	(7,224)	(11,304)	(10,037)	(16,215)	(15,507)	(36,644)	(27,853)	(38,380)	(287,173)
PWP2_2_RECIP7-12	(5,486)	(87,549)	(10,927)	6,652	2,535	(4,571)	(1,170)	(7,975)	(10,124)	(31,567)	(34,193)	(42,342)	(226,717)
Total	**($48,619)**	**($378,879)**	**($86,384)**	**$153,370**	**$118,889**	**$102,710**	**($321,185)**	**($212,775)**	**($43,173)**	**($197,239)**	**($28,972)**	**($74,640)**	**($1,016,897)**

UIE Incr (MWh)

PositionName	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
BNP1_5_BOARDMAN	903	2,520	848	0	22	0	283	(138)	4	708	451	435	6,036
BRP1_2_BEAVER1-7	78	106	(61)	131	211	(363)	1,796	650	(183)	107	230	693	3,395
CSP1_5_COYOTE1	(298)	(473)	(557)	(57)	73	(953)	(2,124)	(784)	(710)	(22)	(989)	(1,343)	(8,237)
CYP1_5_CARTY1	1,389	(761)	(738)	(239)	152	239	1,313	17	(536)	(406)	119	419	968
MIDC_5_PGESHARE	1,794	1,054	1,638	679	59	2,400	5,486	4,923	3,647	1,333	668	455	24,136
MIDC_7_DOPDPGESHARE	(139)	39	(246)	999	29	2,105	1,509	2,701	1,289	1,717	908	250	11,161
PNP-RBP_2_PELRB	206	(497)	548	126	885	948	385	1,959	1,272	2,995	2,420	3,494	14,741
PWP1_2_PORTWEST1	383	(169)	(117)	(333)	(269)	(471)	(2,157)	(2,444)	(1,609)	(565)	(510)	(2,198)	(10,459)
PWP2_2_RECIP1-6	(154)	(160)	113	(99)	(141)	(209)	(354)	(553)	(474)	(286)	(199)	(399)	(2,915)
PWP2_2_RECIP7-12	(60)	(211)	(190)	(161)	(324)	(421)	(435)	(777)	(550)	(517)	(334)	(659)	(4,639)
Total	**4,102**	**1,448**	**1,238**	**1,046**	**697**	**3,275**	**5,702**	**5,554**	**2,150**	**5,064**	**2,764**	**1,147**	**34,187**

RTD UIE Rev ($)

PositionName	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
BNP1_5_BOARDMAN	23,951	149,360	21,736	0	305	0	845	(5,931)	(2,039)	8,262	13,114	15,704	225,307
BRP1_2_BEAVER1-7	2,151	14,777	(6,799)	2,371	4,017	(11,427)	34,967	(1,992)	10,182	7,002	7,907	27,663	90,819
CSP1_5_COYOTE1	(10,233)	(35,075)	(19,606)	(4,055)	(1,784)	(23,024)	(51,400)	(16,585)	(22,532)	(4,105)	(30,276)	(44,280)	(262,955)
CYP1_5_CARTY1	37,953	(65,328)	(38,251)	(22,285)	3,034	(5,704)	21,564	(6,615)	(21,670)	(10,399)	4,765	10,175	(92,761)
MIDC_5_PGESHARE	45,635	40,943	48,946	6,480	(9,858)	42,031	121,034	112,564	96,126	36,470	15,864	6,409	562,644
MIDC_7_DOPDPGESHARE	(4,903)	427	(4,633)	(11,034)	(8,852)	46,395	32,730	63,415	36,481	50,142	22,687	7,554	230,409
PNP-RBP_2_PELRB	(1,731)	(59,856)	17,535	7,775	24,525	21,344	5,870	47,402	89,289	84,646	(640)	(17,684)	218,475
PWP1_2_PORTWEST1	(2,127)	(16,147)	(6,571)	(13,753)	(36,342)	(17,463)	(52,146)	(59,456)	(45,763)	(18,230)	(24,693)	(66,351)	(359,042)
PWP2_2_RECIP1-6	(3,026)	(9,169)	2,669	3,419	8,519	(9,510)	22,801	(12,822)	(12,074)	(5,128)	(2,587)	6,601	(10,307)
PWP2_2_RECIP7-12	(2,287)	(5,635)	(10,488)	(3,820)	(12,879)	(15,226)	20,685	(19,054)	(13,381)	(12,988)	(6,289)	(8,094)	(89,456)
Total	**$85,383**	**$14,297**	**$4,538**	**($34,902)**	**($29,315)**	**$27,416**	**$156,950**	**$100,926**	**$114,619**	**$135,672**	**($148)**	**($62,303)**	**$513,133**

June 22, 2020

TO: Jesse O. Gorsuch
Alliance of Western Energy Consumers

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to AWEC Data Request No. 027
Dated June 8, 2020

Request:

Please refer to #FINAL_Hydro Limit Summary.xlsx, sheet Hydro_Pivo, columns G and H.

a. Do these values represent the hourly limit for hydro resource EIM dispatches in PGE's EIM benefit model? If no, what are these values used for in the EIM benefit model?

b. Please explain why PGE believes these values represent the appropriate hourly limit for limit for hydro resource EIM dispatches in PGE's EIM benefit model.

c. Please explain why the average increment and decrement amounts are calculated using the total number of hours within each month, rather than the total number of hours in the month with increments and the total number of hours within each month with decrements.

Response:

a. No, not predominantly. The purchase (i.e., "Dec") limits are predominantly transactional volumes where PGE is using its base schedule and bids to purchase energy from the EIM during the hour (instead of the real-time market prior to the balancing hour). That is, Dec limits are effectively capturing trading activity PGE implements without impacting PGE's intended hydro dispatch. With respect to sales (i.e., "Inc") limits, it is more often the case that a hydro dispatch would support the sale. Therefore, the Inc limit will effectively represent EIM dispatches. In part b of this response, PGE explains why "EIM dispatch" is a small part of the hourly limit.

b. PGE discussed its method for attaining value from hydro resources in its technical workshop presentation on June 5, 2020. The presentation materials are included in PGE's Response to AWEC Data Request No. 32. Slide 9 of the presentation provides an example of using hydro base schedules and bids as a method to purchase energy in the EIM. In the example, the predominant benefit driver is CAISO "re-scheduling" the resource from 125 MW to 25 MW in the fifteen-minute market. This "re-scheduling" is effectively transactional purchase volume that PGE is implementing through EIM scheduling and bidding. PGE has identified a need to purchase energy and is electing to purchase the energy via the EIM during the hour instead of through the bilateral real-time market prior to the hour. In other words, PGE's intended dispatch (i.e., desired operating level) for the hydro resource based on its resource planning and optimization prior to the operating hour was 25 MW. Instead of purchasing 100 MW bilaterally prior to the trading hour, the real-time trader elected to purchase the energy via the EIM through their use of the hydro base schedule and accompanying bids.

Because the predominant EIM benefit driver associated with hydro is the base schedule as a trading tool, not EIM dispatch, the limits are the appropriate limits for assessing the value hydro resources provide via EIM. If PGE limited the hydro volumes to dispatches (i.e., deviations from the planned operating level prior to the operating hour communicated via base schedules and bids), the hydro limits, particularly for purchase volume, would be much smaller. PGE also notes that under the current method, MONET hydro energy generation does not recalibrate each hour based on EIM dispatches. Therefore, there is likely a small increase in power costs not accounted for in the current MONET / EIM benefit construct. However, since hydro sales that result from EIM dispatch are less frequent and lower in magnitude, PGE believes the simplification is reasonable as part of its effort to more closely align NVPC forecasts resulting from MONET and EIM assumptions.

c. As is the case with many MONET inputs and the AUT/PCAM construct, PGE seeks to establish a NVPC forecast based on a set of conditions and assumptions that does not overweight real-world conditions that deviate from the MONET/AUT construct of 'normal' operating conditions.

With respect to the increment and decrement amounts, PGE elected to use the total number of hours within each month in order to estimate the reasonable level of transactional volume that PGE could execute under normal market conditions, and the total number of hours is one approach for smoothing out the impacts from hours that had non-normal market conditions.

As the question in part c. suggests, there are other approaches. PGE notes that if only the total number of hours in the month with increments (or decrements) is used, the value may be more susceptible to events in historical data that do not represent 'normal' operating conditions. For example, included in PGE's Q1 2019 operating data are the market impacts from the Enbridge gas pipeline explosion as well as unexpected cold weather and below normal hydro during February 2019 that caused Mid-C prices to clear considerably above expectations in the AUT forecast. This was a time period where PGE's hydro trading methods in the EIM were used extensively in 'non-normal' conditions, because it could purchase more economically in the EIM (relative to the real-time bilateral market). In other words, PGE had a higher decremental ("Dec") volume than PGE would expect under normal market conditions. If PGE established the decrement average using only decrement hours during the 'non-normal' conditions, it would likely over-predict usage in future years.

Table 1 compares the hydro decrement limit in PGE's initial filing to the method identified by AWEC in part c. of this response. If the 2019 data was used to predict hydro decrement volumes in 2020, AWEC's method would have over-predicted decremental trading (based only on the averages of hours when decremental trading occurred) in every month. PGE's method would have more closely aligned with the 2020 results based on the alternative method identified in part c. Employing the approach identified by AWEC in part c of DR 027 would likely require the use of multiple years of data or an identification and removal of outlier data impacting both incremental and decremental limits in order to more reasonably represent 'normal' market conditions.

Finally, PGE notes that while its use of all hours in a month places downward pressure on the average, PGE also places upward pressure on the average through its use of 5-minute data instead of a net hourly value. For example, if a hydro resource decreased 5 MW from its base schedule during the first 5-minute interval and increased 5 MW from its base schedule during the second 5-minute interval, PGE's method includes the 5MW in its hydro limit calculation for both "Inc" and "Dec" directions, where the hourly aggregated value would have shown 0 MW in the limits calculation. The 0 MW result from a net hourly value is more closely aligned with the bi-lateral trading timeline where decisions to buy or sell are for a forward hour, not a 5-minute to 5-minute basis. Attachment 027-A provides the analysis that informs the hydro decrease limits reflected in the table below.

Table 1 - Hydro Decrease Limit			
	2019	**2019**	**2020**
	PGE Initial Filing	AWEC DR 27 Method	AWEC DR 27 Method
Jan	87.31 MW	133.64 MW	104.12 MW
Feb	119.51 MW	166.36 MW	110.08 MW
Mar	91.90 MW	143.83 MW	114.84 MW

Attachment 027-A is protected information subject to Protective Order No. 20-100.

June 23, 2020

TO: Jesse O. Gorsuch
Alliance of Western Energy Consumers

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to AWEC Data Request No. 034
Dated June 9, 2020

Request:

Please refer to MFRs (confidential)\Vol 3 - Thermal\Thermal Forced Outage\Carty\Data 2019. Please provide this data for 2016, 2017, and 2020.

a. Please clarify what infant mortality is.

b. Does PGE expect Carty to continue experiencing infant mortality issues in 2021 operations? If no, why is the value in the referenced file included in the 2021 AUT forecast?

c. Please refer to Docket No. UE 1355 PGE/100 Hager - Tinker/14 at lines 4 to 7. Please provide all materials from each of the referenced sources regarding Carty or similar unit outage rates.

Response:

Confidential Attachment 034-A provides Carty availability reports for 2016, 2017, and January to May of 2020.

a. "Infant mortality" is a slang term used in the industry to describe the premature failure of equipment and parts. This occurs when a series of new parts and equipment are simultaneously installed in a new plant during construction, and a certain percentage of them fail at a faster rate than planned. Often during the first few years of operation, there are some parts and equipment that will fail faster than the normal population of parts, typically due to manufacturing faults. After the initial 3 to 5 years, plants are often thought to have passed through the "infant mortality" of parts period, and then proceed into a period of normal forced outage rates for similarly designed plants with similar ages of equipment.

b. In July 2021 Carty will have been operational for 5 years and will be out of the "infant mortality" period. The value is referenced in the supporting data for 2021 modeling because the Carty forced outage rate forecast uses 2016 and 2017 initial forced outage rate estimates that include the infant mortality assumption.

c. The UM 1355 citation referenced by AWEC is specific to PGE's Port Westward plant. PGE does not have similar materials related to Carty. As noted in UM 1355 PGE/100 Hager-Tinker/14, lines 15-16, the methodology applied to develop an estimate forced outage rate for the first years of Port Westward operations is not necessarily applied to all new gas facilities.

   As noted in the MFRs, to develop the forced outage rate estimate for MONET modeling when Carty was added to PGE's resource portfolio in the 2016 general rate case, PGE relied on discussions with PGE's Generation Projects and also reviewed NERC data for similarly sized Combined Cycle Combustion Turbine gas plants that were built recently. Please see these supporting materials in PGE's April 15 MFRs, Vol 3 - Thermal\Thermal Forced Outage\Carty.

Attachment 034-A is protected information subject to Protective Order No. 20-100.

UE 377

Attachment 033-A

Provided in Electronic Format

Protected Information Subject to Protective Order 20-100

Carty Availability Reports
2016, 2017, and January-May 2020

Page 18 of Exhibit AWEC/102 contains Protected Information Subject to Order No. 20-100 and has been redacted in its entirety.

June 23, 2020

TO: Jesse O. Gorsuch
Alliance of Western Energy Consumers

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to AWEC Data Request No. 036
Dated June 9, 2020

Request:

Please refer to WUTC Docket No. UE-190882 - Final Order 05. If the response to DR 35 is no, please provide the following:

a. The tests and communications related to the tests referenced in Par. 28, 33, 36, as well as any other tests performed by Talen related to MATS PM.
b. Agenda, notes, presentations and all other data and documents related to the meetings referenced in Par. 29.
c. All communications referenced in Par. 30, 32, 34,
d. The root cause analysis and all related documents and communications identified in Par. 37.
e. The O&O committee meeting minutes, attendee list, presentations, handouts, and all other materials related to Colstrip Owner and Operator committee meetings in 2018.
f. All communication between PGE and Talen related to Colstrip MATS compliance in 2018.
g. All actions taken by PGE in 2018 related to Colstrip MATS compliance and oversight of Talen.

Response:

PGE objects to this request on the basis that it is overly broad and unduly burdensome. Subject to and without waiving its objection PGE responds as follows:

Pursuant to a telephone and email communication, AWEC modified the data request to ask the following:

a. Confirm that Q1 2018 PM MATS testing for Colstrip showed a site-wide emissions rate of 0.030 lb/MMBtu. Also confirm that this represents the limit for the site. If PGE does not confirm these statements, please explain and provide all relevant documentation.

b. Provide agenda, meeting minutes, presentations related to MATS PM testing, and any PGE notes related to MATS PM testing from the February 21, March 21, April 15, May 16, and June 20 committee meetings.

c. AWEC withdrew this part.

d. The root cause analysis and all related documents and communications identified in Par. 37.

e. AWEC withdrew this part.

f. Referring to paragraph 30 of WUTC Final Order 05, does PGE agree that the statements in this paragraph are accurate? If not, please explain what PGE believes is inaccurate and provide supporting documentation. If yes, please provide any communications PGE made to Talen in response to Talen's communications that it expected Colstrip to pass its Q2 MATS PM testing.

PGE responds as follows:

a. PGE confirms that the 0.030 lb/MMBtu emission rate is the emissions limit for the Colstrip site. Attachment 036-A provides the Colstrip 2018 MATS 1st Semi-Annual Report. The Q1 2018 PM MATS testing results for all Colstrip Units are provided in Appendix D, starting on page 11. As reflected in Appendix D of the report, the Q1 2018 PM MATS testing resulted in an emission rate range from 0.021lb/MMBtu to 0.035 lb/MMBtu for Colstrip Units 1 through 4. Given the emission rates reported for each unit, the site-wide average emission rate for the Q1 2018 PM MATS testing appears to have been at 0.029 lb/MMBtu.

b. Attachment 036-B provides meeting agendas and PGE notes from 2018 Colstrip owners meetings. Due to personnel retirement and turn-over, PGE was not able to locate the notes for the February 21, 2018 Colstrip owners meeting. Should PGE locate the February 21, 2018 notes, we will supplement the response to this data request and provide them as soon as possible.

c. N/A

d. Attachment 036-C provides the root cause analysis report. Please see PGE's response to AWEC Data Request No. 035, Attachment 035-A, which provides PGE's request that the plant operator and co-owners have an independent third-party facilitation of the Root Cause Analysis.

e. N/A

f. AWEC refers to the following paragraph in WUTC Docket No. UE-190882, Final Order 05:

"*At times from February 14, 2018, to June 27, 2018, including at the O&O Committee Meetings between February 21 and June 20, 2018, Talen communicated to the Companies its expectation and recurring recommendation that Colstrip would pass its second quarterly (Q2) MATS PM Testing. This expectation was based upon observations of the CAM Plan's alternative and indicators and their historic correlation with PM emissions levels.*"

PGE cannot confirm the statements in the paragraph are accurate. PGE's notes from the Colstrip Units 3 and 4 owners meetings that took place between January and May, 2018 do not show any discussions that would confirm the statement. However, as noted above in part b, due to personnel retirement and turn-over PGE was not able to locate communications that would include PGE's notes from the February 21, 2018 owners meeting. According to PGE's notes provided in Attachment 036-B, the MATS testing was first discussed during the meeting that took place on June 20, 2018. During that meeting PGE requested that the plant operator ensure the accuracy of the testing and raised the coal quality issue.

Attachments 036-A through 036-C are protected information subject to Protective Order No. 20-100.

UE 377

Attachment 036-B

Provided in Electronic Format

Protected Information Subject to Protective Order 20-100

2018 Colstrip Owners Meeting Notes

Pages 23-48 of Exhibit AWEC/102 contain Protected Information Subject to Order No. 20-100 and have been redacted in their entirety.

May 28, 2020

TO: Sabrinna Soldavini
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to OPUC Data Request No. 004
Dated May 14, 2020

Request:

Please refer to PGE/100, Seulean – Kim – Batzler/22, which state "MONET does not assume any availability of non-firm delivered gas from December to February."

a. Does PGE confirm this assumption matches with actual operations? That is, historically, has non-firm gas been delivered to the PW/Beaver complex in December through February?

b. Please provide the amount of non-firm gas delivered to the PW/Beaver complex, by month in the years 2017, 2018, and 2019.

Response:

a. Yes, PGE's assumption matches with actual operations. PGE does not assume non-firm delivered gas is available to supply at the PW/Beaver complex from December to February because historically PGE had very limited purchases of non-firm delivered gas in that period .

b. Attachment 004-A provides the requested information. As reflected in Attachment 004-A, the non-firm gas purchased in the period December to February for the years 2017 to 2019 is only approximately 1.8% of total non-firm gas delivered at the PW/Beaver complex from January 1, 2017 to December 31, 2019.

Attachment 004-A is protected information subject to Protective Order No. 20-100.